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Indiana Utility Regulatory Commission

2011 INTEGRATED RESOURCE PLAN

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

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11. ACTION PLAN

IRP Rule 7 Requirements Cross Reference Table

Rule Reference	Rule 7 Description	Report Reference (As Page # or Attachment)
170-IAC 4-7-4	Methodology and documentation requirements - Sec. 4. An IRP covering at least a twenty (20) year future period prepared by a utility must include a discussion of the methods, models, data, assumptions, and definitions used in developing the IRP and the goals and objectives of the plan. The following information must be included:	
4-7-4 (1)	(1) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be presented in the form of a reference. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media and hard copy, or as specified by the commission.	Specific data may be available upon request
4-7-4 (2) A-E	(2) A description of the utility's effort to develop and maintain, by customer class, rate class, SIC code, and end-use, a data base of electricity consumption patterns. The data base may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	63, 74-77
4-7-4 (3)	(3) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	77-78
4-7-4 (4)	(4) A discussion of customer self-generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	94
4-7-4 (5)	(5) A description of model structure and an evaluation of model performance.	66-74
4-7-4 (6)	(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	172-186
4-7-4 (7)	(7) A description of the fuel inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	168
4-7-4 (8)	(8) A description of the SO2 emission allowance inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	43-48

4-7-4 (9)	(9) A description of the generation expansion planning criteria used in developing the integrated resource plan. The description must fully explain the basis for the criteria selected, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP.	161
4-7-4 (10) A-F	(10) A regional, or at a minimum, Indiana specific power flow study prepared by a regional or subregional organization. This requirement may be met by submitting Federal Energy Regulatory Commission (FERC) Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. The power flow study shall include the following: (A) Solved real flows. (B) Solved reactive flows. (C) Voltages. (D) Detailed assumptions. (E) Brief description of the model(s). (F) Glossary of terms with cross references to the names of buses and line terminals.	150
4-7-4 (10) (G) i-iii	(G) Sensitivity analysis, including, but not limited to, the forecast of the following: (i) Summer and winter peak conditions. (ii) Light load as well as heavy transfer conditions for one (1), two (2), five (5), and ten (10) years out. (iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency.	150
4-7-4 (11)	(11) Any recent dynamic stability study prepared for the utility or by the utility. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	150
4-7-4 (12)	(12) Applicable transmission maps. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	151, Appendix
4-7-4 (13)	(13) A description of reliability criteria for transmission planning as well as the assessment practice used. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	151-152
4-7-4 (14)	(14) An evaluation of the reliability criteria in relation to present performance and the expected performance of the utility's transmission system. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	152-153
4-7-4 (15)	(15) A description of the utility's effort to develop and improve the methodology and the data for evaluating a resource (supply-side or demand-side) option's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including transmission, distribution, and generation.	151
4-7-4 (16)	(16) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	187

4-7-4 (17)	(17) The hourly system lambda and the actual demand for all hours of the most recent historical year available. For purposes of comparison, a utility must maintain three (3) years of hourly data and the corresponding dispatch logs.	Not Applicable
4-7-4 (18)	(18) A description of the utility's public participation procedure if the utility conducts a procedure prior to the submission of an IRP to the commission.	Not Applicable
170-IAC 4-7-5	Energy and demand forecasts - Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	
4-7-5 (a) (1)	(1) An historical and projected analysis of a variety of load shapes, including, but not limited to, the following:	75-77, Appendix
4-7-5 (a) (1) (A)	(A) Annual load shapes.	76, Appendix
4-7-5 (a) (1) (B)	(B) Seasonal load shapes.	Appendix
4-7-5 (a) (1) (C)	(C) Monthly load shapes.	Appendix
4-7-5 (a) (1) (D)	(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	76-77, Appendix
4-7-5 (a) (2)	(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	75-77, Appendix
4-7-5 (a) (3)	(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	75-77, Appendix
4-7-5 (a) (4)	(4) The use and reporting of actual and weather normalized energy and demand levels.	58-60, 63-74
4-7-5 (a) (5)	(5) A discussion of all methods and processes used to normalize for weather.	63-64, 66-74
4-7-5 (a) (6)	(6) A twenty (20) year period for energy and demand forecasts.	59
4-7-5 (a) (7)	(7)An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:	78-81
4-7-5 (a) (7) (A)	(A) Total system.	79
4-7-5 (a) (7) (B)	(B) Customer classes or rate classes, or both.	80-81
4-7-5 (a) (7) (C)	(C) Firm wholesale power sales.	81
4-7-5 (a) (8)	(8) If an end-use methodology has not been used in forecasting, an explanation as to why this methodology has not been used.	57-58, 67
4-7-5 (a) (9) (A)	(9) For purposes of section 5(a)(1) and 5(a)(2) *[subdivisions (1) and (2)]*, a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(2) of this rule.	
4-7-5 (b) (9) 1-7	(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on combinations of alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Changes in technology. (5) Behavioral factors affecting customer consumption. (6) State and federal energy policies. (7) State and federal environmental policies.	58-62

170-IAC 4-7-6	Resource assessment - Sec. 6. (a) For each year of the planning period, excluding subsection 6(a)(6) *[subdivision (6)]*, recognizing the potential effects of self-generation, an electric utility shall provide a description of the utility's electric power resources that must including:	
4-7-6 (a) (1)	(1) The net dependable generating capacity of the system and each generating unit.	166-167
4-7-6 (a) (2) A-E	(2) The expected changes to existing generating capacity, including, but not limited to, the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	166-167
4-7-6 (a) (3) (A)	(3) A fuel price forecast by generating unit.	167-168
4-7-6 (a) (4)	(4) The significant environmental effects, including:	
4-7-6 (a) (4) (A)	(A) air emissions;	43-44
4-7-6 (a) (4) (B)	(B) solid waste disposal;	52-54
4-7-6 (a) (4) (C)	(C) hazardous waste; and	43-54
4-7-6 (a) (4) (D)	(D) subsequent disposal; at each existing fossil fueled generating unit.	43-54
4-7-6 (a) (5)	(5) The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility.	92-93
4-7-6 (a) (6)	(6) An analysis of the existing utility transmission system that includes the following:	
4-7-6 (a) (6) (A)	(A) An evaluation of the adequacy to support load growth and long term power purchases and sales.	154-155
4-7-6 (a) (6) (B)	(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses.	155
4-7-6 (a) (6) (C)	(C) An evaluation of the potential impact of demand-side resources on the transmission network.	154
4-7-6 (a) (6) (D)	(D) An assessment of the transmission component of avoided cost.	155
4-7-6 (a) (7) (A)	(7) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	105-147
4-7-6 (b)	(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's plan shall, at a minimum, include the following:	
4-7-6 (b) (1)	(1) A description of the demand-side program considered.	123-124
4-7-6 (b) (2)	(2) A detailed account of utility strategies designed to capture lost opportunities.	116
4-7-6 (b) (3)	(3) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	122
4-7-6 (b) (4)	(4) The customer class or end-use, or both, affected by the program.	126-146
4-7-6 (b) (5)	(5) A participant bill reduction projection and participation incentive to be provided in the program.	126-146

4-7-6 (b) (6)	(6) A projection of the program cost to be borne by the participant.	126-146
4-7-6 (b) (7)	(7) Estimated energy (kWh) and demand (kW) savings per participant for each program.	126-146
4-7-6 (b) (8)	(8) The estimated program penetration rate and the basis of the estimate.	126-146
4-7-6 (b) (9)	(9) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	126-146
4-7-6 (c) 1-4	(c) A utility shall consider supply-side resources as an alternative in meeting future electric service requirements. The utility's plan shall include, at a minimum, the following: (1) Identify and describe the resource considered, including the following: (A) Size (MW). (B) Utilized technology and fuel type. (C) Additional transmission facilities necessitated by the resource. (2) Significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (3) An analysis of how a proposed generation facility conforms with the utility-wide plan to comply with the Clean Air Act Amendments of 1990. (4) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Not Applicable
4-7-6 (d) 1-4	(d) A utility shall identify transmission and distribution facilities required to meet, in an economical and reliable manner, future electric service requirements. The plan shall, at a minimum, include the following: (1) An analysis of transmission network capability to reliably support the loads and resources placed upon the network. (2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities. (3) A description of the timing and types of expansion and alternative options considered. (4) The approximate cost of expected expansion and alteration of the transmission network.	151-152, 155-157
170-IAC 4-7-7 4-7-7 (a)	Selection of future resources - Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through (c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported.	85-87
4-7-7 (b) 1-5	(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e): (1) Participant. (2) Ratepayer impact measure (RIM). (3) Utility cost (UC). 4) Total resource cost (TRC). (5) Other reasonable tests accepted by the commission.	119-125
4-7-7 (c)	(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	119-122, 125
4-7-7 (d)	(d) A utility is required to:	
4-7-7 (d) (1)	(1) Specify the components of the benefit and the cost for each of the major tests; and	119-122
4-7-7 (d) (2)	(2) Identify the equation used to express the result.	119-122

4-7-7 (e)	(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	
4-7-7 (f)	(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	119-125
170-IAC 4-7-8	Resource integration - Sec. 8. A utility shall select a mix of resources consistent with the objectives of the integrated resource plan. The utility must provide the commission, at a minimum, the following information:	
4-7-8 (1)	(1) Describe the utility's resource plan.	15-22
4-7-8 (2)	(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the least-cost mix of resources.	160-161
4-7-8 (3)	(3) Determine the present value revenue requirement of the utility's resource plan, stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	173
4-7-8 (4)	(4) Demonstrate that the utility's resource plan utilizes, to the extent practical, all economical load management, conservation, nonconventional technology relying on renewable resources, cogeneration, and energy efficiency improvements as sources of new supply.	84-96
4-7-8 (5)	(5) Discuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations.	43-54
4-7-8 (6)	(6) Demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan.	84-102, 161
4-7-8 (7)	(7) Discuss the utility's evaluation of dispersed generation and targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	95-96
4-7-8 (8)	(8) Discuss the financial impact on the utility of acquiring future resources identified in the utility's resource plan. The discussion shall include, where appropriate, the following:	
4-7-8 (8) (A)	(A) The operating and capital costs of the integrated resource plan.	160-173
4-7-8 (8) (B)	(B) The average price per kilowatt-hour as calculated in the resource plan. The price must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	Not Applicable
4-7-8 (8) (C)	(C) An estimate of the utility's avoided cost for each year of the plan.	188
4-7-8 (8) (D)	(D) The impact of a planned addition to supply-side or demand-side resources on the utility's rate.	Not Applicable
4-7-8 (8) (E)	(E) The utility's ability to finance the acquisition of a required new resource.	Not Applicable
4-7-8 (9)	(9) Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP.	31-40, 43-54, 105-147
4-7-8 (10) A-C	(10) Demonstrate, to the extent practicable and reasonable, that the utility's resource plan incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances and preserves the plan's ability to achieve its intended purpose. Unexpected changes include, but are not limited to the following: (A) The demand for electric service. (B) The cost of a new supply-side or demand-side technology. (C) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	172-186

170-IAC 4-7-9 1-5	Short-term action plan - Sec. 9. A short term action plan shall be prepared as part of the utility's IRP filing or separately, and shall cover each of the two (2) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the resource options or programs contained in the utility's current integrated resource plan where the utility must take action or incur expenses during the two (2) year period. The short-term action plan must include, but is not limited to, the following: (1) A description of each resource option or program included in the short term action plan. The description must include, but is not limited to, the following: (A) The objective of the resource option or program. (B) The criteria for measuring progress toward the objective. (C) The actual progress toward the objective to date. (2) The participation of small business in the implementation of a DSM resource option or program. (3) The implementation schedule for the resource option or program. (4) The timetable for implementation and resource acquisition. (5) A detailed budget for the cost to be incurred for each resource or program.	191-193

List of Acronyms/Abbreviations

AC	Air Conditioning
ACESA	American Clean Energy and Security Act of 2009
ADSP	Aero Derivative Steam Path
AMI	Advanced Metering Infrastructure
ARR	Auction Revenue Rights
ARRA	American Recovery and Reinvestment Act
ASHRAE	American Society of Heating, Refrigeration, and Air-Conditioning Engineers
ASPEN-OneLiner	Advanced Systems for Power Engineering, Incorporated
AUPC	Average Use Per Customer
BAGS	Broadway Avenue Gas Turbines
BCR	Benefit-cost Ratio
BPM	MISO's Business Practice Manual
CAA	Clean Air Act
CAC	Citizens Action Coalition
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAP	Community Action Partnership
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CEII	Critical Electric Infrastructure Information
CERES	Combined Energy Efficiency and Renewable Electricity Standard
CFB	Circulating Fluidized Bed
CFC	Chlorofluorocarbons
CFL	Compact Fluorescent Lighting
CO_2	Carbon Dioxide
CPI	Consumer Price Index
CPP	Critical Peak Pricing
CSAPR	Cross-State Air Pollution Rule
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DA	Distribution Automation
DGS	Demand General Service
DLC	Direct Load Control
DMS	Distribution Management System
DOE	United States Department of Energy
DR	Demand Response
DSM	Demand-side Management
DSMCC	Demand Side Management Coordination Committee
EA	Emission Allowances
EAP	Energy Assistance Program
ECAR	East Central Area Reliability Coordination Agreement
ECC	Economic Carrying Charge
ECM	Electronically Commutated Motor
EDR	Emergency Demand Response
EGU	Electric generating units
EIA	Energy Information Administration
EMS	Enterprise Management System
EMT	Energy Market Tariff
EM&V	Evaluated, Measured, & Verified
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
EVA	Energy Ventures Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FTR	Financial Transmission Rights
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	Greenhouse Gas

List of Acronyms/Abbreviations (continued)

GS	General Service
GWH	Gigawatt hour
HAN	Home Area Network
HAP	Hazardous Air Pollutants
HCFC	Hydro Chlorofluorocarbons
HDD	Heating Degree Days
HFC	Hydro Fluorocarbons
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
HWAP	Home Weatherization Assistance Program
ICAP	Interconnection Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
INCAA	Indiana Community Action Association
IPP	Independent Power Producers
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IVVC	Integrated Volt-VAR Control Strategy
LDC	Local Distribution Company
LMR	Load Management Receivers
LOLE	Loss of Load Expectation
LP	Low Pressure
LSE	Load Serving Entity
MACT	Maximum Achievable Control Technology Standards
MAPE	Mean absolute percentage error
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midwest Independent System Operator
MMBTU	One million British Thermal Unit
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hour
NAICS	North American Industry Classification System
NDC	Net Dependable Capacity
NEF	National Energy Foundation
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrous Oxide
O&M	Operation and Maintenance
OH	Overhead
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PC	Pulverized Coal
PCCI	Power Capital Cost Index
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
$PM_{2.5}$	Particulate Matter
PRC	Planning Reserve Credit
PRM	Planning Reserve Margin
PSD	Prevention of Significant Deterioration
PTI-PSS/E	Power Technologies Incorporated's Power System Simulator Program for Engineers
PVRR	Present Value of Revenue Requirements
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RECEB	Regional Expansion Criteria and Benefits
RFC	Reliability First Corporation
RFP	Request for Proposal
RIM	Ratepayer Impact Measure

List of Acronyms/Abbreviations (continued)

ROW	Right of Way
RPS	Renewable Portfolio Standard
SAE	Statistically Adjusted End-use
SCADA	Supervisory Control and Data Acquisition
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SGIG	Smart Grid Investment Grant
SGS	Small General Service
SIP	System Integration Plan
SO_2	Sulfur Dioxide
TA	Transmission Automation
TOU	Time of Use
TPA	Third Party Administrator
TPY	Tons Per Year
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity Rating
UG	Underground
VCA	Voluntary Capacity Auction
VCEPS	Voluntary Clean Energy Portfolio Standard
VUHI	Vectren Utility Holdings Inc.

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CHAPTER 1

EXECUTIVE SUMMARY

COMPANY BACKGROUND

Vectren Corporation is an energy holding company headquartered in Evansville, Indiana. Vectren's wholly owned subsidiary Vectren Utility Holdings, Inc. (VUHI) is the parent company for three operating utilities: Indiana Gas Company, Inc. (Vectren North), Southern Indiana Gas and Electric Company (Vectren South), and Vectren Energy Delivery of Ohio (VEDO).

Vectren North provides energy delivery services to more than 560,000 natural gas customers located in central and southern Indiana. Vectren South provides energy delivery services to over 140,000 electric customers and approximately 110,000 gas customers located in southwestern Indiana. VEDO provides energy delivery services to approximately 315,000 natural gas customers in west central Ohio.

Vectren South's company-owned generation fleet represents 1,285 megawatts (MW)[1] of summer capacity as shown in Table 1-1.

Table 1-1 Generating Units

Unit	Summer Capability (MW)	Primary fuel	Commercial Date
AB Brown 1	245 MW	Coal	1979
AB Brown 2	245 MW	Coal	1986
AB Brown 3	75 MW	Gas	1991
AB Brown 4	75 MW	Gas	2002
FB Culley 2	90 MW	Coal	1966
FB Culley 3	270 MW	Coal	1973
Warrick 4	150 MW	Coal	1970
BAGS 1	50 MW	Gas	1971
BAGS 2	65 MW	Gas	1981
Northeast 1	10 MW	Gas	1963
Northeast 2	10 MW	Gas	1964
Blackfoot	3 MW	Landfill Gas	2009

[1] Blackfoot landfill gas project is considered behind-the-meter and is therefore currently accounted for as a reduction to load and is omitted from the capacity total

In addition to company owned generating resources, Vectren has access to an additional 30 MW of capacity as a result of its ownership interest in Ohio Valley Electric Corporation (OVEC). Vectren has also purchased 100 MW of firm peaking capacity for the three years 2010 through 2012. Vectren is also contracted to receive 80 MW of nominal capacity wind energy through two separate long-term purchased power agreements. The total firm capacity credit for the MISO 2011-2012 planning year for these wind resources is 6.2 MW. Vectren is interconnected with other utilities at both 345 kV and 138 kV and is able to exchange capacity and energy through the market mechanisms of the Midwest Independent System Operator (MISO).

THE IRP PROCESS

The Integrated Resource Plan (IRP) process was developed to assure a systematic and comprehensive planning process that produces a reliable, efficient approach to securing future resources to meet the energy needs of the utility and its customers. The IRP process encompasses an assessment of a range of feasible supply-side and demand-side alternatives to establish a diverse portfolio of options to effectively meet future generation needs. In Indiana, the IRP is also guided by rules of the Indiana Utility Regulatory Commission (IURC). Those rules, found in the Indiana Administrative Code at 170 I.A.C. 4-7-4 through 4-7-9, provide specific guidelines for plan contents and filing with the Commission.

Details of the highly methodical process utilized by Southern Indiana Gas and Electric Company, d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren) to develop the recommended plan in this IRP are found in Chapters 2 through 10 of this report. Chapter 11 sets forth the action plan for Vectren over the next several years to achieve the long-term resource objectives described in this IRP.

Included in the process is an updated demand and energy forecast (detailed in Chapter 5 Sales and Demand Forecast). Table 1–2, shows a summary of the demand and energy forecast.

VECTREN'S QUANTITATIVE AND QUALITATIVE IRP PROCESS

Historically, as in the case of all prior IRPs filed by Vectren since 1983, Vectren has used modeling to perform the evaluations, screenings, and assessments of various potential scenarios to arrive at a single plan that represented its "Resource Plan Additions." Vectren continues to use the Strategist modeling software from Ventyx (formerly New Energy Associates) as it has in its last several IRP studies. This software is also used by some of the other Indiana utilities. The submitted plan was the result of a process that was primarily a quantitative evaluation performed using an industry standard computerized planning model.

Vectren has performed traditional modeling as part of this IRP process. However, Vectren also believes that a few industry trends that are difficult to quantify must also be considered before a final plan is recommended. Such changes have resulted principally from:

1. the increased emphasis on conservation and energy efficiency; and
2. the possibility of passage of greenhouse gas (GHG) legislation/ regulation which will increase the cost of fossil fuel-fired generation, as well as other environmental uncertainties.

These real world risks and uncertainties cannot be adequately captured in a computer model and must be addressed by Vectren management as part of the decision making process. In the case of Vectren, one of the smallest investor-owned electric utilities in the nation, the ramifications of major capacity decisions are particularly important.

Equally important, Vectren believes one of the major objectives of the Commission's reporting and filing requirements regarding the IRP process is to communicate with the IURC regarding the decision processes, evaluations, and judgments that Vectren uses to assist in making the resource planning decisions that are in the long-term best interest of our customers and the communities we serve. Vectren understands that the Integrated Resource Plan, which results from the IRP process, is to be used as a guide by the Company and the IURC in addressing long-term resource needs, as we both attempt to carry out our respective responsibilities in the most effective manner possible.

CHANGES SINCE LAST IRP

In 2009 and 2010 the industry saw multiple attempts to pass climate change legislation in Congress. These various House and Senate bills failed to pass, and with the current state of the economy and a presidential election approaching, the Company does not currently foresee that Congress will take up any new attempts to regulate greenhouse gases from utility boilers for at least two more years. However, the Environmental Protection Agency (EPA) continues to expand its regulation of greenhouse gases from large stationary sources such as coal-fired utility boilers. Given the uncertainty surrounding this issue, Vectren has decided not to include the potential impacts of greenhouse gas legislation/regulation in our base case forecast. Alternatively, we have modeled the potential impact of carbon legislation/regulation in Chapter 4 Environmental and in the Sensitivity and the Risk Analysis section of Chapter 10 Electric Integration Analysis.

Utilities are facing many challenges in the environmental arena. Vectren has made significant investment in environmental compliance, from its $410 million in recent air emissions control investments to its $20 million investment in ash handling and loading, which enables Vectren to beneficially reuse 100% of its fly ash. While Vectren's previous investments in pollution control equipment position it to comply with the myriad of new federal air regulations aimed at the coal-fired power industry, Vectren will see an increase in chemical and other operating costs to achieve these reductions. Vectren is also carefully monitoring potential new requirements with respect to water discharges and ash handling which could require additional investments in the future.

On December 9, 2009 the IURC released the Phase II Generic Demand Side Management (DSM) order, which established statewide electric savings goals for utilities starting in 2010 at 0.3% of average sales and ramping up to 2% per year in 2019. The impacts of this order have been modeled and are included in our base case forecast. On August 31, 2011 the IURC approved Vectren's DSM Plan under Cause No. 43938. The Core and Core Plus programs outlined in the plan are expected to meet the savings identified in the Phase II Order for the years 2011-2013.

As a part of Vectren's Core Plus programs, Vectren has launched a pilot that incentivizes qualifying customers to convert their inefficient electric water heaters to more efficient natural gas units. The direct use pilot is an innovative program that is designed to use natural resources more efficiently and help reduce regional electric demand. The program follows a national trend in promoting the direct use of natural gas versus using it to generate electricity. Vectren recently approached 3,000 qualifying electric customers in its southwestern Indiana service territory to consider the program and is hopeful to convert 250 customers within the next three years, which should save 1,220 megawatt hours (MWh) annually. More information on this and other conservation programs is mentioned in Chapter 8 DSM Resources.

On July 13, 2011 the Commission published an amended net metering rule which included additional modifications to the rules, including eligibility to all customer classes, increase to the size of net metering facilities (1MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load). The new rules also required that at least forty percent (40%) of the amount of net metering allowed would be reserved solely for participation by residential customers. Vectren has worked with customers over the past several years to facilitate the implementation of net metering installations. As of August 1, 2011 Vectren had 22 active, 1 inactive and 1 pending net metering customers with a total nameplate capacity of 149.4 kW.

Finally, over the last year, Vectren has worked with Itron, Inc. to enhance our sales and demand forecasting models. As discussed later in Chapter 5 Sales and Demand

Forecast, the models' statistics were strengthened and were determined to be good predictors of Vectren sales and demand.

PLAN RESULTS / RECOMMENDATIONS

As of the time of this filing, Vectren does not recommend the installation of any additional generation on its system, nor does Vectren propose additional purchase power agreements during the planning period. Vectren proposes to utilize demand-side management programs to help customers use less energy, thus, lowering their total bill. Table 1-2 shows the peak and energy forecast, while Table 1-3 shows that no capacity additions are currently deemed necessary.

Vectren's base case scenario assumptions are detailed in Chapter 10. In summary, we assumed a minimum planning margin of 12.1%[1] for each year of the study. Implementation of the Phase II Generic DSM order began in 2010. Savings goals of 0.3% of average sales and ramping to 2% per year in 2019 were incorporated into our base case forecast. Additionally, incremental energy savings of .5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. All assumptions are discussed in depth throughout this IRP.

Sensitivity analyses were performed around load growth rate, gas pricing, carbon pricing, no new conservation savings beyond 2019, and the addition of industrial load on the system. These results are shown in Chapter 10 Electric Integration Analysis.

CONCLUSION

Vectren recognizes that the electric utility industry is experiencing an extremely volatile time in terms of potential regulations, fuel availability and costs, environmental mandates, and technology advances. Given the significant impact of any decision on both our customers and our other stakeholders, Vectren will continue to actively monitor

[1] ReliabilityFirst Planning Reserve Standard discussed further Chapter 3 MISO, pages 33-34

developments in the regulatory, environmental, and technology arenas for both their impact on future generation needs and existing facilities.

Open communication with the IURC and other parties such as the OUCC will be key to Vectren's ability to make the best decisions for all stakeholders.

Table 1-2 Peak and Energy Forecast

Year	Peak (MW)*	Annual Energy (GWh)*
2010 act. Peak, Calendar Energy	1,275	6,271
2011 proj.	1,218	6,146
2012	1,168	5,896
2013	1,168	5,867
2014	1,177	5,863
2015	1,164	5,772
2016	1,160	5,725
2017	1,151	5,657
2018	1,145	5,590
2019	1,139	5,520
2020	1,144	5,538
2021	1,149	5,543
2022	1,155	5,554
2023	1,159	5,563
2024	1,165	5,580
2025	1,171	5,588
2026	1,177	5,603
2027	1,184	5,618
2028	1,191	5,646
2029	1,199	5,660
2030	1,207	5,685
2031	1,215	5,711
Compound Annual Growth Rate, 2012-2031 Including Wholesale	0.21%	-0.17%
Compound Annual Growth Rate, 2012-2031 Without Wholesale	0.26%	-0.12%

*Includes wholesale contract sales for 2010-2014

Table 1-3 Base Case Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.2%
2015	1,164		1,164	1,285	24	35	38			1,382	18.8%
2016	1,160		1,160	1,285	24	35	38			1,382	19.2%
2017	1,151		1,151	1,285	24	35	38			1,382	20.0%
2018	1,145		1,145	1,285	24	35	38			1,382	20.7%
2019	1,139		1,139	1,285	24	35	38			1,382	21.3%
2020	1,144		1,144	1,285	24	35	38			1,382	20.8%
2021	1,149		1,149	1,285	24	35	38			1,382	20.2%
2022	1,155		1,155	1,285	24	35	38			1,382	19.7%
2023	1,159		1,159	1,285	24	35	38			1,382	19.2%
2024	1,165		1,165	1,285	24	35	38			1,382	18.7%
2025	1,171		1,171	1,285	24	35	38			1,382	18.0%
2026	1,177		1,177	1,285	24	35	38			1,382	17.4%
2027	1,184		1,184	1,285	24	35	38			1,382	16.8%
2028	1,191		1,191	1,285	24	35	38			1,382	16.0%
2029	1,199		1,199	1,285	24	35	38			1,382	15.3%
2030	1,207		1,207	1,285	24	35	38			1,382	14.5%
2031	1,215		1,215	1,285	24	35	38			1,382	13.7%

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CHAPTER 2

PLANNING PROCESS

INTRODUCTION

Vectren's IRP objectives are based on the need for a resource strategy that provides value to its customers, communities, and shareholders. In addition, this strategy must accommodate the ongoing changes and uncertainties in the competitive and regulated markets. Specifically, Vectren's IRP objectives are as follows:

- Provide all customers with a reliable supply of energy at the least cost reasonably possible
- Develop a plan with the flexibility to rapidly adapt to changes in the market while minimizing risks
- Provide high-quality, customer-oriented services which enhance customer value
- Improve the local environment
- Enhance shareholder value over the long-term

PLANNING PROCESS

As shown in Figure 2-1, the IRP process has two distinct components: the long-term planning process and the short-term implementation of market-based decisions. The long-term process guides resource decisions, while the short-term decisions consider the rapid changes that occur in the market.

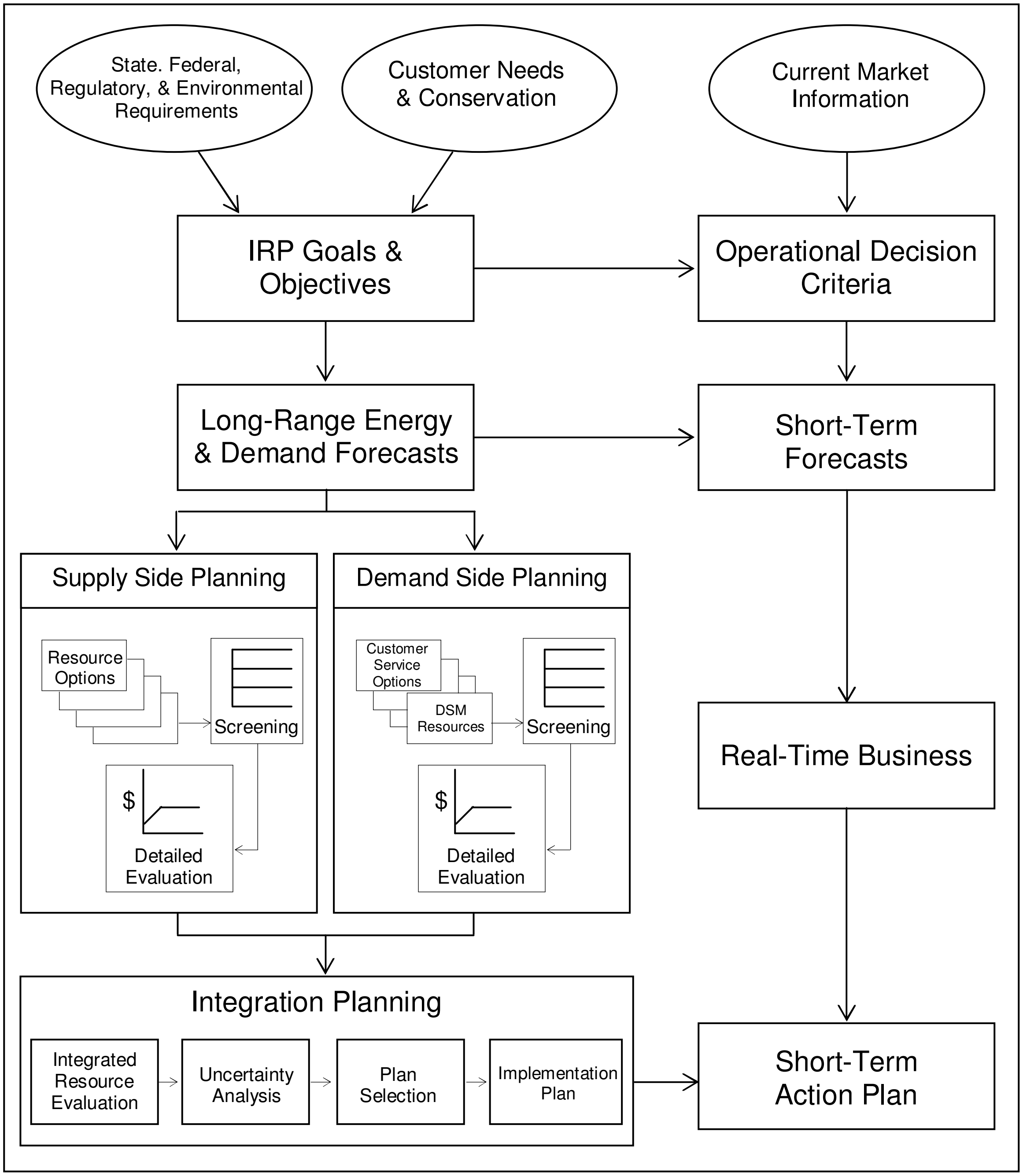
The planning process is driven by the characteristics of Vectren's markets and the needs of its customers. These elements serve to define the utility's objectives and help establish a long-term forecast of energy and demand.

Using the forecast as a baseline, the IRP process entails evaluation of both supply-side and demand-side options designed to address the forecast. These options serve as input into a formal integration process that determines the benefits and costs of various combinations of supply-side and demand-side resources. Because the IRP modeling process requires significant amounts of data and assumptions from a variety of sources, a process is needed to develop appropriate inputs to the models.

The process criteria for inputs include:

- Maintain consistency in developing key assumptions across all IRP components
- Incorporate realistic estimates based on up-to-date documentation with appropriate vendors and available market information, as well as internal departments
- Consideration of impacts and experiences gained in prior IRP processes and demand-side program efforts

Figure 2-1 Overview of Vectren's IRP Process



The remainder of this IRP is organized as follows:

MISO

Chapter 3 - Discusses Vectren's participation in MISO and the implications for resource planning

Environmental

Chapter 4 - Discusses current and pending environmental issues and regulations and the potential considerations for resource decisions

Forecast

Chapter 5 - Contains the electric sales and demand forecast

Supply-Side

Chapter 6 - Describes the electric supply analysis including a review and screening of the various electric supply options

Chapter 7 - Describes the viability and application of renewable and clean energy technologies and renewable energy credits (RECs)

Chapter 9 - Contains a discussion of Vectren's transmission and distribution expansion plan forecast

Demand-Side

Chapter 8 - Presents a discussion of DSM resources including screening results and program concept development

Integration

Chapter 10 - Details the formal integration process which includes conducting sensitivity analyses and obtaining the final resource plan

Chapter 11 - Contains action plans designed to implement the resource plan over the next two years

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CHAPTER 3

MISO

INTRODUCTION

Vectren was an original signer of the Transmission Owners Agreement, which organized the Midwest Independent Transmission System Operator (MISO), and under which authority the MISO administers its Open Access Transmission Tariff. As a traditional vertically integrated utility with responsibility for serving load within the MISO footprint, Vectren has integrated many functions with the operating procedures of the Midwest Independent System Operator (MISO). This integration involves the coordinated operation of our transmission system and generating units and the functions range from owning and operating generation and transmission, to complying with certain reliability standards. These standards are set by both the North American Electric Reliability Council (NERC) and the regional reliability entity ReliabilityFirst and include planning of resources to meet the needs of loads in the future.

MISO OVERVIEW

MISO, headquartered in Carmel, Indiana, was approved as the nation's first regional transmission organization in 2001. MISO manages one of the world's largest energy and operating reserves markets; the market generation capacity was 134,850 MW as of June 1, 2011, and its peak load in July, 2011 was 103,975 MW. This market operates in 12 states and one Canadian province.

Key Dates

- February 1, 2002 - Transmission service began under MISO Open-Access Transmission Tariff with Vectren as a full Transmission Owning Member
- April 1, 2005 - Midwest markets launch
- April 16, 2008 - NERC certified MISO as Balancing Authority
- January 6, 2011 - Ancillary Services Markets began

Vectren in Relation to MISO Footprint

With a peak load of about 1,200 MW, Vectren is approximately 1.5% of the MISO market footprint and is one of 28 local balancing authorities. Figure 3-1 below is a drawing of the entire MISO market footprint.

Figure 3-1 MISO Market

MISO's GOALS

The goal of MISO's regional transmission planning process is the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. This process identifies solutions for reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects and increased operating expenses from redispatching network resources or other operational actions.

The MISO Board of Directors has adopted five planning principles to guide the MISO regional plan:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs
- Provide a transmission infrastructure that safeguards local and regional reliability
- Support state and federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand-side management)

- Create a mechanism to ensure that investment implementation occurs in a timely manner
- Develop a transmission system scenario model and make it available to state and federal energy policymakers to provide context and information regarding potential policy choices[1]

MISO PLANNING PROCESS

MISO Transmission Planning Process

MISO's transmission planning process begins with the models for the current planning cycle and includes opportunities for stakeholder input on the integration of transmission service requests, generator interconnection requests, and other studies to contribute to the development of an annual MISO Transmission Expansion Plan (MTEP) report.

The 2010 MTEP recommends $1.2 billion in new projects across the MISO footprint through the year 2020. In addition, effective July 16, 2010, MISO added Multi-value projects, which are intended to provide regional public policy and/or economic benefits, and for which costs are shared.

MISO's role in meeting Vectren's requirements as a member of ReliabilityFirst for a Planning Reserve Margin

As a result of the Energy Policy Act of 2005, regional entities were delegated authority by FERC to establish standards to provide for reliable operation of the bulk-power system. Vectren is a member of regional entity ReliabilityFirst, and so must comply with regional entity ReliabilityFirst standards, including the Planning Resource Adequacy Analysis and the Assessment and Documentation Standard BAL-502-RFC-02. This assessment and documentation standard requires planning coordinators to perform annual resource adequacy analyses. This includes calculating a planning reserve margin (PRM) that will result in the sum of the probabilities for loss of load for the

[1] From Transmission Planning Business Practice Manual BPM-020-r4, effective date 03-09-2011

integrated peak hour for all days of each planning year equal to a one day in 10 year criterion. This PRM requirement also includes documenting the projected load, resource capability, and PRM for the years under study, and other particular criteria.

The first year the ReliabilityFirst Planning Reserve Standard was in effect (June 2008-May 2009), Vectren complied with the ReliabilityFirst Planning Resource Adequacy standard by participating in the Midwest Planning Reserve Sharing Group. The calculated required PRM for Vectren was 14.3%. For planning year June 2009-May 2010 and beyond, Vectren and all other MISO utilities have delegated their tasks assigned to the Load Serving Entities (LSEs) under BAL-502-RFC-02 to MISO. The specific section of the MISO tariff that addresses planning reserves is Module E-Resource Adequacy. Vectren is complying with the ReliabilityFirst Planning Resource Adequacy standard by meeting the MISO Module E individual LSE required PRM (after accounting for load diversity). This PRM is 12.06% for June 2011-July 2012.

MISO's Module E

As previously mentioned, Module E- Resource Adequacy is the portion of the MISO Energy and Operating Reserves Tariff which requires MISO to determine the amount of PRM(s) that load serving entities like Vectren are required to hold. Module E and its associated business practice manual, lay out the mandatory requirements to ensure access to deliverable, reliable and adequate planning resources to meet peak demand requirements on the transmission system. These procedures establish an installed reserve margin and also consider the effect of load diversity to establish an individual planning reserve requirement for load serving entities. To perform these calculations, MISO requires entities to utilize their Module E Capacity Tracking Tool (MECT) to submit a forecast of demand and list their qualified resources. This same tool is then leveraged to accept bids and offers into MISO's monthly voluntary capacity auction.

Loss of Load Expectation and Determination of Planning Reserve Margins

MISO used a Loss of Load Expectation (LOLE) of 1 day in 10 years as the probabilistic method to determine expected number of days per year for which available generating capacity is insufficient to serve the daily peak demand (load). This LOLE, along with other LSE-specific data, is used to perform a technical analysis on an annual basis to establish the PRMs for each LSE. The PRM analysis considers other factors such as generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources, forecasting uncertainty, and system operating reserve requirements.

For this year, an installed reserve margin of 17.4% applied to the MISO system coincident peak has been established for the planning year of June 2011 through May 2012. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch, which provided the congestion-driven zonal definitions used within MARS. The analysis also resulted with one uniform PRM, applicable to the West, Central, and East planning areas that make up the MISO market footprint. The 17.4% coincident peak reserve margin requirement is lowered to 12.06% due to the effects of load diversity, which represents one of the benefits of the MISO membership since not all entities across the footprint peak at exactly the same time.

Effect of Load Diversity

Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a diversity factor, which was developed through the Loss of Load Expectation Working Group. The diversity factor leverages the fact that utilities experience their individual peak hour of the year at different times than the MISO footprint as a whole. It results in an individual LSE reserve level of 12.06%, reduced from what would otherwise be a 17.4% reserve without accounting for diversity. As modeled within the GE MARS software, the system will achieve this reliability level when the amount of installed capacity available is 1.174 times that of MISO system coincident peak.[1]

Forecast LSE Requirements

LSEs must demonstrate that sufficient planning resources are allocated to meet the forecast LSE requirement multiplied by one plus the PRM. The submission of this forecast follows MISO's prescribed processes.

LSEs must report their non-coincident peak forecasted demand for each month of the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years.

MISO calculates the forecast LSE requirements for each month of the current planning year. Forecasted demand in MISO reflects the expected "50/50" peak demand and includes the effect of all distribution and transmission losses. This means there is a 50% chance that actual demand will be higher and a 50% chance that actual demand will be lower than the forecasted level.

LSEs must also report their Net Energy For Forecasted Demand for the same time periods: monthly for the next two planning years and for each summer period (May-October) and winter period (November-April) for an additional eight (8) planning years.

LSEs must separately register demand resources in order to have them subtracted from their forecasted demand in determining compliance with planning reserve requirements.

[1] From MISO 20011-2012 LOLE Study Report, dated December, 2010

As described in MISO's Business Practice Manual (BPM-011-r8) for Resource Adequacy, LSE's must submit a resource plan which meets certain requirements, including qualification of resources and includes the opportunity to participate in their monthly Voluntary Capacity Auction. MISO performs certain evaluations of these plans and will report results to state commissions.

Resource Plan Requirements

LSEs are obligated to provide MISO with resource plans demonstrating that planning reserve credits (PRCs) will be available to meet their resource adequacy requirements. Generally, the PRM is the forecast LSE requirement multiplied by 1 plus MISO PRM, unless the state utility commission establishes a PRM that is different from MISO's.

If a state utility commission establishes a minimum PRM for the LSEs under their jurisdiction, that state-set PRM will be adopted by MISO for affected LSEs in such state. If a state utility commission establishes a PRM that is higher than the MISO established PRM, the affected LSE's must meet the state-set PRM.[1] Indiana does not have a stated minimum planning reserve margin.

Qualification of Resources, Including Unforced Capacity Ratings (UCAP), Conversion of UCAP MW to Planning Resource Credits

To comply with MISO Resource Adequacy provisions, LSEs must submit data for their eligible resources for MISO to determine the total installed capacity that the resource can reliably provide, called Unforced Capacity Rating (UCAP).

MISO will calculate unforced capacity for all generation resources interconnected to the MISO Transmission System while respecting the interconnection study results and the results of the aggregate deliverability analysis.

[1] From MISO BPM-011-r8 Resource Adequacy Section 3.6 State Authority to set PRM

The first step is to compare a Generation Resource Net Dependable Capacity (NDC) to the tested capacity from the interconnection process to determine the total installed capacity that the generation resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). A unit's NDC for the Planning Year is determined by averaging the NDC data that is entered into MISO's Generating Availability Data System (GADS) database.

The UCAP rating represents the MW's that are eligible to be converted into PRCs.

Submission of Annual and Monthly Resource Plans

By March 1st of each planning year, each LSE submits the LSE's resource plan into the Module E Capacity Tracking tool by designating PRCs toward meeting its PRM requirement for the upcoming planning year.

Prior to the first calendar day of each of the months preceding the applicable planning month in the applicable planning year (Resource Plan Deadline), each LSE documents its compliance via the MECT tool, stating for that planning month the LSE has a resource plan that includes a sufficient number of designated PRCs to meet the LSE's PRM requirement.

Evaluation and Reporting

MISO will maintain databases and will report to states upon request the extent to which each LSE has met or has not met the requirements in section 69.1 of the Energy Market Tariff (EMT) during relevant time periods, subject to the data confidentiality provisions in section 38.9 of the Energy and Operating Reserves Tariff.

Voluntary Capacity Auction and Financial Settlements

The VCA facilitates the procurement of monthly PRCs by providing an optional monthly forum for sellers and buyers to interact in order to buy and sell PRCs to meet their last-minute capacity needs.

Deficiency Procedures

When an LSE is determined by MISO to be capacity deficient for a given month, the LSE will be responsible for the payment of a financial settlement charge. That charge is calculated as some percentage of the Cost of New Entry, defined as the capital, operating, financial, and other costs of acquiring a new generation resource and is calculated by MISO every year.

Vectren's approach to the Voluntary Capacity Auction

Due to the long lead time generally required to build capacity resources, Vectren does not consider MISO's monthly VCA an appropriate means to meet the needs of the 20 year Integrated Resource Plan and continues to pursue more traditional means of ensuring adequate resources.

Future of MISO's Module E

MISO proposed Capacity Market

The MISO tariff and associated business practice manuals, which include details of their planning processes and procedures, have undergone several changes, some of which are still pending FERC approval. In particular, they have proposed extending their one-month voluntary capacity market to a one-year forward procurement requirement beginning with the planning year that begins in June, 2013.

Footprint Changes

Also, the MISO market footprint is subject to change, evidenced by the June 1, 2011 withdrawal of First Energy and the anticipated December 31, 2011 withdrawal of Duke Ohio/KY and potential integration of Entergy Corporation, which is slated for December, 2013.

DEMAND RESPONSE

Vectren acknowledges that demand response is an integral part of a utility's system, operations, and planning, and as such it helps efficiently meet our obligation to serve all customers. Effective July 1, 2011 and pursuant to Commission order in Cause 34566 MISO 4, Vectren filed Rider DR, which provides qualifying customers the optional opportunity to reduce their electric costs by participating in the MISO wholesale energy market. This rider helps the Company's efforts to preserve reliable electric service through customer provision of a load reduction during MISO high price periods and declared emergency events. This initial Rider DR offers two programs, emergency demand response (EDR) and demand response resource Type 1 ("DRR-1") energy programs.

Vectren's Approach to Resource Adequacy

Vectren will continue to comply with MISO's Module E requirements, which includes the possibility for varying amounts of planning reserves. As the MISO market continues to evolve, we will continue to evaluate the proper reserve margin target.

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Chapter 4

ENVIRONMENTAL

INTRODUCTION

Compliance planning associated with existing and anticipated environmental laws and regulations in each of the three media (air, water and waste) is discussed in this chapter.

ACID RAIN PROGRAM

Vectren's Acid Rain compliance program was approved by the IURC in Cause No. 39347, which authorized the construction of a combined sulfur dioxide (SO_2) scrubber for Culley Units 2 and 3. As Brown Units 1 and 2 are newer vintage units, the units' original construction included scrubber technology. Vectren relies upon its existing scrubber technology for compliance with acid rain requirements and has sufficient allowance allocations to meet its future acid rain obligations. See, Table 4-1, a listing of current air pollution control devices for each Vectren unit, Table 4-2, a listing of emission rates for each Vectren unit, and Table 4-3 a listing of the acid rain allowances allocated to Vectren units.

Table 4-1 Air Pollution Control Devices Installed

	Culley 2	Culley 3	Warrick 4	Brown 1	Brown 2
Vintage	1966	1972	1970	1979	1986
MW (net)	90	270	150	245	245
NO_X	Low NO_X Burner	SCR	SCR	SCR	SCR
SO_2	FGD	FGD	FGD	FGD	FGD
PM	ESP	FF	ESP	FF	ESP

Table 4-2 Current (2010) Emission Rates (lbs./mm Btu)

Units	SO_2	Annual NO_X	Ozone Season NO_X
Brown 1	0.5550	0.1470	0.1400
Brown 2	0.4500	0.3800	0.1600
Brown 3	0.0006	0.1670	0.1600
Brown 4	0.0006	0.0250	0.0200
Culley 2/3	0.1500	0.1910	0.1430
Warrick 4	0.1800	0.2520	0.0900
BAGS 1	0.0006	0.2600	0.2500
BAGS 2	0.0006	0.2300	0.2000

Table 4-3 2010 SO_2 Acid Rain Allowances Allocated to Vectren Units

Plant Name	Percent Ownership	Allowances Allocated (per year) 2010	2011-2038
Brown	100%	10,546	10,546
Culley	100%	9,922	9,922
Warrick 4	50%	5,122	5,122

* Number of allowances shown are for Vectren's portion of Warrick 4

For purposes of compliance year 2011, acid rain allowances will continue to be used for compliance with the SO_2 emission reductions requirements of the Clean Air Interstate Rule (CAIR). However, as detailed more fully below, CAIR has been superseded by the new Cross-State Air Pollution Rule (CSAPR), which becomes effective January 1, 2012. Neither the CAIR rule nor CSAPR supersedes the Acid Rain program, and facilities will still be required to annually surrender acid rain allowances to cover emissions of SO_2 under the existing Acid Rain program.

NOx SIP CALL

Vectren's NOx SIP Call compliance plan was approved by the IURC in Cause Nos. 41864 and 42248, which authorized Vectren to retrofit selective catalytic reduction (SCR) technology on Culley Unit 3, Warrick Unit 4, and Brown Units 1 and 2. Vectren relies upon its existing SCR technology for compliance with the seasonal NOx reductions required in the NOx SIP Call. When CAIR was finalized in March of 2005, the EPA included a seasonal NOx emission reduction requirement, which incorporated, and in most cases, went beyond the seasonal NOx emission reductions required under the NOx SIP Call. For purposes of compliance year 2011, CAIR NOx seasonal allowances will continue to be used for compliance with the seasonal NOx emission reductions requirement under the current CAIR rule. CAIR and CSAPR are discussed more fully below.

CAIR and CSAPR

On March 10, 2005, the US Environmental Protection Agency (EPA) finalized its determination in the CAIR rule that emissions from coal-burning electric generating units (EGUs) in certain upwind states result in amounts of transported fine particles ($PM_{2.5}$) and ozone that significantly contribute to nonattainment of the applicable ambient air quality standards for those pollutants in downwind states. The CAIR rule required revisions to state implementation plans in twenty eight states, including Indiana, requiring further reductions of NOx and SO_2 from EGUs beyond those required in the NOx SIP Call and Acid Rain programs. Emissions reductions under the CAIR rule were to be implemented in two phases, with requirements for first phase reductions in 2009 (NOx) and 2010 (SO_2), and second phase reductions starting in 2015. The Warrick 4 scrubber was constructed to comply with the CAIR regulation and approved in Cause No. 42861. The CAIR rule provided a federal framework for a regional cap and trade system, and those allowances allocated to the Vectren units under the CAIR rule will be used for compliance in 2011. However, any excess CAIR allowances (vintage 2011 or older) that are not needed for compliance in 2011 cannot be used for compliance with CSAPR, which is effective January 1, 2012.

In July of 2008, a reviewing court vacated the CAIR rule. According to the court, the EPA did not present a persuasive case that the CAIR cap and trade program would bring all areas into attainment for ozone and fine particulate as required by the Clean Air Act. The court also determined that the EPA did not have authority to terminate (or reduce) the value of acid rain allowances that were created by legislation. Allowance markets were roiled by the uncertainty created by the court's remand. This uncertainty was underscored by the EPA Clean Air Market Division's announcement on its web-site that the EPA would not guarantee the value of allowances beyond the date of the CAIR revision (i.e. acid rain allowances may not be used for compliance in a revised CAIR), and a March 26, 2009, letter from the EPA to all designated representatives cautioning about uncertainty of future NOx allowance allocations.

On July 6, 2010, the EPA proposed its Clean Air Transport Rule ("Transport Rule") in response to the court's remand of CAIR. In an effort to address the court's finding that CAIR did not adequately ensure attainment of ozone and $PM_{2.5}$ air quality standards in certain eastern states due to unlimited trading and banking of allowances, the Transport Rule proposal dramatically reduced the ability of facilities to meet the required emission reductions through allowance trading. Like CAIR, the Transport Rule proposal set individual state caps for SO_2 and NOx; however, unlike CAIR, individual unit allowance allocations were set out directly in the Transport Rule proposal. Interstate allowance trading was severely restricted and limited to trading within a zonal group. On July 7, 2011, the EPA finalized the Transport Rule proposal and (somewhat inexplicably) renamed it the Cross State Air Pollution Rule. CSAPR sets individual allowance allocations for Vectren's units directly in the rule. See Table 4-4, a listing of individual unit allowance allocations under the recently finalized CSAPR. Given the stringent state emission caps, the limited allowance trading available under the CSAPR, and the limited amount of time utilities and states have had to review the trading restrictions established in the rule, at this time it is virtually impossible to predict with any certainty the availability of excess allowances for compliance and the costs of those allowances.

Table 4-4 CSAPR Allowances Allocated to Vectren Units

	SO_2 Allocation		Annual NO_X		Seasonal NO_X	
	2012	2014	2012	2014	2012	2014
Brown 1	3,761	2,080	1,393	1,376	595	586
Brown 2	3,889	2,151	1,440	1,422	601	591
Brown 3	1	1	19	19	14	14
Brown 4	0	0	6	6	4	4
BAGS 1	0	0	4	4	3	3
BAGS 2	0	0	26	26	18	8
Culley 2	1,488	925	619	612	268	264
Culley 3	2,923	2,799	1,874	1,851	792	780
Warrick 4	2,802	1,550	1,037	1,025	444	437

Vectren's original multi-pollutant compliance plan was approved under IURC Cause No. 42861. While Vectren's original multi-pollutant planning focused on compliance with the CAIR regulation which was in place at the time, the successful execution of the approved multi-pollutant plan enables Vectren to comply with these new more stringent SO_2 and NOx emission caps in CSAPR without further significant capital investment; however, while currently well controlled, Vectren will incur increased costs attributable to the new regulation such as an increase in chemical costs to achieve the lower emission targets. With the completion of the Warrick 4 scrubber pursuant to the approved order in Vectren's multi-pollutant proceeding, Vectren's generating system is 100% scrubbed for SO_2 and has selective catalytic reduction technology on all but one unit (Culley Unit 2). See Table 4-1. As such, Vectren will be well-positioned to comply with the new, more stringent SO_2 and NOx caps that are required by CSAPR starting on January 1, 2012, without reliance on a highly uncertain allowance market or further significant capital expenditures. It is important to note that the CSAPR is still subject to revision. The CSAPR is currently being litigated in federal court, and on October 6, 2011, the EPA announced it's intent to propose technical adjustments to the current regulation.

CLEAN AIR MERCURY RULE

The 1990 Amendments to the Clean Air Act (CAA or Act) required that the EPA determine whether EGUs should be required to reduce hazardous air pollutants, including mercury, under § 112 of the Act. In December of 2000, EPA officially listed coal-fired EGUs as subject to CAA § 112 Maximum Achievable Control Technology (MACT) Standards for mercury, thus lifting a previous exemption from the air toxics requirements. On March 15, 2005, the EPA finalized its Clean Air Mercury Rule (CAMR) which set "standards of performance" under CAA §111 for new and existing coal-fired EGUs and created a nation-wide mercury emission allowance cap and trade system for existing EGUs which sought to reduce utility emissions of mercury in two phases. The first phase cap would have started in 2010, except the CAMR rule was similarly vacated by a reviewing court in March of 2008. Thus, like the CAIR rule, utilities were preparing for compliance with a finalized CAMR regulation that was ultimately found to be deficient by a reviewing court. The reviewing court directed the EPA to proceed with a MACT rulemaking under AA § 112 which would impose more stringent individual plant-wide limits on mercury emissions and not provide for allowance trading.

On March 16, 2011, the EPA released its proposed MACT for utility boilers. The proposal sets plant-wide emission limits for the following hazardous air pollutants (HAPs): mercury, non-mercury HAPs (e.g. arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The EPA proposed stringent plant-wide mercury emission limits for two sub-categories of coal and proposed surrogate limits for non-mercury HAPs (total particulate matter limit of .03 lb/MMBtu) and acid gases (HCL limit of .002 lb/MMBtu). The surrogate limits can be used instead of individual limits for each HAP. EPA is currently under a consent decree deadline of November 16, 2011, to finalize its utility HAPs rule.

Vectren's original CAMR compliance plan as approved in Cause No. 42861 and part of its multi-pollutant compliance plan relied upon the co-benefits of its existing pollution control configuration to achieve the CAMR reductions. Based upon an initial review of the proposed HAPs emission limits for mercury, acid gases and non-metal HAPs, as set forth in the EPA's March 16th proposal, Vectren believes that it is well-positioned to meet these new stringent emission limits for HAPs without further significant capital investment or premature retirement of any units.

CARBON REGULATION

In 2009 and 2010, the industry saw multiple attempts to pass climate change legislation in Congress. These various House and Senate bills failed to pass, and with the current state of the economy and a presidential election approaching, the Company does not currently foresee that Congress will take up any new attempts to regulate greenhouse gases from utility boilers for at least two more years.

However, even though the Company does not expect Congress to finalize any major legislation in the next few years, the EPA continues to expand its regulation of greenhouse gases from large stationary sources such as coal-fired utility boilers. In 2007, the US Supreme Court determined that greenhouse gases were "pollutants" as defined by the CAA and directed the EPA to make an endangerment finding with respect to whether global warming attributed to US sources threatens public health and welfare. The EPA finalized its finding of endangerment in December of 2009. A positive endangerment finding is the first step in regulating greenhouse gas emissions from major stationary sources. In anticipation of triggering mandatory greenhouse gas permitting requirements under existing provisions under the Act, on June 3, 2010, the EPA finalized its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. Following finalization of its endangerment finding and its rule to control greenhouse gas emissions from light-duty vehicles, the EPA was obligated under the Act to also issue prevention of significant deterioration (PSD) and Title V regulations for stationary sources with greenhouse gas emissions that exceed thresholds for regulated pollutants. The Act sets those thresholds at 100 tons for stationary sources in listed categories and 250 tons for any stationary source, but greenhouse gases are emitted in far greater quantities than other pollutants in the PSD program. Applying the existing PSD framework to greenhouse gases would subject literally millions of facilities to standards and permitting requirements for the first time. The PSD permitting program was never intended for these myriad of small sources, so the PSD program needed to be "tailored" to ensure that only the largest sources of greenhouses are regulated.

The new PSD tailoring rule was finalized in June of 2010 and rolled out in two phases. The first phase, from January 2, 2011 to June 30, 2011, applied only to sources such as coal-fired generating units that were already subject to PSD permitting for another PSD pollutant. The modification would also result in an increase of 75,000 tons of total greenhouse gases (CO2-equivalent or CO2e), which will trigger requirements for Best Available Control Technology (BACT) review and installation of BACT. BACT controls are selected on a case-by-case basis, taking into account commercial availability, cost effectiveness of the control, and energy and environmental impacts. During this initial phase, no sources were subject to PSD permitting due solely to an increase in greenhouse gas emissions. However, starting on July 1, 2011, PSD permitting applies to modifications of existing units solely on the basis of a 75,000 tons / year (tpy) increase in total greenhouse gas emissions.

As discussed above, greenhouse gas legislation has stalled on a federal level due to political and economic considerations. While Vectren does not currently anticipate finalization of any significant federal greenhouse gas legislation in the near term, Vectren is including a carbon sensitivity scenario in the current modeling. For the purposes of the current model, Vectren assumes that a national cap and trade plan is adopted beginning 2016. As such, Vectren has relied on a carbon price curve provided by Wood Mackenzie in its North American Gas Long Term View (September 2010) which starts at $14 / metric ton in 2016 and grows 6% annually, reaching $32 / metric ton by 2030.

WATER

Vectren's units currently discharge process and cooling water to the Ohio River under water discharge permits issued by the Indiana Department of Environmental Management (IDEM). There are currently two major regulatory rulemakings that could, when finalized, require more stringent limits for these discharges.

Indiana's anti-degradation rules have been in various stages of review and proposed regulation for the last twelve years. The anti-degradation implementation procedures proposed in this rule will apply to a new or increased loading of a "pollutant of concern" to a surface water of the state. The current proposal has been issued as a second notice, and it is anticipated it will be issued as final in the fall of 2011. A facility that proposes a new or increase to an existing water discharge can be required to incorporate Best Available Demonstrated Control Technology if the discharge results in the receiving water having sufficient amounts of a pollutant of concern such that the discharge has a potentially detrimental impact on the designated or existing use of the receiving water. When finalized, plant upgrades or significant process changes at the Brown, Warrick, and Culley stations, even if federally or locally mandated, may be viewed as a new discharge and subject to increased regulation.

In addition to Indiana's anti-degradation rulemaking, the Ohio River Valley Sanitation Commission's (ORSANCO) regional water quality standards are being revised. ORSANCO is a regional state compact focused on water quality issues for the Ohio River. Once final, these water quality standards will be used as guidance by states in setting discharge limits in water discharge permit renewals for industrial facilities, including Vectren units, discharging to the Ohio River. Issues that could potentially impact the operation of Vectren's units include lower standards for selenium and mercury, lowered thermal discharge standards, and the elimination of mixing zones for Bioaccumulative Chemicals of Concern, including but not limited to mercury.

As a result of litigation filed by environmental organizations, the EPA is drafting regulations for utility cooling water structures under Section 316(b) of the Clean Water Act (CWA). Section 316(b) requires that electric generating units use the "Best Technology Available" to prevent and / or mitigate adverse environmental impacts to shellfish, fish, and wildlife in a waterbody. On March 28, 2011, the EPA released its draft 316(b) regulations. The proposed rule maintains the agency's current standard for new units (mandatory cooling water towers), but provides flexible options for existing facilities. If finalized in its current form, the regulations will require extensive sampling and testing programs to support case by case arguments that cooling water towers are not necessary at individual facilities. Vectren's Culley and Warrick units currently use a "once through" cooling water intake system and are clearly impacted by this proposed regulation. Vectren's Brown plant currently uses a closed cooling water system. However, under the proposal Vectren would still be required to conduct extensive sampling protocols to confirm that the existing cooling water tower mitigates impingement and entrainment.

WASTE DISPOSAL

Over the course of the last twenty years the EPA has conducted numerous studies and issued two reports to Congress on the management of coal combustion by-products (primarily fly ash, bottom ash, and scrubber by-product), concluding both times that these materials generally do not exhibit hazardous waste characteristics and can be managed properly under state solid waste regulations. However, in response to the TVA's catastrophic ash pond spill in December of 2008, the EPA was pressured to re-evaluate its regulatory options for the management of coal combustion by-products. On June 21, 2010, the EPA published three options for a proposed rule. Two options would regulate combustion by-products as solid waste under the Resource Conservation and Recovery Act (RCRA) Subtitle D, with the only significant difference being whether existing ponds are retrofitted or closed within five years, or whether utilities will be permitted to continue to use an existing pond for its remaining useful life. The third option would regulate combustion by-products as hazardous waste under RCRA Subtitle C. Under all three options, certain beneficial re-uses of ash will continue to be allowed. The EPA has not indicated when it intends to finalize the new regulation.

As a direct result of the TVA spill referenced above, the EPA undertook to inspect all surface impoundments and dams holding combustion by-products. The EPA conducted site assessments at Vectren's Brown and Culley facilities and found the facilities' surface impoundments to be satisfactory and not posing a high hazard. Historically, the Brown surface impoundments handled both fly ash and bottom ash through a wet sluicing system that sent ash to a one hundred acre on-site ash pond system. Scrubber by-products are sent to an on-site landfill permitted by IDEM. Starting in February 2010, Brown fly ash is now diverted to a new dry ash handling system and sent for beneficial reuse to a cement processing plant in St. Genevieve, Missouri, via a river barge loader and conveyor system. This major sustainability project will serve to mitigate negative impacts from the imposition of a more stringent regulatory scheme for ash disposal, as the majority of Vectren's coal combustion materials are now being diverted from the existing ash pond structures and surface coal mine backfill operations and transported offsite for recycling into a cement application.

Fly ash from the Culley facility is similarly transported off-site for beneficial reuse in cement. Until mid 2009, fly ash from the Culley facility was sent to the Cypress Creek Mine for backfill pursuant to the mine's surface coal mine permit. In May 2009, Culley began trucking fly ash to the St. Genevieve cement plant. Upon completion of the barge loading facility at the Brown facility, Culley's fly ash is now transported to the Brown loading facility and shipped to the cement plant via river barge. The Culley facility sends its bottom ash to one of two on-site ponds via wet sluicing. The ponds are seven and eighteen acres in size. Scrubber by-product generated by the Culley facility is also used for beneficial reuse and shipped by river barge from Culley to a wallboard manufacturer. In summary, the majority of Vectren's coal combustion material is no longer handled on site, but is being recycled and shipped off-site for beneficial reuse.

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CHAPTER 5

SALES & DEMAND FORECAST

INTRODUCTION

The electric sales and demand forecasts provide the basis for evaluation of supply-side and demand-side options to meet the electric needs of Vectren's customers. These forecasts reflect local and regional economic impacts, the effects of past, present, and proposed DSM/DR programs, mandated efficiency standards, and the effects of normal market forces on electricity sales.

Overview of Vectren's Customers and Their Usage

Vectren provides delivery services to approximately 142,000 electric residential, general service (commercial), and large (industrial) customers with electricity in southern Indiana. A high proportion of Vectren's sales are made to electric-intensive general service and large customers. In 2010, about 29% of Vectren's annual retail electric energy sales were consumed by residential customers, 24% of sales were consumed by general service, and 47% of sales were consumed by approximately 100 large customers. Less than 1% served other load, including street lights. Significant general service and large load creates complexity in load forecasting. These customers have the ability to significantly impact Vectren's demand for electricity as economic factors affect their businesses' success.

ELECTRIC LOAD FORECAST OVERVIEW

Development of this IRP required base and high forecasts of annual energy sales and requirements (e.g. sales plus related delivery losses) and peak loads (e.g. demand plus losses). These forecasts, and the activities undertaken to develop them, are described in this section. A low case forecast was deemed unnecessary, as the outcome of the base case required no new generation to serve Vectren customers in the planning period.

Development of the Vectren system-wide long-term electric load forecast involves the aggregation of multiple models. Vectren uses statistically adjusted end use (SAE) modeling and econometric modeling to forecast customer needs for the future. Vectren has investigated the use of pure end-use modeling for forecasting purposes but believes that a combination of statistically adjusted end-use and econometric modeling best accommodates our forecasting needs. End-use modeling involves building and maintaining a detailed end-use database to capture appliance and thermal shell characteristics, as well as end-use consumption information. The basic structure of an end-use model is households multiplied by appliance saturation and unit energy consumption. Each component of the end-use model is modeled separately. For these reasons, end-use modeling is very expensive to develop and maintain. It is meant primarily for long-term modeling (5-20 years). Often a separate short term forecast is necessary, which is hard to integrate with the long-term forecast. Vectren utilizes statistically adjusted end-use models to forecast residential and general service loads. Large customer needs are forecasted with an econometric linear regression model, while lighting load is forecasted with a simple trend model. The detail of our forecasting methodology is discussed later in this chapter.

FORECAST RESULTS

The base case forecasts of annual energy requirements and peak loads for the 2012 - 2031 planning period are provided in Tables 5-1 and 5-2. We have included wholesale contracts to municipal customers in our territory through contract expiration in 2014. These contracts are competitively bid and are at risk for future loss. We have included growth rates on all charts both inclusive and exclusive of wholesale contracts because of the uncertainty surrounding these loads. Annual energy requirements, excluding wholesale, are projected to have a -.12% compound annual growth rate over the twenty year planning period. Peak requirements (excluding wholesale) are projected to grow at compound annual growth rates of .26% over the twenty year planning period.

Table 5-1 Base Case Energy and Demand Forecast

Year	Annual Energy Requirements		Hourly Peak Demand	
	GWh*	Growth,%	MW*	Growth,%
2010 Calendar	6,271		1,275	
2011 proj.	6,146	-2.0%	1,218	-4.5%
2012[1]	5,896	-4.1%	1,168	-4.1%
2013	5,867	-0.5%	1,168	0.0%
2014	5,863	-0.1%	1,177	0.8%
2015[2]	5,772	-1.5%	1,164	-1.1%
2016	5,725	-0.8%	1,160	-0.4%
2017	5,657	-1.2%	1,151	-0.7%
2018	5,590	-1.2%	1,145	-0.5%
2019	5,520	-1.3%	1,139	-0.5%
2020	5,538	0.3%	1,144	0.5%
2021	5,543	0.1%	1,149	0.5%
2022	5,554	0.2%	1,155	0.5%
2023	5,563	0.2%	1,159	0.4%
2024	5,580	0.3%	1,165	0.4%
2025	5,588	0.1%	1,171	0.5%
2026	5,603	0.3%	1,177	0.5%
2027	5,618	0.3%	1,184	0.6%
2028	5,646	0.5%	1,191	0.6%
2029	5,660	0.2%	1,199	0.7%
2030	5,685	0.4%	1,207	0.7%
2031	5,711	0.5%	1,215	0.7%
Compound Annual Growth Rate, 2012-2031 Including Wholesale		-0.17%		0.21%
Compound Annual Growth Rate, 2012-2031 Without Wholesale		-0.12%		0.26%

*Includes wholesale contract sales for 2010-2014

[1] Drop in sales in 2012 is primarily due to new lighting standards and real price change in 2011
[2] Included wholesale contracts to municipal customers in our territory through contract expiration in 2014. This accounts for approximately a 1% drop in sales and demand in 2015.

Table 5-2 Base Case Energy Forecast by Customer Class

Annual Sales by Class (GWh)

Year	Residential (GWh)	General Service (GWh)	Large (GWh)	Conservation (GWh)	Other (GWh)	Wholesale (GWh)	Losses (GWh)	Total Requirements (GWh)	Total Requirements (GWh) without Wholesale
2010 Calendar	1,604	1,363	2,655		21	314	313	6,271	5,957
2011 proj.	1,511	1,358	2,657	(23)	22	314	307	6,146	5,831
2012	1,501	1,387	2,696	(60)	22	57	295	5,896	5,840
2013	1,483	1,409	2,714	(110)	22	57	293	5,867	5,810
2014	1,493	1,441	2,728	(171)	22	57	293	5,863	5,806
2015	1,501	1,463	2,740	(242)	22		288	5,772	5,772
2016	1,511	1,480	2,750	(324)	22		286	5,725	5,725
2017	1,518	1,489	2,763	(417)	22		283	5,657	5,657
2018	1,530	1,504	2,776	(520)	22		279	5,590	5,590
2019	1,544	1,520	2,785	(627)	22		276	5,520	5,520
2020	1,559	1,539	2,795	(653)	22		277	5,538	5,538
2021	1,570	1,551	2,803	(680)	22		277	5,543	5,543
2022	1,585	1,566	2,809	(706)	22		278	5,554	5,554
2023	1,601	1,580	2,813	(732)	22		278	5,563	5,563
2024	1,622	1,598	2,819	(758)	22		279	5,580	5,580
2025	1,636	1,609	2,825	(784)	22		279	5,588	5,588
2026	1,655	1,625	2,832	(811)	22		280	5,603	5,603
2027	1,673	1,642	2,838	(837)	22		281	5,618	5,618
2028	1,695	1,664	2,846	(863)	22		282	5,646	5,646
2029	1,710	1,680	2,855	(890)	22		283	5,660	5,660
2030	1,729	1,702	2,865	(916)	22		284	5,685	5,685
2031	1,749	1,724	2,874	(943)	22		285	5,711	5,711
Compound Annual Growth Rate for (2012-2031)	0.81%	1.15%	0.34%		0.00%			-0.17%	-0.12%

High energy and demand forecasts were developed by modifying the assumptions about the long-term growth trends of different customer classes. Base economic and demographic data were not altered for the development of the high forecasts. The annual growth rates of the load classes were adjusted to result in a 20 year compound annual growth rate of 1.0% for the high cases. The results are shown in Table 5-3 and 5-4.

Table 5-3 Base and High Case Energy Forecasts

Year	Base Annual Requirements		High Growth Annual Requirements	
	GWh*	Growth,%	GWh*	Growth,%
2010 Calendar	6,271		6,271	
2011 proj.	6,146	-2.0%	6,146	-2.0%
2012	5,896	-4.1%	5,896	-4.1%
2013	5,867	-0.5%	5,955	1.0%
2014	5,863	-0.1%	6,014	1.0%
2015	5,772	-1.5%	6,017	0.0%
2016	5,725	-0.8%	6,077	1.0%
2017	5,657	-1.2%	6,138	1.0%
2018	5,590	-1.2%	6,199	1.0%
2019	5,520	-1.3%	6,261	1.0%
2020	5,538	0.3%	6,324	1.0%
2021	5,543	0.1%	6,387	1.0%
2022	5,554	0.2%	6,451	1.0%
2023	5,563	0.2%	6,515	1.0%
2024	5,580	0.3%	6,580	1.0%
2025	5,588	0.1%	6,646	1.0%
2026	5,603	0.3%	6,713	1.0%
2027	5,618	0.3%	6,780	1.0%
2028	5,646	0.5%	6,848	1.0%
2029	5,660	0.2%	6,916	1.0%
2030	5,685	0.4%	6,985	1.0%
2031	5,711	0.5%	7,055	1.0%
Compound Annual Growth Rate, 2012-2031 Including Wholesale		-0.17%		0.95%
Compound Annual Growth Rate, 2012-2031 Without Wholesale		-0.12%		0.95%

*Includes wholesale contract sales for 2010-2014

Table 5-4 Base and High Case Demand Forecasts

Year	Base Annual Hourly Peak		High Growth Annual Hourly Peak	
	MW	Growth,%	MW*	Growth,%
2010 act.	1,275		1,275	
2011 proj.	1,218	-4.5%	1,218	-4.5%
2012	1,168	-4.1%	1,168	-4.1%
2013	1,168	0.0%	1,180	1.0%
2014	1,177	0.8%	1,191	1.0%
2015	1,164	-1.1%	1,191	0.0%
2016	1,160	-0.4%	1,203	1.0%
2017	1,151	-0.7%	1,215	1.0%
2018	1,145	-0.5%	1,227	1.0%
2019	1,139	-0.5%	1,239	1.0%
2020	1,144	0.5%	1,252	1.0%
2021	1,149	0.5%	1,264	1.0%
2022	1,155	0.5%	1,277	1.0%
2023	1,159	0.4%	1,290	1.0%
2024	1,165	0.4%	1,302	1.0%
2025	1,171	0.5%	1,315	1.0%
2026	1,177	0.5%	1,329	1.0%
2027	1,184	0.6%	1,342	1.0%
2028	1,191	0.6%	1,355	1.0%
2029	1,199	0.7%	1,369	1.0%
2030	1,207	0.7%	1,383	1.0%
2031	1,215	0.7%	1,396	1.0%
Compound Annual Growth Rate, 2012-2031 Including Wholesale		0.21%		0.94%
Compound Annual Growth Rate, 2012-2031 Without Wholesale		0.26%		0.94%

*Includes wholesale contract sales for 2010-2014

FORECAST INPUTS & METHODOLOGY

Forecast Inputs

Energy Data

Historical Vectren sales and revenues data were obtained through our internal database. The internal database contains detailed customer information including rate, service, NAICS codes (if applicable), usage, and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were exported out of the database and compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

Economic and Demographic Data

Economic and demographic data was provided by Moody's Economy.com for the nation, the state of Indiana, and the Evansville Metropolitan Statistical Area (MSA). Moody's Economy.com, a division of Moody's Analytics, is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to Vectren contains both historical results and projected data throughout the IRP forecast period. This information is input into our load forecasting software and used to project residential, GS, and large sales.

Weather Data

The daily maximum and minimum temperatures for Evansville, IN were obtained from DTN, our provider of National Oceanic and Atmospheric Administration (NOAA) data. NOAA data is used to calculate monthly heating degree days (HDD) and cooling degree days (CDD). HDDs are defined as the number of degrees below the base temperature of 65 degrees Fahrenheit for a given day. CDDs are defined as the number of degrees above the base temperature of 65 degrees Fahrenheit for a given day. HDDs and CDDs are averaged on a monthly basis. Normal degree days, as obtained from NOAA, are based on the thirty year period between 1971 and 2000. Historical weather data[1] is imported into our load forecasting software and is used to normalize the past usage of

[1] The large sales model also includes CDDs.

residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional (East North Central Region) Energy Information Administration (EIA) historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. Note that in 2010 Vectren conducted an appliance survey of our residential customers to compare our actual territory market share data with the regional EIA data. In order to increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of our actual territory.

Model Overview

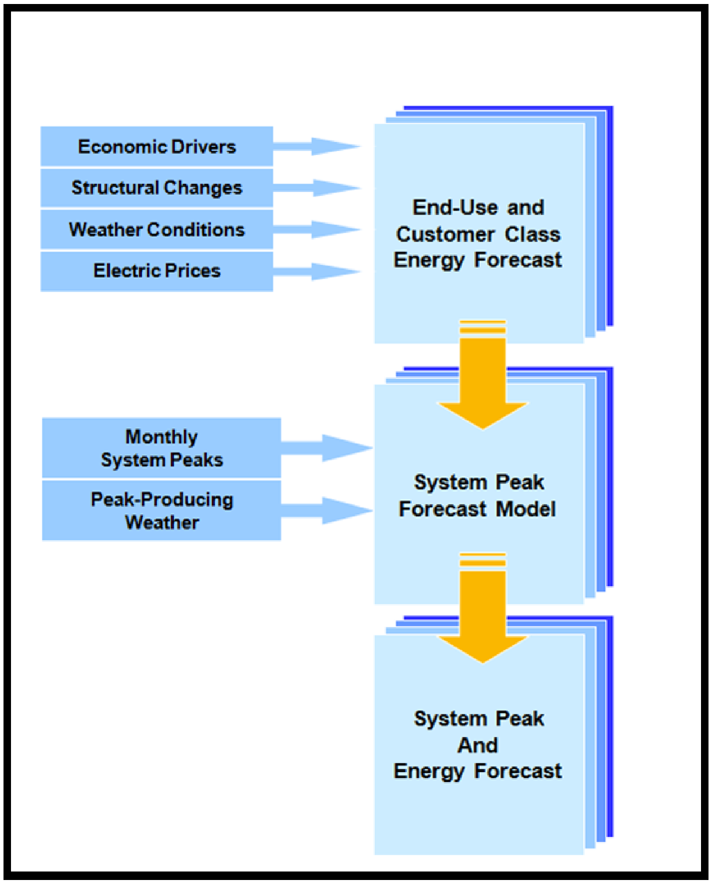
Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following primary revenue classes:

- Residential (residential average usage and customer models)
- General Service
- Large
- Street Lighting

In the long-term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential average use and general service sales forecast models through Statistically Adjusted End-Use (SAE) model specifications. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new end-use standards and naturally occurring efficiency gains. The large sales forecast is derived using an econometric model that relates large sales to regional manufacturing GDP growth. Street light sales are forecasted using a simple trend and seasonal model. The results of the sales forecast modes are imported into our demand forecast model.

The long-term demand forecast is developed using a “build-up” approach. This approach entails first estimating class and end-use energy requirements and then using this information to build a system peak demand model. The following factors, which affect class and end-use energy requirements, are captured in monthly class sales forecast models: economic and demographic changes, electricity prices, and changes in the appliance stock. The system energy forecast is then calculated by applying monthly loss factors to the calendarized monthly class sales forecasts. End-use energy projections derived from the sales models combined with peak-day weather conditions drive monthly system peak demand through a peak demand model. Through this construction, end-use and customer class energy growth drive changes in long-term peak demand. Note that the forecast is adjusted to reflect future conservation impacts. Figure 5-1 shows the general approach.

Figure 5-1: Forecast Approach



Analytic Methodology Used in Forecast

Residential Average Use Model

Residential customer usage is a product of heating, cooling, and other load. Both heating and cooling are weather sensitive and must be weather normalized in a model to remove weather noise from projections. Other major drivers of load are historical and projected market saturation of electronics, appliances, and equipment and their respective efficiencies. Vectren's service territory has a high saturation rate of central air conditioning equipment that is growing at a very slow pace, which helps to minimize average use growth. As equipment wears out and is replaced with newer, more efficient equipment, the reduced average energy use per customer (AUPC) will be balanced against the increasing use of household electronics and appliances. Changes in lighting standards are also likely to impact residential customer usage.

The price of electricity and household income also influence average customer energy use. In general, there is a positive correlation between household income and usage. As household income rises, total usage rises. Conversely, there is a negative correlation between price and usage. As price goes up, average use goes down. Finally, the size of the home (number of inhabitants and square footage) and the thermal integrity of the structure affect residential consumption.

The residential average use model is a statistically adjusted end-use (SAE) model that addresses each of the previously discussed drivers of residential usage. SAE models incorporate many of the benefits of econometric models and traditional end-use models, while minimizing the disadvantages of each.

SAE models are ideal for identifying sales trends for short-term and long-term forecasting. They capture a wide variety of relevant data, including economic trends, equipment saturations and efficiencies, weather, and housing characteristics. Additionally, SAE models are cost effective and are easy to maintain and update. In the SAE model, use is defined by three primary end uses: heating (XHeat), cooling (XCool), and other (XOther). XHeat, XCool, and XOther are explanatory variables in the model that explain customer usage. By design, the SAE model calibrates results into actual sales.

ResAvgUsem = B0 + B1XHeatm + B2XCoolm + B3XOtherm + em

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

XHeat = HeatUse * HeatIndex

Where

HeatUse = f(HDD, Household Income, Household Size, and Price)

HeatIndex = g(Heating Saturation, Efficiency, Shell Integrity, Square Footage)

The cooling variable is defined as:

XCool = CoolUse * CoolIndex

Where

CoolUse = f(CDD, Household Income, Household Size, and Price)

CoolIndex = g(Cooling Saturation, Efficiency, Shell Integrity, Square Footage)

XOther captures non-weather sensitive end-uses:

XOther = OtherUse * OtherIndex

Where

OtherUse = f(Seasonal Use Pattern, Household Income, Household Size, and Price)

OtherIndex = g(Other Appliance Saturation and Efficiency Trends)

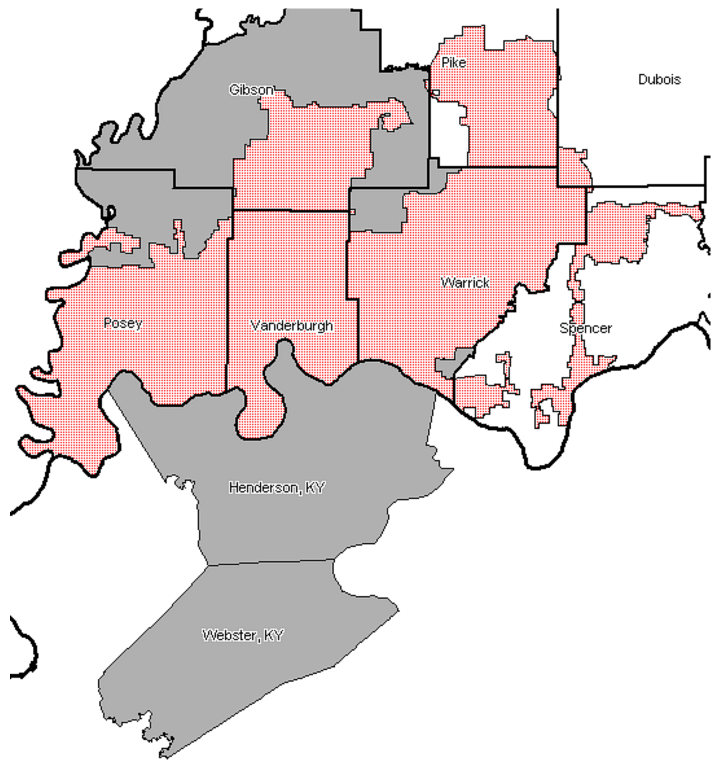
Monthly residential usage was regressed on the XHeat, XCool, and XOther variables. Prior to conservation measures, Vectren has forecasted residential average usage to grow an average of .40% per year throughout the forecast period. The model statistics were evaluated, and the model was determined to be a good predictor of residential average use, with an adjusted R^2 value of .981 and an in-sample mean absolute percentage error (MAPE) of 2.51%.

Residential Customers Model

A simple linear regression model was used to predict the number of residential customers. The number of residential customers was forecasted as a function of population projections for the Evansville Metropolitan Statistical Area (MSA) from Moody's Economy.com.

The Evansville MSA is a good proxy for our service territory. Figure 5-2 shows Vectren's service territory (in red) and the Evansville MSA in gray. The number of residential customers is projected to grow an average of .41% throughout the planning period. The adjusted R^2 for this model was .987, while the MAPE was .09%.

Figure 5-2 Vectren Service Territory Map



General Service (GS) Sales Model

Similar to the residential average use model, the General Service SAE model expresses monthly sales as a function of XHeat, XCool, and XOther. The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use efficiency improvements, with non-manufacturing GDP and employment (ComVarm), real price (Pricem), and monthly HDD and CDD:

XHeatm = EIheat * Pricem -.10* ComVarm* HDDm

XCoolm = EIcool * Pricem -.10* ComVarm* CDDm

XOtherm = EIother * Pricem-.10 * ComVarm

The coefficients on price are imposed short-term price elasticities. A monthly forecast sales model is then estimated as:

ComSalesm = B0 + B1XHeatm + B2XCoolm + B3XOtherm + em

Commercial Economic Driver

Non-manufacturing output and employment are combined through a weighted economic variable where ComVar is defined as:

ComVarm = (NonManuf_Employm0.3) * (NonManuf_Outputm0.7)

The employment weight is 0.3 and the output weight is 0.7. The weights were selected by evaluating the in-sample and out of sample model statistics for different sets of employment and output weights.

The resulting general service sales model performs well with an adjusted R^2 of 0.918 and an in-sample MAPE of 2.94%.

<u>Large Sales Model</u>

Large customer sales are forecasted using a monthly regression model where large sales are specified as a function of manufacturing employment, manufacturing output, monthly CDD, and monthly binaries to capture seasonal load variation. Similar to the GS sales model, the economic driver is a weighted combination of real manufacturing output and manufacturing employment. The industrial economic (IndVar) variable is defined as:

IndVarm = (Manuf_Employm0.3) * (Manuf_Outputm0.7)

Again, the imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model's adjusted R^2 is 0.837 with an in-sample MAPE of 4.47%.

The adjusted r-squared of the GS and Large models is considered good for the type of information being forecasted. There are many variables that impact large customer consumption that are not easily forecasted. These unforeseeable impacts make forecasting GS and large customers' usage with a high degree of certainty very difficult, as these customers' usage is extremely sensitive to economic conditions.

Lighting Sales Model

Street light sales are fitted with a simple seasonal exponential smoothing model. The result is that monthly street lighting sales are held constant through the forecast period. The model yielded an adjusted r-squared of .703 and a MAPE of 5.71%.

Vectren's total energy requirements include forecasted sales for the four sectors described above, wholesale contracts, DSM savings, and delivery losses. Losses were estimated to be approximately 5.0 percent of requirements. DSM savings are highlighted separately in the sales forecast, and the DSM programs are discussed in detail in Chapter 8.

Peak Demand Forecast

The energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the monthly sales (calendarized) forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy. The energy adjustment factor is calculated as the average of the monthly ratios over the last three years.

The long-term system peak forecast is derived through a monthly peak linear regression model that relates monthly peak demand to heating, cooling, and base load requirements:

Peakm = B0 + B1HeatVarm + B2*CoolVarm + B3* BaseVarm + em

The model variables (HeatVarm, CoolVarm, and BaseVarm) incorporate changes in heating, cooling, and base-use energy requirements derived from the class sales forecast models as well as peak-day weather conditions.

Heating and Cooling Model Variables

Heating and cooling requirements are driven by customer growth, economic activity, changes in end-use saturation, and improving end-use efficiency. These factors are captured in the class sales forecast models. The composition of the models allows us to estimate historical and forecasted heating and cooling load requirement.

The estimated model coefficients for the heating (XHeat) and cooling variables (XCool) combined with heating and cooling variable for normal weather conditions (NrmXHeat and NrmXCool) gives us an estimate of the monthly heating and cooling load requirements. Heating requirements are calculated as:

HeatLoadm = B1 * ResNrmXHeatm + C1 *ComNrmXHeatm

B1 and C1 are the coefficients on XHeat in the residential and GS models.

Cooling requirements are estimated in a similar manner. As there is a small amount of cooling in the industrial sector, industrial cooling is included by multiplying the large model coefficient for the CDD variable by normal monthly CDD. Cooling requirements are calculated as:

CoolLoadm = B2 * ResNrmXCoolm + C2 *ComNrmXCoolm+D2*NrmCDDm

B2 and C2 are the coefficients on XCool in the residential and commercial models and D2 is the coefficient on CDD in the large sales model.

In constructing the monthly peak model variables, the heating and cooling load requirements are normalized for the number of days and hours in the month by expressing heating and cooling load requirements on an average MW load basis:

HeatAvgMWm = HeatLoadm/ Daysm /24
CoolAvgMWm = CoolLoadm/ Daysm /24

The impact of peak-day weather conditions are then captured by interacting peak-day HDD and CDD with average monthly heating and cooling load requirements. The peak model heating and cooling variables are calculated as:

HeatVarm = HeatAvgMWm * PkHDDm
CoolVarm = CoolAvgMWm * PkCDDm

Base Load Model

The peak model base load variable (BaseVarm) is derived from the sales forecast models by first aggregating non-weather sensitive monthly sales estimates across the residential, GS, large, and street lighting revenue classes:

OtherUsem = ResOtherm + ComOtherm + IndOtherm + StLightingm

To express base load on a MW basis, the model variable is calculated as:

BaseVarm = OtherUsem / Daysm / 24

The peak-day HDD is indexed to the January normal HDD (38.5) and the peak-day CDD is indexed to the August normal CDD (21.1). This allows us to give a MW meaning to the calculated model variables.

The peak-day weather (measured using the CDD and HDD on the day of the peak), is derived from historical daily average weather data for Evansville. Peak-day HDD and CDD are calculated by first finding the peak in each month (the maximum hourly demand), identifying the day, and finding the average temperature for that day. The average peak-day temperature is then used to construct peak-day HDD and CDD variables. The appropriate breakpoints for the HDD and CDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature. Winter peaks occur when temperatures are below 55 degrees and summer peaks occur when temperatures exceed 65.

Normal peak-day CDD and HDD are calculated from daily HDD (base 55 degrees) and CDD (base 65 degrees) for Evansville. Normal peak-day HDD and CDD are calculated using ten-years of historical weather data (2001 to 2010). The calculation process entails using a rank and average approach.

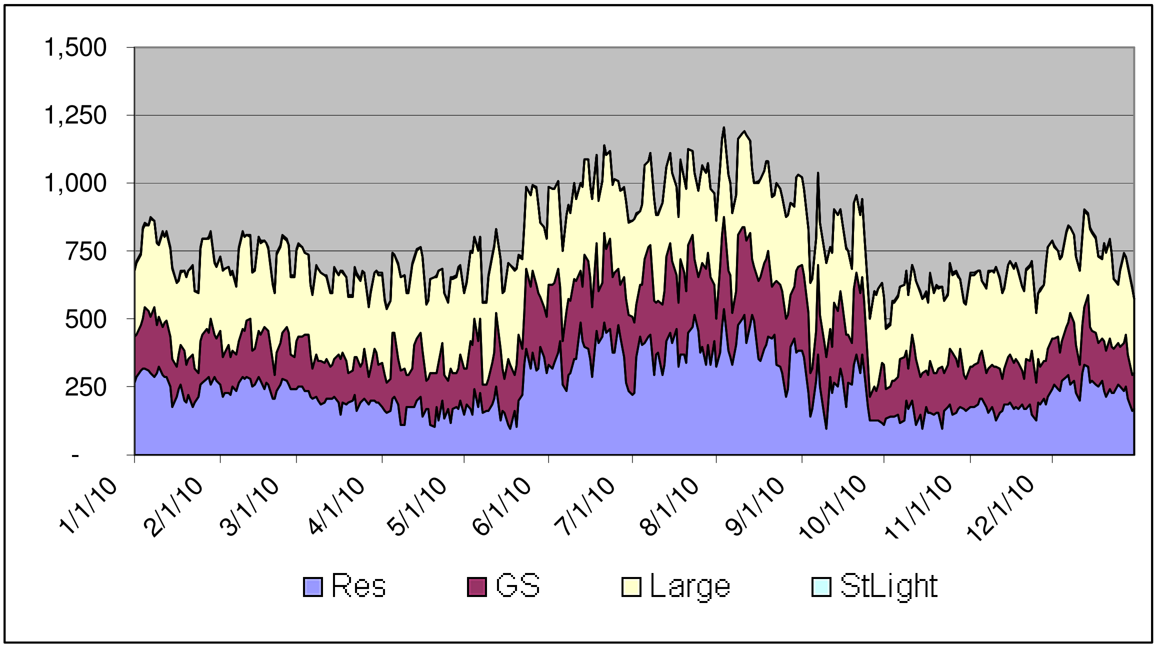
Model Results

The model explains monthly peak variation well with an adjusted R^2 of 0.925 and an in-sample MAPE of 3.22%.

OVERVIEW OF LOAD RESEARCH ACTIVITIES

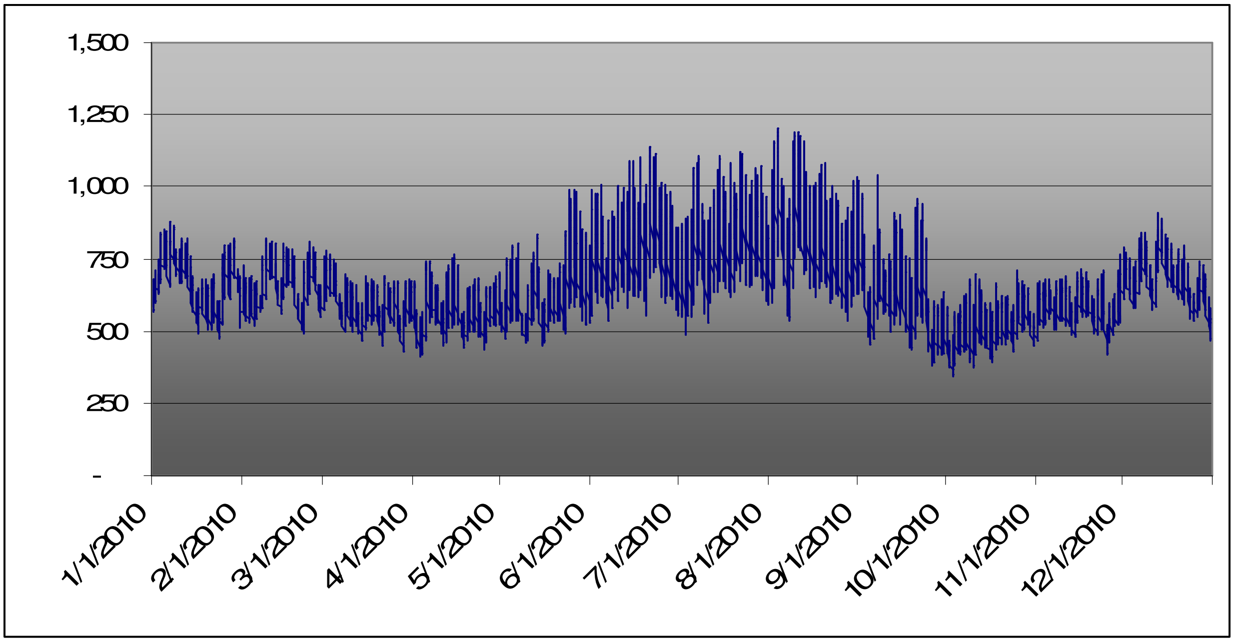
Vectren has interval meters installed on a sample of residential and GS customers. Large customers who have a monthly minimum demand obligation of 300kVA are required to have interval meters installed. Vectren collects and stores this information for analysis as needed. Detailed load shapes are used to better understand customers' usage, primarily for cost of service studies. For this IRP, Vectren borrowed class load shapes from Itron's Indiana library to break down our hourly load profile by class. We applied these load shapes to historical peak demand. Graph 5-1 shows daily class contribution to peak for 2010.

Graph 5-1 Daily Class Contribution to Peak for 2010 (MW)

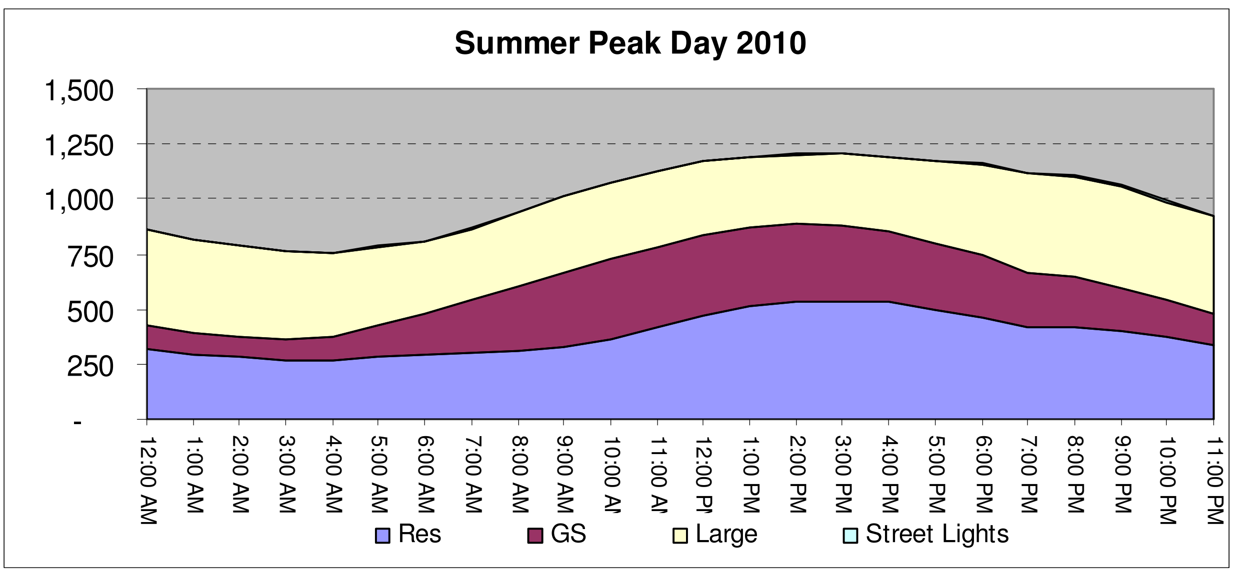


The following graphs (5-2 through 5-4) show the actual system load by day for 2010, the actual summer peak day for 2010 by hour, and the winter peak day for 2010 by hour. Note that these graphs do not include wholesale contract sales. Also included in the Technical Appendix are additional load shapes.

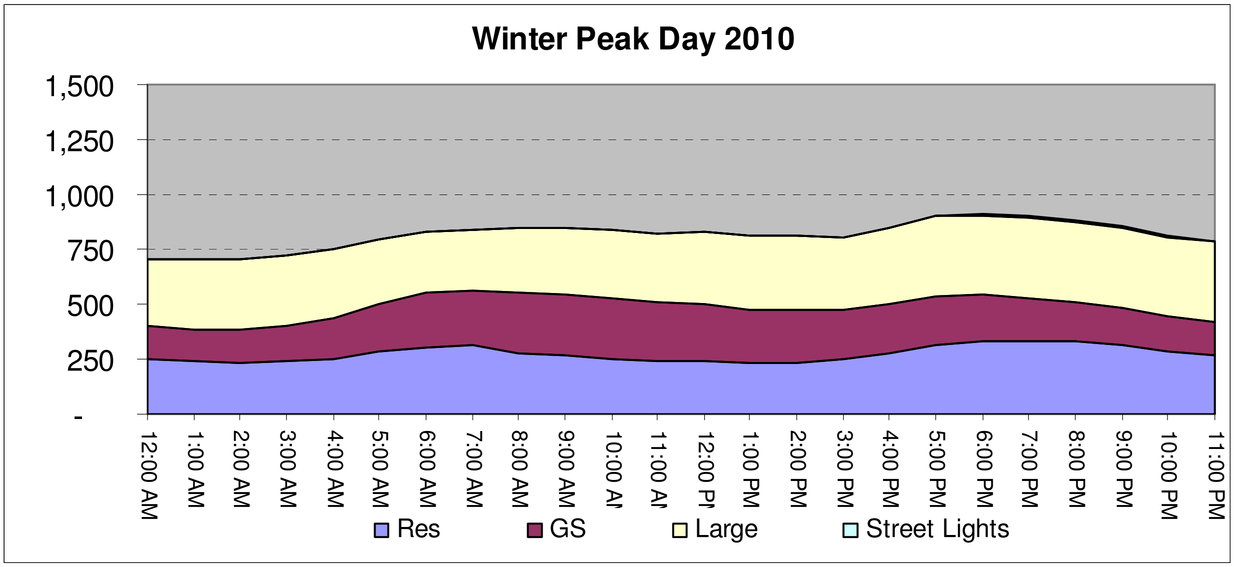
Graph 5-2 Total System Load for 2010 (MW)



Graph 5-3 Summer Peak 2010 (MW)



Graph 5-4 Winter Peak 2010 (MW)



APPLIANCE SATURATION SURVEY

Vectren surveys residential customers on an as-needed basis. A residential appliance saturation survey was conducted in the spring of 2010. The survey was completed by a representative sample of customers. Results from this survey were used to reflect market shares of our actual residential customers. The residential average use model statistics were improved by including the appliance saturation of our customers in place of regional statistics. It is not necessary to run this appliance saturation survey every year. The next survey is scheduled to be sent in 2012.

At this time, Vectren does not conduct routine appliance saturation studies of our GS and large customers. These customers are surveyed when needed for special programs. However, our large and GS marketing representatives maintain close contact with our largest customers. This allows Vectren to stay abreast of pending changes in demand and consumption of this customer group. Additionally, Vectren recently purchased software that allows us to send paper surveys to businesses. In early 2011 Vectren had success in surveying commercial gas customers using a paper survey. In an effort to better understand Vectren's electric GS customers and their energy efficiency needs, Vectren plans to conduct a mail GS appliance saturation baseline survey during the fall of 2011. The survey will ask questions about the energy-using equipment at their business, their building characteristics, and energy conservation practices employed at their business. Data provided by this survey should yield usage trends and characteristics representative of a typical electric GS customer in Vectren's service territory.

OVERVIEW OF PAST FORECASTS

The following tables outline the performance of Vectren's energy and demand forecasts. Forecasts from previous IRP filings from 2001 through 2010 were compared to actual values in order to evaluate the reliability of Vectren's past energy and demand forecasts. The following tables show the actual and forecasted values for:

- Total Peak Demand
- Total Energy Sales
- Residential Energy Sales
- GS Energy Sales
- Large Energy Sales
- Other Energy Requirements

Tables 5-5 through 5-10 present comparisons of actual values versus forecasted values from previous IRP filings. The percentage deviation of the actual values from the most recent forecast is shown in the last column of each table. The deviations of the total energy and total peak forecasts are better than for the individual classes, which is to be expected. <u>Note that all of the forecasted values are weather-normalized, but the actual loads are not.</u> This comparison would show much closer correlation if the actual loads were normalized to match the forecasts. Another source of potential error is the use of the direct load control program, which reduces the peak demand on hot days by cycling off customer appliances to reduce system load.

Table 5-5 Total Peak Requirements (MW)

Year	Actual	Forecasts 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	1,209						1,272	-5.2%
2002	1,259					1,289		-2.4%
2003	1,272					1,305		-2.6%
2004	1,222					1,325		-8.4%
2005	1,316				1,313			0.2%
2006	1,325			1,326				-0.1%
2007	1,341			1,346				-0.4%
2008	1,166		1,184					-1.6%
2009	1,143		1,216					-6.4%
2010[1]	1,275	1,153						9.6%
Compound Annual Growth Rate, 2001-2010	0.59%							

Table 5-6 Total Energy Requirements (GWh)

Year	Actual	Forecasts 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	6,102						6,204	-1.7%
2002	6,532					6,274		3.9%
2003	6,444					6,348		1.5%
2004	6,303				6,514			-3.3%
2005	6,508				6,624			-1.8%
2006	6,352			6,543				-3.0%
2007	6,527		6,469					0.9%
2008	5,931		6,160*					-3.9%
2009	5,598	5,592						0.1%
2010[1]	6,221	5,608						9.9%
Compound Annual Growth Rate, 2001-2010	0.22%							

*Adjusted to include wholesale sales

[1] 2010 was more than 30% hotter than normal in the Vectren service territory, which contributed to a higher peak and higher energy use than was projected in the 2009 IRP

Table 5-7 Residential Energy Sales (GWh)

Year	Actual	Forecasts (Residential) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	1,424					1,452		-2.0%
2002	1,513					1,479		2.2%
2003	1,460					1,506		-3.2%
2004	1,502				1,519			-1.1%
2005	1,571			1,536				2.2%
2006	1,475			1,584				-7.4%
2007	1,631		1,570					3.7%
2008	1,604		1,578					1.6%
2009	1,449	1,451						-0.1%
2010	1,598	1,467						8.2%
Compound Annual Growth Rate, 2001-2010	1.29%							

Table 5-8 General Service Energy Sales (GWh)

Year	Actual	Forecasts (GS) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	1,387					1,350		2.7%
2002	1,423					1,369		3.8%
2003	1,443					1,389		3.7%
2004	1,502				1,468			2.3%
2005	1,556			1,539				1.1%
2006	1,515			1,566				-3.4%
2007	1,412		1,371					2.9%
2008	1,363		1,379					-1.2%
2009	1,299	1,296						0.2%
2010	1,361	1,275						6.3%
Compound Annual Growth Rate, 2001-2010	-0.21%							

Table 5-9 Large Energy Sales (GWh)

Year	Actual	Forecasts (Large) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	2,428					2,506		-3.2%
2002	2,444					2,522		-3.2%
2003	2,494					2,539		-1.8%
2004	2,346				2,568			-9.5%
2005	2,389			2,404				-0.6%
2006	2,376			2,379				-0.1%
2007	2,538		2,573					-1.4%
2008	2,655		2,567					3.3%
2009	2,251	2,247						0.2%
2010	2,601	2,281						12.3%
Compound Annual Growth Rate, 2001-2010	0.77%							

Table 5-10 Other Sales, Wholesale Contract Sales, and Losses (GWh)

Year	Actual	Forecasts (Other, Wholesale & Losses) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	863						949	-10.0%
2002	1,152					904		21.5%
2003	1,047					914		12.7%
2004	953				959			-0.6%
2005	992			967				2.5%
2006	986			1,014				-2.9%
2007	946		954					-0.9%
2008	309		636*					5.3%
2009	600	598						0.3%
2010	661	585						11.6%
Compound Annual Growth Rate, 2001-2010	-2.91%							

*Adjusted to include wholesale sales

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CHAPTER 6

ELECTRIC SUPPLY ANALYSIS

INTRODUCTION

The purpose of the Electric Supply Analysis is to determine the best available technologies for meeting the potential future supply-side resource needs of Vectren. A very broad range of supply alternatives were identified and screened and from this large sampling a smaller subset of alternatives were chosen for the final planning and integration analysis. In general terms the supply-side alternatives can be grouped as follows:

- Construction of new generating facilities
- Refurbishment or modifications to existing facilities
- Capacity purchases from the wholesale market
- Distributed generation

TECHNOLOGY ASSESSMENT

For the 2009 Electric IRP process, Vectren retained the services of Sargent & Lundy to assist in performing a technology assessment for conventional coal and gas technologies. For the 2011 IRP process Vectren elected not to fund the significant expense required to develop a detailed supply side assessment, primarily because early indications were that no supply side resource decisions would be required in the short term action plan (consistent with the 2009 IRP).

The results from the 2009 assessment were updated to current dollar terms using an appropriate cost tracking index. To develop updated capital costs, the Power Capital Cost Index (PCCI)[1] published by IHS CERA was used. Specifically, the PCCI values for the 24 month period between Q1 2009 and Q1 2011 were applied and resulted in an inflator value of 3.44% to be applied to the results of the 2009 technology assessment. It is important to note that the most recent update for the PCCI, published in July, exhibited the most significant increase in the past several years. Presumably as the result of increased construction activity and recovering commodity prices.

[1] Source: www.ihsindexes.com

Table 6-1 Capital Cost Inflator

	Q1 2009	Q1 2011	Capital Cost Inflator (CCI)
PCCI, w/o nuclear	174	180	1.0344

For O&M costs, the Consumer Price Index (CPI) as published by the Bureau of Labor Statistics of the United States Department of Labor was utilized. Specifically, the seasonally adjusted CPI values for the 24 month period of July 2009 through June 2011 were applied.

Table 6-2 O&M Cost Inflator

	Jul 2009	Jun 2011	O&M Inflator (OMI)
CPI (US, all items)	214.782	224.304	1.0443

A detailed discussion of renewable technologies can be found in Chapter 7 Renewables and Clean Energy. The full Technology Assessment report can be found in the Technical Appendix of this IRP.

NEW CONSTRUCTION ALTERNATIVES

The first step in the analysis of new construction alternatives was to survey the available list of technologies and to perform a preliminary screening of each of the options, eliminating those options that were determined to be unfeasible or marginal. The screening criteria included an extensive list of qualitative and quantitative considerations. Table 6-3 lists the criteria that were considered.

Table 6-3 Qualitative Generation Screening Criteria

Amount of Generating Capacity Needed	
Electric energy consumption growth	Peak demand growth
Plant retirements	System reliability
Capital Cost Considerations	
Capital requirements	Cash flow during construction
Carrying charges on investment	Life expectancy
Electricity Cost	
Capital-related charges	Operating costs
Plant Characteristics	
Unit size	Reliability/availability
Compatibility	Efficiency
Fuel flexibility	Required fuel quality
Resource Requirements	
Fuel	Water
Land	Construction manpower
Staffing	
Environmental Factors	
Air	Water
Solid waste	Potential hazardous pollutant regulations
Environmental siting	requirements
Licensing Factors	
Safety issues	Regulatory climate
Public perception	
Siting Considerations	
Environmental factors	Resource requirements
Geological foundation requirements	Aesthetics
Transmission distance	Transmission routing
Central or dispersed location	Impact on construction cost
Sociological impact	Demographic impact
Lead Time	
Construction	Startup
Licensing, including preliminary requirements	
Geographic Applicability	
Commercialization Aspects	
Market potential	Manufacturing capability
Materials availability	Current utility investment
Current supplier investment	Commercialization cost
Technical uncertainty	Business uncertainty
Political uncertainty	Utility interest
Utility participation	

The set of new construction alternatives that was selected for further assessment as a result of the screening process are presented in Table 6-4. The capital cost and O&M characteristics of these selected alternatives were assessed and developed in detail.

Table 6-4 New Construction Alternatives

COAL	Nominal MW
Supercritical Pulverized Coal (PC)	750
Atmospheric Fluidized Bed (CFB)	600
Integrated (Coal) Gasification Combined Cycle (IGCC)	625
NATURAL GAS	
GE LM6000 Simple Cycle	40
GE 7EA Simple Cycle	80
GE LMS100 Simple Cycle	100
GE 7FA Simple Cycle	190
GE 2x1 7EA Combined Cycle	600
GE 2x1 7FA Combined Cycle	260
RENEWABLE	
Biomass	50

Coal-Fueled Technologies

Three major types of coal fired generation technologies were assessed:

- A supercritical pulverized coal (PC) option was evaluated for a generating capability of 750 Megawatts (MW).
- Circulating fluidized bed (CFB) technology was assessed for a capability of 600 MW.
- Integrated coal gasification combined cycle (IGCC) technology was assessed for a capability of 625 MW.

The assessments for each of these three technologies were developed for two cases; with and without carbon capture and sequestration (CCS). For the CCS cases the assumed level of control was 90%.

Sole ownership of a viable coal alternative was deemed to be unrealistic due to maximum reserve margin and capital investment constraints associated with adding a large increment of capacity relative to the size of the Vectren electric system. However, it is recognized that partial ownership positions in such projects would allow Vectren to capture the economies of scale and the improved efficiencies associated with larger generating units.

In general, new construction costs for PC and CFB technologies in the 200-300 MW capability range are converging as CFB technology matures and PC technology becomes more environmentally constrained. However, the application of CFB technology has been limited to unit capabilities of relatively small size, less than 300 MW, thereby limiting the available economies of scale. In contrast, PC technology possesses significant economies of scale over a very broad range of unit capability sizes. These economies of scale apply to both new construction and O&M costs.

For the purposes of the technology assessment, the conventional PC technology that was assessed included a 750 MW supercritical generation unit with full environmental controls. For the CFB technology a nominal 600 MW generating unit consisting of two CFB steam generators and one steam turbine was evaluated.

The IGCC industry is coalescing around a nominal 625 MW design using two distinct chemical trains. Per the EIA, capital costs for IGCC technology require a premium when compared to more conventional pulverized coal technologies, about 12.5% according to their published capital cost estimates updated for the 2010 Annual Energy Outlook (http://205.254.135.24/oiaf/beck_plantcosts/). The premium is somewhat less, about 5% in relative terms, when CCS is considered. In consideration of the EIA data and given the notable cost escalation concerns regarding IGCC plants currently under construction, the IGCC capital cost values from the 2009 Technology Assessment were revised accordingly. The relative percentages mentioned earlier were applied to the Pulverized Coal Supercritical option to derive the IGCC capital costs.

Vectren investigated CCS for coal fueled alternatives as part of the Technology Assessment (see Technical Appendix). The additional costs for CO_2 capture technology are very significant for coal fueled generation technologies.

Table 6-5 presents the results of the detailed assessment for the three selected coal alternatives with and without CCS. For the purposes of the integration analysis performed for this IRP, Vectren selected a partial ownership position (25%) of a large supercritical type coal unit (750 MW) or IGCC (625 MW) to be representative of coal fueled alternatives. The partial ownership assumption achieves two important study objectives: the capture of economies of scale coupled with obtaining an appropriate amount of incremental capacity. Both alternatives were simulated using an assumption of installed carbon controls (with CCS).

TABLE 6-5 Assessment of Coal Technologies

Primary Fuel	Coal					
Carbon Controls	Without CCS			With CCS		
Technology Description	Pulverized Coal Supercritical (PCSC)	Circulating Fluidized Bed (CFB)	Integrated Gasification Combined Cycle (IGCC)	Pulverized Coal Supercritical (PCSC)	Circulating Fluidized Bed (CFB)	Integrated Gasification Combined Cycle (IGCC)
Nominal Capability (MW)	750	600	623	517	415	518
Assumed Vectren Share				25%		25%
Vectren Summer Capability, MW				129		130
Base Load Net Heat Rate (Btu/kWh)	9,069	9,568	9,050	11,790	12,438	11,313
Fixed O&M (2011$/kW-yr)	28.54	35.75	28.73	50.74	62.09	39.76
Variable O&M (2011$/MWh)	4.19	5.82	7.44	14.39	16.79	8.98
Equivalent Forced Outage Rate (%)	4.60	3.50	7.80	4.60	3.50	7.80
Total Capital (2011 $000,000)	2,373	1,889	2,217	3,071	2,518	3,231
Total Capital (2011$/kW)	3,164	3,148	3,559	5,940	6,066	6,237

Gas-Fueled Technologies

Two major types of gas-fired power generation technology representing six alternatives were selected for the detailed assessment. These were either simple cycle or combined cycle technology.

- Simple cycle gas turbine (SCGT) technology was evaluated for four levels of generating capability.
- Combined cycle gas turbine (CCGT) technology was evaluated for two levels of generating capabilities.

All four of the simple cycle alternatives were included in the final integration analysis. With respect to the combined cycle alternatives, Vectren assumed that it would take a partial ownership position at the levels shown in Table 6-6, which follows. As with the coal-fired options, this assumption was made on the basis of capturing economies of scale and high efficiencies while satisfying reserve margin and capital investment constraints. CCS was not evaluated for gas fuel technologies as part of the 2009 Technology Assessment. However, many of the same CCS technologies in development for coal fueled power systems can be applied to gas fueled systems as well. The inherent advantage of natural gas as compared to coal with respect to greenhouse gas concerns has thus far typically limited the discussion of CCS as applied to natural gas power generation.

Table 6-6 Assessment of Gas Technologies

Primary Fuel	Gas					
Configuration	Simple Cycle				Combined Cycle	
Technology Description	Aeroderivative GE LM6000	Aeroderivative GE LMS100	Heavy Duty GE 7EA	Heavy Duty GE 7FA	2 X 1 GE 7EA	2 X 1 GE 7FA
Nominal Capability (MW)	85 (2x42.5)	98	84	209	263	612
Assumed Vectren Share, %	100	100	100	100	50	20
Vectren Summer Capability, MW	74	90	73	185	122	113
Base Load Net Heat Rate (Btu/kWh)	9,845	9,305	11,730	9,937	7,430	6,665
Fixed O&M (2011$/kW-yr)	6.40	10.32	9.94	8.18	20.92	11.28
Variable O&M (2011$/MWh)	3.25	2.49	19.66	15.84	8.14	6.64
Equivalent Forced Outage Rate (%)	2.4	2.4	1.0	1.0	2.5	2.5
Total Capital (2011 $000,000)	126	125	88	136	151	105
Total Capital (2011$/kW)	1,705	1,389	1,206	736	1,238	928

MODIFICATIONS TO EXISTING FACILITIES

Vectren has evaluated the feasibility of refurbishing or modifying existing facilities as part of the supply-side resource analysis of previous IRP submittals. Some of the options that have been considered in prior IRP's and remain feasible include dense pack steam turbine refurbishments and potential conversion of the Brown 3 and Brown 4 combustion turbines to a combined cycle configuration. Another potential option would be some form of parallel repowering of the steam units, Brown 1 and Brown 2, with the co-located combustion turbines, Brown 3 and Brown 4.

A.B. Brown Dense Pack Refurbishments

Vectren will perform dense pack steam turbine refurbishments during the next planned turbine-generator overhauls for both Brown 1 (2012) and Brown 2 (2013). The refurbishment of the Brown 1 and Brown 2 steam units will primarily consist of replacing the existing high pressure and intermediate pressure steam turbine sections with a more efficient dense pack arrangement. A dense pack conversion requires significant preliminary engineering by the turbine equipment manufacturer to estimate expected performance levels. For both units, it was assumed that net unit heat rate would improve 5% due to the dense pack refurbishments.

A.B. Brown Combined Cycle Conversions

The Brown 3 and Brown 4 combustion turbines (CTs) could potentially be converted to combined cycle operation. The technology assessment examined a configuration that would consist of installing Heat Recovery Steam Generators (HRSG) on the exhaust of each CT and using the steam to power a new steam turbine power block. The overall nominal capacity rating of the resulting 2 CT by 1 steam turbine arrangement would be 250 MW. The summer capability of the combined cycle arrangement would be about 80 MW higher than the current capability of two CTs during simple cycle. In the 2007 Vectren IRP, the capital costs for the conversion project were estimated to be $171 million, yielding a cost for the incremental summer capacity of $2,080/kw. Because the cost of this project was estimated to be significantly higher than new combined cycle costs (Table 6-6), this project was not selected for further consideration in the 2007 IRP. Likewise, Vectren did not include this option as part of the integration analysis for this IRP. Vectren continues to be mindful that future considerations and developments may warrant detailed investigation of this alternative at some point in time.

A.B. Brown Parallel Repowering

A second Brown plant modification would consist of a parallel repowering project. The two steam units, Brown 1 and Brown 2, at the Brown facility are located in close proximity to the two combustion turbine units, Brown 3 and Brown 4. For the 2007 IRP, the technology assessment investigated a parallel repowering configuration that would consist of installing a heat recovery steam generator (HRSG) on the exhaust of the CT units for feedwater heating of the steam units. This concept would yield significant improvements in plant heat rate for the hours that the CT(s) are in operation. However, there would actually be an estimated loss in capability of 9 MW total for the steam units due to Low Pressure (LP) turbine flow restrictions. For this type of project to be become viable it will probably have to be mutually inclusive with refurbishment projects for the two steam units to reduce or eliminate any capability loss. Although such a project is feasible in concept, the costs, benefits, and other potential implications are not satisfactorily developed at this time. Therefore, a parallel repowering project at the Brown station was not selected for further consideration in this IRP study.

Table 6-7 Assessment for AB Brown Plant Modifications

	Nominal		Summer		Capital Cost
Modification	Incremental Output (MW)	Plant Heat Rate (Btu/kWh)	Incremental Output (MW)	Plant Heat Rate (Btu/kWh)	(2007 $000)
Parallel Repowering	-9	9,850	-9	9,924	54
Combined Cycle Conversion	90	7,830	82	7,916	171

F.B. Culley Biomass

Vectren has performed preliminary feasibility assessments of biomass co-firing for Culley Unit 2. This is discussed in more detail in the Biomass section of Chapter 7 Renewables and Clean Energy.

PURCHASED POWER ALTERNATIVES

Another set of options available for assisting in meeting future supply-side resource requirements is purchased power from the wholesale electric market for both capacity and/or energy needs. Vectren is a participant in the wholesale electric power market and is a member of the ReliabilityFirst Corporation (RFC) a regional reliability organization operating within the framework of the North American Electric Reliability Council (NERC). Vectren is also a member of MISO, the independent transmission system operator that serves much of the Midwest and Canada.

Estimating the market price for power that will be available for purchase in future years is difficult. In general, forward market information for "standard" products is available from brokers, counterparties, and published price indices. However, the liquidity and price transparency of the forward market is inversely proportional to the proximity of the delivery date of the product. The forward market becomes much less liquid (less trade volume) as the delivery date of the product moves further out into the future. Price discovery is more difficult as the more forward products are less traded and therefore less transparent.

Vectren currently has a contract for 100 MW of year-round capacity that began in 2010 and expires in 2012. To determine availability and pricing of future capacity, Vectren issued a RFP in spring of 2009 for capacity beginning in 2013. Given the outcome of the 2009 IRP analysis in the Fall of 2009, Vectren elected not to pursue any of the bids received at that time.

For the early years of the current 2012-2031 IRP study period, regional reserve margins are projected to be sufficient to allow for relatively attractive capacity pricing. However, Vectren does not foresee a near term need for capacity. In the long run, regional reserve margins will approach equilibrium due to a combination of load growth and generation retirements. At that time capacity prices will converge with replacement build prices. If at some future point in time Vectren foresees a projected need for capacity, purchased power options will be fully and explicitly considered at that time.

CUSTOMER SELF- GENERATION

Vectren previously spoke with its commercial and industrial customers to determine operating hours, building types, end-use saturations, and the amount of backup and/or cogeneration in use, among other things. Using this information and applying more recent information from discussions with commercial and industrial customers, utility employees, and other energy services groups, Vectren estimated that the total MW capacity of all electric self-generation in its electric service territory is about 50 MW. This generation is generally reserved for emergency operation. The condition and readiness of this equipment varies widely. Other than company owned facilities, Vectren does not have direct control of this generation. Vectren is considering incremental opportunities related to Demand Response as discussed hereafter.

In addition, larger electric customers might be candidates for cogeneration opportunities. Vectren's marketing department is in periodic discussions with customers most likely to participate in such a project. Should such a scenario develop, Vectren would work with that customer to see if it would be financially attractive for Vectren to participate in such a project by possibly increasing the output of the cogeneration plant and thus supplying the Vectren system with the excess. Such a project can only be evaluated on a case by case basis and is not modeled in the IRP.

RENEWABLE TECHNOLOGIES

Wind

As will be discussed further in Chapter 7 Renewables and Clean Energy, Vectren has recently executed two separate long-term purchased power agreements for a total of 80 MW (nominal) of wind energy capacity. These agreements were included in all integration analysis cases for the entire 20 year study period.

Biomass

A 50 MW nominal biomass alternative was included in the detailed Technology Assessment study. It was assumed that this alternative would consist of a circulating fluidized bed boiler firing wood waste with a conventional steam turbine generator set.

Table 6-8 Assessment of Biomass Technology

Primary Fuel	BioMass Wood Waste
Technology Description	CFB and Steam Turb.
Nominal Capability (MW)	48.00
Assumed Vectren Share, %	100.00
Base Load Net Heat Rate (Btu/kWh)	13,391.00
Fixed O&M (2011$/kW-yr)	111.01
Variable O&M (2011$/MWh)	3.26
Equivalent Forced Outage Rate (%)	3.50
Total Capital (2011 $000,000)	186.00
Total Capital (2011$/kW)	3,875.03

Other

Solar and landfill gas projects are viable renewable sources of energy. However, due to their typically small relative size compared to the larger overall system needs for capacity, they weren't considered explicitly in the technology assessment or included in the integration analysis of this IRP. Vectren believes these technologies may be considered for viable projects in the future, primarily in the context of distributed generation as discussed in the following section, and that such projects will be duly evaluated as they develop.

Distributed Generation

Vectren is in the early stages of developing a formal process for the discovery and evaluation of opportunities to apply distributed generation technology. The goal of this effort will be to institutionalize the consideration of distributed generation into Vectren's business strategies and operations. This will include the consideration of distributed generation technology as an alternative for electric T&D planning and design. It will also formalize the evaluation of distributed generation as an energy and capacity resource, although this is not expected to play a significant role in the near term.

Current activities include

- engineering and cost research on distributed generation technologies,
- assessment of current and potential customer-owned distributed generation,
- cross-functional business & operational strategy development,
- and the development & design of case studies and / or potential pilot projects to build knowledge & competencies for operating utility-owned distributed generation and / or accommodating customer-owned distributed generation.

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CHAPTER 7

RENEWABLES

and

CLEAN ENERGY

CURRENT PROJECTS

Vectren currently receives renewable energy from three projects: two purchased power contracts from Indiana wind projects and one landfill methane gas project.

Benton County Wind Farm

The Benton County Wind Farm, located in Benton County, Indiana, began providing electricity to Vectren in May 2007 under a 20 year purchased power agreement. The nominal nameplate rating for this contract is 30 MW, and the expected annual energy to Vectren from this project is 94,500 MWh.

Fowler Ridge II Wind Farm

Vectren began receiving energy from the Fowler Ridge II wind farm, also located in Benton County, Indiana in December of 2009 under a 20 year purchased power agreement. The nominal nameplate rating for this contract is 50 MW, and the expected annual energy to Vectren from this project is 145,000 MWh.

Blackfoot Landfill Gas Project

Vectren owns the Blackfoot Landfill Clean Energy Project located in Pike County, Indiana. Vectren officially took over ownership of this project on June 22, 2009. This facility consists of 2 internal combustion engine-generator sets that burn methane gas collected from the adjacent Blackfoot Landfill. Total nameplate capacity is 3.2 MW gross combined for the two machines. Vectren projects to produce approximately 20,000 MWh per year from this facility. Pending future expansion of the Blackfoot landfill and corresponding development of a viable gas field, Vectren may consider adding an additional generator set to this facility at some point in the future.

RENEWABLE ENERGY CREDITS

In addition to participation in actual renewable energy projects, both through ownership and purchase power agreements, Vectren will also consider purchasing renewable energy credits (RECs) to meet future renewable mandates. Vectren will monitor the market development for RECs over the next several years to determine the soundness of such a strategy.

ADDITIONAL RENEWABLE AND CLEAN ENERGY CONSIDERATIONS

2009 Renewable RFP

Prior to the 2009 IRP submittal, Vectren issued a request for proposal (RFP) for additional renewable energy. Vectren received around 25 separate bids from renewable sources, including wind, solar, biomass, and biogas. Following evaluation of these bids, as well as Vectren's energy forecast, economic conditions, the existing renewable portfolio, and the lack of legislation to define requirements, Vectren declined to accept any of the bids. Vectren will continue to monitor the development of the renewable marketplace.

Indiana Voluntary Clean Energy Portfolio Standard

The rules for the Voluntary Clean Energy Portfolio Standard (VCEPS), as outlined in Indiana SB251, have not been finalized at the time of the submission of this plan. Vectren has not yet determined whether or how it will participate in the program. Vectren estimates observe that the current projections for renewable generation and conservation programs as outlined in the base case of this IRP would provide enough clean energy credits to adequately comply with the proposed standards (Table 7-1). If Vectren were to enter into the program and deem it necessary to obtain additional sources of clean energy, a broad range of potential options, including utility owned projects, purchased power agreements, and / or clean energy credits would be fully considered.

Table 7-1 Clean Energy Projections

		Clean Energy Source				
	Retail Sales before conservation programs	Wind Generation	Landfill Gas Generation	Conservation Programs	Vectren Clean Energy	SB251 VCEPS Standard
Year	GWh	GWh	GWh	GWh	% of sales	
2012	5,606	240	20	60	6%	
2013	5,627	240	20	110	7%	4%
2014	5,684	240	20	171	8%	
2015	5,726	240	20	242	9%	
2016	5,763	240	20	324	10%	
2017	5,792	240	20	417	12%	
2018	5,831	240	20	520	13%	
2019	5,871	240	20	627	15%	7%
2020	5,915	240	20	653	15%	
2021	5,946	240	20	680	16%	
2022	5,982	240	20	706	16%	
2023	6,017	240	20	732	16%	
2024	6,060	240	20	758	17%	
2025	6,093	240	20	784	17%	10%
2026	6,133	240	20	811	17%	
2027	6,175	240	20	837	18%	
2028	6,227	240	20	863	18%	
2029	6,267	240	20	890	18%	
2030	6,317	240	20	916	19%	
2031	6,368	240	20	943	19%	

Biomass

In 2010, Vectren commissioned KEMA to perform a high-level study assessing the regional availability of wood biomass resources. The assessment considered biomass volumes sufficient to co-fire 10% biomass with coal for F.B. Culley Unit #2 (90 MW nominal net capacity). At a co-fire level of 10%, it was estimated that minimal plant modifications would be required and the operational impacts would be minimal as well. Higher levels of biomass co-fire are feasible from a plant perspective but would require more detailed assessment and analysis. The KEMA study utilized secondary research methods and publicly available biomass resource databases. KEMA assumed a maximum radius from the generating unit of 100 miles. This “woodshed” area, including portions of Illinois, Indiana, and Kentucky, was found to contain more than adequate biomass for the minimum required tonnage of 85,000 tons per year to meet 10% co-fire.

However, the scope of the study did not involve investigation of actual supply contracts or quotes. Nor did it assess the biomass demand competition of other biomass consumers or the impact that hypothetical biomass demand from F.B. Culley Unit #2 would have on the regional market for biomass, wood, or forestry products. KEMA suggested that the "primary" wood production within the woodshed was likely fully met by demand from current consumers and that Vectren would either need to induce additional production of approximately 9% from these sources or procure biomass supply from the "merchantable forest residue" market. KEMA considered both of these supply sources to be reasonable alternatives.

With the knowledge that the regional biomass supply would likely be adequate, Vectren continues to monitor biomass co-firing opportunities for F.B. Culley Unit #2.

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CHAPTER 8

DSM RESOURCES

INTRODUCTION

The demand-side resource assessment process is based on a sequential series of steps designed to accurately reflect Vectren's markets and identify the options which are most reasonable, relevant, and cost-effective. It is also designed to incorporate the guidelines from the IURC. This chapter presents a discussion of the planning and screening process, identification of the program concepts, and a listing of the demand-side management (DSM) options passed for integration.

HISTORICAL PERFORMANCE

Since 1992, Vectren has continuously utilized DSM as a means of reducing customer load and thereby providing reliable electric service to its customers. These DSM programs were approved by the Indiana Utility Regulatory Commission (IURC or Commission) as part of Vectren's IRP process. The DSM programs provided for both peak demand and energy reductions.

Historically, DSM programs were implemented, modified, and discontinued when necessary based on program evaluations. The programs were approved by the Commission and implemented pursuant to such orders. Vectren managed the programs in an efficient and cost effective manner, and the load reductions and energy savings from the programs were significant. In all, past Vectren DSM programs reduced demand by over 70,000 kW and provided annual energy savings of over 80,000,000 kWh. Since 1992, the two programs that have continued to be offered and have historically proven to remain cost-effective over time are the Residential and Commercial Direct Load Control (DLC) Programs.

EXISTING DSM RESOURCES and PROGRAMS

Tariff Based Resources

Vectren has offered tariff based DSM resource options to customers for a number of years. Vectren has also recently began to offer new tariff based resources to our customers as a means to encourage efficient use of energy.

Interruptible Rates

In addition to the conservation DSM programs described in this chapter, Vectren has offered interruptible rate programs for commercial and industrial customers. Vectren currently has approximately 35 MW of interruptible load under contract.

Rider IP – 2 Interruptible Power Service

This rider is available to rate schedule DGS, OSS, LP, and HLF customers with an interruptible demand of at least 200 kW who were taking service under this rider during September 1997. This rider is closed to new participants.

Rider IC Interruptible Contract Rider

This rider is available to any rate schedule LP or HLF customer electric who can provide for not less than 1,000 kVa of interruptible demand during peak periods.

Rider IO Interruptible Option Rider

This rider is available to any rate schedule DGS, MLA, OSS, LP, or HLF customer who will interrupt a portion of their normal electrical load during periods of request from Vectren. A Customer's estimated load interruption capability must exceed 250 kW to be eligible. This rider is not applicable to service that is otherwise interruptible or subject to displacement under rate schedules or riders of Vectren. Customers currently taking service under Vectren's rider IP – 2, which is closed to new business, may apply for service under this rider, if eligible, for the balance or renewal of the existing contracts.

Direct Load Control (DLC)

The DLC program provides remote dispatch control for residential central cooling/heat pumps, electric water heating, and pool pumps through radio controlled load management receivers (LMR). The DLC program was implemented in April 1992 by Vectren, with the objective of reducing summer peak demand by direct, temporary cycling of participating central air conditioners and heat pumps and by shedding connected water heating and pool pump loads. Participating customers receive credits on their bills during the months of June through September based on the number and type of equipment participating in the program. The DLC program was identified, in 2007, as part of Vectren's DSM Market Assessment study, prepared by Forefront Economics Inc. and H. Gil Peach & Associates LLC, as "…of high quality and notable for its participation and program longevity." Vectren's customers have achieved significant benefits from the existing DLC program.

The program consists of the remote dispatch and control of a DLC switch installed on participating customers' central cooling units (central air conditioners and heat pumps), as well as electric water heating units where a DLC switch is also installed on the central cooling unit. For commercial customers, other equipment may participate in the program and is evaluated on an individual basis to determine the amount of peak load reduction possible, as well as the appropriate bill credit based upon the kW load controlled by the switch. The control of central cooling units is typically a 33% cycling strategy and involves cycling the compressor off ten minutes out of every half hour during the cycling period. Based on load reduction requirements, a 50% cycling strategy may also be utilized. The direct load control of water heating equipment utilizes a shedding strategy. This involves shutting off these units for the duration of the cycling period. Cycling periods are typically between two and six hours in duration.

Vectren manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction.

The DLC system has the capability to obtain approximately 25 MW of peak reduction capacity from the DLC system when all switches are fully functional. Because of the age of the existing DLC equipment in use by Vectren customers and based on recent field sample inspections of that equipment, in order to continue to obtain the peak demand reduction benefits from the DLC system, the Commission approved a multi-year DLC Inspection & Maintenance Program in Cause No. 43839. This effort is timely, given 14 - 19 years has passed since the majority of DLC switches were first installed. Over time, the operability of the DLC switches has declined for a variety of reasons, including mechanical failure, contractor or customer disconnection, and lack of re-installation when customer equipment was replaced. Vectren has embarked upon an inspection and maintenance/restoration plan that will ultimately ensure maximum load reduction. By investing in the inspection and maintenance of the DLC system over the next few years, Vectren can continue its ability to rely on this demand reduction resource as part of its resource planning. Based upon recent field inspections, the percentage of switches that have been removed or are inoperable is approximately 50%.

As of July 2011, Vectren's Residential DLC Program had approximately 27,011 customers with 37,087 switches and 630 commercial customers with 2,463 switches. The following schedule provides a forecast for the amount of load reduction available from the DLC system considering the current level of operation and the DLC Inspection and maintenance program which was recently initiated:

Table 8-1 DLC System Load Reduction Capability

DLC System Demand Reduction Projection		
	Residential and Commercial Demand Reduction (kW)	
	33% Cycling	50% Cycling
2011 DLC System Technical Potential	26,849	38,702
2011 Achievable Load Reduction	13,425	19,351
2012 Achievable Load Reduction	16,110	23,221
2013 Achievable Load Reduction	18,795	27,092
2014 Achievable Load Reduction	21,480	30,962
2015 Achievable Load Reduction	24,165	34,832
2016 Forward Load Potential	24,165	34,832

Cause No. 43839 – Rate Design

In Cause No. 43839, approved by the IURC on May 3, 2011, specific structural rate modifications were proposed by Vectren to better align Vectren's rate design to encourage conservation. These structural changes include:

- For all rate schedules, Vectren separated its variable costs from its fixed costs. These changes are intended, among other things, to provide more clarity and transparency in the rate schedules as to the variable costs that Vectren South customers can avoid as customers reduce usage.
- Combined the customers under Rate A (the "Standard" customers) and Rate EH (the "Transitional" customers) into a single rate schedule, called Rate RS - Residential Service. The results of these changes resulted in the elimination of the Rate A declining block rate design in favor of a single block rate design for the Rate RS - Standard customer group versus the previous declining block rates. The transition from a declining block rate design to a flat block rate design has been recognized as a method to encourage energy conservation.
- The availability of Rate RS-Transitional (now Rate EH) will be terminated on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition plan to gradually move the existing Rate RS-Transitional customers to RS-Standard based upon a revenue neutral transition plan is to be filed for the Commission's consideration within two years of May 3, 2011.
- The availability of the commercial Rate OSS (Off Season Service) will also be terminated on May 3, 2012 in order to eliminate the promotion of all-electric space heating. A transition plan to gradually move the existing Rate OSS customers to a comparable Rate DGS, based upon a revenue neutral transition plan, is to be filed for the Commission's consideration within two years of May 3, 2011.

The impacts of the rate modifications have not been explicitly quantified but should be reflected via the sales forecast based upon modeling the impacts of future rates.

MISO DR Program

Vectren rider DR provides qualifying customers the optional opportunity to reduce their electric costs through customer provision of a load reduction during MISO high price periods and declared emergency events. Rider DR currently offers two programs, emergency demand response ("EDR") and demand response resource Type 1("DRR-1") energy programs.

Rider DR is applicable to any customer served under rates DGS or OSS with prior year maximum demand greater than 70 kW, MLA, LP, or HLF. A customer may participate in the rider DR only with kVa or kW curtailment load not under obligation pursuant to rider IC or IO or special contract. Customers must offer Vectren a minimum of one (1) MW of load reduction, or the greater minimum load reduction requirement that may be specified by the applicable MISO BPM for the type of resource offered by customer. A customer may participate in an aggregation as described in the Rider DR in order to meet the minimum requirement.

Vectren currently does not have any customers participating in rider DR. The impacts of rider DR have not been explicitly quantified in this IRP due to rider DR being a relatively new customer offering.

Net Metering – Rider NM

Rider NM allows certain customers to install renewable generation facilities and return any energy not used by the customer from such facilities to the grid. This tariff originally allowed residential, K-12 schools and municipal customers who have installed, on their premises, photovoltaic, wind, or hydroelectric generator systems, which generate less than 10 kW of electrical power, to participate in Rider NM. As part of Cause No. 43839, Vectren sought and the IURC approved several variances from the current IURC rules as to the size of net metering facilities, the amount of net metering Vectren would allow and participation by commercial customers. On July 13, 2011 the Commission published an amended net metering rule, which included additional modifications to the rules, including eligibility to all customer classes, increase to the size of net metering facilities (1MW) and an increase in the amount of net metering allowed (1% of most recent summer peak load). The new rules also required that at least forty percent (40%) of the amount of net metering allowed would be reserved solely for participation by residential customers.

Vectren has worked with customers over the past several years to facilitate the implementation of net metering installations. As of August 1, 2011, Vectren had 22 active, 1 inactive and 1 pending net metering customers with a total nameplate capacity of 149.4 kW.

Smart Grid Resources

Smart Grid technology has the potential to enable higher levels of energy efficiency and demand response, as well as improved evaluation, measurement, and verification of energy efficiency and demand response efforts. The advanced metering infrastructure (AMI) portion of a Smart Grid project, as well as new dynamic pricing offerings, enable those customers who decide to actively manage their energy consumption to have access to significantly more information via enhanced communication. This provides those customers a better understanding and more control of their energy consumption decisions and the resulting energy bills. These improvements can provide benefits toward carbon foot print reduction as a result of the overall lowered energy consumption. The potential conservation and DSM benefits related to Smart Grid include:

- Peak reductions resulting from enabling Vectren customers to actively participate in demand response programs via dynamic pricing programs
- Enhanced load and usage data to the customer to foster increased customer conservation
- Conservation voltage and line loss reductions due to the improved operating efficiency of the system.

In 2009, as part of the funding available from the United States Department of Energy (DOE) pursuant to American Recovery and Reinvestment Act (ARRA), Vectren conducted a business case analysis of the broad benefits of a Smart Grid implementation. According to the October 27, 2009 DOE announcement, Vectren did not receive a grant award for our Smart Grid project. Vectren re-evaluated the business case and determined that it would not be prudent to proceed with a broad Smart Grid project at this time. As part of this initiative Vectren completed the development of its Smart Grid strategy where it identified the need to invest in some fundamental communication and information gathering technology in order to support future demand response and load management technology. The initial focus of the strategy is to build out a communication network that will support current and future Smart Grid technology, such as distribution SCADA, AMI, conservation voltage reduction, and system automation. Vectren has completed the implementation of a fiber optic communication path across its transmission network, connecting at both primary generating stations. The build out of the communication system has allowed Vectren to bring on additional SCADA points into its distribution substations. These SCADA installations are fundamental to the potential implementation of future conservation and voltage management programs, such as conservation voltage reduction, on the distribution network. Vectren will continue to monitor and evaluate Smart Grid technologies and customer acceptance of Smart Grid enabled energy efficiency and demand response.

Vectren recognizes the potential benefits Smart Grid technology programs offer. While a comprehensive Smart Grid deployment is likely several years in the future, the goal of any Vectren Smart Grid project will be to improve reliability, reduce outage restoration times, and increase energy conservation capabilities. The foundational investments currently being made and those planned over the next few years will enhance our ability to achieve these benefits.

The potential impacts of a robust Smart Grid implementation that would include dynamic pricing, improved information or conservation voltage reduction have not been explicitly quantified in this IRP because no specific project of this magnitude has been approved by Vectren or the Commission.

State and Federal Energy Efficiency Developments

Federal - ARRA Funding

The American Recovery and Reinvestment Act of 2009 (ARRA) was enacted in February 2009. ARRA included several provisions that expanded energy efficiency including increased tax incentives for residential energy efficiency improvements, significant increase in the amount of low-income home weatherization, as well as other significant funds channeled to state and local governments to fund energy efficiency and renewable energy efforts. The challenge over the planning horizon will be the sustainability of energy efficiency efforts in the absence or reduction of funding for these energy efficiency efforts post the ARRA funding expiration. The opportunity exists for utility funded DSM programs to play an even bigger role in moving energy efficiency efforts to new levels.

Federal – Codes, Standards and Legislation

Energy efficiency policies are gaining momentum at both the state and Federal level. Although there are numerous activities going on at the state and Federal level the following are components of significant legislation that are approaching implementation, as well as new codes, standards and legislation being considered that will likely have an impact on energy efficiency in the planning horizon.

- The Energy Independence and Security Act of 2007 requires all general-purpose light bulbs that produce 310–2600 lumens of light be 30% more energy efficient (similar to current halogen lamps) than then-current incandescent bulbs by 2012 to 2014. The efficiency standards will start with 100-watt bulbs in January 2012 and end with 40-watt bulbs in January 2014. The impacts of this legislation have been contemplated and quantified in the sales forecast modeling conducted by Vectren.

- The U.S. Department of Energy's Appliances and Equipment Standards Program develops test procedures and minimum efficiency standards for residential appliances and commercial equipment. On November 16, 2010, the DOE announced that it is making changes to expedite its rulemaking process. The Department has already taken steps to improve its internal management of the rulemaking process and is now making further changes designed to make the rulemaking process more efficient. The likely outcome of this effort will be an acceleration of appliance and equipment efficiency standards, ENERGY STAR, and building energy codes.

State – Codes, Standards and Legislation

Since the submission of the 2009 IRP, Indiana has taken several significant steps to enhance energy efficiency policy in the state.

- Indiana has been working on the development of new building codes, which will likely be implemented in the near future.
- The IURC released the Phase II Generic DSM order on December 9, 2009. The order:
    - Established statewide electric savings goals for utilities starting in 2010 at 0.3% of average sales and ramping to 2% per year in 2019.
    - Defined a list of 5 Core DSM Programs to be offered on a statewide basis by a Third Party Administrator (TPA). Programs include residential lighting, home energy audits/kits, low income weatherization, school education programs and commercial/industrial prescriptive rebates.
    - Allows utilities the option to offer Core Plus programs in an effort to reach the 2% goal.
    - Requires programs to be evaluated, measured and verified (EM&V) by a statewide independent evaluator.
    - Established a Demand Side Management Coordination Committee (DSMCC) to oversee DSM programs.

On July 27, 2011 the IURC approved the selection of the third party administrator and evaluator contracts as submitted by the DSMCC.

- Senate Enrolled Act 251 established a Voluntary Clean Energy Portfolio Standard Program which supports an increase of renewable energy and energy efficiency.

VECTREN DSM STRATEGY

Vectren has adopted a cultural change that encourages conservation and efficiency. Vectren has embraced energy efficiency and actively promotes the benefits of energy efficiency to its employees and customers. Vectren has taken serious steps to implement this cultural change starting with our own employees. Vectren encourages each employee, especially those with direct customer contact, to promote conservation. Internal communications, conservation flyers and handouts, meetings with community leaders, and formal training have all promoted this shift. This cultural shift was a motivating factor in launching a new Vectren motto of "Live Smart" in order to further emphasize efficiency. The following purpose and mission of “Live Smart” is the foundation of the Vectren Strategy related to DSM:

Purpose

With an unwavering focus on the need to conserve natural resources, we provide energy and related solutions that make our customers productive, comfortable and secure.

Mission

We will be the industry leader in helping our customers manage their energy costs. We will achieve best-in-class safety performance and top quartile performance in customer satisfaction and productivity. We will deliver superior investor returns.

Customers are a key component of our values, and we know success comes from understanding our customers and actively helping them to use energy efficiently.

DSM PLANNING PROCESS

The following outlines Vectren's planning process in support of Vectren's strategy to identify cost effective energy efficiency resources. In 2006, Vectren, the OUCC, and CAC formed the DSM Collaborative (Collaborative) as a result of a settlement in Cause No. 42861. The Collaborative provided input in the planning of Vectren's proposed DSM programs. Initially, the Collaborative helped select Forefront Economics and H. Gil Peach and Associates to conduct the Market Assessment Study (Study or Peach Report) and provide input on the development of the Study. Upon completion of the Study (titled "Electric DSM Action Plan" and included in the Technical Appendix), the Collaborative reviewed the Peach Report, as well as other available information regarding DSM programs. The other information included Vectren's own research and the results of commercial customer surveys performed by Vectren. Numerous Collaborative meetings were conducted to consider the design of new programs, funding levels, program reporting, implementation and administration, and cost recovery issues. The Collaborative provided input on the work performed to develop the DSM portfolio. Vista Energy, a DSM consultant employed by Vectren, expanded on the work already provided to the Collaborative via the Peach Report to help finalize a portfolio of DSM programs. While aspects of Vectren's DSM planning updated the Peach Report, the Market Assessment Study served as the foundation of Vectren's efforts to identify and capture energy efficiency and DSM lost opportunities.

Through this process, in years past, Vectren's DSM portfolio of programs were developed through a sequential set of planning steps aimed at taking the most current industry and market information to screen and prioritize the relevant opportunities based on their costs and benefits. Planning steps included:

- <u>Customer Market Research</u>
- <u>Leverage of Past DSM Filing & Market Assessment Information</u>
- <u>Development of Candidate Program Concepts</u>
- <u>Development of Technology and Market Data</u>
- <u>DSM Technology Screening</u>

- Identification of DSM Programs for Resource Integration

On December 9, 2009, the Indiana Utility Regulatory Commission ("IURC" or "Commission") issued the Phase II Order in Cause No. 42693 which established energy saving goals for all jurisdictional utilities in Indiana. The Phase II Order required all jurisdictional utilities to implement 5 specified programs, which the Commission termed Core Programs. The Core Programs are to be administered by a third party administrator (TPA) selected through a process involving the Demand Side Coordination Committee composed of jurisdictional Utilities (IOU's) and other pertinent key stakeholders. The Commission recognized that achieving the goals set out in the Phase II Order would not be possible with Core Programs alone and encouraged the utilities to implement Core Plus Programs to assist in reaching the annual savings goals.

On December 16, shortly after the Phase II Order, the Commission issued an Order in Vectren South-Electric's Petition in Cause No. 43427, in which the Commission approved all of the programs proposed by Vectren and separated them into Core and Core Plus Program categories. The DSM programs approved in Cause No. 43427 did not meet the overall savings requirements of the Phase II Order nor did the DSM plan include DSM programs for large customers. In April of 2010, Vectren began implementing electric conservation programs approved in Cause No. 43427. Table 8-2, shown below, details the programs and associated energy savings and program expenditures for programs offered under Cause No. 43427.

Table 8-2 Vectren Core & Core Plus Programs Data – Cause No. 43427

Cause No. 43427	Gross MWh Savings		Program Expenditures	
CORE PROGRAMS	**2010 Actual**	**2011 Forecast Year End**	**2010 Actual**	**2011 Forecast Year End**
Residential Lighting	0	19,400	$10,050	$600,000
Home Energy Audit	0	25	$10,050	$70,000
Low Income Weatherization	0	25	$10,050	$50,000
Energy Efficient Schools	759	700	$104,958	$105,000
Total Core Programs By Year	759	20,150	$135,108	$825,000
CORE PLUS PROGRAMS	**2010 Actual**	**2011 Forecast Year End**	**2010 Actual**	**2011 Forecast Year End**
Residential Appliance Recycling	1,739	1,600	$210,764	$240,000
Residential New Construction	5	15	$44,274	$120,000
Commercial & Industrial Audit & Custom	974	1,800	$274,774	$225,000
Commercial & Industrial New Construction	0	400	$108,314	$175,000
Total Core Plus Programs By Year	2,718	3,815	$638,126	$760,000

Portfolio Summary	2010 Actual	2011 Forecast Year End	2010 - 2011 Summary
Total Gross MWH Core & Core Plus	3,477	23,965	27,442
Total Program Expenditures Core & Core Plus	$773,234	$1,585,000	$2,358,234

In order to ensure compliance with the Phase II order, Vectren modified existing programs approved in Cause No. 43427 and added new programs, which were approved on August 31st, 2011 in Cause No. 43938. Outlined below is the 2011-2013 DSM Plan approved under Cause No. 43938, which provides details regarding the Core and Core Plus Programs that will be offered by or on behalf of Vectren during the period of 2011-2013 in order to meet the savings identified in the Phase II Order.

Core Programs

- Residential Lighting
- Home Energy Audit and Direct Install
- Low Income Weatherization

- School Energy Efficiency
- Commercial & Industrial Prescriptive

Core Plus Programs

- Residential Second Refrigerator Pick-Up Program
- Residential Window Air Conditioner Pick-Up Program
- Residential New Construction
- Residential HVAC
- Residential Behavioral Savings
- Residential Multi-Family
- Commercial & Industrial Audit & Custom
- Commercial & Industrial New Construction
- Direct Use

DSM SCREENING RESULTS

Terra Vista Energy Group was utilized by Vectren to provide expertise to perform research, model the savings/benefits, and help develop the Vectren Electric DSM Program. The analysis of the energy efficiency and DSM programs was handled through the use of a spreadsheet model designed to conduct the relevant cost-effectiveness results. The model, developed by ANB Enterprises Inc., is structured to handle the accounting of costs and benefits for the various programs and the entire portfolio. The model is structured in an Excel spreadsheet with various worksheets to accommodate the range of needed data inputs.

The model includes a full range of economic perspectives typically used in energy efficiency and DSM analytics. The perspectives include:

- Participant Test
- Utility Cost Test
- Rate Impact Measure Test

- Total Resource Cost Test

All the economic tests are based on the cost-effectiveness methodologies from the *California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects*, California Office of Planning and Research, 2002.

The model has successfully been used in analysis of energy efficiency programs in a number of states including New York, Pennsylvania, Indiana, and Ohio.

The cost effectiveness analysis produces two types of resulting metrics:

1. Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
2. Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

All results are expressed in dollars. The methodology directly copies the algorithms from the California Standard Practice Methodology. The California standard practice manual was first developed in February 1983. It was later revised and updated in 1987–88 and 2001; a correction memo was issued in 2007.

As stated above, the cost effectiveness analysis reflects four primary tests. Each reflects a distinct perspective and has a separate set of inputs reflecting the treatment of costs and benefits. A summary of benefits and costs included in each cost effectiveness test is shown below in Table 8-3.

Table 8-3 Vectren Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, fixed, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, fixed, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

The Participant Cost Test shows the value of the program from the perspective of the utility's customer participating in the program. The test compares the participant's bill savings over the life of the DSM program to the participant's cost of participation.

The Utility Cost Test shows the value of the program considering only avoided utility supply cost (based on the next unit of generation) in comparison to program costs.

The Ratepayer Impact Measure (RIM) Test shows the impact of a program on all utility customers through impacts in average rates. This perspective also includes the estimates of revenue losses which may be experienced by the utility as a result of the program.

The Total Resource Cost (TRC) Test shows the combined perspective of the utility and the participating customers. This test compares the level of benefits associated with the reduced energy supply costs to utility programs and participant costs.

In completing the tests listed above, Vectren used 7.29% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on April 27, 2011 in Cause No. 43839. The avoided costs used in the tests are shown below in Table 8-4.

Table 8-4 Vectren Avoided Costs

	Generation Avoided Cost	Transmission/ Distribution Avoided Cost	Total Capacity Avoided Cost	Marginal Energy Cost	Marginal Energy Cost
	$/kW	$/kW	$/kW	$/MWh	$/KWh
2012	69.02	6.90	75.92	44.23	0.0442
2013	70.41	7.04	77.45	42.01	0.0420
2014	71.81	7.18	78.99	44.47	0.0445
2015	73.25	7.33	80.58	49.11	0.0491
2016	74.72	7.47	82.19	52.21	0.0522
2017	76.21	7.62	83.83	55.92	0.0559
2018	77.74	7.77	85.51	60.34	0.0603
2019	79.29	7.93	87.22	64.85	0.0649
2020	80.88	8.09	88.97	69.55	0.0696
2021	82.49	8.25	90.74	73.44	0.0734
2022	84.14	8.41	92.55	77.18	0.0772
2023	85.83	8.58	94.41	82.37	0.0824
2024	87.54	8.75	96.29	87.04	0.0870
2025	89.29	8.93	98.22	94.74	0.0947
2026	91.08	9.11	100.19	99.61	0.0996
2027	92.90	9.29	102.19	103.99	0.1040
2028	94.76	9.48	104.24	108.07	0.1081
2029	96.65	9.67	106.32	112.80	0.1128
2030	98.59	9.86	108.45	118.48	0.1185
2031	100.56	10.06	110.62	125.81	0.1258

A review of the benefit/cost results for each of the technologies considered in the screening analysis is detailed below in Table 8-5.

Table 8-5 Vectren DSM Technology Screening Results

Residential Technology Analysis Results

Results for Technology Only - One Participant in Start Year and No Program Costs

ID	Program Name	Participant Test NPV $	Participant Test BCR	RIM Test NPV $	RIM Test BCR	TRC Test NPV $	TRC Test BCR
1	Res 2nd Refrigerator Pickup	$1,028	0.00	($518)	0.46	$510	0.00
2	Room AC Pickup-Ridew/Ref	$65	0.00	$313	6.16	$378	0.00
3	Energy Star Windows	$60	1.40	$1,252	7.38	$1,312	9.75
4	Low Income Weatherization	$1,152	6.26	($140)	0.89	$1,012	5.62
5	Res. Lighting	$34	9.51	($15)	0.46	$12	4.87
6	Water Heater Pipe Insulation	$197	7.80	($97)	0.54	$100	4.45
7	Water Heater Pipe Insulation	$197	7.80	($97)	0.54	$100	4.45
8	Residential Audit	$757	5.33	($166)	0.81	$591	4.38
9	Low Flow Showerheads (2)	$484	7.36	($216)	0.54	$222	4.25
10	Energy Efficient Pool Pump-Pilot	$504	3.80	$33	1.05	$536	3.98
11	Smart Strip Plug-PA TRM	$89	4.42	($16)	0.86	$73	3.82
12	Energy Eff. Electric Water Heater .91-.93	$65	1.86	$80	1.61	$145	2.93
13	Std Gas Water Heater Conversion	$785	5.02	($416)	0.53	$311	2.45
14	House Sealing-Blower Door-All Electric	$752	3.51	($330)	0.66	$422	2.41
15	Res. New Construction-	($219)	0.88	$957	1.65	$738	1.41
16	Eff Split System CAC-R13-R17	($661)	0.48	$926	2.60	$265	1.21
17	Eff Split System CAC-R13-R16	($608)	0.48	$833	2.58	$225	1.19
18	Eff Split System CAC-R13-R18	($924)	0.42	$1,109	2.75	$184	1.12
19	Ceiling Insulation R10-R30	($159)	0.53	$162	1.98	$3	1.01
20	Smart Strip-7 Plug-Ohio TRM	$27	2.04	($29)	0.42	($1)	0.94
21	Smart Strip-5 Plug-Ohio TRM	$13	1.83	($14)	0.47	($1)	0.93
22	Ceiling Insulation R10-R38	($234)	0.45	$176	1.99	($58)	0.86
23	Res Ht Pump Tune Up	$129	1.74	($159)	0.44	($30)	0.83
24	House Sealing-Blower Door-Electric/Gas	($90)	0.70	$32	1.16	($58)	0.81
25	Energy Star Clothes Dishwasher	($22)	0.83	($14)	0.87	($36)	0.73
26	Solar Water Heater	($5,722)	0.40	$833	1.24	($4,889)	0.49
27	Res AC tune up	($101)	0.42	($27)	0.61	($128)	0.27
28	Basement Wall Insulation R0-R19 batts	($2,658)	0.04	$185	2.72	($2,473)	0.11
29	Basement Wall Insulation R0-R13 batts	($2,417)	0.04	$166	2.93	($2,251)	0.10
30	Cool Roof	($8,197)	0.03	$95	1.39	($8,102)	0.04

Measures with a benefit-cost ratio of 0.00 indicates no direct technology costs are applied.

Utility Cost test results are not provided since there are no program costs.

Commercial/Industrial Technology Analysis Results

Results for Technology Only - One Participant in Start Year and No Program Costs

		Participant Test		RIM Test		TRC Test	
ID	Program Name	NPV $	BCR	NPV $	BCR	NPV $	BCR
1	Commercial DLC	$0	0.00	$857	0.00	$857	0.00
2	Engineered Nozzles	$510	37.41	$175	1.36	$685	49.90
3	Comm Premium Motors	$1,577	7.31	$33	1.02	$1,610	7.44
4	Commercial New Construction	$29,526	4.11	$14,996	1.41	$44,522	5.69
5	Commercial Lighting-Replacement	$12,734	4.46	($1,049)	0.93	$11,686	4.17
6	Recast Prescriptive Rebate Program	$299	4.32	($26)	0.93	$273	4.03
7	RetroCommissioning-Lite	$9,684	5.84	($4,264)	0.61	$5,420	3.71
8	Energy Efficient Packaged AC-Commercial-Small Office	$5,560	2.86	$2,514	1.31	$8,075	3.71
9	Energy Efficient Packaged AC-Commercial-Large Office	$9,261	2.72	$4,387	1.32	$13,648	3.54
10	Energy Star Refrigerated Beverage Machine Controls	$1,256	5.48	($579)	0.60	$676	3.42
11	Commutated Motors	$2,475	3.65	($217)	0.93	$2,258	3.41
12	Commercial Lighting-Retrofit	$11,813	3.57	($1,049)	0.93	$10,765	3.34
13	VendMiser	$642	3.99	($201)	0.75	$441	3.05
14	Commercial Commissioning	$4,669	3.33	($1,291)	0.79	$3,377	2.69
15	Older Building Roof Insulation-Large Office	$755	1.13	$6,727	2.13	$7,483	2.34
16	Vending Machine Sensors	$695	4.22	($490)	0.42	$205	1.95
17	Upgrade Ceiling Insulation-Old Bldg	($484)	0.81	$2,761	2.39	$2,278	1.90
18	Older Building Roof Insulation-Small Office	($1,603)	0.37	$3,074	4.52	$1,471	1.58
19	Comm Window Film	$118	1.44	($31)	0.91	$87	1.33
20	Occupoancy Sensor-Plug Loads-Large Office	$19	1.16	($2)	0.98	$17	1.14
21	Occupancy Sensor-Lighting	$134	2.15	($126)	0.48	$9	1.07
22	Occupoancy Sensor-Plug Loads-Small Office	$19	1.16	($11)	0.92	$9	1.07
23	Older Building Roof Insulation-Education	($14,788)	0.18	$11,086	4.66	($3,702)	0.79
24	Solar Water Heater	($4,740)	0.41	$1,776	1.56	($2,859)	0.64
25	Low E Windows (1500 SF)	($16,361)	0.45	$3,631	1.28	($12,730)	0.58
26	Light Colored Roof	($31,482)	0.10	($1,071)	0.66	($32,553)	0.07

Measures with a benefit-cost ratio of 0.00 indicates no direct technology costs are applied.

Utility Cost test results are not provided since there are no program costs.

Table 8-6, listed below, shows the Core and Core Plus Programs benefit/cost data per the portfolio of programs approved under Cause No. 43938. Core Programs savings, budgets and program designs are based on the Statewide TPA contract. It should be noted that the Statewide TPA Core Programs implementation is not expected to begin until 2012, thus the tables reflect no participation in 2011 for those programs. For the purposes of this IRP, the benefit/cost results were updated utilizing the avoided costs contained in Table 8-4.

Table 8-6 Program Benefit/Cost Results for Three Year DSM Plan

Core Programs

ID	Program Name	Participant Test NPV, 000$	Participant Test BCR	Utility Test NPV, 000$	Utility Test BCR	RIM Test NPV, 000$	RIM Test BCR	TRC Test NPV, 000$	TRC Test BCR
1	Program Outreach-Core	$0	0.00	($128)	0.00	($128)	0.00	($128)	0.00
2	Residential On Site Audit and Kit	$6,376	6.13	$1,575	1.63	($2,759)	0.60	$1,423	1.46
3	Residential Energy Efficient Lighting	$13,605	11.00	$2,609	2.91	($4,890)	0.45	$3,250	2.95
4	Low Income Weatherization	$3,079	7.98	$982	1.58	($1,600)	0.62	$1,183	1.70
5	School Energy Efficiency	$3,407	6.39	($523)	0.63	($2,522)	0.26	($110)	0.91
7	C&I Prescriptive Rebate Program	$50,596	5.15	$36,973	7.51	($2,422)	0.95	$35,123	4.09
	TOTAL	$77,062	5.86	$41,488	4.25	($14,321)	0.79	$40,742	3.12

Core Plus Programs

ID	Program Name	Participant Test NPV, 000$	Participant Test BCR	Utility Test NPV, 000$	Utility Test BCR	RIM Test NPV, 000$	RIM Test BCR	TRC Test NPV, 000$	TRC Test BCR
1	Residential Program Outreach	$0	0.00	($509)	0.00	($509)	0.00	($509)	0.00
2	Residential Refrigerator Recycling and Pickup	$6,635	0.00	$1,239	2.54	($1,922)	0.52	$1,780	3.57
3	Room AC Recycling-Ride Along	$46	0.00	$13	1.16	($1)	0.99	$32	1.54
4	Res Multi Family Program	$2,582	33.97	$792	2.68	($888)	0.59	$977	3.15
5	Res HVAC	$2,757	2.50	$3,964	4.35	$1,133	1.28	$3,268	2.53
6	Res New Construction	$181	1.59	($26)	0.95	($263)	0.64	($125)	0.79
8	Residential O Power	$5,592	0.00	$695	1.42	($3,952)	0.37	$1,061	1.64
9	Direct Use Program	$785	5.02	$259	2.21	($416.08)	0.53	$311	2.45
10	Commercial Industrial Outreach	$0	0.00	($274)	0.00	($274)	0.00	($274)	0.00
11	Comm and Industrial New Construction	$2,698	5.12	$3,128	5.00	$738	1.23	$2,942	3.51
12	Commercial and Industrial Audit-Custom	$5,668	3.66	$1,102	1.42	($3,389)	0.52	$668	1.19
	TOTAL	$26,944	6.18	$2	1.86	($9,743)	0.67	$10,130	1.90

Table 8-7, listed below, shows program inputs for an individual participant in the program as well as the associated estimated bill impacts.

Table 8-7 Vectren DSM Programs Input Data

Core Programs

Program Name	Annual Energy Savings, kWh	Incremental Technology Cost	Customer Incentive	Program Cost Borne By Participant	Projected Participant Annual Bill Reduction
Residential On Site Audit and Kit	1,036	$ 175.00	$ 33.15	$ 141.85	$ 138.82
Residential Energy Efficient Lighting	61	$ 4.00	$ 1.59	$ 2.41	$ 8.17
Low Income Weatherization	1,304	$ 219.07	$ 219.07	$ -	$ 174.74
School Energy Efficiency	376	$ 48.50	$ 48.50	$ -	$ 50.38
C&I Prescriptive Rebate Program	363	$ 89.97	$ 29.99	$ 59.98	$ 44.07

Core Plus Programs

Program Name	Annual Energy Savings, kWh	Incremental Technology Cost	Customer Incentive	Program Cost Borne By Participant	Projected Participant Bill Reduction
Residential Refrigerator Recycling	1,647	$ -	$ 30.00	$ (30.00)	$ 220.70
Room AC Recycling	104		$ 30.00	$ (30.00)	$ 13.94
Res Multi Family Program	704	$ 20.00	$ 20.00	$ -	$ 94.34
Residential HVAC ECM Program	484	$ 200.00	$ 60.00	$ 140.00	$ 64.86
Residential Cooling Program-CAC	475	$ 900.00	$ 300.00	$ 600.00	$ 63.65
Residential Cooling Program-HP	700	$ 1,100.00	$ 400.00	$ 700.00	$ 93.80
Res New Construction	949	$ 1,800.00	$ 1,000.00	$ 800.00	$ 127.22
Residential Behavioral Savings	280	$ -	$ -	$ -	$ 37.52
Comm and Industrial New Construction	28,000	$ 9,486.00	$ 3,360.00	$ 6,126.00	$ 3,399.20
Commercial and Industrial Audit/Custom Program-Med CI	13,246	$ 4,166.00	$ 1,590.00	$ 2,576.00	$ 1,608.06
Commercial and Industrial Audit/Custom Program-Large CI	26,492	$ 8,332.00	$ 3,179.00	$ 5,153.00	$ 3,216.13
Direct Use Program	4,879	$ 850.00	$ 850.00	$ -	$ 653.79

PROGRAM CONCEPTS

Customer Outreach and Education

Program

This program will raise awareness and drive customer participation to the Core and Core Plus DSM Programs as well as educate customers on how to manage their energy bills. The program will include the following goals as objectives:

- Build awareness
- Educate consumers on how to conserve energy and reduce demand
- Educate customers on how to manage their energy costs and reduce their bill
- Communicate Vectren's support of customer energy efficiency needs
- Drive participation in the Core and Core Plus DSM Programs

This annual program will include paid media, web-based tools to analyze bills, energy audit tools, and energy efficiency and DSM program education and information. Informational guides and sales promotion materials for specific programs will also be included.

The TPA will oversee and coordinate the outreach and education programs for the Core programs. Vectren will oversee the outreach and education programs for the Core Plus programs. Vectren will work closely with the TPA to provide consistent messaging across Core and Core Plus outreach and education efforts. Vectren will utilize the services of communication and energy efficiency experts to deliver the demand and energy efficiency message.

Eligible Customers

Any Vectren electric customer will be eligible.

Energy/Demand Savings

This communications effort differs from typical DSM programs in that there are no direct estimates of participants, savings, costs, and cost-effectiveness tests. Such estimates are considered impractical for these types of overarching efforts to educate consumers and drive participation in other DSM programs. The California Standard Practice Manual (p. 5) addresses this issue as follows:

> *"For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts."*

The budget will have $71,321 annually dedicated to Core Programs, which will be administered by the TPA, as well as $300,000 annually for Core Plus Programs to be administered by Vectren. The actual amount of the statewide Core Outreach Program is much larger but this value represents Vectren's portion of the outreach for Core Programs.

Table 8-8 DSM Outreach & Education Program Budget

DSM Outreach & Education Program Budget		
Market	Year	Program Budget $,000
Residential & Commercial/Industrial	2011 2012 2013	$ 300 $ 371 $ 371
Total Program		$ 1,042

Core Programs

School Energy Efficiency Program

Program

The School Energy Efficiency Program is designed to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity. The program consists of two components:

a. A school education program for selected students attending schools served by Vectren. To help in this effort it is envisioned that each student that participates will receive a free take-home kit containing energy saving measures.
b. A school energy savings assistance program consisting of technical assistance and building energy audits. The audits help schools identify operational and capital improvements to school facilities served by Vectren.

Eligible Customers

The program will be available to selected students/schools in the Vectren electric service territory. The School Energy Efficiency Program targets two primary customer sectors:

a. Energy education targets K-12 students. The program may initially focus on a limited number of schools and students in a particular grade.

b. The school energy savings assistance program targets K-12 schools that are greater than ten (10) years old.

Energy/Demand Savings

The proposed savings are attributed to the take-home kits provided to the elementary school children for parents to install. For modeling purposes, the energy savings estimate is 376 kWh per participant.

Table 8-9 School Energy Efficiency Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	School Energy Efficiency					
	2011					
	2012	6,535	5.4%	2,457	0	$726
	2013	7,987	6.6%	3,003	0	$843
Cumulative Program Total		14,522		5,460		$ 1,569
Potential Participants						121,000
Per Participant Energy Savings (kWh)						376
Per Participant Demand Savings (kW)						0.000
Measure Life						5
Net To Gross Ratio						0.70

Residential Lighting Program

Program

The Residential Lighting Program is proposed as a market-based residential DSM program designed to reach residential customers through retail outlets. The program design consists of a buy-down strategy to provide the incentive to consumers to facilitate their purchase of energy-efficient lights. This program is justified based on direct energy savings targets, but also has a significant market transformation opportunity.

The value of the program addresses the following: empowering customers to take advantage of new lighting technologies, accelerate the adoption of proven energy efficient technologies, and experience the benefits of energy efficiency and decrease their energy consumption.

Eligible Customers

Any Vectren residential electric customer is eligible.

Energy/Demand Savings

The program is designed to provide an incentive for the purchase and installation of CFL bulbs. For modeling purposes, the savings estimates per bulb are 61 kWh annually with demand savings of 0.007 kW.

Table 8-10 Residential Lighting Program Data

Market	Program & Year	Number of Participants (Bulbs)	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential Lighting					
	2011					
	2012	170,557	141.0%	10,404	1,177	$714
	2013	208,443	172.3%	12,715	1,438	$804
Cumulative Program Total		379,000		23,119	2,615	$ 1,518
Potential Participants						121,000
Per Participant Energy Savings (kWh)						61
Per Participant Demand Savings (kW)						0.007
Measure Life						5
Net To Gross Ratio						0.62

Residential Audit & Direct Install Program

Program

The Residential Audit and Direct Install Program is proposed to help produce long-term, cost effective electric savings in the residential market sector by helping customers analyze and understand their energy use; recommending appropriate weatherization measures, and facilitating the direct installation of specific low-cost energy saving measures. Direct install measures will include CFLs and hot water saving products.

Eligible Customers

Any Vectren single family residential electric customer is eligible.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,036 kWh and .46 kW per participant.

Table 8-11 Residential Audit & Direct Install Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential Audit & Direct Install					
	2011					
	2012	3,565	2.9%	3,693	1,640	$1,261
	2013	4,356	3.6%	4,513	2,004	$1,505
Cumulative Program Total		7,921		8,206	3,644	$ 2,766
Potential Participants						121,000
Per Participant Energy Savings (kWh)						1,036
Per Participant Demand Savings (kW)						0.46
Measure Life						8
Net To Gross Ratio						0.70

Low Income Weatherization

Program

The Low Income Weatherization program is designed to produce long-term energy and demand savings in the residential market. The program will provide weatherization upgrades to low income homes that otherwise would not have been able to afford the energy saving measures. The program will provide direct installation of energy saving measures, educate consumers on ways to reduce energy consumption, and identify opportunities for additional weatherization measures.

Eligible Customers

The Residential Low Income Weatherization Program targets single-family homeowners and tenants, who have utility electric service in their name with Vectren and with a total household income up to 200% of the federally-established poverty level. Priority will be given to:

a. Single parent households with children under 18 years of age living in dwelling.
b. Households headed by occupants over 65 years of age.
c. Disabled homeowners as defined by the Energy Assistance Program (EAP).
d. Households with high energy intensity usage levels.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 1,304 kWh annually with demand savings of 0.55 kW.

Table 8-12 Low Income Weatherization Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Low Income Weatherization					
	2011					
	2012	1,010	4.6%	1,317	556	$853
	2013	1,235	5.7%	1,610	679	$1,023
Cumulative Program Total		2,245		2,927	1,235	$ 1,876
Potential Participants						21,780
Per Participant Energy Savings (kWh)						1,304
Per Participant Demand Savings (kW)						0.55
Measure Life						10
Net To Gross Ratio						1

Commercial and Industrial Prescriptive Program

Program

The Commercial and Industrial (C&I) Prescriptive Program is designed to help facility managers and building owners achieve long-term, cost-effective savings in the commercial and industrial market sector by assisting them in upgrading to energy efficient products. The incentives are designed to promote lower electricity consumption, assist customers in managing their energy costs, and build a sustainable market around energy efficiency.

Eligible Customers

Any Vectren electric commercial or industrial customer is eligible.

Incentive

This program includes a prescriptive rebate structure that rewards participants with monetary rebates based on their installation of energy efficiency equipment upgrades.

Energy/Demand Savings

For modeling purposes, the energy savings estimate is 363 kWh per participant (measure) and demand savings of .09 kW.

Table 8-13 Commercial and Industrial Prescriptive Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Commercial & Industrial	C&I Prescriptive					
	2011					
	2012	67,983	543.9%	24,678	6,200	$2,897
	2013	83,091	664.7%	30,162	7,578	$3,428
Cumulative Program Total		151,074		54,840	13,778	$ 6,325
Potential Participants						12,500
Per Participant Energy Savings (kWh)						363
Per Participant Demand Savings (kW)						0.09
Measure Life						12
Net To Gross Ratio						0.8

Core Plus Programs

<u>Residential Second Refrigerator Pick-Up</u>

Program

The Vectren Residential Second Refrigerator Pick-Up Program is designed to provide for the removal and disposal of operable, inefficient secondary refrigerators and freezers in an environmentally safe manner. Purely from an energy perspective, the value of this program is in the disassembly of inefficient refrigerators and freezers so they do not operate on the power system. It is a tendency of some households to retain an old refrigerator in the garage or basement when a new refrigerator takes its place in the kitchen. Generally, the old refrigerator is plugged in, but used as a convenience to cool canned beverages or casual meals or snacks. Although viewed as a convenience, the actual price, both on the household electric bill and to the electric system, is disproportionate to the benefits provided.

The removal and proper disposal of older secondary refrigerators and freezers provides many other environmental and safety benefits. Utility programs that focus on replacing and comprehensively recycling old appliances can prevent pollution in a number of valuable ways by:

- Preventing the release of chlorofluorocarbons (CFCs), hydro chlorofluorocarbons (HCFCs) and hydro fluorocarbons (HFCs), from cooling systems and insulation, which destroy the ozone layer and accelerate global climate change
- Capturing toxic materials from lubricating oil and capacitors that could contaminate surface and ground water
- Recovering and reusing metals, plastics, and other potentially valuable materials that make up the bulk of the appliance which would otherwise waste valuable landfill space

Eligible Customers

Any Vectren residential electric customer with an operable secondary refrigerator or freezer is eligible.

Incentive

The program offers customers free pick-up of working refrigerators or freezers and a $30 cash incentive.

Energy/Demand Savings

The program is designed to remove the old, secondary refrigerator or freezer. The savings estimate is 1,647 kWh annually, with a summer demand savings of 0.19 kW.

Table 8-14 Residential Second Refrigerator Pick-Up Program Data

Market	Program & Year	Number of Participants	Percent of Participants	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential Second Refrigerator Pickup					
	2011	1,200	3.5%	1,976	228	$ 270
	2012	1,600	4.7%	2,636	304	$ 330
	2013	1,600	4.7%	2,635	304	$ 330
Cumulative Program Total		4,400		7,247	836	$ 930
Potential Participants						33,880
Per Participant Energy Savings (kWh)						1,647
Per Participant Demand Savings (kW)						0.19
Measure Life						8
Net To Gross Ratio						0.6

Residential Room Air-Conditioner Pick-Up

Program

The Residential Room Air Conditioner program is designed to allow Vectren customers with old, inefficient room air conditioners to turn these units in and remove them from use. The program serves as a complimentary offering with the proposed Second Refrigerator Pick-Up program. Customers will be able to schedule pick-up and removal of working room air conditioners

Once picked up, the appliances will be decommissioned and dismantled so that the components can be recycled in an environmentally responsible way. Only a bare minimum of material will reach landfill sites. Particular attention will be paid to the chemicals used in units that are significant atmospheric pollutants and responsible for ozone depletion. These will be contained and destroyed.

Eligible Customers

Any Vectren South residential electric customer with an operable window air conditioner is eligible.

Incentive

For each residential room air conditioner collected, an incentive of $30 will be provided to the customer.

Energy/Demand Savings

The program is designed to remove the old room air conditioner and assumes participants will purchase a new, energy efficient room air conditioner. The savings estimate, is 104 kWh annually, with a summer demand savings of 0.9 kW.

Table 8-15 Residential Second Window AC Pick-Up Program Data

Market	Program & Year	Number of Participants	Percent of Participants	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential Window A/C Pickup					
	2011	200	1.0%	21	180	$ 28
	2012	230	1.2%	24	207	$ 30
	2013	260	1.3%	26	234	$ 33
Cumulative Program Total		690		71	621	$ 91
Potential Participants						19,360
Per Participant Energy Savings (kWh)						104
Per Participant Demand Savings (kW)						0.9
Measure Life						3
Net To Gross Ratio						0.6

<u>Residential HVAC Program</u>

Program

The Residential HVAC Program provides a financial incentive in the form of a prescriptive rebate on electronically commutated motors (ECMs), central air conditioners, and heat pump systems installed in existing residences.

Electronically commutated motors were selected to be part of the program because of their low energy usage, as compared to standard motors typically utilized in HVAC equipment. When used in a variable speed blower scenario, the devices offer significant energy savings, better comfort, and increased humidity removal.

The goal of the program is to influence the residential sector to choose higher efficiency HVAC equipment when purchasing new equipment.

Eligible Customers

Any residential customer located in the Vectren electric service territory is eligible.

Incentive

The rebates will be a set amount of $60 per electronically commutated motor (ECM), $300 per central air conditioner (CAC) with a SEER rating of 16 or greater, and $400 per heat pump (HP) with a SEER rating of 16 or greater paid to residential customers who complete a rebate application and submit documentation of the equipment purchase. Note that heat pump rebates will only be paid to customers who do not have natural gas available to the premise.

Energy/Demand Savings

For modeling purposes, the energy/demand savings estimates are 484 kWh/.25 kW per ECM participant, 475 kWh/.35 kW per CAC participant, and 700 kWh/.35 kW per HP participant.

Table 8-16 Residential HVAC Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential HVAC					
	2011	1,520	1.7%	737	412	$ 472
	2012	1,975	2.2%	958	541	$ 420
	2013	2,125	2.4%	1,028	594	$ 466
Cumulative Program Total		5,620		2,723	1,547	$ 1,358
Potential Participants						88,800
Per Participant Energy Savings (kWh) - ECM						484
Per Participant Energy Savings (kWh) - CAC						475
Per Participant Energy Savings (kWh) - HP						700
Per Participant Demand Savings (kW) - ECM						0.25
Per Participant Demand Savings (kW) - CAC & HP						0.35
Measure Life						18
Net To Gross Ratio - ECM & HP						0.9
Net To Gross Ratio - CAC						0.8

Residential Behavioral Savings Program

Program

Behavior-based programs motivate customers to take actions that result in measurable, large-scale energy savings. The Residential Behavioral Savings Program motivates behavior change and provides relevant, targeted information to the consumer through regularly scheduled direct contact. The direct contact, typically through letters, helps the consumer to better understand their energy use. Once a consumer has a better understanding of how they use energy, they can then start conserving energy.

The program, as modeled, will provide letters to consumers combining energy usage data along with customer demographic, housing and utility data to develop specific, targeted recommendations that educate and motivate consumers to reduce their energy consumption. The recommendations provided in the letter give the consumer a variety of ways to save energy in their home, from low to no cost to higher cost investments. The program has been implemented by a number of utilities across the country, such as Puget Sound Energy, Dominion Power, and Southern California Edison.

Program data and design were provided by OPower, who is expected to be the implementation vendor for the program. OPower provides energy usage insight that drives customers to take action by selecting the most relevant information for each particular household, which ensures maximum relevancy and high response rate to recommendations.

Eligible Customers

Any residential homeowner located in the Vectren electric service territory is eligible.

Energy/Demand Savings

To identify the measurable savings, Vectren proposes to have a set of customers who receive the letter with energy tips and suggestions and a set of control customers who do not receive the letter. The energy consumption of the 2 groups will be compared to determine the measurable savings. For modeling purposes, the annual energy savings was estimated at 280 kWh with demand savings of .05 kW.

Table 8-17 Residential Behavioral Savings Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential Behavioral Savings					
	2011	24,250	20.2%	6,790	1,213	$ 420
	2012	24,250	20.2%	6,790	1,213	$ 624
	2013	24,250	20.2%	6,790	1,213	$ 879
Cumulative Program Total		72,750		20,370	3,639	$ 1,923
Potential Participants						120,000
Per Participant Energy Savings (kWh)						280
Per Participant Demand Savings (kW)						0.05
Measure Life						1
Net To Gross Ratio						1

<u>Residential New Construction</u>

Program

The Residential New Construction Program will provide incentives and encourage home builders to construct homes that are more efficient than current building codes. Energy savings are estimated to be approximately 15% versus a home built to current building codes. The Residential New Construction Program will work closely with builders, educating them on the benefits of building energy efficient homes. Homes may feature additional insulation, better windows, and higher efficiency appliances. The homes should also be more efficient and comfortable than standard homes constructed to current building codes.

The Residential New Construction Program will address the “lost opportunities” segment, promoting energy efficiency at the time the initial decisions are being made. This will ensure efficient results for the life of the home.

Eligible Customers

Any home builder willing to construct an energy efficient home in the Vectren electric service territory is eligible.

Incentives

Program incentives are designed to be paid to both all-electric and combination homes that have natural gas heating and water heating. The modeled incentive is $1,000 for an all-electric home. Vectren also plans to offer a reduced incentive for a combination home. It is important to note that the program is structured such that an incentive will not be paid for an all-electric home that has natural gas available to the home site.

Energy/ Demand Savings

For modeling purposes, the savings estimates per home are calculated at 949 kWh and .18 kW, based upon the blended savings estimate of all participating homes. The specific energy and demand impacts will vary by size and composition of the home and will be characterized through follow-up evaluation and verification procedures.

Table 8-18 Residential New Construction Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Residential New Construction					
	2011	25	1.9%	24	5	$ 120
	2012	75	5.8%	71	13	$ 205
	2013	100	7.7%	95	18	$ 245
Cumulative Program Total		200		190	36	$ 570
Potential Participants						1,300
Per Participant Energy Savings (kWh)						949
Per Participant Demand Savings (kW)						0.18
Measure Life						25
Net To Gross Ratio						0.95

Multi-Family Direct Install Program

Program

The Multi-Family Direct Install Program is designed to reduce the consumption of energy by the direct installation of CFLs and low-flow water fixtures in rental units. The rental segment of customers is a hard group to target due to the varying nature of which party pays for the utility bills. If the utility bill is included in rent, the tenant has no motivation to reduce their consumption. If the tenant is paying for the utility bill, they want to reduce but not make a substantial investment because they do not own the property. The program provides the installation and energy saving products free of charge to the landlord and/or tenant. This removes the barrier of who will make the investment to save energy.

Eligible Customers

Any all electric multi-family complex with more than 8 units is eligible.

Energy/Demand Savings

For modeling purposes, the energy/demand savings estimates are 704 kWh/.112 kW per participant.

Table 8-19 Multi-Family Direct Install Program Data

Market	Program & Year	Number of Participants		Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Multi-Family Direct Install					
	2011	1,500	15.0%	1,056	168	$ 213
	2012	1,500	15.0%	1,056	168	$ 163
	2013	1,500	15.0%	1,056	168	$ 163
Cumulative Program Total		4,500		3,168	504	$ 539
Potential Participants						10,000
Per Participant Energy Savings (kWh)						704
Per Participant Demand Savings (kW)						0.112
Measure Life						8
Net To Gross Ratio						0.8

<u>Commercial and Industrial Audit and Custom Efficiency Program</u>

Program

This program targets commercial and industrial customers by providing technical assistance and financial incentives for custom energy efficiency projects. The program targets a broad array of technologies and energy end-uses reflecting the diversity that exists with Vectren's commercial and industrial customers. The various types of commercial and industrial customers present challenges due to the diversity of the buildings, as well as the services and measures that may assist them in saving energy. The measures, which may include areas such as (but not limited to) HVAC upgrades, water heating, pumps, refrigeration, and building energy system controls tend to exhibit site-specific energy savings and impacts. As a result, it becomes difficult to establish a predetermined set of measures and incentives which addresses each option.

Another component of the program available to customers is a reduced cost energy audit. This service will provide a comprehensive facility energy audit at a reduced price to qualifying customers. Vectren will pay for 1/3 of the audit price up to a cap of $2,500.

Eligible Customers

Any commercial or industrial customer receiving electric service from Vectren is eligible.

Incentive

Vectren will provide a customer incentive based on the estimated kWh savings at a modeled rate of .12 cents per kWh.

Energy/Demand Savings

The custom nature of the program makes it difficult to develop a prototypical example. Each building will have very site specific projects and impacts. For modeling purposes the energy/demand savings estimates are 13,246 kWh/2.3 kW for small and medium customers and 26,492 kWh/4.6 kW for large customers.

Table 8-20 Commercial and Industrial Audit & Custom Efficiency Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Commercial & Industrial	C&I Audit & Custom Efficiency					
	2011	124	1.1%	2,053	357	$ 824
	2012	148	1.4%	2,451	425	$ 925
	2013	204	1.9%	3,377	587	$ 1,274
Cumulative Program Total		476		7,881	1,369	$ 3,023
Potential Participants						10,861
Per Participant Energy Savings (kWh) - Small/Medium Customers						13,246
Per Participant Energy Savings (kWh) - Large Customers						26,492
Per Participant Demand Savings (kW) - Small/Medium Customers						2.3
Per Participant Demand Savings (kW) - Large Customers						4.6
Measure Life						9
Net To Gross Ratio						0.8

Commercial and Industrial New Construction Program

Program

The program offers rebates and assistance for customers that construct new facilities or significantly renovate existing facilities.

Similar programs have been successfully implemented in New Jersey (Smart Start Program, which has achieved a market share estimate of nearly 30% of all new construction) and National Grid's Design 2000 Program.

Eligible Customers

Any new or existing commercial/industrial customer building in Vectren's electric service territory is eligible.

Incentive

The program is designed to pay .12 cents per kWh saved.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings are 28,000 kWh/5.4 kW.

Table 8-21 Commercial and Industrial New Construction Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Commercial & Industrial	C&I New Construction					
	2011	20	8.0%	560	108	$ 311
	2012	30	12.0%	840	162	$ 289
	2013	30	12.0%	840	162	$ 299
Cumulative Program Total		80		2,240	432	$ 899
Potential Participants						250
Per Participant Energy Savings (kWh)						28,000
Per Participant Demand Savings (kW)						5.4
Measure Life						20
Net To Gross Ratio						0.95

Direct Use Program

Program

The program offers rebates and assistance for customers who choose to convert their electric water heaters to natural gas units.

Eligible Customers

Any Vectren electric residential customer on an electric water heating rate (Rate B) with an active natural gas service on their property is eligible.

Incentive

The program is designed to pay up to $850 for conversion costs.

Energy/Demand Savings

For modeling purposes the estimated energy/demand savings are 4,879 kWh/.3 kW.

Table 8-22 Direct Use Program Data

Market	Program & Year	Number of Participants	Percent of Participation	Energy Savings MWh	Peak Demand kW	Program Budget $,000
Residential	Direct Use Program					
	2011	50	1.5%	244	15	$ 50
	2012	100	2.9%	488	30	$ 85
	2013	100	2.9%	488	30	$ 85
Cumulative Program Total		250		1,220	75	$ 220
Potential Participants						3,396
Per Participant Energy Savings (kWh)						4,879
Per Participant Demand Savings (kW)						0.3
Measure Life						13
Net To Gross Ratio						1

DSM Portfolio Objective and Impacts

Vectren plans to reduce residential and commercial/industrial customer usage by 139,663 MWh after the third year of the program. Vectren also projects to achieve a reduction in summer peak demand of 30.3 MW after the third year. In implementing these programs, consideration will be given to utilizing small businesses when feasible. Table 8-23 outlines the portfolio and the associated programs, as well as the projected energy/demand impacts, program costs, and customer participation of Core and Core Plus programs offered under Cause No. 43938.

Table 8-23 Projected Energy and Peak Savings – Cause No. 43938

	Vectren DSM Program Portfolio Impacts, Participation & Budget - Cause No. 43938					
Program Year	Participants/ Measures	Energy Savings MWh - Annual Incremental	Energy Savings MWh - Cumulative	Peak Demand Savings MW - Annual Incremental	Peak Demand Savings MW - Cumulative	Program Budget $,000
2011	28,889	13,461	13,461	2.7	2.7	$3,009
2012	279,558	57,861	71,322	12.6	15.3	$9,901
2013	335,281	68,341	139,663	15.0	30.3	$11,754
Total	643,728	139,663		30.3		$24,664

	Vectren DSM Program Core Portfolio Impacts, Participation & Budget - Cause No. 43938					
Program Year	Participants/ Measures	Energy Savings MWh - Annual Incremental	Energy Savings MWh - Cumulative	Peak Demand Savings MW - Annual Incremental	Peak Demand Savings MW - Cumulative	Program Budget $,000
2011						
2012	249,650	42,549	42,549	9.6	9.6	$6,525
2013	305,112	52,003	94,552	11.7	21.3	$7,676
Total	554,762	94,552		21.3		$14,201

	Vectren DSM Program Core Plus Portfolio Impacts, Participation & Budget - Cause No. 43938					
Program Year	Participants/ Measures	Energy Savings MWh - Annual Incremental	Energy Savings MWh - Cumulative	Peak Demand Savings MW - Annual Incremental	Peak Demand Savings MW - Cumulative	Program Budget $,000
2011	28,889	13,461	13,461	2.7	2.7	$3,009
2012	29,908	15,312	28,773	3.0	5.7	$3,376
2013	30,169	16,338	45,111	3.3	9.0	$4,078
Total	88,966	45,111		9.0		$10,463

While Vectren believes this level of savings is achievable, it will require robust programs for all classes of retail customers.

Given the market assessment, collaborative process, portfolio cost/benefit modeling efforts, and recently approved DSM program portfolio proposal, Vectren used the projected demand-side reductions from the programs as an input into the IRP process, rather than allowing the integration modeling to independently select some level of DSM to meet customer requirements. With respect to DSM, the programs that pass cost effectiveness testing are input into the integration analysis as a resource.

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CHAPTER 9

TRANSMISSION AND DISTRIBUTION PLANNING

INTRODUCTION

In accordance with IURC Rule 170 IAC, Vectren analyzed its transmission and distribution system's ability to meet future electric service requirements reliably and economically through the year 2031. This chapter describes the criteria applied in the analysis and the system conditions studied. The study was conducted to maintain compliance with the requirements of the Midwest Independent System Operator (MISO), the Reliability First Corporation (RFC) in conjunction with NERC requirements, as well as Vectren's internal planning criteria. Internal Long Range Plans are completed annually. In addition, Vectren has worked closely with MISO Transmission Expansion Plans (MTEP) and RFC in performing regional studies which include proposed projects identified in Vectren studies.

Modeling of the transmission system was conducted with steady-state conditions using the Power Technologies Inc.'s Power System Simulator Program for Engineers (PTI-PSS/E). The models and the studies and assessment on these models comply with all NERC, RFC, MISO and IURC requirements and include real and reactive flows, voltages, generation dispatch, load, and facilities appropriate for the time period studied. The primary criteria for assessing the adequacy of the internal Vectren transmission system were (1) single contingency outages of transmission lines and transformers during peak conditions, and (2) selected double and multiple contingencies. Interconnections were also assessed by examining single, double, and other multiple contingencies.

In addition, short circuit models were developed and analyzed through the use of Advanced Systems for Power Engineering, Inc.'s short circuit program (ASPEN-OneLiner).

Dynamic simulation was also performed using PTI-PSS/E to examine the performance of the interconnected transmission system to various electrical faults. The Vectren system remains stable for a variety of faulted conditions.

Maps of Vectren's Electric Transmission System are defined as Critical Electric Infrastructure Information (CEII), as defined by guidelines by Homeland Security, FERC and NERC and other agencies requirements. The Maps are being provided confidentially to the IURC in the Technical Appendix. Vectren also keeps its facilities current on RFC, MISO, IEA, and MEA maps as required.

METHODOLOGY

The distribution system review covers native load, as described in previous chapters in this IRP. The transmission system review additionally covers loads connected to our transmission system, such as municipals and Independent Power Producers (IPP's) that Vectren is not obligated to serve or include in our generation resources. The primary reason is to determine impacts or limitations in the transmission capacity to serve the Vectren native load. Vectren is a member of the Midwest Independent System Operator (MISO) and is part of the Reliability First Corporation (RFC) region of the North America Electric Reliability Council (NERC). As such, Vectren adheres to the transmission planning criteria developed and published by MISO in its document MISO *Transmission Expansion Planning*; (MTEP) and by RFC through NERC in its *Reliability Standards* under *Transmission Planning (TPL-001 through TPL-004)*.

The basis for the selection of RFC reliability criteria offers five points for member recognition.

1. The need to plan Bulk Electric Systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions.
2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area.
3. The importance of considering local conditions and requirements in establishing transmission reliability criteria for the local area power supply

and the need, therefore, to view reliability in local areas, primarily as the responsibility of the individual RFC members. However, local area disturbances must not jeopardize the overall integrity of the Bulk Electric System.

4. The importance of mitigating the frequency, duration, and extent of major Bulk Electric System outages.

5. The importance of mitigating the effect of conditions that might result from events such as national emergencies, strikes, or major outages on other regional networks.

SYSTEM INTEGRITY ANALYSIS – 2010 (SEASONAL ANNUAL, INCLUDES SPRING, SUMMER, FALL, AND WINTER)

Based on initial conditions for load, generation, and system topology the following tests were conducted.

1. Single contingency:
   - Outage of any line
   - Outage of any transformer
   - Outage of any generator
2. Multiple contingencies:
   - Double outage of any combination of generators, lines and transformers.
   - Double outages of generators.
   - Triple outages: two generators plus one line or transformer.
3. Extreme contingencies:
   - Loss of all generation at a plant site.
   - Loss of entire switchyard with associated load, generation, and line connectivity where three or more 100kV or higher voltage lines are connected.

As a result of these tests, various system operational or construction improvements have been postulated. These improvements may be either operator action, (such as shifting generation or switching lines), or the installation of actual substations, the construction of transmission lines, or the upgrading of facilities. Required construction improvements have been prioritized by where they fall in the contingency spectrum. Improvements that must be made in response to a single line outage have higher priority than improvements resulting from a more unlikely occurrence.

SYSTEM INTEGRITY ANALYSIS – 2012 (NEAR TERM – WITHIN 1-5 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2010 system. Contingency analysis is also the same as for the 2010 system.

SYSTEM INTEGRITY ANALYSIS – 2016 (LONG TERM – 6-10 YEARS)

Using updated load and generation forecasts and included planned upgrades, the same analysis is performed for the 2010 system. Contingency analysis is the same as for the 2010 system.

TRANSMISSION ADEQUACY SUMMARY TABLE

Table 9-1 shows the Vectren generation and load resources as summarized from previous chapters, as well as the generation and load resources expected to be served from the transmission system for the entire Vectren Local Balancing Authority (LBA) as coordinated by MISO.

Table 9-1 Transmission Import Adequacy/Shortfall Assessment

Year	Vectren Available Gen (MW)	IPP's & other Gen (MW)	Vectren Firm Peak Demand (MW)	Muni's & Other Load (MW)	Proj. Inter-Change (MW)	Trans. System Import Cap (MW)
2012	1,285	587	1,156	690	26	756
2013	1,285	668	1,156	690	107	847
2014	1,285	668	1,165	690	98	840
2015	1,285	668	1,164	690	99	846
2016	1,285	668	1,160	690	103	442
2017	1,285	668	1,151	690	112	454
2018	1,285	668	1,145	690	118	461
2019	1,285	668	1,139	690	124	469
2020	1,285	668	1,144	690	119	463
2021	1,285	668	1,149	690	114	362
2022	1,285	668	1,155	690	108	319
2023	1,285	668	1,159	690	104	315
2024	1,285	668	1,165	690	98	308
2025	1,285	668	1,171	690	92	301
2026	1,285	668	1,177	690	86	294
2027	1,285	668	1,184	690	79	287
2028	1,285	668	1,191	690	72	279
2029	1,285	668	1,199	690	64	269
2030	1,285	668	1,207	690	56	260
2031	1,285	668	1,215	690	48	251

The table reflects that the expected net interchange would be positive or exporting for all years. The lower import capability values in future years is driven by changes near a neighboring utility generation station and can be mitigated by Operational Guides (Op-Guides) and switching to maintain over 600 MW. Even without Op-Guides the import capability remains greater than the need. This reliability measure indicates that additional import transmission capacity is not needed to serve generation to load. However, the table does not reflect several other factors, such as potential purchases and sales. The table reflects total generation capability and not a reasonable economic dispatch. It is likely that renewable energy resources may be imported using the transmission system in lieu of running local generation. It is assumed that the gas peaking turbines would likely not be dispatched during some near peak summer conditions, in which it is not only possible, but likely that the expected interchange could be importing 300-400 MW. These values are also supported by actual historical interchange. In any event, MISO will dispatch the available resources to serve the load based on N-1 contingency analysis and economics and losses. With the largest generation resource on our system at 300 MW (Warrick 4), the transmission system capacity is adequate under reasonable expected resource dispatches and contingencies and additional growth. Within each PSS/E case, the actual load, generation dispatch, firm purchases and sales, and expected interchange is appropriate for the time period.

RECOMMENDATIONS: 2010 - 2021

No transmission facilities were identified specifically, due to proposed generation interconnections, transmission service requests or energy resources in this IRP process. Since the projected load growth is essentially flat and no new generation resources or retirements are planned, no new transmission facilities have been identified. In addition, significant upgrades were constructed in 2010, and are planned to continue into 2012 and future years, as a result of the MISO Regional Expansion Criteria and Benefits (RECB) process. The completed projects include the construction of a new 345 kV line from the Duke Gibson Station to the Vectren AB Brown Station to the BREC Reid Station. The Gibson to AB Brown segment is complete and energized. This project included the construction of a 345/138 kV substation at Vectren's AB Brown Station, which is also complete. Right of Way (ROW) procurement and construction of the segment from AB Brown to BREC Reid EHV Substation will continue through 2012. A new 138kV line (Z77) from FB Culley Substation to Oak Grove Substation is complete and an extension to Northeast Substation is in construction with completion expected in 2012. This facility allows for better generation dispatch diversity with lower congestion costs under contingencies. Multiple distribution substation upgrades were completed to include Aventine and Savatran. Bergdolt Road and Libbert Rd Substations are presently in construction with completion expected in 2012. Demand side management and energy conservation is expected to provide some load reduction on the Vectren system.

Local load growth areas have been identified for potential new business loads. Near term projections indicate the need for at least 2 more distribution substations, tentatively identified as Roesner Road and Toyota South areas.

The specific projects to be completed in the future years will depend on the load growth, the location of generation facilities, and/or on the source of purchased power. General recommendations are as follows:

1. A number of 69 kV transmission upgrades will be needed. An engineering evaluation will be conducted for upgrading the identified lines to higher operating temperature and for reconductoring some lines.
2. A number of substations will need to be modified.
3. Several new 138 and 69 kV lines and substations are planned to be added in this timeframe.
4. New high voltage interconnections with neighboring utilities are being investigated, including 345 kV facilities, to improve import capability and improve regional reliability.
5. If new generation capacity is added within the Vectren system, transmission facilities would also be planned to incorporate the new power source.
6. If new generation capacity were acquired outside the Vectren system, additional new interconnections may be needed. These projects would be investigated and would require involvement of other utilities.

All of these potential transmission projects would be planned with and coordinated through the MISO.

COST PROJECTIONS:

Vectren is projecting its annual transmission, substation, and distribution expenditures to decrease slightly over the next five years. The primary factor is the 345kV project , expected to be complete in 2012, and spending in following years are expected to be lower. However, the Federal Stimulus Plan funding is expected to force some transmission and distribution relocations, increasing in some areas due to roadway improvements. Approximately half of these are expected to be reimbursable with the remaining cost incurred by Vectren. Also, increasing demands for Smart Grid technology and infrastructure are resulting in some additional expenditure. New business and forecasted load growth is expected to stay flat or slightly decreasing. The need for import capability due to generation additions and retirements are expected to remain mostly unchanged as well. Tables 9-2 and 9-3 reflect both previous annual costs and projected annual spend:

Table 9-2 Actual Expenditures

	Dist. Feeder	Dist. Substation	Trans. Lines	Trans. Substation	Annual Total
2006	$16.8M	$4.1M	$25.7M	$10.8M	$57.4M
2007	$15.5M	$3.2M	$15.5M	$24.6M	$58.8M
2008	$15.2M	$12.5M	$14.7M	$22.3M	$64.7M
2009	$27.3M	$5.2M	$27.2M	$20.2M	$79.9M
2010	$15.4M	$5.2M	$40.6M	$10.5M	$71.7M

Table 9-3 Planned Expenditures

	Dist. Lines	Dist. Substation	Trans. Lines	Trans. Substation	Annual Total
2011	$17.6M	$3.5M	$20.4M	$4.6M	$46.1M
2012	$19.6M	$7.4M	$24.7M	$6.7M	$58.4M
2013	$16.8M	$9.1M	$17.9M	$14.0M	$57.8M
2014	$21.5M	$9.8M	$16.6M	$10.0M	$57.9M
2015	$20.4M	$5.8M	$28.5M	$3.4M	$58.1M

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CHAPTER 10

ELECTRIC INTEGRATION ANALYSIS

INTRODUCTION

The purpose of the electric integration process is to develop the optimal strategy for adding the resources necessary to reliably meet the future demand requirements of Vectren's electric customers. The process is integrated in that both supply-side and demand-side alternatives are considered and evaluated. The optimal plan is defined as the best possible combination of resource additions that result in reliable service at the lowest cost to customers over the twenty year planning horizon. The optimal resource plan is determined by evaluating all of the possible resource combinations and choosing the plan that minimizes the present value of revenue requirements (PVRR).

ELECTRIC INTEGRATION APPROACH

The process of determining the best resource plan can be approached as an optimization problem. Vectren internal resources utilized the Strategist software tool developed and supported by Ventyx (formerly New Energy Associates) of Atlanta, GA to perform the optimization analysis. Strategist is a strategic planning system that integrates financial, resource, marketing, and customer information. Strategist allows for addressing all aspects of integrated planning at the level of detail required for informed decision making. Strategist handles production costing, capital expenditure and recovery, financial and tax implications, and optimization all within one software system.

It is very important to note that not all of the components of utility costs and revenue requirements were included in the analysis. Cost components that were considered include: capital costs of new construction alternatives, fuel costs of existing generation and new alternatives, economy interchange, non-fuel O&M of existing generation and new alternatives, and emissions costs.

An optimization problem has three elements: an objective, constraints, and alternatives. For the electric integration process, the three elements can be summarized as follows:

Objective

The objective of the integration analysis was to determine the optimal resource plan by minimizing the PVRR. For the purposes of this discussion, the planning period PVRR is defined as the present value of revenue requirements for the 20 year period, 2012 – 2031, over which the optimization analysis was performed. “End effects”, estimates of revenue requirements beyond the twenty year planning period, were also considered when selecting the optimal plan. “End effects” are important due to their full consideration of the impact of resource additions that occur toward the end of the discrete 20 year planning period. The study period PVRR is defined as the planning period PVRR plus the end effects. The optimal resource plans as presented in this study were selected on a study period basis. The annual nominal revenue requirements for future years were converted to present value terms by discounting at Vectren’s projected after tax weighted cost of capital of 7.29%, consistent with the most recent rate case order under IURC Cause 43839.

Constraints

The primary constraint was to maintain a minimum planning reserve margin of 12.1% for each year of the study period. Other constraints include the project development and build times for new construction alternatives, transmission import constraints, reliability considerations, and the characteristics of existing resources and demand. The 12.1% reserve margin constraint is lower than the 15% value that Vectren has used in prior IRP submittals. The lower value recognizes the benefits of regional load diversity that Vectren receives as a member of MISO, as discussed in Chapter 3 MISO on pages 35-36 of this IRP. This diversity is realized due to the large MISO footprint and the load diversity that exists within the MISO system during peak periods.

The 12.1% reserve margin value is the applicable value from the MISO Planning Year 2011 LOLE (Loss of Load Expectation) Study Report, found in the Technical Appendix. This value is the requirement for LSE (load serving entities) peaks on an installed capacity basis. From the report, “The goal of the study is to determine the minimum planning reserve margin that would result in the MISO system experiencing less than one loss of load event every ten years."

Alternatives

A broad array of alternatives was included in the optimization analysis. The full range of supply-side resource alternatives were identified and discussed in Chapter 6 Electric Supply Analysis. Likewise, the demand-side alternatives were covered in Chapter 8 DSM Resources.

The next several sections of this chapter discuss several of the key inputs and assumptions used for developing the integration model.

DISCUSSION OF KEY INPUTS AND ASSUMPTIONS

The annual revenue requirements were determined by evaluating all of the pertinent costs that could impact future resource additions. The annual revenue requirements include both the operating and maintenance (O&M) costs of existing and new facilities and the financial costs associated with capital investments. O&M costs include both fixed and variable expenses such as fuel, production labor, maintenance expenses, and chemical costs for environmental controls.

Again, it is important to consider that this analysis does not explicitly include all of Vectren's Power Supply and Energy Delivery costs related to serving retail electric customers. Costs that would be common to all of the potential resource plans (e.g., allocated admin and general costs, transmission and distribution costs, other embedded costs, etc.) were not included because they had no impact on the comparative economic analysis. The considered costs were primarily related to O&M and new capital associated with power generation activities. Therefore comparisons between the base case and alternate scenarios should be viewed within this context.

Following are discussions of key inputs and assumptions used for the integration analysis:

New Construction Alternatives

New construction alternatives are discussed in detail in Chapter 6 Electric Supply Analysis. The new construction alternatives that were selected to be included in the detailed integration analysis are summarized in Table 10-1. The following new construction options were included as feasible and representative alternatives in the detailed optimization and integration analysis.

Table 10-1 Characteristics of New Construction Alternatives

Primary Fuel	Coal		Gas					BioMass
	With 90% CCS		Simple Cycle				Comb. Cyc.	
Technology Description	Pulverized Coal Supercritical (PCSC)	Integrated Gasification Combined Cycle (IGCC)	Aero-derivative GE LM6000	Aero-derivative GE LMS100	Heavy Duty GE 7EA	Heavy Duty GE 7FA	2 X 1 GE 7FA	CFB Steam Turb. Wood Waste
Nominal Capability (MW)	517	518	85 (2x42.5)	98	84	209	612	48
Assumed Vectren Share, %	25	25	100	100	100	100	20	100
Vectren Summer Capability, MW	129	130	74	90	73	185	113	48
Base Load Net Heat Rate (Btu/kWh)	11,790	11,313	9,845	9,305	11,730	9,937	6,665	13,391
Fixed O&M (2011$/kW-yr)	50.74	39.76	6.40	10.32	9.94	8.18	11.28	111.01
Variable O&M (2011$/MWh)	14.39	8.98	3.25	2.49	19.66	15.84	6.64	3.26
Equivalent Forced Outage Rate (%)	4.6	7.8	2.4	2.4	1.0	1.0	2.5	3.5
Total Capital (2011 $000,000)	3,071	2,455	126	125	88	136	105	186
Total Capital (2011$/kW)	5,940	4,739	1,705	1,389	1,206	736	928	3,875

Conservation

<u>Programs</u>

Chapter 8 DSM Resources contains a detailed discussion of demand-side management alternatives. Implementation of the Phase II Generic DSM order began in 2010. Conservation goals of 0.3% of average sales and ramping to 2% per year in 2019 were incorporated into the base case peak and energy forecast discussed in Chapter 5 Sales

and Demand Forecast. Additionally, incremental energy savings of 0.5% per year were assumed beginning in 2020 and were carried throughout the rest of the planning period. These assumptions are fully considered in the base case peak and energy forecasts.

Direct Load Control

Vectren has offered and managed a direct load control (DLC) program since 1992. This program is discussed in detail in the “Existing DSM Resources and Programs” section of Chapter 8 DSM Resources. The current and projected impacts of this program are summarized in the following table, reproduced from Chapter 8. For the purposes of the integration analysis, the 2016 level of performance was assumed to remain constant throughout the remainder of the study period.

Table 10-2 DLC System Load Reduction Capability

DLC System Demand Reduction Projection		
	Residential and Commercial Demand Reduction (kW)	
	33% Cycling	50% Cycling
2011 DLC System Technical Potential	26,849	38,702
2011 Achievable Load Reduction	13,425	19,351
2012 Achievable Load Reduction	16,110	23,221
2013 Achievable Load Reduction	18,795	27,092
2014 Achievable Load Reduction	21,480	30,962
2015 Achievable Load Reduction	24,165	34,832
2016 Forward Load Potential	24,165	34,832

Electric Demand Forecast

As mentioned in the prior section, the electric peak and energy forecast is discussed in detail in Chapter 5 Sales & Demand Forecast. The base case forecast results used in the optimization analysis are summarized in Table 10-3.

Table 10-3 Electric Demand and Energy Forecast

	Retail			Firm Wholesale		Total Requirements		
Year	Peak (Mw)	Annual Energy (Gwh)	Load Factor (%)	Peak (Mw)	Annual Energy (Gwh)	Peak (Mw)	Annual Energy (Gwh)	Load Factor (%)
2012	1,156	5,840	56.9%	12	57	1,168	5,897	56.9%
2013	1,156	5,810	56.6%	12	57	1,168	5,867	56.6%
2014	1,165	5,806	56.2%	12	57	1,177	5,863	56.1%
2015	1,164	5,772	55.9%			1,164	5,772	55.9%
2016	1,160	5,725	55.6%			1,160	5,725	55.6%
2017	1,151	5,657	55.4%			1,151	5,657	55.4%
2018	1,145	5,590	55.0%			1,145	5,590	55.0%
2019	1,139	5,520	54.6%			1,139	5,520	54.6%
2020	1,144	5,538	54.5%			1,144	5,538	54.5%
2021	1,149	5,543	54.3%			1,149	5,543	54.3%
2022	1,155	5,554	54.2%			1,155	5,554	54.2%
2023	1,159	5,563	54.1%			1,159	5,563	54.1%
2024	1,165	5,580	54.0%			1,165	5,580	54.0%
2025	1,171	5,588	53.8%			1,171	5,588	53.8%
2026	1,177	5,603	53.6%			1,177	5,603	53.6%
2027	1,184	5,618	53.5%			1,184	5,618	53.5%
2028	1,191	5,646	53.4%			1,191	5,646	53.4%
2029	1,199	5,660	53.2%			1,199	5,660	53.2%
2030	1,207	5,685	53.1%			1,207	5,685	53.1%
2031	1,215	5,711	52.9%			1,215	5,711	52.9%
Compound Average Growth Rate (%) 2012-2031	0.26%	-0.12%				0.21%	-0.17%	

Characteristics of Existing Generating Resources

The operating characteristics of existing Vectren owned electric generating resources, as they were simulated for the purposes of the integration analysis are summarized in Table 10-4. These characteristics were applied to all years of the study period as Vectren does not project any changes in the operating status or capacity of any existing company owned generating units in the foreseeable future.

Table 10-4 Characteristics of Existing Generating Resources

Resource Name	Summer Capability (MW)	Primary Fuel	Resource type	EFOR (%)	Planned Maint. (Wks/yr)	Estimated Full Load Heat Rate (Btu/kwhn)	Variable O&M (2011 $/Mwh)	Fixed O&M (2011 $/Kw-yr)
A.B. Brown 1	245	coal	steam	7.0	2.5	10,800	4.4	24.81
A.B. Brown 2	245	coal	steam	7.0	2.5	10,700	4.4	24.00
F.B. Culley 1	retired 12/31/2006							
F.B. Culley 2	90	coal	steam	8.0	2.5	11,700	1.4	32.97
F.B. Culley 3	270	coal	steam	7.0	2.5	10,400	1.5	22.16
Warrick 4	150	coal	steam	7.0	2.5	10,200	1.5	20.84
A.B. Brown 3	75	gas	comb. turb.	2.0	2.5	12,000	5.5	11.07
A.B. Brown 4	75	gas	comb. turb.	2.0	2.5	11,700	5.5	11.07
Broadway 1	50	gas	comb. turb.	2.0	2.5	14,000	5.5	11.07
Broadway 2	65	gas	comb. turb.	2.0	2.5	13,000	5.5	11.07
Northeast 1	10	gas	comb. turb.	10.0	2.5	15,000	5.5	11.07
Northeast 2	10	gas	comb. turb.	10.0	2.5	15,000	5.5	11.07
Blackfoot[1]	3	landfill gas	IC engine	5.0	2.0	9,000		

Existing Purchased Power

Vectren has an existing and ongoing firm purchased capacity and energy commitment with the Ohio Valley Electric Corporation (OVEC). The summer capability of this commitment was assumed to be 30 MW. It was also assumed that this resource would be present throughout the 20-year study period. Additionally, Vectren has a capacity purchase for 100 MW of year-round capacity for the years 2010 through 2012.

[1] Blackfoot is "behind the meter" and is accounted for as a credit to load

Finally, as discussed in Chapter 7 Renewables and Clean Energy, Vectren has entered into two long-term purchased power agreements for wind energy. These purchases were assumed to be in place for the entire IRP study period. For the purposes of this IRP, it was assumed that 10% (8 MW) of the combined nominal capacity of 80 MW was firm capacity contributing to reserve margin requirements. This is consistent with the current MISO treatment of wind generation.

Fuel Prices

The cost of fuel is one of the largest components of revenue requirements. Therefore, the assumptions that are made regarding future fuel prices are a very important variable for developing a least cost resource plan.

Vectren utilized data and expertise from Energy Ventures Analysis, Inc. (EVA) to develop the fuel price forecasts for this IRP. The natural gas price forecast is consistent with information available in EVA's 2011 FUELCAST Long-Term Outlook for Natural Gas. Basis assumptions were applied to simulate the delivered burner tip gas cost to Vectren generators. To develop the coal price forecast; known costs under contract and indicative RFP pricing was utilized in the early years of the study period and escalation rates provided by EVA for Indiana Illinois Basin coal were applied to develop the later years of the study period.

An important factor to consider when developing or analyzing long-term fuel price forecasts is that the trends fail to reflect any short term volatility that may occur beyond the near term. Historically, the conventional thinking has been that price volatility was primarily a concern for natural gas, with coal prices being considered relatively predictable. However, due to well known domestic and global factors beyond the scope of this report, recent years have seen this paradigm largely reversed with coal prices exhibiting significant volatility and natural gas prices becoming much more stable.

Market conditions and customer demand are continually evaluated when procuring fuel for use in our electric generation units. Vectren maintains an adequate supply of coal in physical inventory on the ground at each of our plant locations to ensure reliable service to our customers as a prudent contingency in the event of unforeseen supply interruptions due to weather, labor, etc.

Table 10-5 Base Fuel Price Projection

	Coal Illinois Basin High Sulfur FOB plant	Natural Gas (burner tip)
Year	(2011 $/mmBtu)	(2011 $/mmBtu)
2012	2.98	4.41
2013	2.40	4.54
2014	2.39	4.75
2015	2.44	5.28
2016	2.45	5.45
2017	2.46	5.63
2018	2.47	5.81
2019	2.47	6.08
2020	2.48	6.35
2021	2.51	6.39
2022	2.52	6.43
2023	2.54	6.53
2024	2.55	6.63
2025	2.56	6.92
2026	2.57	6.93
2027	2.58	6.94
2028	2.58	6.94
2029	2.59	6.97
2030	2.60	7.00
2031	2.61	7.15

Wholesale Market Activity

Economy Interchange

Full economic interchange was assumed and simulated for this IRP analysis. This assumption is consistent with Vectren's participation in the MISO markets. The system dispatch model was allowed to purchase and sell non-firm energy to and from a simulated external market. Purchase and sale decisions were made by comparing the Vectren system marginal costs against a projected forward price curve. The projected forward price curve was developed using a fundamentals based regional Power Markets Model developed for Vectren by Pace Global. Purchases were charged to revenue requirements and economy sales were a credit to revenue requirements, consistent with the terms of the wholesale sales sharing agreement under the most recent rate case order under IURC Cause 43839.

Firm Capacity Purchases

With respect to firm capacity purchases in the integration analysis, Vectren did not simulate the availability of future capacity alternatives beyond the existing purchase arrangements. This is discussed in more detail in the "Purchased Power Alternatives" section of Chapter 6 Electric Supply Analysis.

Environmental Considerations

Chapter 4 Environmental discusses environmental issues in detail. Consistent with that discussion, the integration analysis assumed full compliance with CSAPR allocation levels of emissions using existing environmental controls. Variable cost impacts associated with running FGD and SCR equipment at higher removal efficiencies were included in the revenue requirement calculations as part of the integration analysis.

Financial Assumptions

The financial assumptions with respect to capital investments required to add new construction resource alternatives are summarized in Table 10-6.

Table 10-6 Financial Assumptions

Resource Type	Book Life (yrs)	Tax Life (yrs)	Accounting Depreciation	Tax Depreciation	AFUDC Rate (%)	Construction Term (yrs)
coal / biomass	30	20	Straight Line	MACRS	5.0	4
gas: combined cycle	30	20	Straight Line	MACRS	5.0	3
gas: simple cycle	25	15	Straight Line	MACRS	5.0	2

Inflation

The GDP chain-type price index forecast[1], as published by the Department of Energy (DOE) Energy Information Administration (EIA) in the 2011 Annual Energy Outlook (AEO), was used as a forecast for general inflation.

[1] Source: http://www.eia.gov/forecasts/aeo/topic_macroeconomic.cfm

Table 10-7 General Inflation Forecast

Year	GDP Chain-type Price Index (2000=1.000)	Year to Year Increase, %
2011	1.120	
2012	1.133	1.16
2013	1.152	1.68
2014	1.173	1.82
2015	1.197	2.05
2016	1.220	1.92
2017	1.246	2.13
2018	1.272	2.09
2019	1.298	2.04
2020	1.324	2.00
2021	1.350	1.96
2022	1.374	1.78
2023	1.399	1.82
2024	1.424	1.79
2025	1.450	1.83
2026	1.476	1.79
2027	1.504	1.90
2028	1.532	1.86
2029	1.561	1.89
2030	1.589	1.79
2031	1.619	1.89

Source: EIA; *Annual Energy Outlook 2011,* Reference Case, Macroeconomic Indicators, /http://www.eia.gov/forecasts/aeo/topic_macroeconomic.cfm

INTEGRATION ANALYSIS RESULTS

The remainder of the chapter discusses the results of the resource planning integration and optimization modeling and analysis.

Case 1: Base Case

This case represents the base set of assumptions and inputs as presented in the preceding sections of this chapter. For this analysis, no additional constraints were introduced that would prevent the planning model from selecting the set of future supply-side resources that resulted in the lowest PVRR. The following Table 10-8 shows the optimal resource plan for the base case that minimizes the study period PVRR.

Consistent with the 2009 Vectren IRP, the base case results in no supply-side resource additions being required for the planning period. Reserve margin remains above the 12.1% constraint for the full twenty years. In the early years of the planning period the lowest reserve margin occurs in the year 2014 with a value of 17.2%. The reserve margin begins to decline slowly in the later years of the planning period and subsequently, the lowest reserve margin occurs in the last year of the planning period, 2031, with a value of 13.7%.

Table 10-8 Case 1: Base Case Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.2%
2015	1,164		1,164	1,285	24	35	38			1,382	18.8%
2016	1,160		1,160	1,285	24	35	38			1,382	19.2%
2017	1,151		1,151	1,285	24	35	38			1,382	20.0%
2018	1,145		1,145	1,285	24	35	38			1,382	20.7%
2019	1,139		1,139	1,285	24	35	38			1,382	21.3%
2020	1,144		1,144	1,285	24	35	38			1,382	20.8%
2021	1,149		1,149	1,285	24	35	38			1,382	20.2%
2022	1,155		1,155	1,285	24	35	38			1,382	19.7%
2023	1,159		1,159	1,285	24	35	38			1,382	19.2%
2024	1,165		1,165	1,285	24	35	38			1,382	18.7%
2025	1,171		1,171	1,285	24	35	38			1,382	18.0%
2026	1,177		1,177	1,285	24	35	38			1,382	17.4%
2027	1,184		1,184	1,285	24	35	38			1,382	16.8%
2028	1,191		1,191	1,285	24	35	38			1,382	16.0%
2029	1,199		1,199	1,285	24	35	38			1,382	15.3%
2030	1,207		1,207	1,285	24	35	38			1,382	14.5%
2031	1,215		1,215	1,285	24	35	38			1,382	13.7%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	2,269,501
End Effects (beyond 20 years)	1,041,144
Study Period (20 years and beyond)	3,310,645

SENSITIVITY AND RISK ANALYSIS

Virtually all of the parameters associated with the resource options considered by the IRP analysis possess a level of uncertainty. Therefore, the concept of an optimal resource strategy inherently depends on a discrete set of assumptions. While a single plan might emerge as being optimal for a given set of assumptions, uncertainties may be introduced into the assumptions that may result in a different optimal plan.

The first step in the sensitivity and risk analysis was to identify a set of possible future states and subsequently consider and assess the potential impact on key variables and assumptions for each of these future states. The second step was to use the planning model to determine the optimal plan (minimized PVRR) for each of the identified future states. The final step in the sensitivity and risk analysis was to compare the optimal plans from each future state and evaluate the short-term and long-term potential risks in terms of PVRR. Risk considerations are also discussed in qualitative terms.

Five potential future scenarios were selected for further analysis. They are as follows:

Case 2: High Demand Growth
Case 3: Industrial Load Addition
Case 4: Carbon Price
Case 5: High Natural Gas Prices
Case 6: Alternate Conservation

Case 2: High Demand Growth

For this sensitivity case the annual peak and energy from the high growth case as presented in Chapter 5 Sales and Demand Forecast were used for the load growth projection. This high growth case assumes that annual aggregate peak and energy increase at a rate of 1% over the prior year for each year of the study period.

This case resulted in the addition of two supply side resources during the 20 year planning period. The additions occur in the years 2019 and 2027. The selected generation technology for both additions was combined cycle. As discussed in Chapter 6 Electric Supply Analysis, Vectren assumed an ownership share of a large combined cycle unit for modeling purposes. Although purchased power options were not explicitly simulated, the combined cycle alternative, as modeled, could also be considered to be a placeholder or proxy for other market arrangements that would be investigated in due course: purchased power agreement, gas tolling arrangement, etc.

Table 10-9 Case 2: High Demand Growth Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Existing Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,167	12	1,179	1,285	19	35	38			1,377	16.8%
2014	1,179	12	1,191	1,285	21	35	38			1,379	15.8%
2015	1,191		1,191	1,285	24	35	38			1,382	16.0%
2016	1,203		1,203	1,285	24	35	38			1,382	14.9%
2017	1,215		1,215	1,285	24	35	38			1,382	13.8%
2018	1,227		1,227	1,285	24	35	38			1,382	12.6%
2019	1,239		1,239	1,285	24	35	38	113	Comb. Cyc.	1,495	20.7%
2020	1,252		1,252	1,285	24	35	38			1,495	19.5%
2021	1,264		1,264	1,285	24	35	38			1,495	18.3%
2022	1,277		1,277	1,285	24	35	38			1,495	17.1%
2023	1,290		1,290	1,285	24	35	38			1,495	15.9%
2024	1,302		1,302	1,285	24	35	38			1,495	14.8%
2025	1,315		1,315	1,285	24	35	38			1,495	13.7%
2026	1,329		1,329	1,285	24	35	38			1,495	12.5%
2027	1,342		1,342	1,285	24	35	38	113	Comb. Cyc.	1,608	19.9%
2028	1,355		1,355	1,285	24	35	38			1,608	18.7%
2029	1,369		1,369	1,285	24	35	38			1,608	17.5%
2030	1,383		1,383	1,285	24	35	38			1,608	16.3%
2031	1,396		1,396	1,285	24	35	38			1,608	15.2%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	2,747,968
End Effects (beyond 20 years)	1,583,267
Study Period (20 years and beyond)	4,331,234

Case 3: Industrial Load Addition

This case represents the base case set of assumptions with the addition of a large industrial load. The load addition was simulated to represent 75 MW of peak demand at an 85% annual load factor for the year 2015 and all subsequent years of the study period. Given the size of Vectren's load, the addition of a single large industrial customer can have a significant impact on resource adequacy considerations; thus, it is prudent to consider such an impact in the planning process.

This scenario resulted in the addition of one new resource within the 20 year study period. As would be expected, the addition of a combined cycle alternative in 2015 directly corresponded to the timing of the load addition. The higher revenue requirements for this scenario are somewhat compounded by the fact that the resource addition occurs relatively early in the study period and therefore has a correspondingly higher impact in present value terms. Similar to the high growth case, the selected resource addition was the combined cycle option. As alluded to in the high growth case, the combined cycle addition should be considered to be the long-term solution to this scenario, and Vectren may pursue market based solutions for resource adequacy needs during the earlier years where additional capacity is needed.

Table 10-10 Case 3: Industrial Load Addition Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.1%
2015	1,242		1,242	1,285	24	35	38	113	Comb. Cyc.	1,495	20.4%
2016	1,238		1,238	1,285	24	35	38			1,495	20.8%
2017	1,230		1,230	1,285	24	35	38			1,495	21.6%
2018	1,224		1,224	1,285	24	35	38			1,495	22.2%
2019	1,217		1,217	1,285	24	35	38			1,495	22.8%
2020	1,223		1,223	1,285	24	35	38			1,495	22.3%
2021	1,228		1,228	1,285	24	35	38			1,495	21.8%
2022	1,233		1,233	1,285	24	35	38			1,495	21.2%
2023	1,238		1,238	1,285	24	35	38			1,495	20.8%
2024	1,243		1,243	1,285	24	35	38			1,495	20.3%
2025	1,249		1,249	1,285	24	35	38			1,495	19.7%
2026	1,255		1,255	1,285	24	35	38			1,495	19.1%
2027	1,262		1,262	1,285	24	35	38			1,495	18.5%
2028	1,269		1,269	1,285	24	35	38			1,495	17.8%
2029	1,277		1,277	1,285	24	35	38			1,495	17.1%
2030	1,285		1,285	1,285	24	35	38			1,495	16.3%
2031	1,294		1,294	1,285	24	35	38			1,495	15.6%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	2,583,352
End Effects (beyond 20 years)	1,257,568
Study Period (20 years and beyond)	3,840,919

Case 4: Carbon Price

This scenario involved adding consideration of carbon pricing. CO2 price impacts were included, starting in 2016 at a level of $14/ metric ton and escalated at 6% annually for subsequent years.

The first step was to estimate the impact of CO2 price on the forecasted peak and energy. No allocation was assumed, so it was further assumed that all carbon related costs would be fully captured in retail pricing. The estimated retail price impact was approximately 15% by the end of the forecast period. Correspondingly, a certain level of demand reduction was projected to occur based on price elasticity. This was estimated to be a little more than 1% reduction of both peak and energy for the last year of the forecast period, 2031. The second step was to develop an alternate forward price curve for the wholesale market based on the CO2 price assumptions. This was developed using the Pace Global Power Markets Model discussed earlier in this chapter. The final step was to incorporate the revised peak and energy forecast, forward electric market price curve, and other pertinent CO2 related considerations into the integration model.

Similar to the base case, the carbon price scenario indicates no builds required for the entirety of the 20 year study period. However revenue requirements are significantly higher in consideration of the added cost component of carbon pricing.

Table 10-11 Case 4: Carbon Price Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.2%
2015	1,164		1,164	1,285	24	35	38			1,382	18.8%
2016	1,154		1,154	1,285	24	35	38			1,382	19.8%
2017	1,143		1,143	1,285	24	35	38			1,382	20.9%
2018	1,136		1,136	1,285	24	35	38			1,382	21.6%
2019	1,130		1,130	1,285	24	35	38			1,382	22.3%
2020	1,134		1,134	1,285	24	35	38			1,382	21.8%
2021	1,139		1,139	1,285	24	35	38			1,382	21.3%
2022	1,144		1,144	1,285	24	35	38			1,382	20.8%
2023	1,148		1,148	1,285	24	35	38			1,382	20.3%
2024	1,153		1,153	1,285	24	35	38			1,382	19.8%
2025	1,159		1,159	1,285	24	35	38			1,382	19.2%
2026	1,165		1,165	1,285	24	35	38			1,382	18.6%
2027	1,171		1,171	1,285	24	35	38			1,382	18.0%
2028	1,178		1,178	1,285	24	35	38			1,382	17.3%
2029	1,185		1,185	1,285	24	35	38			1,382	16.6%
2030	1,193		1,193	1,285	24	35	38			1,382	15.9%
2031	1,201		1,201	1,285	24	35	38			1,382	15.1%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	3,778,406
End Effects (beyond 20 years)	2,979,091
Study Period (20 years and beyond)	6,757,497

Case 5: High Natural Gas Prices

For this scenario an additional 4% escalation in gas prices was applied to the first ten years of the study period. This resulted in a gas price of $9/mmBtu in 2022 and $10/mmBtu in 2031 on a 2011 constant dollar basis. Coal prices were also adjusted in this scenario as it is generally recognized that coal prices set somewhat of a floor for gas prices. Absent carbon concerns, many of the basic fundamental economic drivers will affect the price of both fuels in the same direction, albeit not necessarily equally. To recognize this linkage, coal prices were escalated at 2% for the first ten years of the study period.

The first step in developing this scenario was to model the regional electric market impacts of the higher gas price assumption using the Pace Power Markets Model. The resulting forward price curve was then incorporated into the integration model to determine the impacts to the resource plan and revenue requirements.

As in the base case, this scenario resulted in no resource additions since the projected peak and energy were unaffected by the changes in assumptions for this case. Note that the PVRR values for the high gas price case are actually slightly lower than for the base case. This is solely due to the simulated economy sales and the associated credit to revenue requirements due to these energy sales. The assumed increase in electric prices results in a larger credit to revenue requirements through increased wholesale sales opportunities and higher wholesale margins that were simulated as a credit to revenue requirements.

Table 10-12 Case 5: High Natural Gas Price Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	Existing DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.2%
2015	1,164		1,164	1,285	24	35	38			1,382	18.8%
2016	1,160		1,160	1,285	24	35	38			1,382	19.2%
2017	1,151		1,151	1,285	24	35	38			1,382	20.0%
2018	1,145		1,145	1,285	24	35	38			1,382	20.7%
2019	1,139		1,139	1,285	24	35	38			1,382	21.3%
2020	1,144		1,144	1,285	24	35	38			1,382	20.8%
2021	1,149		1,149	1,285	24	35	38			1,382	20.2%
2022	1,155		1,155	1,285	24	35	38			1,382	19.7%
2023	1,159		1,159	1,285	24	35	38			1,382	19.2%
2024	1,165		1,165	1,285	24	35	38			1,382	18.7%
2025	1,171		1,171	1,285	24	35	38			1,382	18.0%
2026	1,177		1,177	1,285	24	35	38			1,382	17.4%
2027	1,184		1,184	1,285	24	35	38			1,382	16.8%
2028	1,191		1,191	1,285	24	35	38			1,382	16.0%
2029	1,199		1,199	1,285	24	35	38			1,382	15.3%
2030	1,207		1,207	1,285	24	35	38			1,382	14.5%
2031	1,215		1,215	1,285	24	35	38			1,382	13.7%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	2,468,853
End Effects (beyond 20 years)	1,190,293
Study Period (20 years and beyond)	3,659,147

Case 6: Alternate Conservation

In this scenario it was assumed that the projected impacts due to conservation programs would remain constant after the year 2019. All other base case assumptions were unchanged. The significance of this scenario is that even with the assumption that there would be no additional energy savings above the levels mandated by the Phase II Generic DSM order; Vectren projects no resource additions until 2029. The selected alternative was a combined cycle resource in the year 2029. Years 1-20 revenue requirements are very similar to the base case because the resource addition occurs very late in the planning period.

Table 10-13 Case 6: Alternate Conservation Resource Plan

Year	Retail Peak Requirements (MW)	Firm Wholesale (MW)	Firm Peak Demand (MW)	Company Owned Generation (MW)	DLC (MW)	Interruptible (MW)	Committed Purchases (MW)	Capacity Addition		Total Resources (MW)	Reserve Margin (%)
								Summer (MW)	Description		
2012	1,156	12	1,168	1,285	16	35	138			1,474	26.2%
2013	1,156	12	1,168	1,285	19	35	38			1,377	17.9%
2014	1,165	12	1,177	1,285	21	35	38			1,379	17.2%
2015	1,164		1,164	1,285	24	35	38			1,382	18.8%
2016	1,160		1,160	1,285	24	35	38			1,382	19.2%
2017	1,151		1,151	1,285	24	35	38			1,382	20.0%
2018	1,145		1,145	1,285	24	35	38			1,382	20.7%
2019	1,139		1,139	1,285	24	35	38			1,382	21.3%
2020	1,148		1,148	1,285	24	35	38			1,382	20.4%
2021	1,157		1,157	1,285	24	35	38			1,382	19.4%
2022	1,166		1,166	1,285	24	35	38			1,382	18.5%
2023	1,175		1,175	1,285	24	35	38			1,382	17.6%
2024	1,184		1,184	1,285	24	35	38			1,382	16.7%
2025	1,194		1,194	1,285	24	35	38			1,382	15.7%
2026	1,204		1,204	1,285	24	35	38			1,382	14.8%
2027	1,215		1,215	1,285	24	35	38			1,382	13.8%
2028	1,226		1,226	1,285	24	35	38			1,382	12.7%
2029	1,238		1,238	1,285	24	35	38	113	Comb. Cyc.	1,495	20.8%
2030	1,250		1,250	1,285	24	35	38			1,495	19.6%
2031	1,262		1,262	1,285	24	35	38			1,495	18.5%

Present Value of Revenue Requirements: PVRR	**2011 ($000)**
Planning Period (20 years)	2,323,752
End Effects (beyond 20 years)	1,167,968
Study Period (20 years and beyond)	3,491,719

RESULTS OF SENSITIVITY AND RISK ANALYSIS

The results of the sensitivity cases, as presented in Table 10-14 and discussed previously for each alternative case, show that while there are significant differences in the PVRR values, very few resource additions are required for this set of scenarios. Furthermore, a combined cycle option was selected in all cases where a resource addition was required.

As mentioned previously, the IRP analysis takes into account only a subset of total electric revenue requirements, primarily O&M and new capital related to power generation. Therefore, the percentage comparisons as presented below are material only for the costs that were included and cannot be interpreted as a comparison of the total electric revenue requirements.

Table 10-14 Comparison of Planning Cases

Year	Case 1 Base		Case 2 High Growth		Case 3 Large Load Addition		Case 4 Carbon Price		Case 5 High Gas Price		Case 6 Alternate Conservation	
	MW	Description	MW	Description	MW	Description	MW	Description	MW	Description	MW	Description
2012												
2013												
2014												
2015					113	Comb. Cyc.						
2016												
2017												
2018												
2019			113	Comb. Cyc.								
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027			113	Comb. Cyc.								
2028												
2029											113	Comb. Cyc.
2030												
2031												
PVRR												
Difference from Base												
Years 1 -20				21%		14%		66%		9%		2%
Beyond Year 20				52%		21%		186%		14%		12%
Total				31%		16%		104%		11%		5%

AVOIDED COST DISCUSSION

As discussed previously, Vectren utilizes the Strategist software tool to perform the resource planning integration analysis and optimization. Strategist utilizes the concept of "economic carrying charge" (ECC) when evaluating new resource additions. In this context, ECC is defined as the capital charges avoided by delaying a resource one year. This approach assumes a replacement cost perspective where the value of an asset increases as a result of inflation and cost escalation. Table 10-15 Avoided Costs presents the ECC values for the Vectren IRP base case. Note that the values provided are for reference purposes only, as the base case resulted in no required resource.

Avoided operating costs can be stated in terms of marginal costs. Table 10-15 also shows the annual average marginal costs values from the Vectren base case resource plan analysis. Avoided transmission and distribution costs were considered. However, since no transmission or distribution project was required or planned due to a result of this study, transmission and distribution facilities were not explicitly listed in the resource planning analysis.

Table 10-15 Avoided Costs

	Economic Carrying Charge		Marginal Cost
	Combustion Turbine	Combined Cycle	
	$/kW	$/kW	$/MWh
2012	69.02	92.75	44.23
2013	70.41	94.61	42.01
2014	71.81	96.50	44.47
2015	73.25	98.43	49.11
2016	74.72	100.40	52.21
2017	76.21	102.41	55.92
2018	77.74	104.46	60.34
2019	79.29	106.54	64.85
2020	80.88	108.68	69.55
2021	82.49	110.85	73.44
2022	84.14	113.07	77.18
2023	85.83	115.33	82.37
2024	87.54	117.64	87.04
2025	89.29	119.99	94.74
2026	91.08	122.39	99.61
2027	92.90	124.84	103.99
2028	94.76	127.34	108.07
2029	96.65	129.88	112.80
2030	98.59	132.48	118.48
2031	100.56	135.13	125.81

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CHAPTER 11

ACTION PLAN

INTRODUCTION

This section presents a summary of the activities Vectren will undertake during the next 24 months to ensure that the customers' long-term energy supply needs are met. The action plan will define the immediate steps the organization will take to achieve a reasonable long-term cost to retail customers with full consideration of the complex issues facing the industry in general.

SUPPLY-SIDE RESOURCES

The overall objective of this study and review is to ensure that Vectren is properly positioned to meet its obligation to serve the needs of its Indiana retail customer base. During the planning period Vectren will continue to monitor changing market factors including, but not limited to, increased environmental regulations, renewable portfolio standards, fuel price volatility, escalation of capital costs, increased emphasis on conservation measures, demand response, Smart Grid/AMI, and RTO related developments. These items will be monitored both for their potential impact on future capacity needs and their impact on the operation of existing assets.

As presented in this plan, Vectren projects to have the capacity needed to meet the needs of our customers without adding any additional generation assets. Additionally, Vectren does not currently anticipate or project the retirement of any existing generating capacity. Vectren has utilized the Pace Power Markets Model to analyze the viability of company owned generation within the regional power market under various environmental and economic scenarios. To date, the findings have indicated that the Vectren generation fleet is fully viable for the foreseeable future. However, Vectren will continue to monitor the energy needs of our customers and will consider retirement of less viable units if justified in the future.

Vectren has formed internal teams that monitor developments in the environmental legislative arena, the renewable marketplace, and power plant efficiency efforts. Although current projections do not indicate a need for additional generation in the near term, Vectren remains committed to monitoring technology progress in all related areas, including the following supply-side options:

- Regional coal based development projects
- Integrated Gasification Combine Cycle (IGCC) Technology
- Carbon capture & sequestration (CCS)
- Other clean coal development projects
- Renewable energy sources
- Simple cycle peaking turbines
- Combined cycle applications
- Distributed generation
- Merchant plant capacity purchases
- Block energy purchases
- Contractual capacity purchases
- Interruptible contract status

DEMAND-SIDE RESOURCES

We plan to continue to pursue DSM, energy efficiency, and demand response opportunities by working through collaborative efforts with the IURC and OUCC. Vectren will continue to implement the DSM Plan under Cause No. 43938. The Core and Core Plus programs outlined in the plan are expected to meet the savings identified in the Phase II Order for the years 2011-2013. While our current resources are adequate to meet the needs of our customers, we believe that conservation is in our customers' best interest. Helping customers learn to conserve energy will benefit our customers through lower bills, our environment through lower emissions, and our rates through the reduced need for additional system capacity in the future.

Vectren will closely monitor trends regarding Smart Grid/AMI throughout the country. We will work collaboratively with key stakeholders to determine the appropriate implementation strategy for Smart Grid/AMI in our territory.

TRANSMISSION AND DISTRIBUTION

Vectren will work closely with MISO to determine those transmission projects that will improve overall grid reliability within our service territory and those surrounding our area. We will implement system upgrades as needed to ensure reliable service to our customers. In addition, ongoing internal studies will monitor additions of industrial and commercial load in different locations within our service territory.

Detailed budgets for the short-term plan will be developed during Vectren's normal budgeting process.

2011 INTEGRATED RESOURCE PLAN

TECHNICAL APPENDIX

By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

November 1, 2011

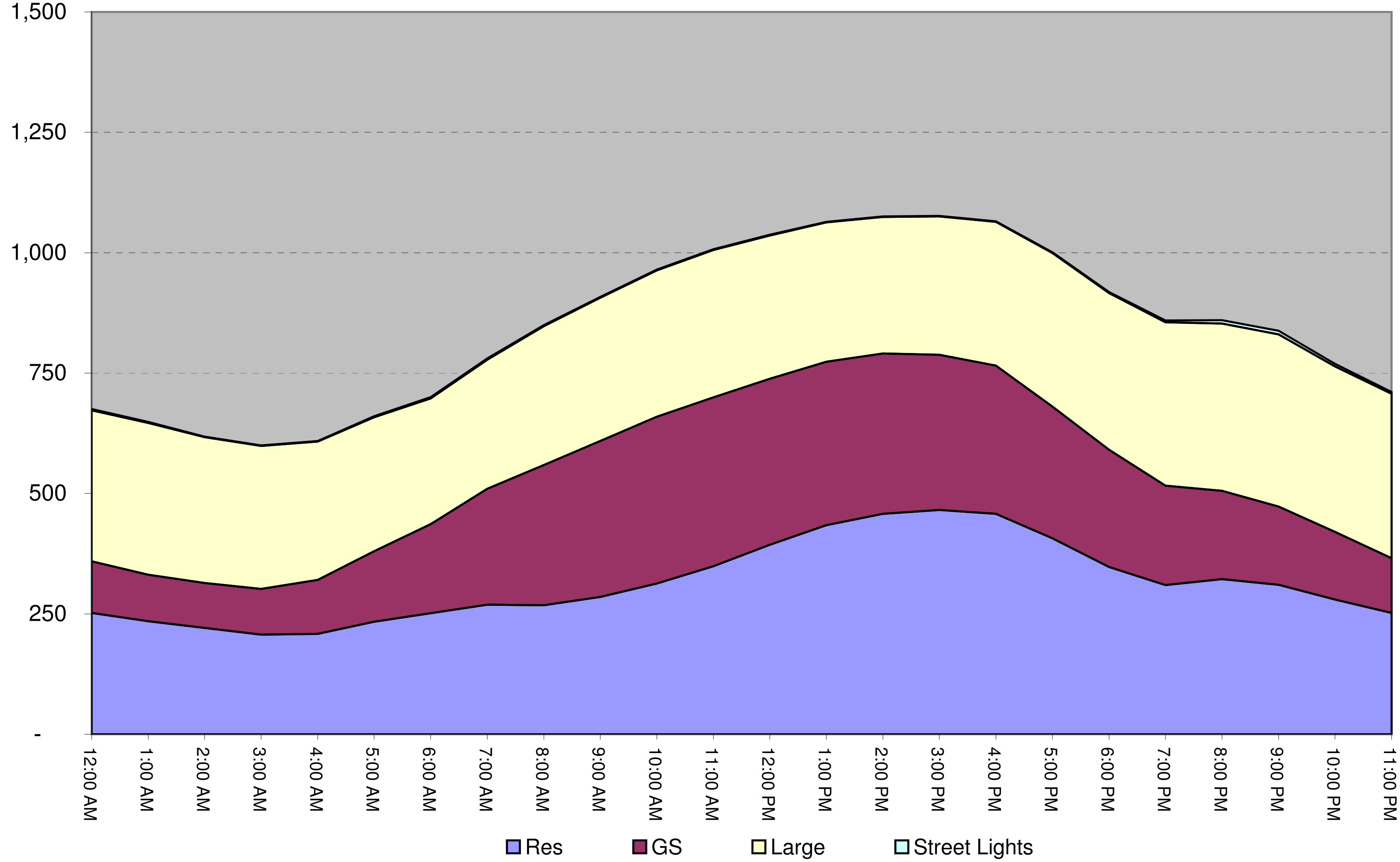
VECTREN
Live Smart

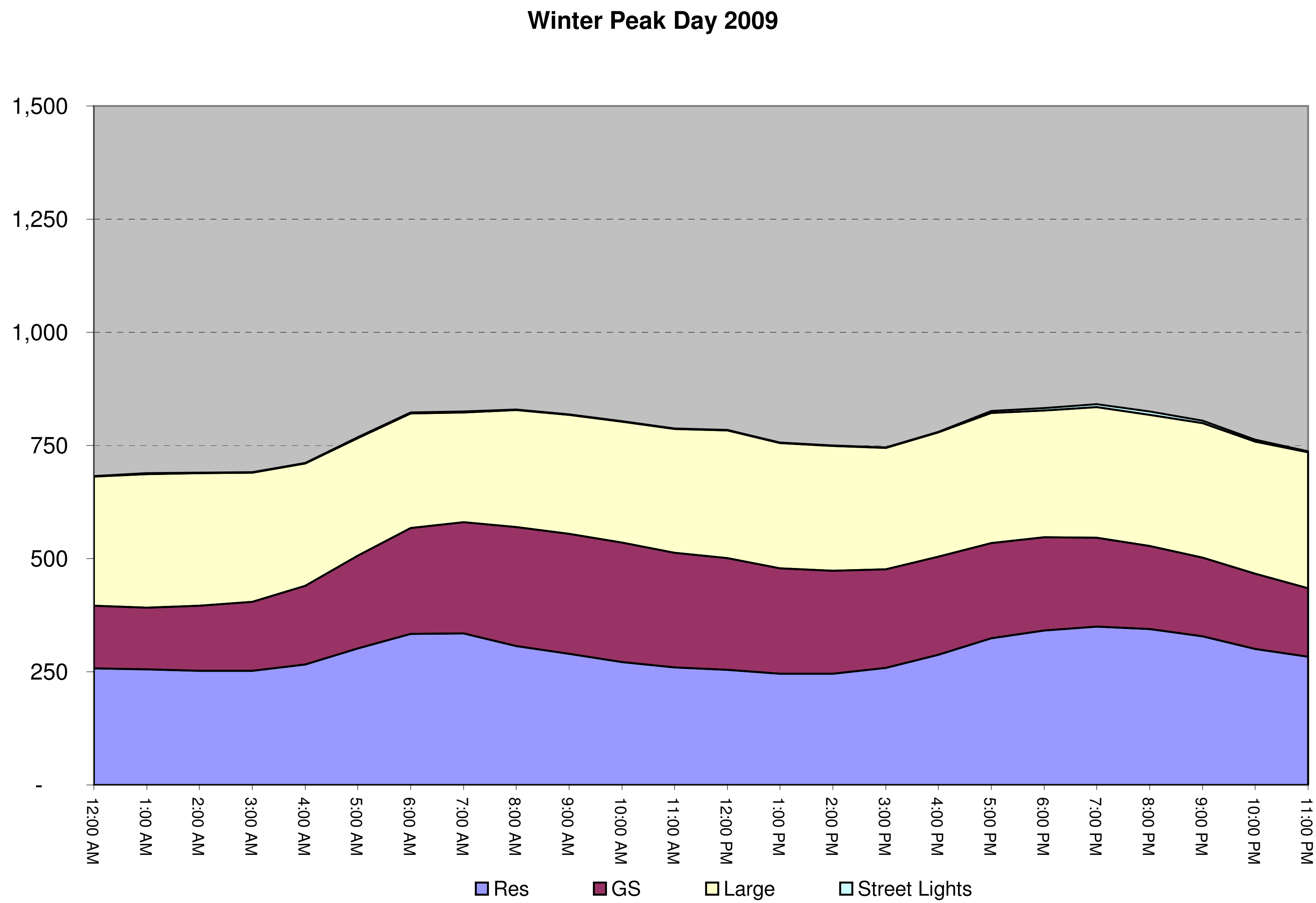
TECHNICAL APPENDIX

INCLUDING:

1. Load Shapes
2. MISO 2009 System Lambda
3. MISO 2010 System Lambda
4. MISO 2011 LOLE Study Report
5. Planning Model Output Cases 1-6
6. Technical Assessment
7. Vectren 2009 Hourly Firm Load
8. Vectren 2010 Hourly Firm Load
9. Vectren South Electric DSM Action Plan

Summer Peak Day 2009




Winter Peak Day 2009
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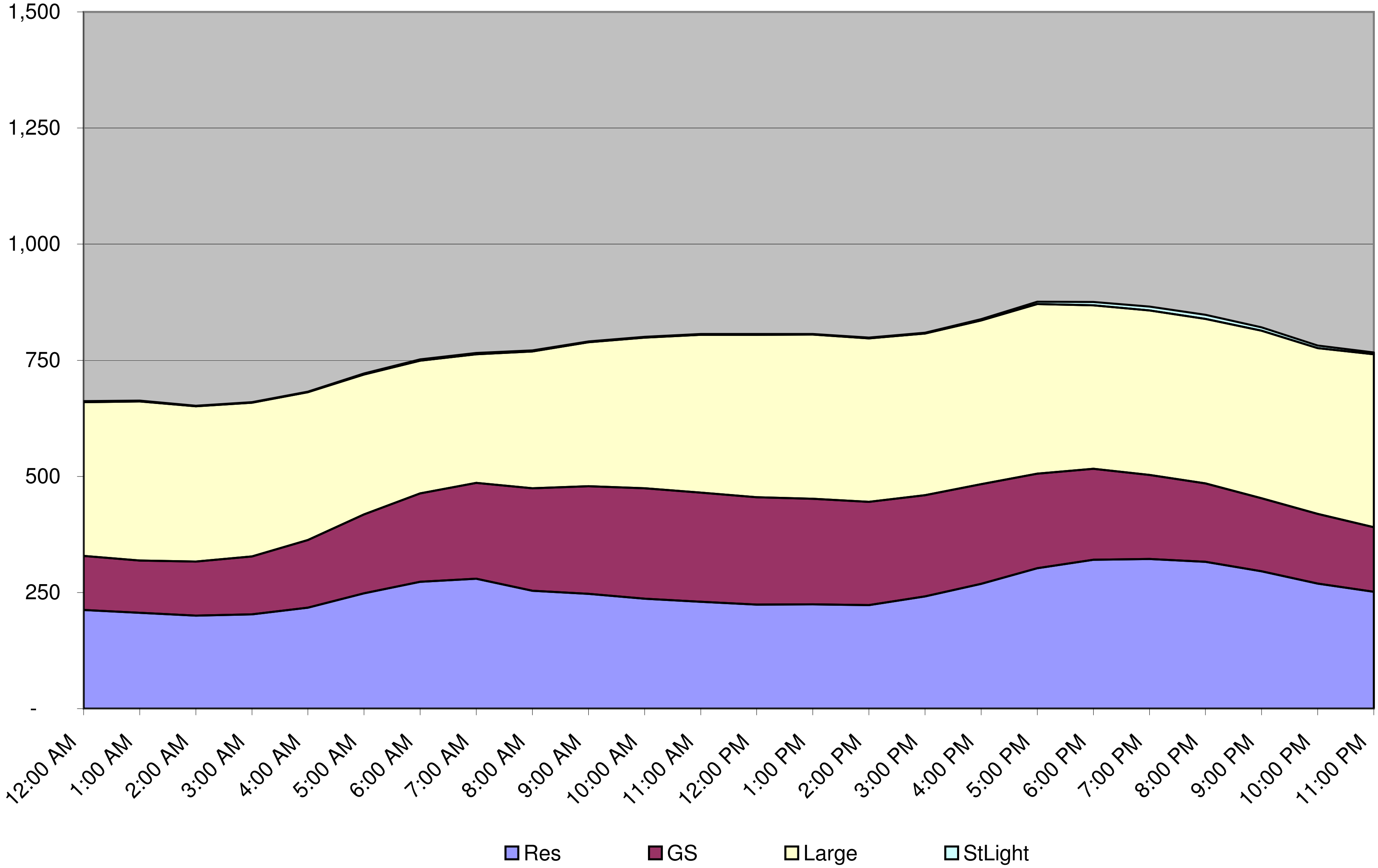
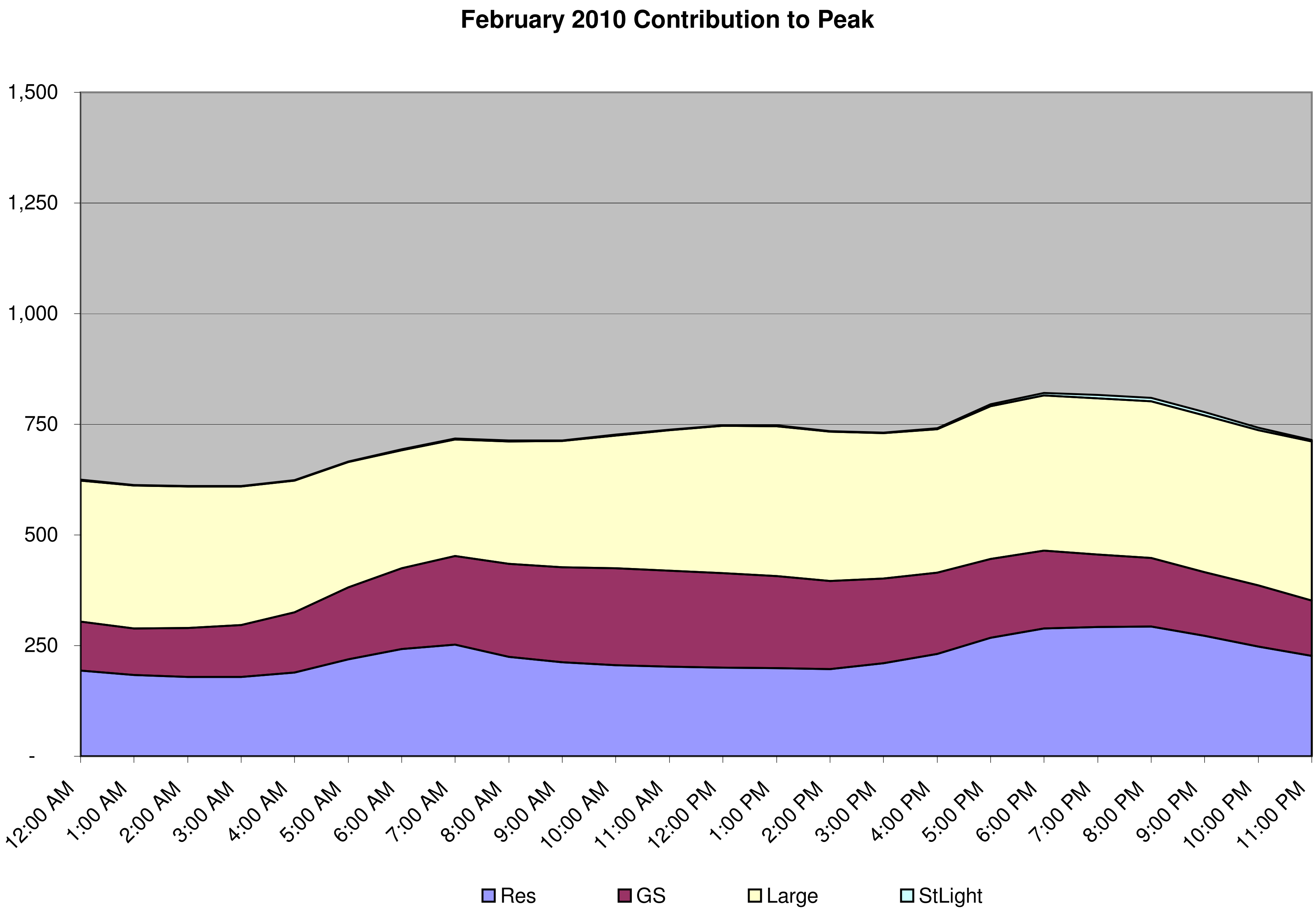
Street Lights

January 2010 Contribution to Peak




February 2010 Contribution to Peak
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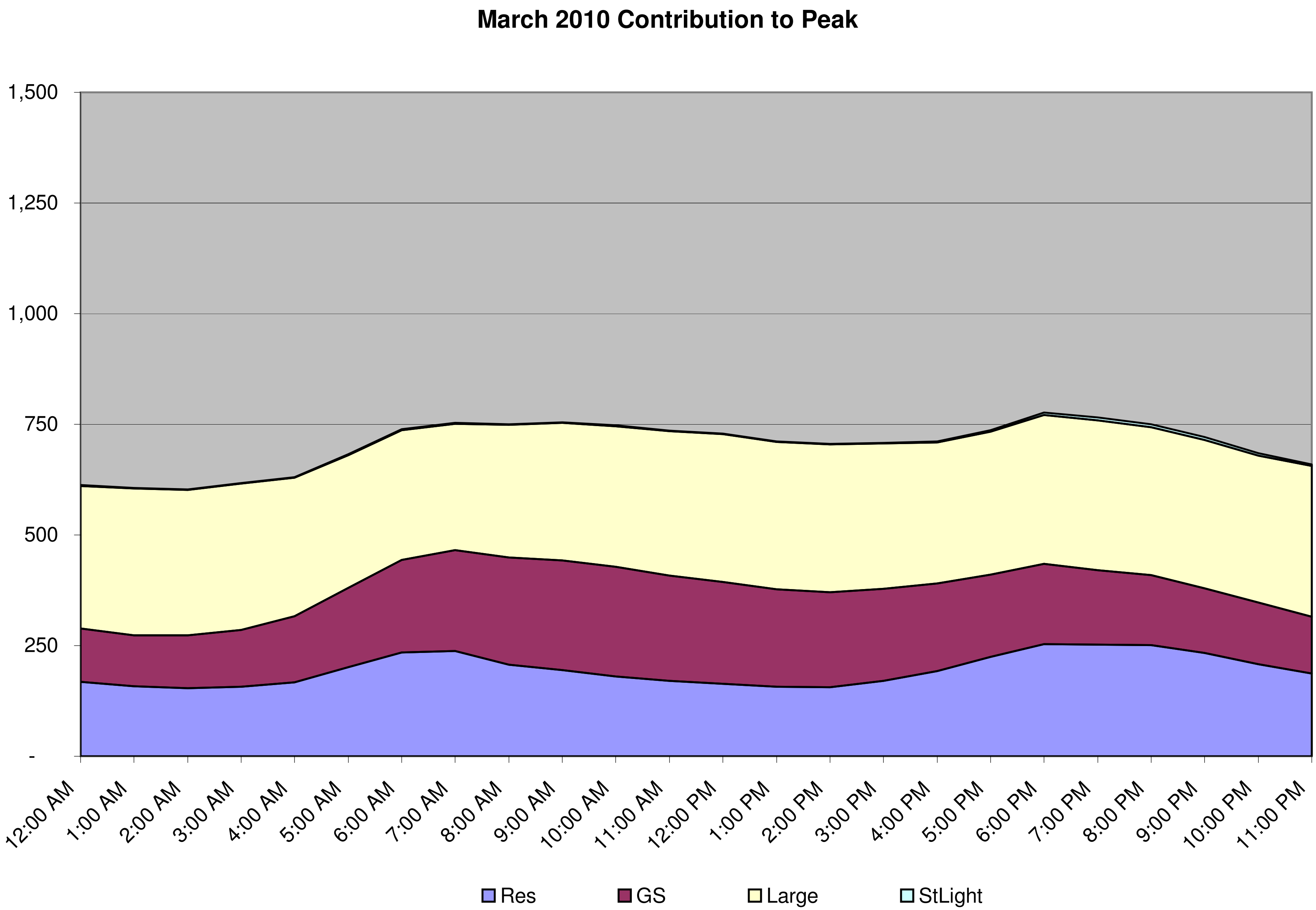
March 2010 Contribution to Peak
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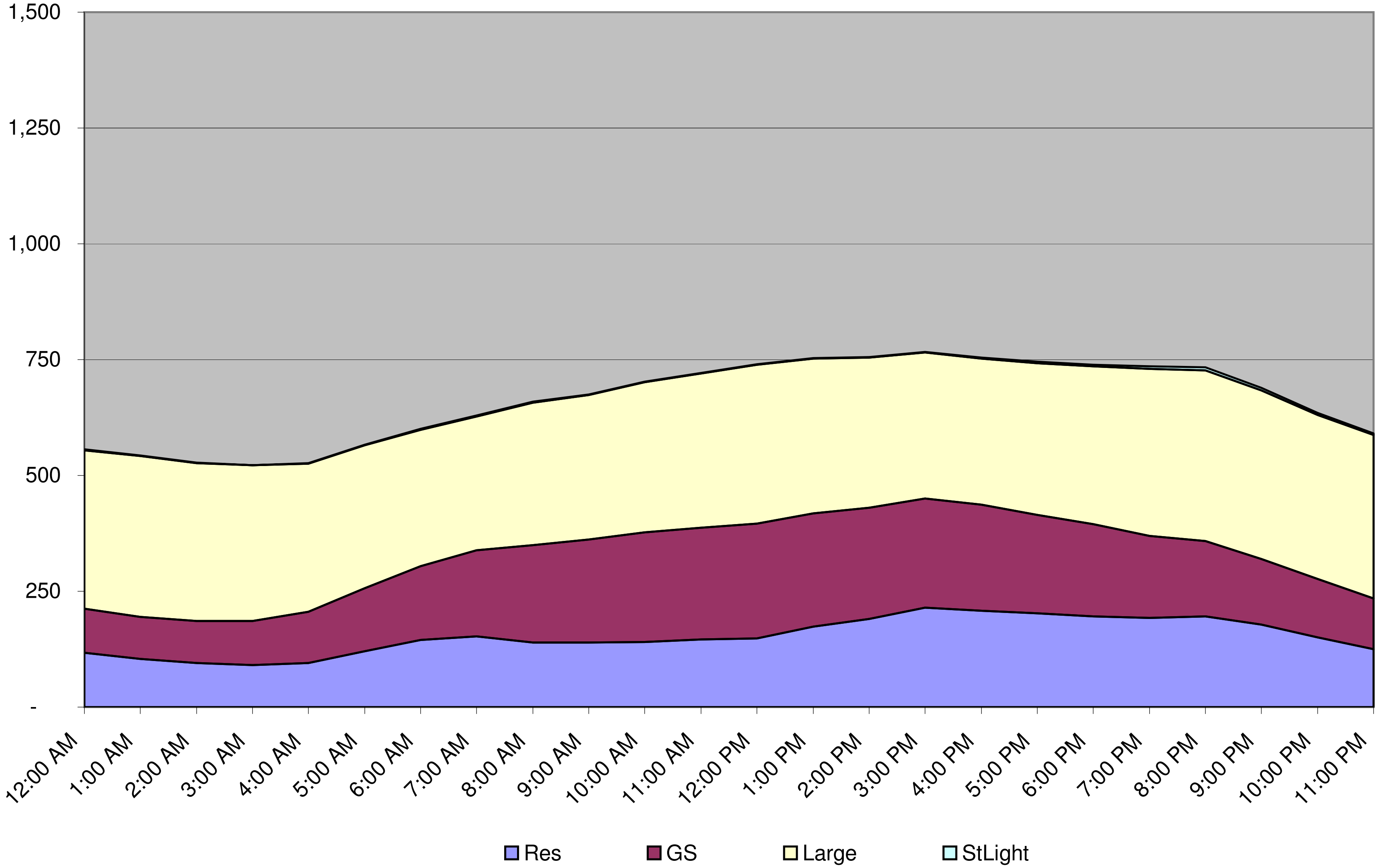
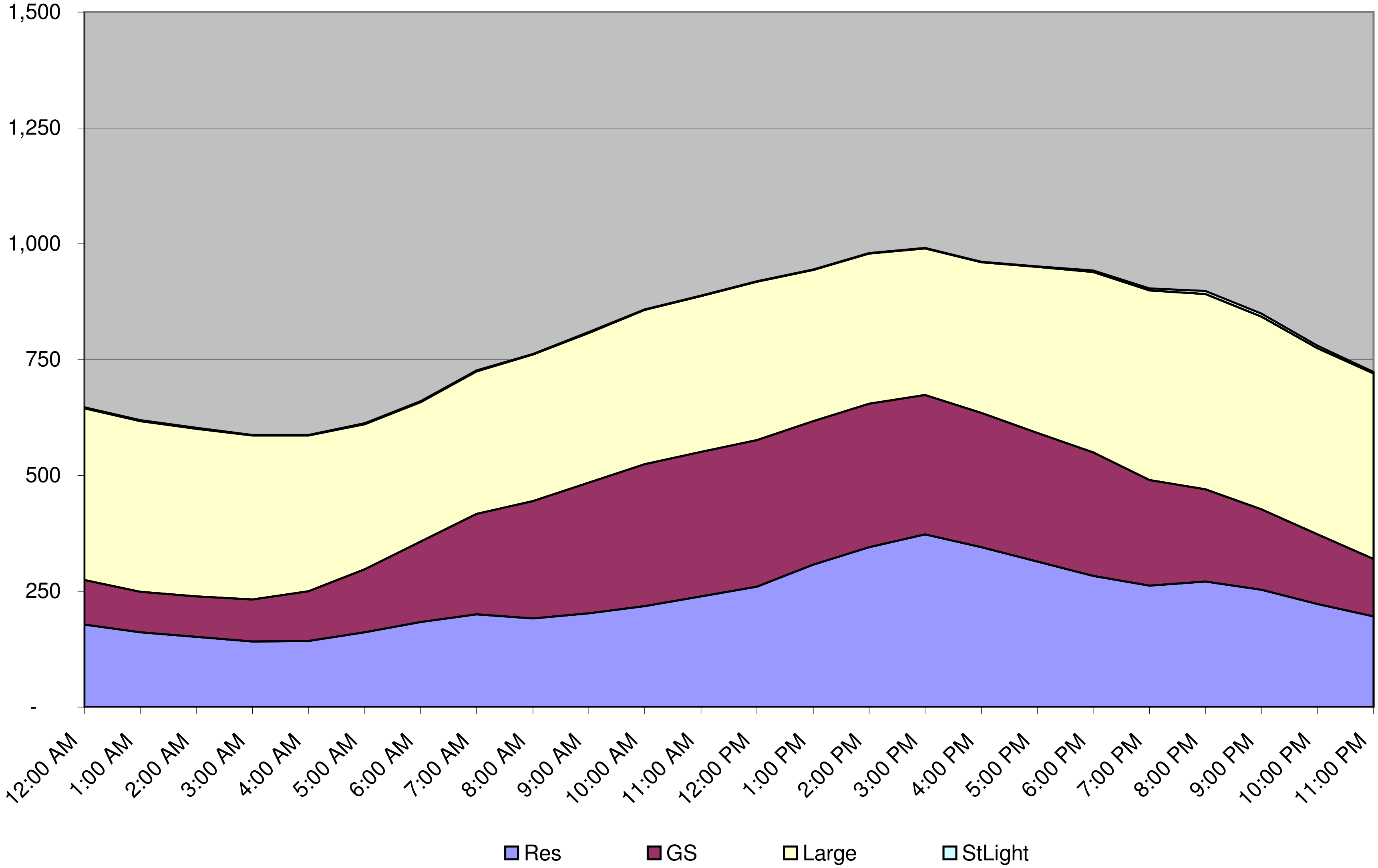
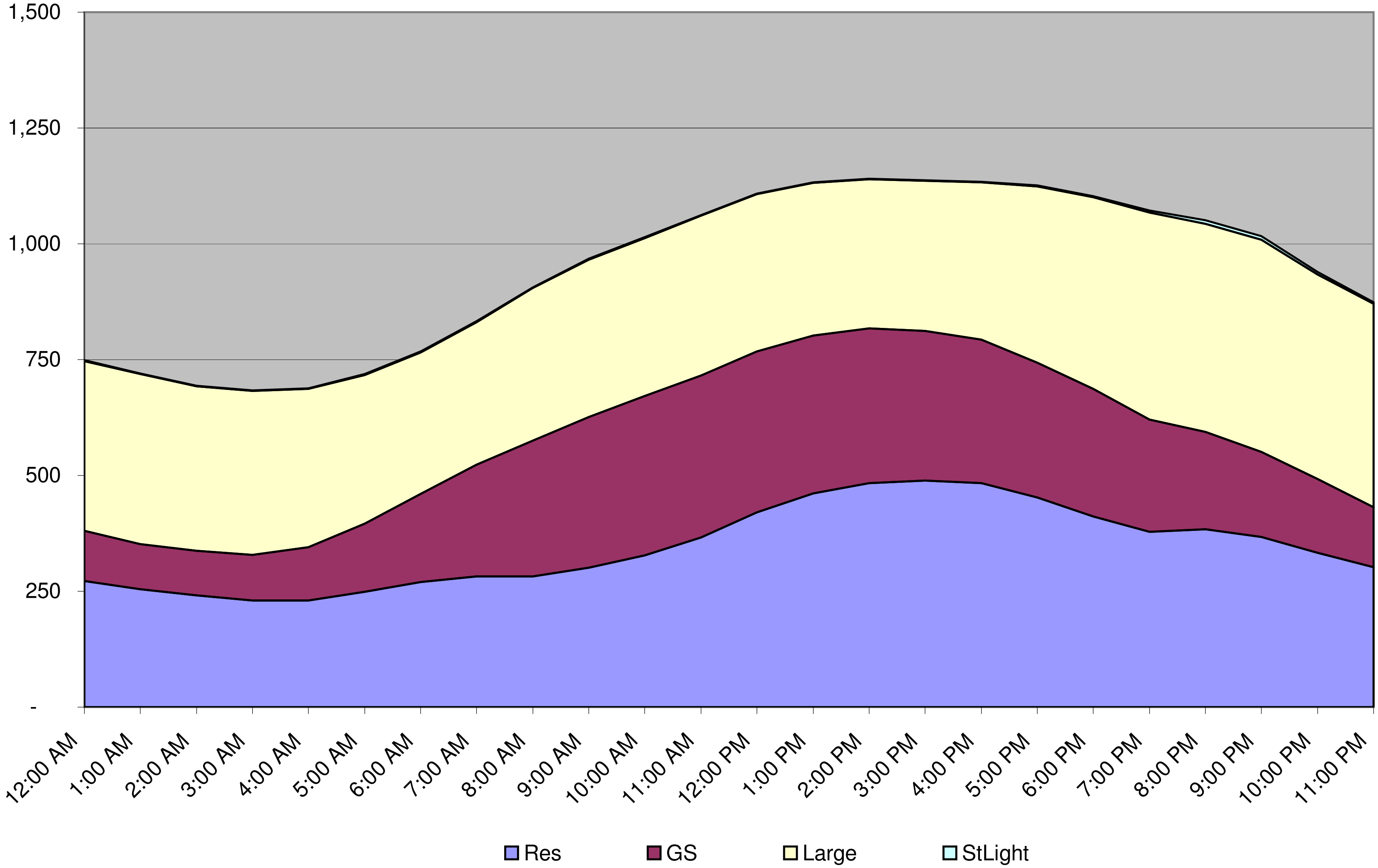
April 2010 Contribution to Peak

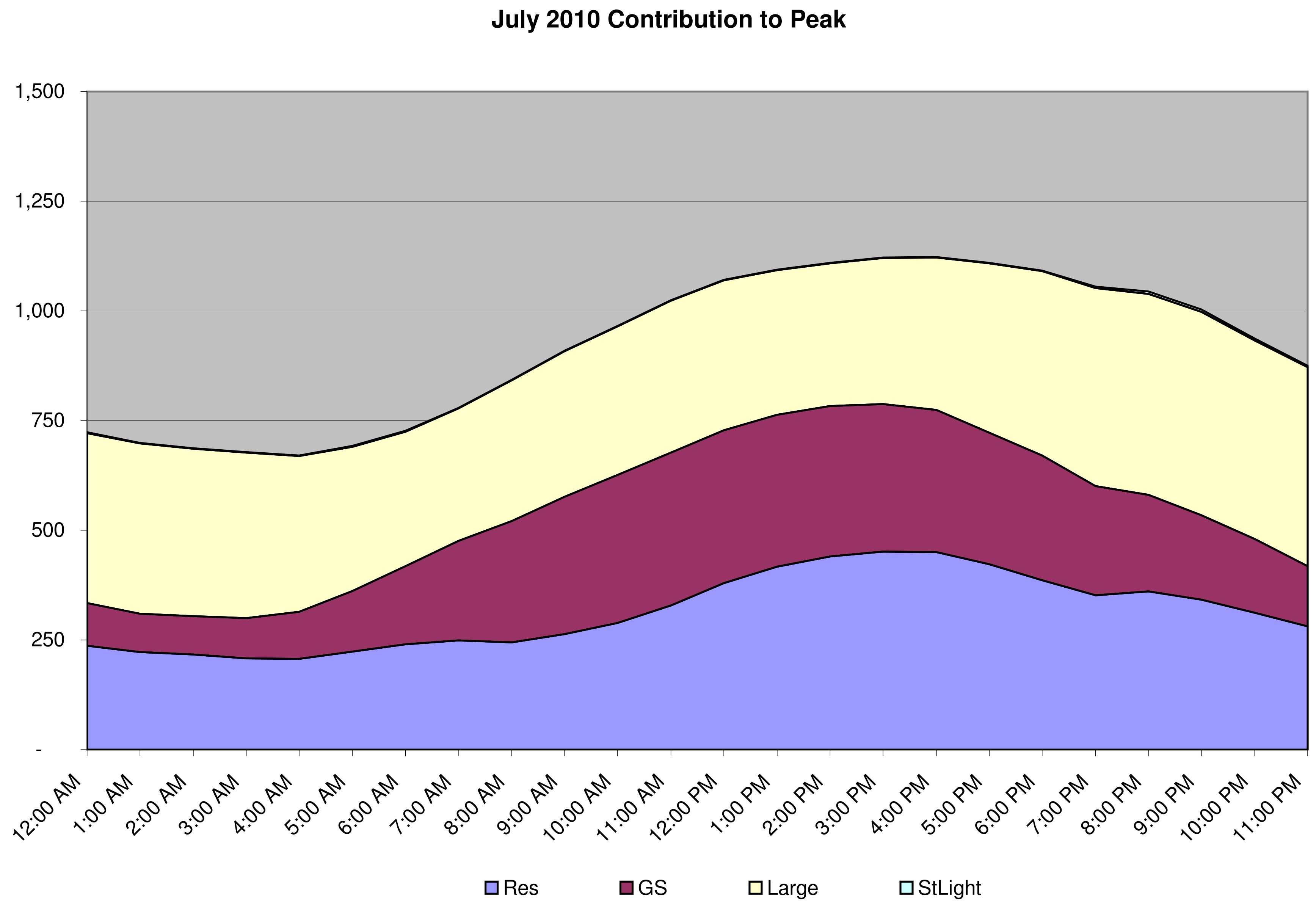


May 2010 Contribution to Peak



June 2010 Contribution to Peak





July 2010 Contribution to Peak
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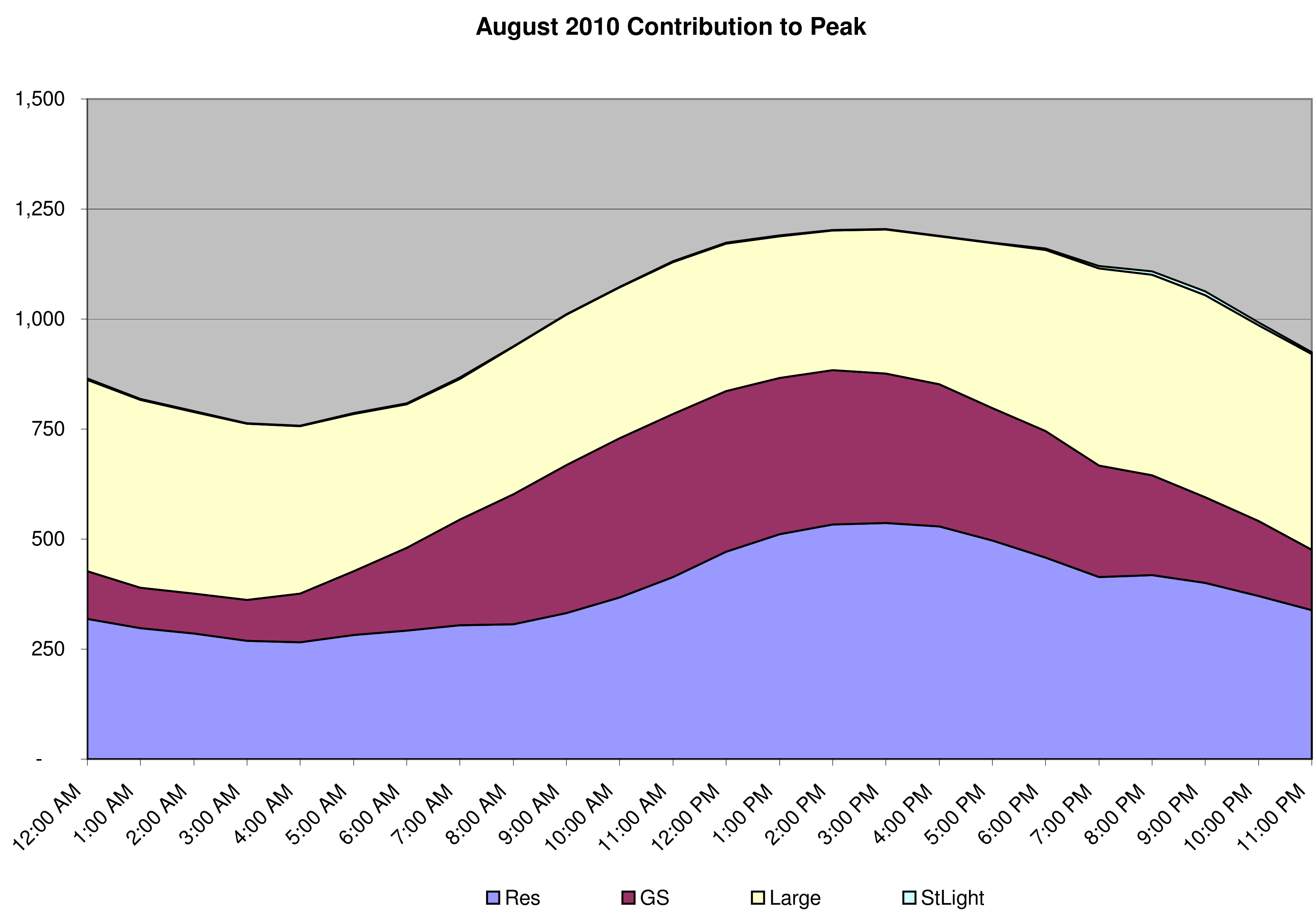

August 2010 Contribution to Peak
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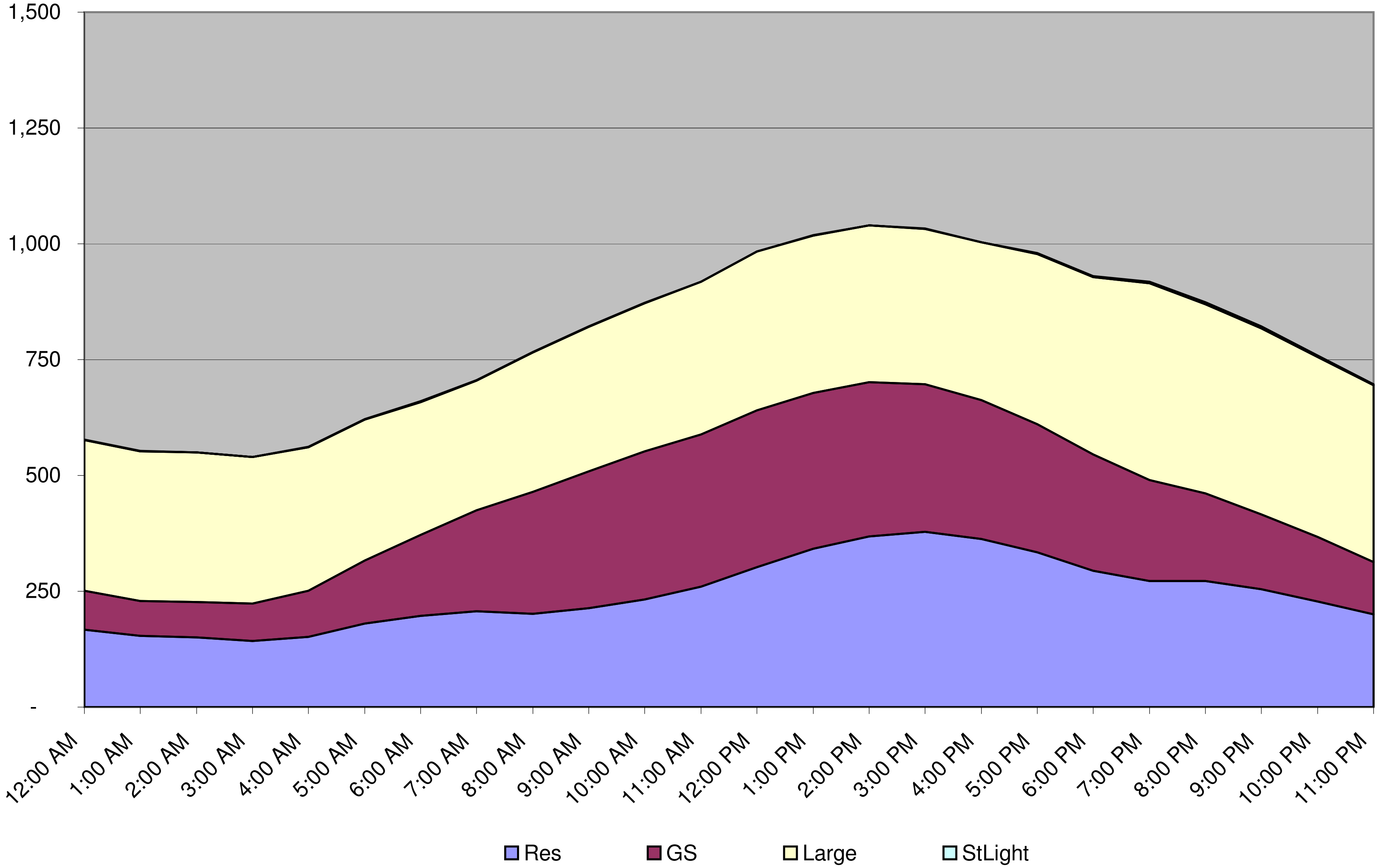
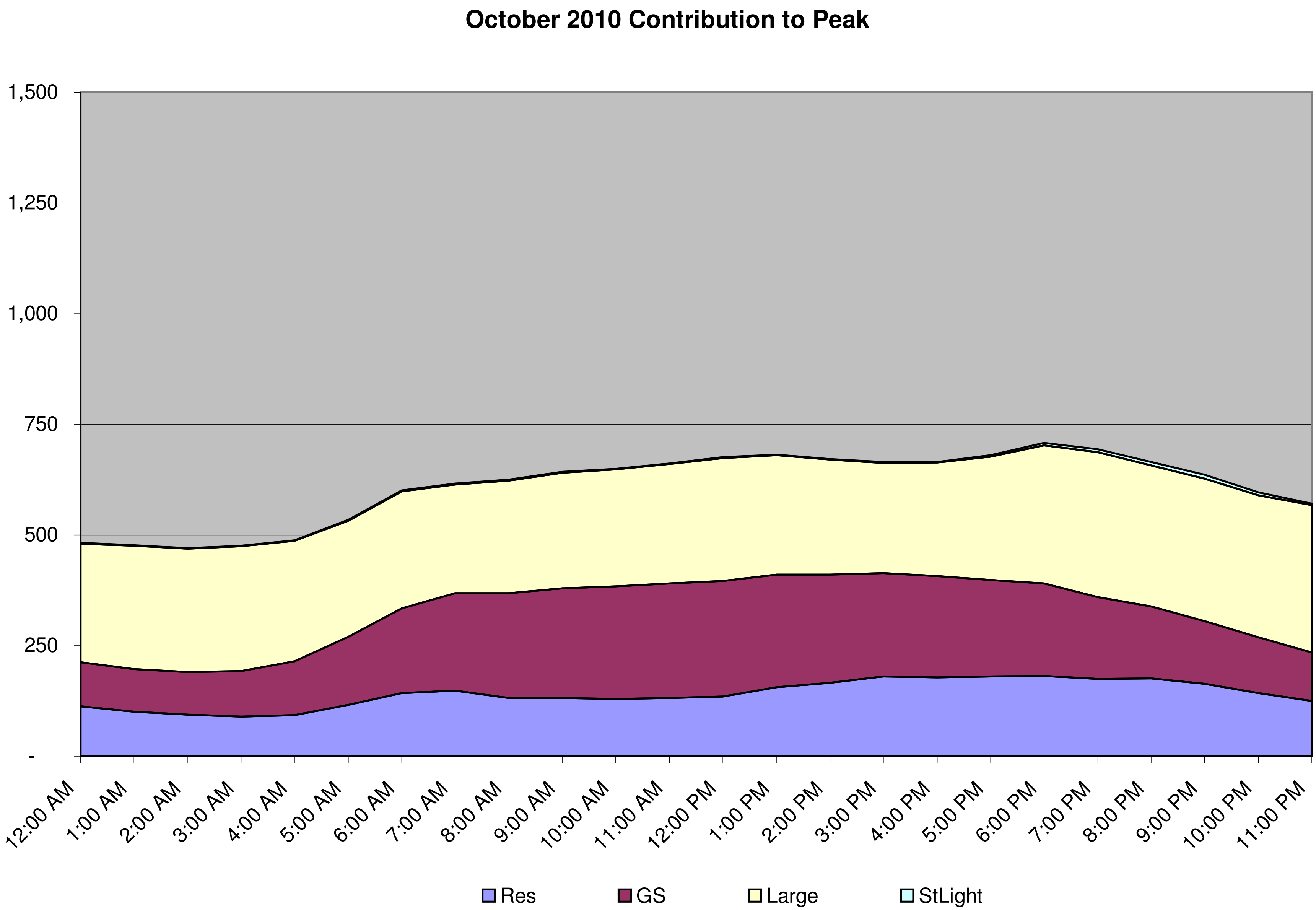
September 2010 Contribution to Peak




October 2010 Contribution to Peak
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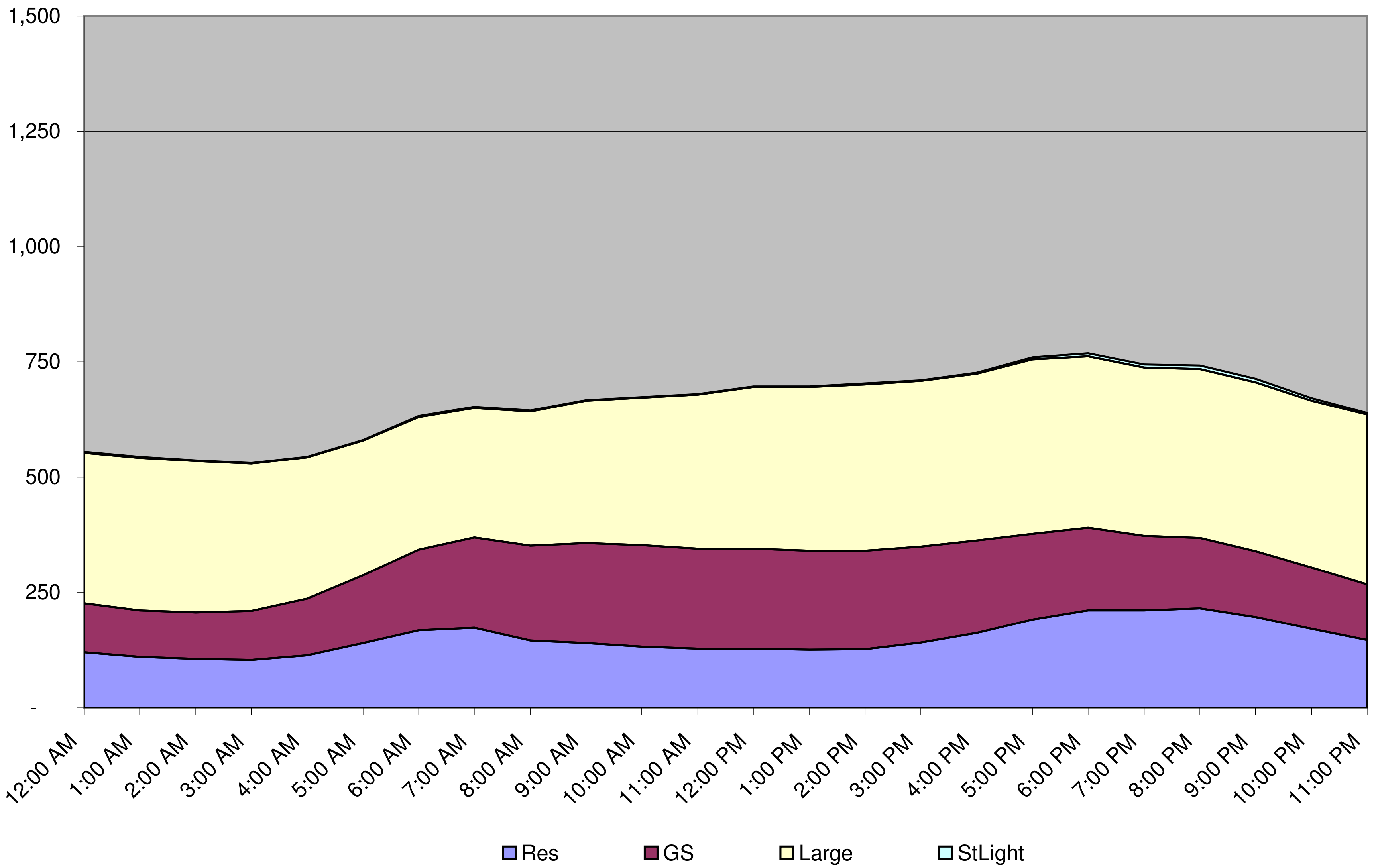
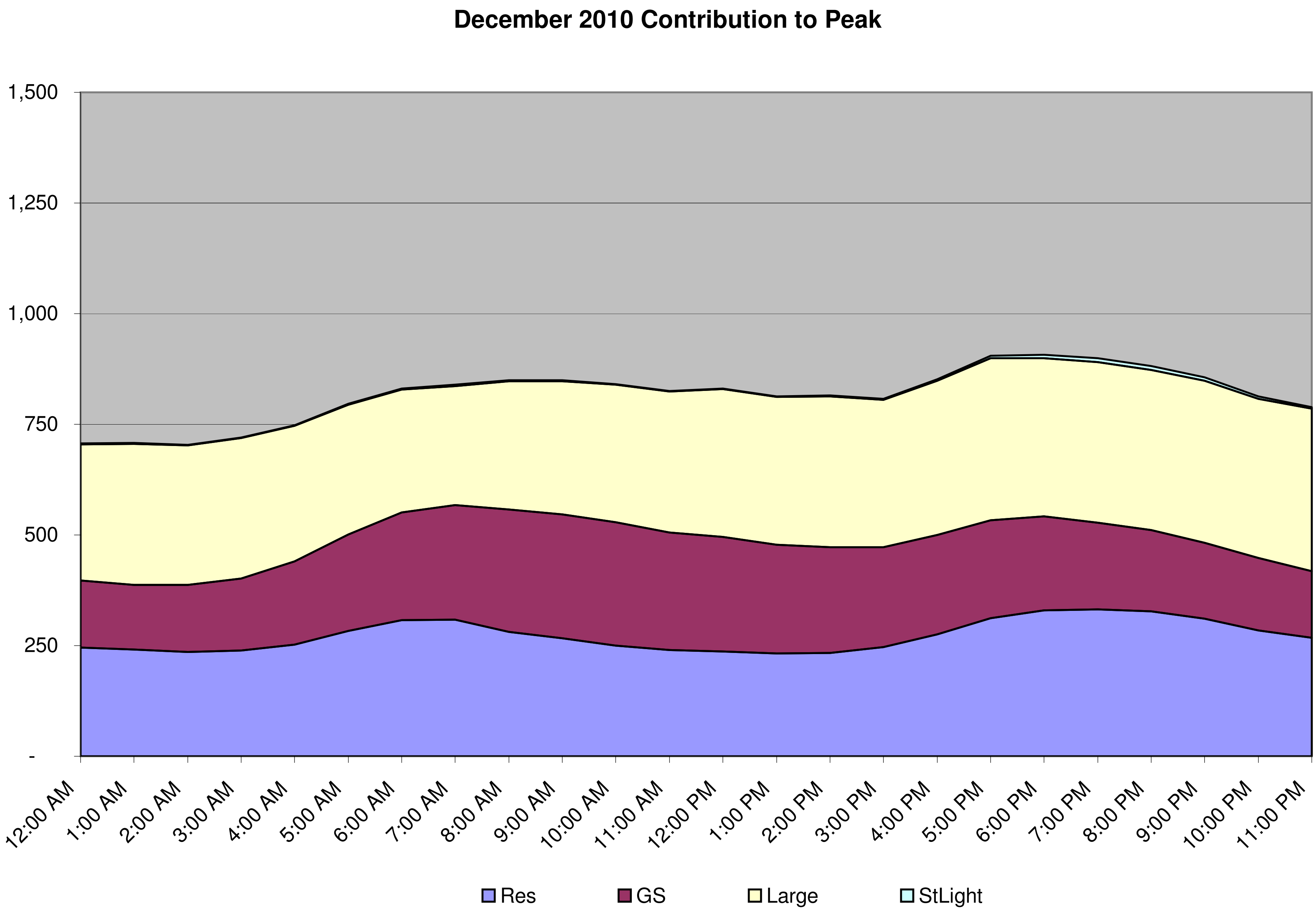
November 2010 Contribution to Peak




December 2010 Contribution to Peak
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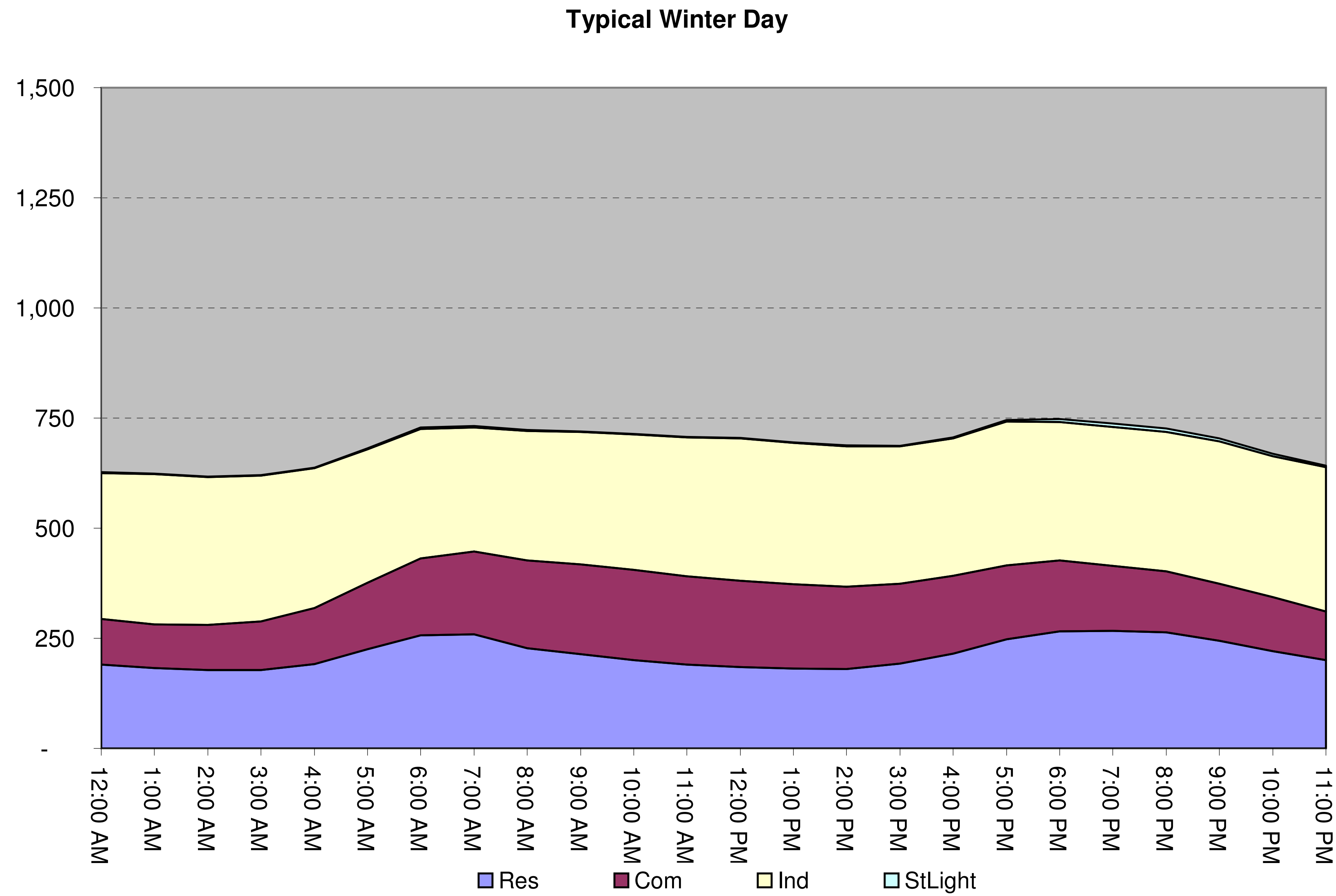
Typical Winter Day
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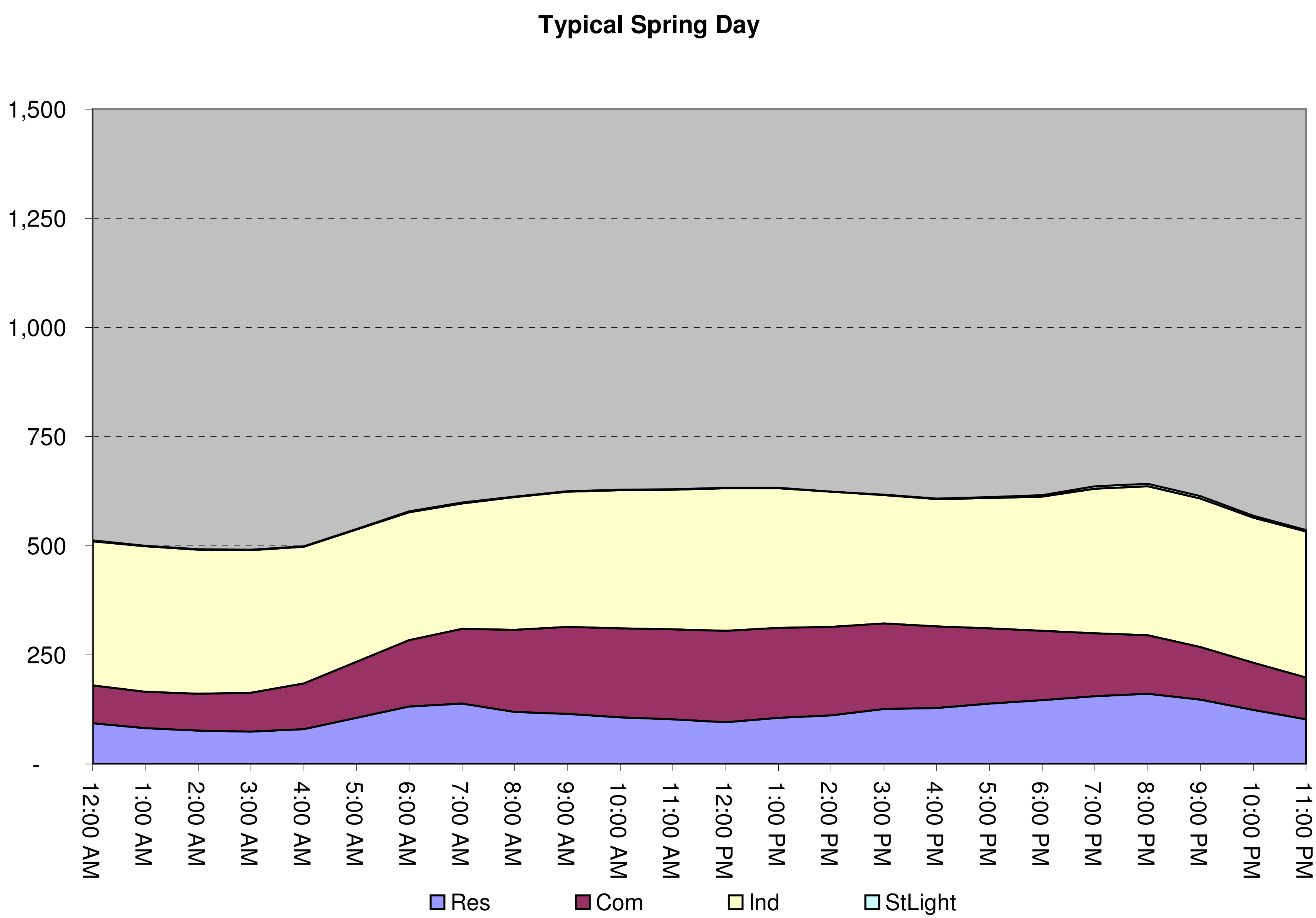
Typical Spring Day
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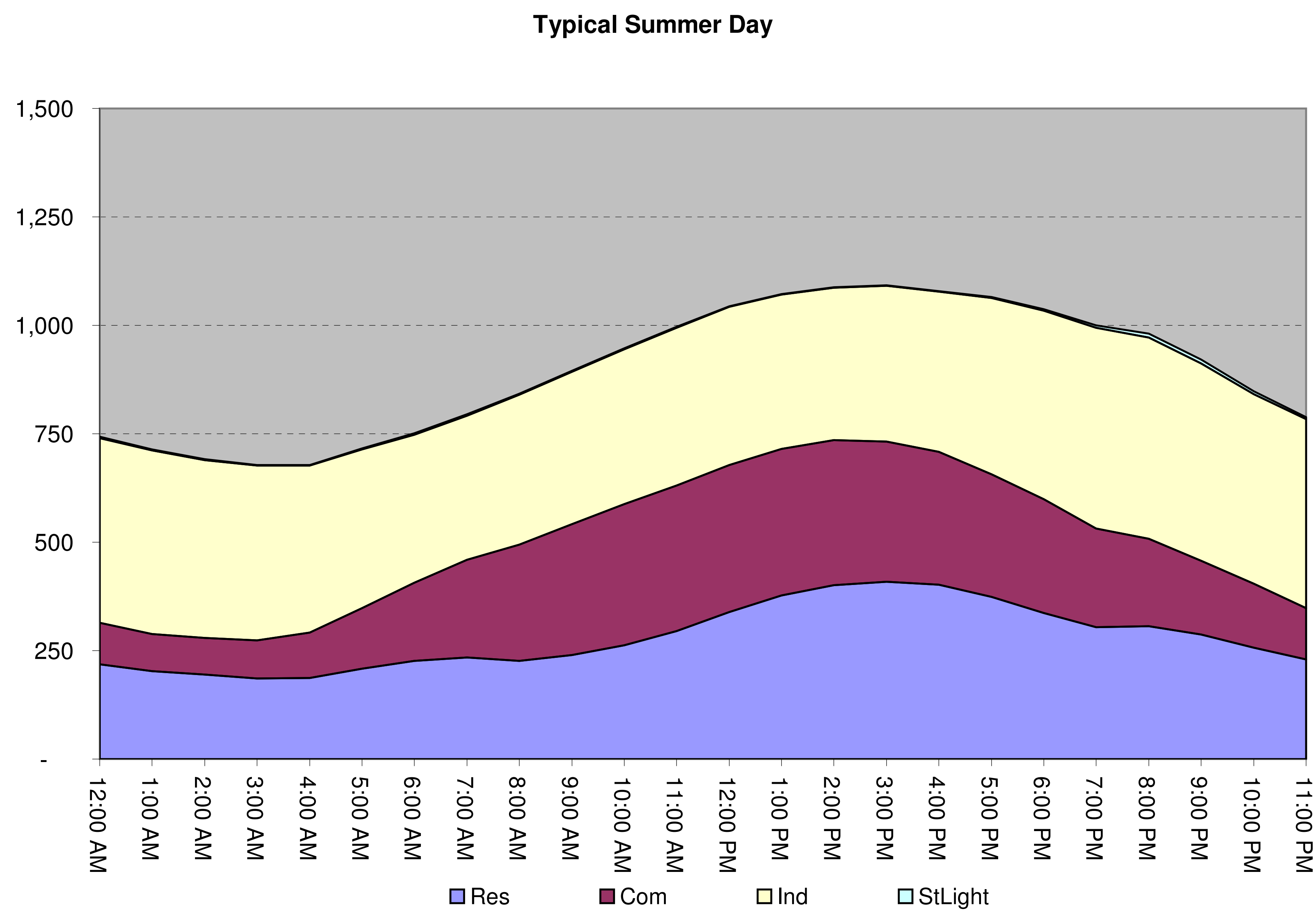
Typical Summer Day
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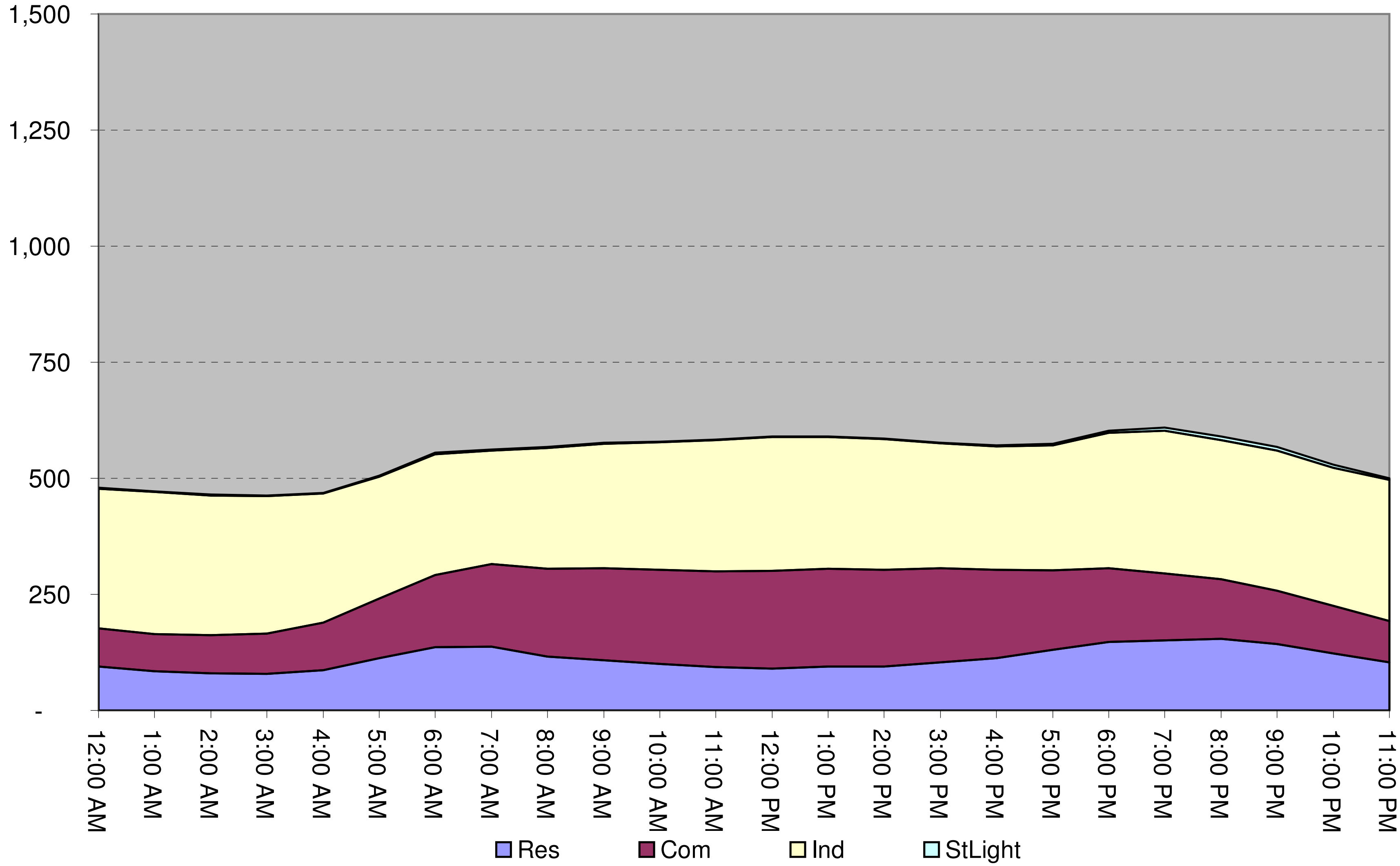
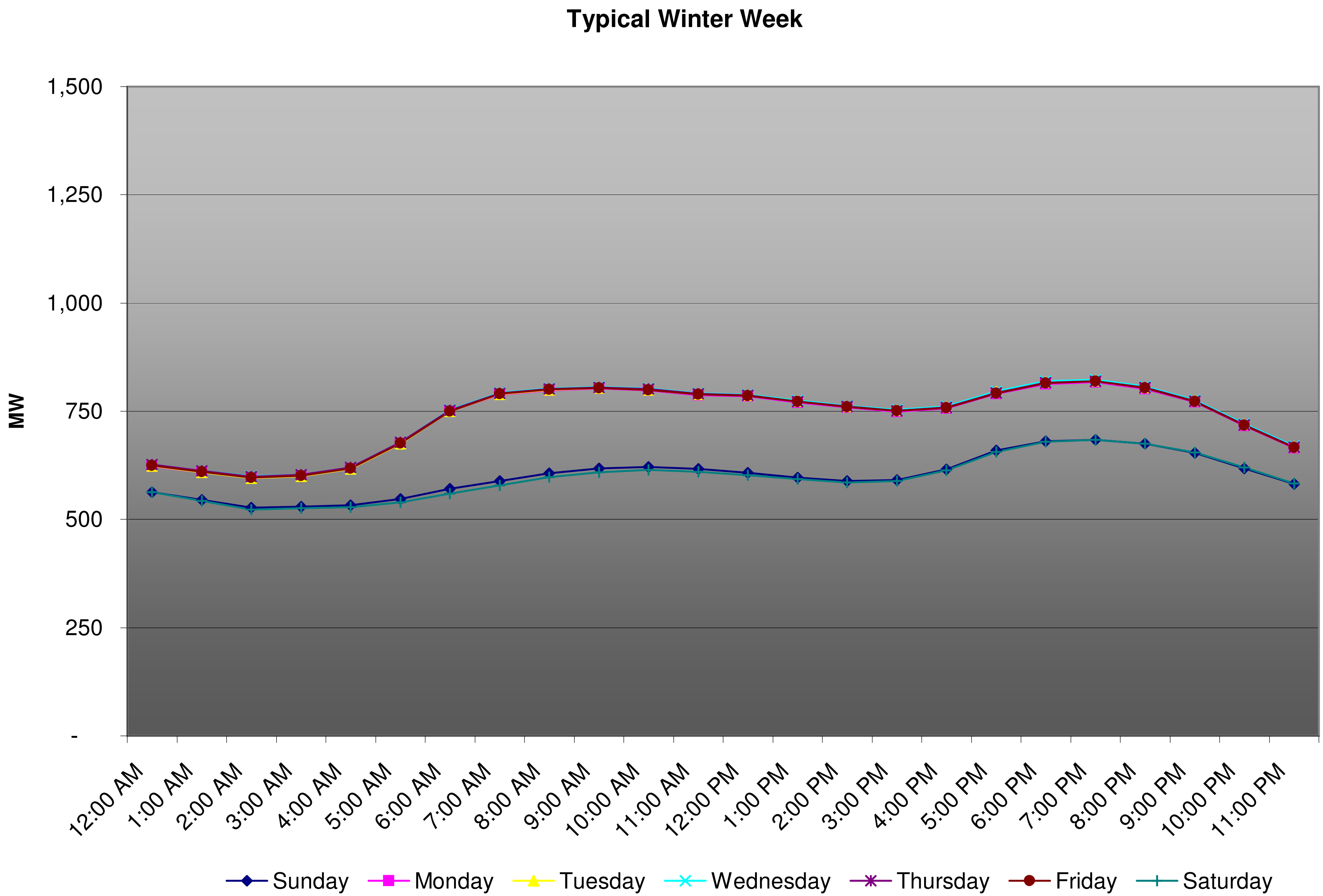
Typical Fall Day





Typical Winter Week
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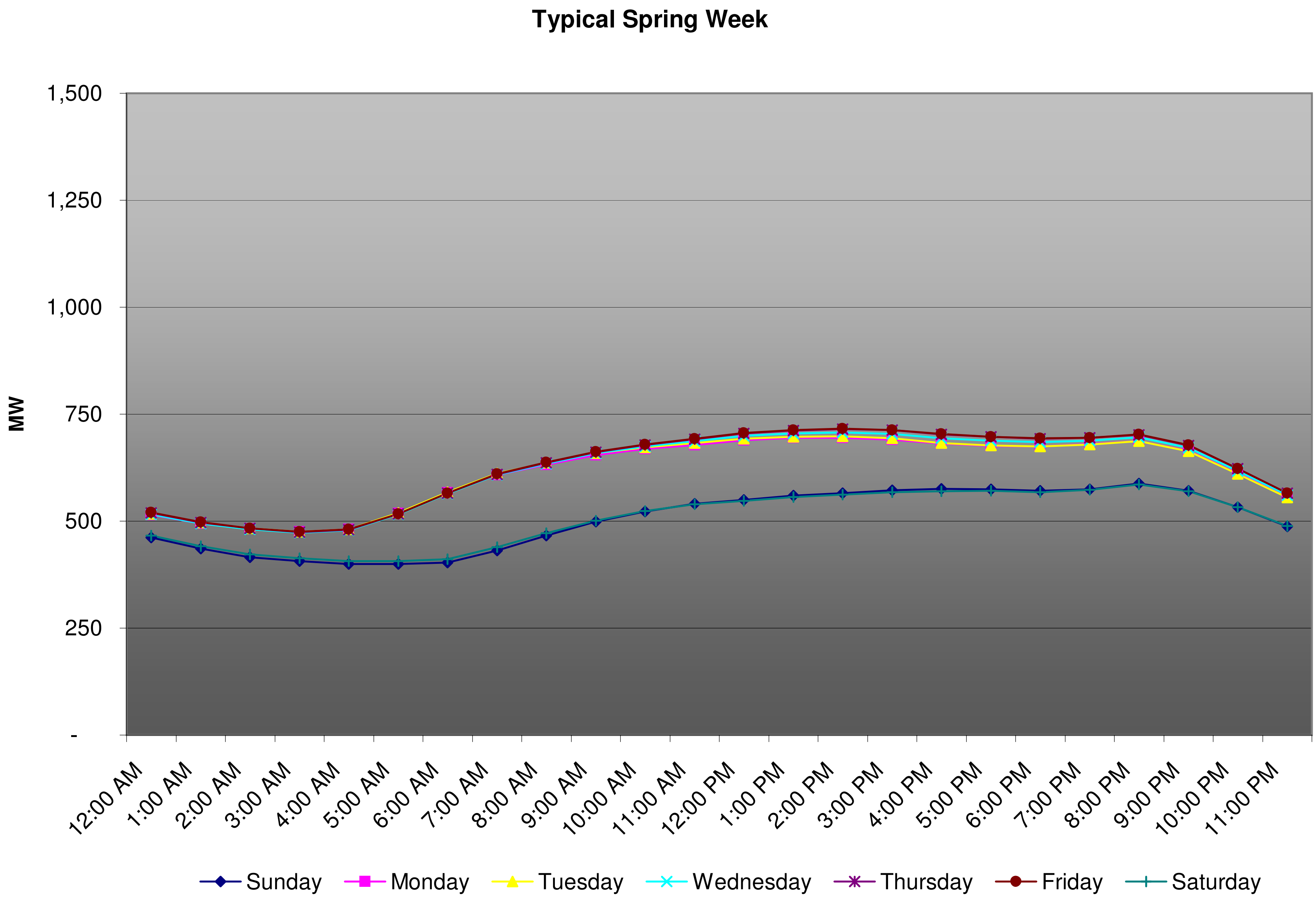

Typical Spring Week
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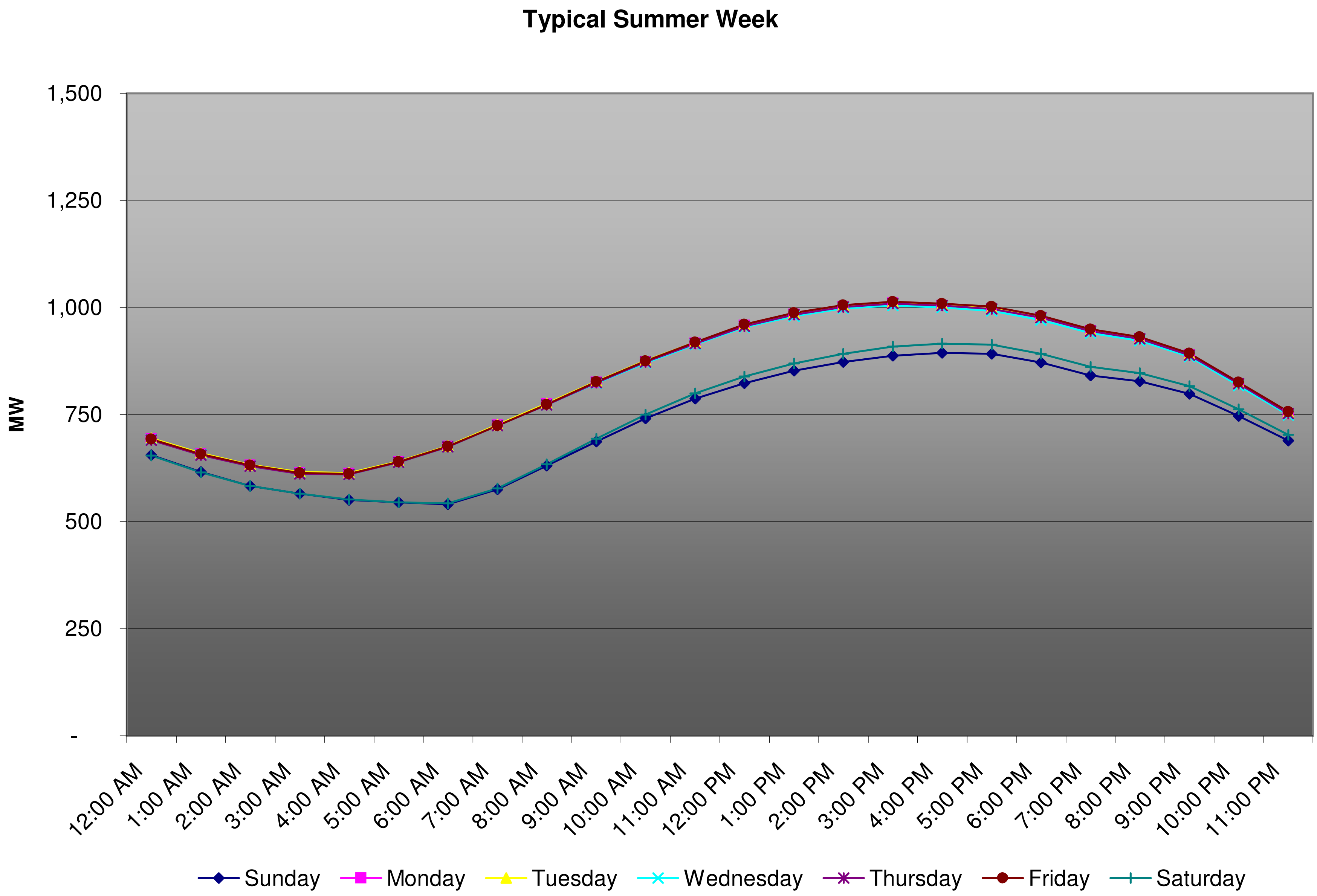
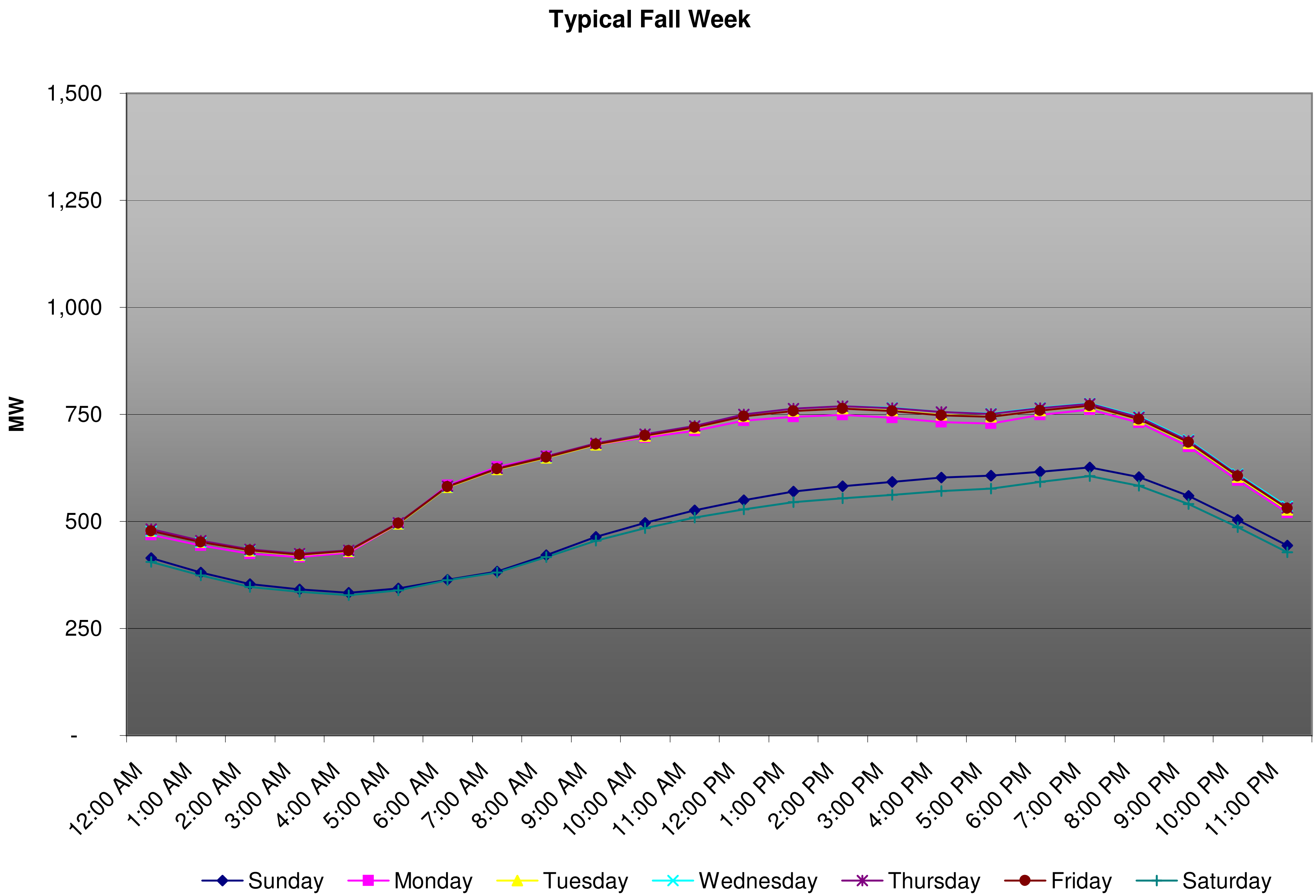
Typical Summer Week





Typical Fall Week
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Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data

For balancing authority areas where demand following is primarily performed by thermal generating units, the system lambda is derived from the economic dispatch function associated with automatic generation control performed at the controlling utility or pool control center. Excluding transmission losses, the fuel cost ($/hr) for a set of on-line and loaded thermal generating units (steam and gas turbines) is minimum 1/ when each unit is loaded and operating at the same incremental fuel cost ($/MWh) 2/ with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other Balancing Authority Areas. This single incremental cost of energy is the system lambda. System lambdas are likely recalculated many times in one clock hour. However, the indicated system lambda occurring on each clock hour would be sufficient for reporting purposes. Respondents must provide the following data: the system lambda, in dollars, for each hour of the year starting with 1 a.m. January 1 as more fully described in the Form 714 instructions. In column (b) indicate the time zone and the days for which daylight savings time was observed. This schedule will have 365 rows for the report year (366 rows for a leap year).

Provide, as a footnote, an explanation describing the reason for the unavailability of system lambda information. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the balancing authority area's thermal units.

Respondents should be able to report system lambda, along with the other information reported on a Balancing Authority Area basis, that describe the operation of such areas from information that should be readily available. The Commission is not requesting Respondents to develop incremental or marginal cost (either short or long term) according to any formula. Nor is the Commission requesting "avoided cost rates" that electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
01/01/2009	EST	27.87	20.97	19.39	-1.22	14.64	15.18	18.68	22.61	18.04	25.24	31.82	29.82	25.70	25.18	23.89	22.97	24.91	49.23	52.03	33.64	27.73	29.08	21.98	20.89
01/02/2009	EST	19.82	22.73	17.40	19.02	21.86	20.97	18.57	23.14	29.21	29.39	34.91	34.29	26.01	25.78	26.42	27.68	20.22	43.31	59.76	38.94	40.83	30.68	26.96	26.38
01/03/2009	EST	30.31	26.24	26.47	25.02	23.54	22.95	25.83	31.42	29.33	32.17	43.26	38.78	30.83	34.09	28.44	27.07	28.76	42.51	68.12	70.05	38.88	33.77	29.43	26.58
01/04/2009	EST	25.48	19.58	22.12	19.96	21.45	22.13	19.97	23.34	25.83	24.30	32.76	36.39	36.83	35.81	29.10	31.28	34.93	64.73	90.24	73.50	45.76	41.43	43.69	22.35
01/05/2009	EST	23.08	25.07	24.06	25.68	25.96	13.86	31.03	55.36	31.70	41.24	34.10	53.36	37.79	32.29	28.68	27.10	25.92	53.10	75.35	35.37	31.94	30.03	25.17	25.97
01/06/2009	EST	29.22	23.52	23.32	23.58	22.18	27.42	36.70	59.69	51.70	37.61	44.41	53.10	44.75	39.21	38.05	37.89	38.06	48.61	48.36	42.49	42.82	29.69	27.97	23.31
01/07/2009	EST	24.97	27.65	26.18	24.45	22.41	25.76	46.95	62.36	59.02	47.36	47.03	47.02	58.80	41.51	26.85	30.61	40.32	55.29	81.54	53.32	47.34	52.06	35.06	30.86
01/08/2009	EST	27.58	28.05	23.45	25.90	29.82	38.38	52.20	69.92	86.07	91.22	65.53	43.88	46.79	43.08	28.36	29.70	32.97	47.41	73.95	66.18	55.50	61.69	32.15	37.71
01/09/2009	EST	31.33	28.62	23.49	24.67	26.41	26.75	28.92	46.57	49.83	48.32	49.39	55.74	39.98	40.36	31.08	26.95	25.67	32.59	34.18	33.73	27.47	26.72	31.65	21.41
01/10/2009	EST	17.93	21.26	25.24	24.20	18.51	24.77	26.71	29.10	22.84	28.94	41.43	67.30	36.41	32.78	27.70	29.90	44.53	35.91	42.57	34.77	40.91	36.83	34.32	30.15
01/11/2009	EST	24.63	27.08	27.83	28.54	26.03	23.68	21.76	30.95	27.13	27.55	31.24	24.09	25.94	25.07	23.99	23.23	25.07	31.55	42.44	59.22	43.47	37.91	29.06	27.53
01/12/2009	EST	23.16	24.22	22.93	22.26	20.81	10.33	28.59	40.92	40.20	41.15	36.05	31.92	30.65	30.02	27.38	26.18	24.91	31.48	36.32	45.83	38.98	23.25	23.59	11.60
01/13/2009	EST	15.05	19.73	9.37	25.73	22.12	19.85	49.70	42.59	53.60	33.13	47.06	41.31	38.82	28.72	31.33	28.66	27.65	32.74	41.54	45.54	43.01	45.21	34.56	35.74
01/14/2009	EST	23.76	25.71	27.37	24.86	20.59	27.27	44.50	53.63	34.48	36.47	31.52	31.45	32.68	27.01	26.50	25.47	27.44	37.59	43.93	52.46	43.76	53.38	36.20	32.17
01/15/2009	EST	37.12	39.35	30.77	29.38	34.64	29.47	47.73	97.67	63.02	72.72	58.29	68.48	56.10	45.90	37.63	36.92	48.26	60.55	89.79	69.47	85.13	75.40	47.72	57.86
01/16/2009	EST	38.30	36.81	28.69	30.78	41.56	30.49	47.56	43.96	67.77	85.17	75.93	49.82	65.68	60.22	42.38	31.42	34.80	35.89	39.90	44.21	38.28	54.58	48.43	46.54
01/17/2009	EST	100.70	34.22	44.72	34.90	28.78	26.92	36.95	34.01	39.81	47.94	61.56	45.91	45.79	38.46	30.92	27.46	28.68	43.51	32.69	33.25	40.26	36.74	27.95	30.94
01/18/2009	EST	29.13	27.20	26.29	23.78	20.65	20.46	25.01	28.19	27.02	33.65	32.67	30.61	28.54	27.72	27.96	27.46	30.94	43.15	49.56	35.02	33.97	29.64	28.04	34.43
01/19/2009	EST	25.13	23.35	23.98	25.41	26.06	28.03	8.87	40.51	35.49	43.33	65.53	40.63	35.30	33.23	28.74	32.10	31.23	32.97	38.28	38.51	32.54	44.95	27.27	34.16
01/20/2009	EST	26.78	26.08	32.62	28.43	36.99	29.10	83.97	93.49	62.27	69.86	70.63	65.30	61.26	83.16	33.10	31.91	34.60	38.32	54.10	82.93	58.25	74.72	35.01	40.14
01/21/2009	EST	30.38	23.74	33.95	21.99	59.72	28.81	63.25	49.12	43.15	72.38	49.17	65.26	41.10	35.30	27.70	24.75	25.47	36.06	55.61	40.60	39.42	30.51	28.38	27.18
01/22/2009	EST	14.70	22.56	20.94	21.84	23.54	27.66	65.57	113.38	60.41	55.49	43.12	35.67	30.96	25.64	24.16	23.23	23.84	37.31	100.71	36.33	32.54	31.63	22.71	8.37
01/23/2009	EST	11.14	19.94	14.75	15.56	16.90	22.00	64.52	33.43	35.17	30.23	32.10	28.66	29.18	26.49	25.09	25.54	26.80	36.71	42.17	46.11	39.06	25.07	25.95	35.48
01/24/2009	EST	21.35	20.38	21.38	22.28	23.23	28.72	29.35	32.07	33.94	36.52	43.33	34.94	31.97	29.78	29.39	27.55	29.01	31.87	125.73	40.43	39.97	33.49	39.31	34.47
01/25/2009	EST	57.31	52.51	42.21	52.26	36.19	46.89	35.54	45.17	47.92	63.99	47.91	46.56	64.01	38.14	35.18	34.69	34.88	35.70	55.47	49.75	48.97	44.15	41.21	37.97

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
01/26/2009	EST	30.80	28.47	28.94	32.62	27.86	34.39	38.43	49.40	54.16	68.88	66.71	47.92	56.23	70.51	45.14	42.65	46.59	42.26	54.29	56.38	53.25	41.12	33.56	37.07
01/27/2009	EST	31.36	34.18	27.41	28.76	29.78	27.71	34.75	53.85	45.41	44.99	45.32	53.09	52.22	48.52	49.98	45.63	46.46	44.84	55.93	41.02	44.15	28.85	33.86	29.53
01/28/2009	EST	24.75	27.59	25.97	25.81	26.57	27.20	36.46	41.35	38.48	44.90	38.01	32.52	30.11	32.28	29.25	27.76	40.92	39.93	56.46	44.25	44.48	37.29	27.96	29.07
01/29/2009	EST	19.37	21.58	20.43	26.61	18.22	24.22	34.95	70.95	45.55	49.61	50.84	44.69	39.60	45.43	42.54	38.18	38.72	36.08	51.40	59.28	47.77	35.23	33.93	27.73
01/30/2009	EST	28.29	28.27	27.51	25.81	26.08	31.86	33.91	58.46	77.20	44.05	41.19	35.64	36.16	35.65	38.46	33.84	33.27	34.57	77.13	39.49	42.67	34.56	32.55	31.04
01/31/2009	EST	28.50	35.83	31.15	25.97	25.63	38.66	37.98	38.04	36.19	29.85	30.20	29.90	38.27	23.98	23.82	20.44	19.68	27.13	36.72	30.10	34.24	21.28	22.30	18.95
02/01/2009	EST	5.88	-45.46	18.72	17.42	11.48	8.69	11.23	21.20	20.34	20.72	20.44	20.76	19.99	18.89	16.50	7.35	19.35	23.51	30.97	23.81	24.10	24.75	23.66	23.15
02/02/2009	EST	21.89	23.89	22.97	21.32	19.24	23.66	32.32	62.79	35.41	34.16	30.37	30.96	33.18	36.93	26.83	27.50	28.99	37.04	102.74	44.67	41.09	35.33	30.77	27.71
02/03/2009	EST	18.14	23.85	24.28	24.45	27.06	29.61	44.96	76.74	75.81	81.91	57.79	49.41	71.73	44.93	42.37	34.28	52.65	43.07	65.07	63.32	80.21	68.46	46.19	92.07
02/04/2009	EST	63.40	68.53	61.44	34.63	30.97	34.11	43.16	78.95	63.70	58.36	49.14	53.09	46.90	37.07	34.23	29.53	30.83	43.89	70.27	64.09	60.11	49.54	32.62	35.64
02/05/2009	EST	33.06	37.48	32.05	44.22	29.36	43.72	56.49	87.65	53.67	49.25	49.62	42.13	37.52	40.09	36.81	29.77	27.14	35.19	52.42	49.93	43.56	34.78	27.05	27.60
02/06/2009	EST	33.63	31.38	28.98	32.25	38.10	23.59	55.50	48.98	43.55	38.78	29.38	26.94	30.44	30.77	22.62	16.42	12.30	27.37	37.83	28.51	24.07	14.63	16.45	23.30
02/07/2009	EST	13.55	11.90	16.36	11.34	12.48	15.52	20.58	24.81	21.95	26.74	24.60	23.67	22.82	23.00	22.99	21.62	22.15	23.86	34.95	25.46	23.86	23.80	21.71	20.69
02/08/2009	EST	19.11	19.82	16.92	15.21	16.73	18.16	20.17	23.31	23.70	25.76	23.52	23.19	23.68	22.17	20.14	21.15	20.47	25.91	45.55	28.27	33.25	27.96	18.46	11.10
02/09/2009	EST	17.45	5.56	2.52	13.16	-4.26	26.95	46.62	74.35	40.27	41.47	42.16	28.81	26.77	26.84	24.93	20.81	23.66	26.20	44.51	35.40	28.43	23.64	18.72	-9.92
02/10/2009	EST	6.77	6.76	9.02	8.12	11.23	20.93	26.21	31.01	24.76	26.40	22.69	21.79	22.92	24.14	19.93	19.04	19.03	24.87	31.80	29.18	28.42	18.05	15.23	11.63
02/11/2009	EST	17.56	16.37	8.64	7.86	15.93	23.39	34.25	47.15	37.04	35.22	34.22	29.82	29.39	28.04	27.08	23.24	27.86	32.65	37.33	35.06	27.19	24.28	21.47	4.46
02/12/2009	EST	12.88	15.45	6.25	12.10	10.97	21.39	31.19	35.20	34.49	41.30	34.30	30.19	27.26	34.01	27.46	24.71	24.76	25.19	44.71	49.61	37.72	34.23	27.72	24.42
02/13/2009	EST	20.59	23.95	24.98	22.15	23.54	24.03	32.31	43.86	41.43	38.48	37.92	38.16	34.65	33.01	31.42	24.85	26.50	25.96	37.99	33.81	27.93	28.24	27.68	21.28
02/14/2009	EST	23.19	21.73	22.72	22.52	21.72	23.43	24.04	25.08	28.46	32.31	41.21	32.62	29.58	27.77	25.85	24.61	26.11	30.44	34.39	36.57	33.01	41.80	60.91	40.96
02/15/2009	EST	23.51	24.09	23.85	24.62	24.88	24.01	27.64	27.43	33.85	37.30	28.93	28.01	25.84	24.55	22.52	22.47	23.06	23.97	34.71	36.11	33.34	29.39	28.58	33.33
02/16/2009	EST	31.07	24.16	24.77	24.03	24.83	27.58	30.12	40.70	33.12	35.74	32.83	30.90	30.55	26.74	26.77	22.71	23.23	26.07	43.07	38.00	33.40	29.09	27.39	23.69
02/17/2009	EST	22.07	23.06	22.26	23.47	24.72	24.28	39.53	46.46	39.58	48.33	41.13	36.75	37.41	38.77	34.33	33.23	32.10	30.01	33.79	36.00	36.47	40.71	29.58	25.91
02/18/2009	EST	22.47	21.77	20.64	19.80	20.18	21.67	27.67	33.38	27.09	32.47	31.68	35.37	34.71	35.34	26.03	30.15	30.34	28.95	38.40	35.37	38.38	33.71	29.41	26.87
02/19/2009	EST	22.14	21.82	23.24	24.43	25.80	25.28	35.31	50.53	48.80	47.07	40.78	72.97	34.37	36.78	38.11	34.29	29.56	29.74	42.00	56.99	49.98	45.73	45.27	45.68
02/20/2009	EST	43.27	32.30	35.51	32.23	27.67	27.49	33.72	37.45	41.84	38.58	39.67	37.97	34.57	34.22	33.23	34.04	33.91	37.80	41.49	40.23	42.54	35.31	34.72	34.48
02/21/2009	EST	35.14	39.82	27.45	28.94	30.38	28.93	29.36	32.41	43.99	45.98	35.51	40.71	36.45	36.86	38.90	32.85	27.15	23.43	39.24	48.52	41.83	39.43	34.53	34.21
02/22/2009	EST	30.06	61.77	34.94	32.30	29.69	30.04	36.73	33.88	32.32	40.04	41.01	34.98	35.78	34.53	32.60	33.02	32.72	32.47	45.74	60.95	50.40	44.83	25.80	34.62
02/23/2009	EST	25.50	28.08	27.27	27.68	27.63	28.13	42.43	55.46	56.45	51.57	52.29	42.13	37.23	31.10	30.90	29.54	27.26	28.52	51.42	51.36	48.39	39.35	30.95	32.65
02/24/2009	EST	26.76	26.20	24.96	21.06	26.98	31.43	62.62	41.10	31.57	35.56	44.58	34.84	31.00	31.67	30.47	28.40	26.33	24.94	32.48	35.50	33.85	28.73	26.59	22.00
02/25/2009	EST	21.04	22.43	20.77	21.31	21.18	31.19	40.61	28.34	27.58	25.35	26.56	26.38	27.67	30.35	26.78	25.03	25.91	27.35	30.02	33.80	31.35	26.66	27.61	22.35
02/26/2009	EST	23.62	21.90	20.64	19.72	20.84	23.88	28.51	30.16	31.35	29.20	37.37	47.58	66.63	37.00	35.93	25.64	31.26	37.27	50.25	49.67	52.33	34.58	25.26	23.84
02/27/2009	EST	13.69	20.27	19.04	20.51	20.68	25.06	29.96	34.12	41.83	47.39	43.22	41.19	45.62	53.65	40.90	33.83	35.90	34.76	44.17	46.21	41.05	38.29	29.81	29.36
02/28/2009	EST	30.64	34.78	34.27	32.80	28.39	30.68	37.36	29.02	31.77	54.72	39.68	43.43	33.54	31.97	32.47	30.69	28.66	33.08	44.01	39.95	38.44	34.29	29.11	30.23
03/01/2009	EST	32.58	25.85	55.47	29.74	27.35	33.22	46.51	25.62	28.66	32.03	34.43	34.83	33.18	28.40	26.75	28.82	32.49	41.81	56.35	67.75	50.99	40.09	37.58	47.85
03/02/2009	EST	26.58	27.72	33.87	30.85	40.52	27.35	50.11	49.60	42.31	61.58	56.09	59.11	78.23	41.78	35.27	34.55	43.16	29.47	34.22	50.68	41.17	36.31	37.85	76.00

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
03/03/2009	EST	67.26	39.12	71.55	34.54	74.55	102.50	145.63	100.05	56.06	62.57	61.59	53.47	47.64	48.81	31.64	34.43	29.61	39.70	54.14	49.25	42.96	35.47	26.56	22.81
03/04/2009	EST	30.63	-1.02	-22.02	6.26	4.27	2.27	5.35	39.69	42.79	42.29	30.02	23.36	25.87	16.70	14.28	13.63	19.51	17.02	26.53	29.25	21.50	22.53	23.99	12.54
03/05/2009	EST	-1.65	17.09	-4.03	14.49	15.85	13.70	76.98	33.70	29.09	30.15	29.11	26.72	25.69	27.50	25.78	22.67	22.80	22.66	29.66	27.13	24.16	22.76	17.95	-9.74
03/06/2009	EST	-8.11	-0.35	10.17	-11.36	7.77	16.64	23.62	28.47	28.01	26.53	27.52	36.45	26.37	23.07	22.86	23.83	23.60	22.99	24.80	45.90	25.90	22.55	18.91	18.61
03/07/2009	EST	16.35	15.89	16.45	14.90	15.92	16.06	16.93	20.34	22.91	24.41	25.00	24.49	25.19	31.02	23.76	22.42	22.76	24.49	31.15	38.27	27.22	24.81	20.31	17.96
03/08/2009	EST	16.18	15.75	-2.95	-14.49	9.17	15.70	17.98	20.22	21.23	26.57	37.95	32.48	55.30	24.56	27.98	30.64	41.65	34.12	29.27	40.27	31.43	25.51	23.86	16.29
03/09/2009	EST	18.17	17.95	17.03	19.37	32.91	56.56	37.57	50.09	36.02	46.98	38.22	35.62	51.40	32.77	30.34	39.55	27.15	30.13	67.92	84.23	29.00	26.51	27.35	20.77
03/10/2009	EST	21.75	19.60	20.08	21.70	29.72	74.75	38.23	37.74	41.33	82.72	47.14	39.14	47.60	29.27	26.80	27.90	33.18	30.01	48.78	27.34	30.34	23.30	24.60	17.84
03/11/2009	EST	18.13	18.93	19.29	20.86	12.46	18.84	36.96	36.37	39.13	35.30	37.24	35.12	35.19	30.38	27.80	27.97	27.93	32.19	34.48	51.52	41.38	26.93	27.78	28.51
03/12/2009	EST	24.93	25.73	22.43	25.73	23.46	33.31	43.28	41.30	36.09	45.75	50.87	36.13	46.51	35.01	31.36	29.48	27.73	26.88	39.57	37.78	34.28	29.83	23.54	16.02
03/13/2009	EST	25.47	22.09	21.37	23.39	30.46	27.15	34.12	33.38	30.71	27.65	29.44	26.92	20.57	22.16	22.02	20.12	17.19	20.76	48.79	44.20	23.93	23.80	20.58	20.22
03/14/2009	EST	15.69	20.86	19.53	19.92	24.28	31.15	39.89	51.30	35.61	26.30	23.92	22.65	19.90	25.45	19.99	25.87	20.35	19.21	26.99	28.37	23.20	14.12	1.17	11.56
03/15/2009	EST	-97.72	3.83	11.65	7.03	13.86	17.79	21.87	20.31	23.04	22.63	19.76	20.20	18.51	16.39	14.75	15.56	17.92	18.95	37.76	30.56	22.35	17.81	-3.12	8.91
03/16/2009	EST	15.54	-27.71	14.48	16.02	17.85	47.50	43.88	26.95	23.69	26.83	38.81	34.35	25.12	23.15	22.35	21.38	19.83	19.32	28.73	25.74	23.47	16.01	6.98	2.53
03/17/2009	EST	16.07	-14.42	-19.07	0.16	15.19	24.39	27.36	22.39	23.65	24.27	25.58	23.55	20.41	23.62	18.92	18.33	18.01	18.33	21.40	29.18	21.90	17.49	14.40	15.89
03/18/2009	EST	-32.79	13.49	14.21	16.29	18.43	45.58	42.00	29.36	23.85	27.63	26.89	27.02	24.45	23.99	21.19	18.27	20.06	20.71	32.82	27.16	23.30	20.89	21.89	20.71
03/19/2009	EST	17.29	18.10	18.56	19.45	20.73	67.92	28.13	35.87	32.87	25.70	24.78	25.16	26.97	25.71	23.30	23.01	23.87	25.64	25.67	44.43	28.47	23.97	24.88	23.39
03/20/2009	EST	14.56	18.35	19.65	22.03	21.05	28.39	54.57	25.36	25.64	25.73	24.99	26.36	24.26	20.67	17.80	18.02	17.10	16.08	20.81	38.06	22.71	20.61	19.94	18.50
03/21/2009	EST	14.85	17.22	18.77	21.98	18.48	24.60	34.05	41.11	26.31	26.50	26.19	23.82	21.85	21.16	20.91	20.71	22.58	22.03	22.71	31.06	24.35	23.72	21.61	9.60
03/22/2009	EST	9.59	18.65	14.09	14.87	13.37	13.35	8.11	17.12	20.93	22.07	22.19	15.53	11.02	16.92	18.85	19.97	19.15	18.47	48.95	47.51	22.72	21.21	15.02	3.15
03/23/2009	EST	-33.10	10.34	4.71	6.92	16.61	26.18	33.36	26.77	38.80	26.72	28.15	86.35	15.91	32.25	28.21	27.37	23.39	23.24	30.16	40.17	24.21	20.70	15.22	14.10
03/24/2009	EST	12.89	13.36	3.09	20.71	23.83	41.54	26.82	32.03	28.51	29.95	30.05	29.58	28.05	27.50	25.20	24.75	33.46	31.18	36.54	37.73	28.59	13.05	15.78	15.43
03/25/2009	EST	17.83	9.01	16.71	18.80	26.56	25.23	43.04	39.22	34.32	37.95	39.20	45.25	41.16	35.61	33.85	32.03	31.49	30.32	30.18	56.88	45.62	32.92	26.09	19.65
03/26/2009	EST	20.41	18.21	19.49	15.72	23.98	41.08	29.90	31.10	30.07	41.87	47.91	33.15	50.44	32.08	25.42	25.44	25.26	23.21	26.29	44.87	28.81	24.50	21.37	20.29
03/27/2009	EST	19.07	18.29	16.21	21.35	18.24	23.14	30.55	49.23	46.03	35.40	33.55	29.11	51.11	29.75	28.32	24.58	21.26	20.99	18.83	31.40	25.36	22.64	18.61	23.26
03/28/2009	EST	22.98	21.73	22.42	22.22	22.42	25.14	23.68	27.90	28.42	29.80	30.02	28.00	30.15	29.74	26.14	27.84	37.32	34.31	27.63	28.39	23.37	18.91	14.09	18.04
03/29/2009	EST	21.04	21.35	16.69	21.61	22.51	23.57	25.07	38.49	34.91	31.44	28.77	31.44	37.16	28.60	25.89	29.23	27.50	28.02	23.52	35.16	31.67	23.02	26.04	23.51
03/30/2009	EST	20.71	20.74	20.58	24.28	24.50	26.58	31.18	32.82	34.91	33.18	30.72	30.16	29.56	29.82	25.76	22.92	18.80	19.79	26.15	33.19	24.42	21.93	17.42	10.29
03/31/2009	EST	16.43	14.40	17.31	5.75	-3.07	42.91	25.49	30.41	27.23	27.40	28.99	57.02	34.65	31.68	28.73	27.98	26.64	25.94	42.42	36.17	22.06	21.34	23.09	19.88
04/01/2009	EST	14.40	16.60	19.10	9.47	16.37	30.77	31.51	29.99	27.83	49.78	29.45	38.98	36.24	26.52	23.45	23.14	21.69	22.77	26.81	65.87	27.35	24.15	19.57	17.88
04/02/2009	EST	16.37	15.91	16.88	17.19	22.26	35.43	47.38	32.44	49.68	42.51	26.83	26.69	30.54	26.41	25.10	23.31	22.56	23.85	42.62	46.31	26.35	20.87	18.78	16.65
04/03/2009	EST	14.31	2.54	16.28	15.75	19.72	29.07	45.43	35.55	34.71	35.57	35.42	35.03	34.60	29.15	30.76	26.58	26.92	26.15	27.97	75.34	37.17	26.97	21.33	21.68
04/04/2009	EST	21.35	20.44	20.59	21.41	21.32	23.48	18.80	23.64	26.48	23.51	21.41	21.05	19.34	19.80	11.86	15.29	18.27	18.61	21.28	51.75	23.49	21.38	20.70	6.07
04/05/2009	EST	5.71	1.87	15.39	14.55	0.86	15.94	3.53	16.66	28.84	22.67	21.80	23.46	24.27	21.49	22.05	20.93	29.20	26.72	31.14	25.99	21.29	15.08	14.18	14.86
04/06/2009	EST	14.67	17.67	18.13	17.92	24.27	36.12	25.47	37.26	32.78	45.11	59.34	30.91	32.78	33.67	28.88	28.47	27.27	29.09	28.37	31.44	30.16	24.64	23.87	23.85
04/07/2009	EST	19.89	18.16	19.14	24.33	24.65	49.34	32.70	41.32	41.44	35.37	38.62	38.67	30.98	30.30	25.90	25.40	26.86	23.51	21.78	28.60	28.92	24.70	20.57	18.35

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
04/08/2009	EST	21.90	23.66	21.47	20.44	23.35	31.40	41.71	28.65	25.31	27.17	33.94	23.18	23.75	24.22	19.76	20.47	19.69	18.30	19.91	31.41	26.97	23.06	21.59	20.48
04/09/2009	EST	21.08	16.90	16.55	18.90	20.90	25.73	24.99	40.74	32.60	29.29	25.94	26.80	27.27	23.60	22.94	21.79	20.01	19.01	21.62	26.30	23.96	19.01	-6.65	-25.25
04/10/2009	EST	17.11	10.44	15.74	15.64	18.05	22.54	21.74	29.28	44.86	24.62	24.94	23.61	22.81	21.88	19.65	18.16	20.02	20.34	20.01	23.94	23.90	20.66	19.32	20.78
04/11/2009	EST	14.57	18.03	16.65	14.19	14.48	3.42	8.77	21.84	22.63	20.88	20.36	18.40	18.06	14.17	16.40	18.71	17.70	18.02	19.54	22.53	24.13	19.12	14.49	-39.05
04/12/2009	EST	-93.07	16.76	9.73	8.94	5.62	13.24	14.11	20.49	21.22	18.94	17.10	15.71	9.09	12.72	10.20	12.52	14.67	17.21	21.88	88.47	23.88	21.51	14.99	16.62
04/13/2009	EST	10.09	9.45	13.22	15.16	21.18	23.04	29.86	36.84	77.12	79.91	45.80	66.07	50.82	34.68	44.72	29.64	88.13	25.40	61.56	58.27	27.19	23.88	21.04	19.17
04/14/2009	EST	16.63	16.85	17.69	17.52	25.37	64.05	64.05	30.84	37.90	35.34	55.45	32.16	110.66	103.18	26.25	25.91	85.30	45.44	49.73	86.94	50.18	35.08	18.35	16.43
04/15/2009	EST	-12.19	35.13	16.98	18.20	17.42	26.74	33.29	59.35	24.50	26.03	145.68	67.94	21.19	22.47	25.82	31.64	21.20	20.18	20.87	87.51	52.68	19.55	17.44	-4.91
04/16/2009	EST	15.43	11.58	10.85	12.23	12.90	23.48	22.98	40.47	21.68	24.48	20.37	22.76	22.65	22.80	33.26	22.05	18.85	19.43	18.12	41.33	40.27	20.59	16.93	14.15
04/17/2009	EST	14.29	17.94	17.57	13.94	17.74	39.62	24.06	39.92	37.99	60.13	40.86	49.62	39.80	26.44	33.88	25.40	21.31	20.61	20.19	60.53	37.07	22.19	19.73	17.02
04/18/2009	EST	4.71	11.25	-15.81	14.71	16.88	9.99	14.80	22.40	22.49	25.05	27.44	32.01	22.89	23.07	22.07	22.93	23.60	22.54	22.92	105.21	39.71	23.42	20.69	20.48
04/19/2009	EST	20.87	15.70	16.36	-10.28	16.23	16.20	13.81	19.33	23.00	22.21	23.66	24.80	24.88	23.61	22.49	26.98	29.24	29.16	36.17	65.99	58.59	22.93	22.75	19.99
04/20/2009	EST	21.35	24.27	21.69	19.82	22.80	115.02	64.34	27.51	25.04	25.45	28.03	28.19	34.74	32.17	33.76	40.91	24.47	30.95	29.55	20.81	24.19	23.00	20.58	20.74
04/21/2009	EST	16.76	12.34	13.65	11.24	9.94	28.92	43.55	43.73	29.19	40.68	33.85	27.77	32.59	53.88	27.31	24.67	34.65	28.02	22.48	23.77	29.22	26.36	20.99	22.47
04/22/2009	EST	19.52	21.45	20.13	23.07	26.63	29.26	23.70	25.76	36.96	45.59	43.40	71.60	38.06	34.91	24.41	24.55	22.72	22.73	21.08	41.71	25.39	22.73	13.93	14.29
04/23/2009	EST	2.62	-0.03	14.55	15.51	15.27	94.67	41.62	27.22	45.87	64.09	27.76	49.09	23.98	26.36	26.10	25.33	22.90	21.31	22.82	33.62	27.25	23.00	17.70	14.02
04/24/2009	EST	10.65	10.24	12.69	13.71	15.99	16.42	20.14	22.46	23.70	24.45	23.69	23.82	32.10	47.14	27.80	25.24	23.16	19.51	17.14	26.67	30.96	19.98	18.42	16.17
04/25/2009	EST	22.41	19.71	17.62	16.70	16.82	17.51	20.48	22.32	22.70	24.71	21.60	22.25	22.46	22.67	21.91	24.02	24.21	24.31	22.93	25.43	24.48	18.58	20.31	19.09
04/26/2009	EST	18.99	5.44	5.69	12.81	1.95	-24.58	16.93	18.68	19.77	19.82	21.78	22.98	25.37	24.43	21.98	22.09	23.17	23.06	25.00	58.21	39.09	18.12	18.53	5.46
04/27/2009	EST	3.60	8.41	11.50	9.13	15.68	20.52	23.85	25.98	29.77	33.51	62.53	41.59	32.34	30.13	32.09	34.52	41.06	26.48	29.93	27.70	41.02	22.55	21.62	11.05
04/28/2009	EST	14.44	-0.88	12.57	3.22	13.25	20.18	39.11	29.71	28.71	25.41	34.26	27.06	34.98	65.51	22.93	20.40	21.66	19.36	17.37	32.46	36.24	22.26	18.12	13.90
04/29/2009	EST	17.64	16.60	16.29	17.30	18.52	25.53	50.63	31.42	28.08	31.92	29.42	28.14	28.78	32.49	27.23	30.12	25.49	22.94	22.35	24.39	50.35	19.91	15.87	14.29
04/30/2009	EST	13.36	15.39	14.73	12.42	17.98	26.60	36.44	43.46	47.99	41.06	47.16	47.26	28.31	30.23	33.72	31.40	60.60	28.19	30.10	53.95	35.59	21.52	18.64	11.06
05/01/2009	EST	17.30	13.44	16.44	15.50	5.67	31.86	26.09	25.55	26.23	30.64	25.00	24.63	22.72	25.29	23.26	22.33	21.39	49.80	20.05	26.87	25.25	22.11	19.38	16.38
05/02/2009	EST	13.84	13.96	18.15	15.43	26.20	16.25	19.01	24.38	24.34	24.90	23.72	22.28	22.32	20.78	18.95	19.78	20.00	19.55	17.53	28.69	36.39	29.02	18.63	15.60
05/03/2009	EST	16.99	14.38	13.43	13.81	-24.26	19.43	17.43	36.02	23.13	22.32	36.45	22.49	23.20	30.33	21.34	21.72	23.02	24.17	22.90	66.70	45.80	22.18	16.23	11.57
05/04/2009	EST	12.09	10.32	-0.12	15.27	16.62	34.44	26.05	35.60	43.73	57.57	29.53	31.29	42.96	42.34	56.38	36.02	22.17	22.59	22.78	47.86	26.68	21.52	16.86	11.86
05/05/2009	EST	20.40	-1.75	6.21	15.71	19.94	18.01	24.91	23.70	23.17	23.93	28.23	26.25	29.50	52.22	37.89	36.85	24.85	24.78	24.36	22.19	43.09	31.13	22.60	11.81
05/06/2009	EST	15.74	19.27	17.80	7.30	16.40	20.05	23.98	74.12	38.16	25.23	31.57	32.45	27.87	31.31	30.93	54.04	40.08	23.86	20.85	22.36	28.05	23.51	19.74	18.72
05/07/2009	EST	19.72	18.99	18.17	18.98	30.54	28.20	30.47	30.49	30.22	34.85	36.97	37.54	39.40	36.02	39.55	41.53	28.36	35.83	26.53	31.03	37.18	24.64	22.67	19.11
05/08/2009	EST	8.49	17.12	16.80	18.76	17.59	25.68	23.48	35.47	55.70	32.33	28.95	29.21	41.89	49.89	38.53	41.97	30.61	23.82	22.77	34.89	32.93	32.09	14.54	17.26
05/09/2009	EST	12.01	14.29	18.79	17.13	16.26	1.17	17.44	21.16	25.54	43.50	45.08	24.87	24.10	23.91	47.35	22.88	23.59	43.10	29.28	20.07	24.16	21.74	17.83	15.72
05/10/2009	EST	19.20	16.68	16.39	16.39	12.39	-42.26	11.92	25.01	19.59	20.07	19.94	18.89	18.43	16.94	17.36	16.84	17.21	18.01	17.90	19.65	28.29	21.86	15.42	16.75
05/11/2009	EST	15.29	15.78	14.97	14.51	19.67	18.44	24.28	26.15	27.75	50.21	37.10	31.01	50.08	40.71	24.31	26.23	24.37	22.76	21.43	22.28	26.16	20.30	-2.83	-43.06
05/12/2009	EST	-2.29	-33.06	8.15	0.31	14.61	22.21	27.51	25.67	40.13	46.09	24.14	26.67	45.75	23.81	39.17	31.02	22.58	20.62	21.24	27.99	25.63	20.73	17.93	-9.00
05/13/2009	EST	16.95	-2.71	-52.67	-13.72	12.23	13.16	34.99	37.87	49.48	74.13	55.12	39.27	45.23	50.48	49.34	47.32	39.42	30.74	32.84	41.56	34.64	22.00	27.80	17.63

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
05/14/2009	EST	12.97	-5.77	-70.62	-11.17	24.24	53.87	29.63	64.73	55.43	69.97	81.30	32.23	58.27	39.51	78.97	108.68	42.75	25.22	37.58	53.22	292.81	22.25	13.35	19.99
05/15/2009	EST	-6.41	14.31	2.36	14.65	13.98	13.29	29.99	27.82	31.50	25.50	51.84	53.88	80.05	42.81	45.62	115.19	56.27	29.26	24.21	27.80	25.64	22.44	24.37	25.35
05/16/2009	EST	22.68	20.01	17.96	18.66	18.52	18.65	12.47	35.00	22.48	24.80	28.69	30.25	22.47	27.60	21.21	25.60	21.92	20.99	20.86	22.17	25.16	24.80	18.61	10.94
05/17/2009	EST	16.02	17.31	-16.41	-2.88	16.25	-15.12	21.67	18.61	26.08	21.42	20.35	19.33	18.10	16.41	17.17	17.89	18.51	18.68	17.60	21.09	23.86	18.12	-12.81	1.96
05/18/2009	EST	11.74	-17.58	1.52	11.92	5.37	1.55	28.80	25.75	64.10	23.36	24.45	42.60	25.64	33.33	25.00	26.38	23.40	21.25	21.12	21.88	26.15	19.30	17.89	13.47
05/19/2009	EST	2.23	-57.45	-10.12	-16.50	5.75	31.34	23.54	25.42	25.71	26.27	38.97	33.33	27.27	27.18	29.33	29.26	35.85	35.90	26.35	24.61	78.63	23.66	20.64	25.06
05/20/2009	EST	-5.36	7.41	15.13	15.30	-0.67	12.35	23.11	27.73	29.23	30.33	33.58	62.52	30.39	31.26	45.16	74.54	37.56	83.32	27.22	26.97	32.95	27.83	29.85	18.90
05/21/2009	EST	5.64	16.50	14.49	0.84	16.82	20.91	31.16	24.75	27.50	35.38	29.75	28.72	28.60	29.22	33.72	45.73	32.66	40.35	28.44	27.52	33.91	26.73	70.44	17.61
05/22/2009	EST	17.44	18.13	16.44	16.34	14.41	17.58	21.58	30.55	26.81	36.67	70.36	43.25	33.49	27.34	27.06	27.84	48.47	30.69	24.25	23.13	76.03	28.93	22.20	16.05
05/23/2009	EST	17.74	16.07	17.53	15.66	17.17	14.16	11.14	22.62	24.51	32.66	25.67	34.60	29.54	36.29	46.55	39.61	61.57	62.04	29.62	34.55	73.63	33.68	38.32	22.29
05/24/2009	EST	20.61	20.49	16.13	15.59	13.82	13.65	16.96	22.53	26.77	56.53	59.46	64.93	36.78	44.16	34.08	45.35	29.60	33.78	33.43	18.39	33.70	24.57	26.78	16.18
05/25/2009	EST	15.20	6.45	13.08	14.16	10.66	-11.82	-19.69	16.10	19.85	19.45	19.42	23.48	39.77	21.49	22.26	21.48	37.32	22.74	21.03	17.03	21.26	18.72	0.14	-8.39
05/26/2009	EST	14.87	14.06	14.07	0.77	-5.03	30.55	21.53	31.87	37.36	29.30	27.99	45.39	35.89	28.38	27.19	25.13	27.83	25.27	24.88	64.96	22.89	17.74	10.72	16.18
05/27/2009	EST	13.73	12.87	10.01	16.09	18.54	15.75	124.32	25.62	39.92	36.53	44.49	41.58	71.57	73.08	74.03	87.34	40.38	30.03	26.88	24.84	32.01	25.21	16.65	16.86
05/28/2009	EST	16.81	16.36	13.32	14.68	17.86	30.05	22.47	24.51	24.21	27.82	26.35	23.52	27.67	26.06	23.82	22.20	21.61	20.56	20.37	20.10	21.60	21.09	14.55	14.07
05/29/2009	EST	12.29	9.30	9.14	7.85	16.96	14.29	77.13	23.88	28.57	25.74	38.62	42.02	29.01	27.18	35.20	48.12	33.42	26.99	22.46	18.76	22.24	19.27	17.52	5.23
05/30/2009	EST	12.20	2.45	-19.23	16.13	15.64	14.76	4.04	16.06	19.52	19.02	20.01	20.20	21.42	22.21	26.38	36.55	40.63	35.45	25.66	23.02	20.87	25.90	16.69	4.89
05/31/2009	EST	15.16	-7.01	0.27	-7.38	3.34	-76.53	-34.49	16.26	16.48	17.82	17.97	17.84	17.51	16.44	17.75	18.90	21.06	20.22	19.43	19.16	20.21	15.01	-58.00	-22.71
06/01/2009	EST	-60.05	3.06	1.22	-0.90	-3.26	15.03	18.83	17.52	21.02	20.32	20.50	21.77	22.62	23.56	25.15	24.22	26.23	25.39	25.36	22.54	20.41	19.64	13.50	-1.73
06/02/2009	EST	19.18	11.56	-20.81	13.39	19.47	21.70	25.01	27.11	31.79	39.09	39.36	25.45	32.53	27.00	27.67	30.25	27.90	24.96	24.33	15.64	23.65	20.10	14.60	8.33
06/03/2009	EST	11.16	-0.61	9.14	6.83	15.89	18.20	30.50	23.55	23.14	22.96	25.28	23.71	25.29	23.07	22.55	22.36	19.37	16.73	17.20	17.49	25.75	21.19	8.03	6.96
06/04/2009	EST	16.76	13.90	3.66	13.13	17.36	14.35	21.14	23.19	25.77	27.52	24.63	31.59	25.93	24.22	22.87	24.94	24.65	20.43	19.56	19.03	23.02	20.87	5.95	-16.77
06/05/2009	EST	11.99	0.05	-37.68	-24.46	-7.95	-8.43	19.28	21.64	21.99	20.81	20.94	20.82	22.21	22.74	22.73	22.21	23.75	19.96	18.53	16.62	17.65	7.39	7.38	9.98
06/06/2009	EST	9.97	-2.12	10.87	-32.50	12.48	-24.58	-3.59	11.24	15.86	20.25	19.44	18.76	18.29	18.25	17.99	19.62	23.67	22.74	19.07	19.15	20.41	18.68	17.03	9.04
06/07/2009	EST	13.31	13.29	5.80	-19.79	-28.74	-4.44	-11.20	15.31	14.47	16.41	19.27	21.24	19.21	20.14	19.39	18.81	20.19	17.29	18.46	15.75	17.89	17.15	16.04	7.90
06/08/2009	EST	1.35	-4.22	-2.30	6.53	17.32	15.95	22.55	24.38	27.35	33.00	27.10	25.27	21.10	22.06	23.24	24.59	28.15	24.26	22.37	22.36	25.63	21.28	28.58	17.50
06/09/2009	EST	15.71	17.07	15.92	17.45	22.54	19.50	42.83	30.15	27.55	57.00	29.58	28.93	47.93	32.62	35.42	40.25	29.49	26.43	21.81	21.59	23.64	19.50	17.53	14.54
06/10/2009	EST	14.77	-2.95	12.90	13.25	4.42	12.80	21.50	53.80	40.97	23.76	24.33	30.10	33.68	25.52	24.82	26.19	26.17	26.98	29.46	27.98	51.49	22.68	18.92	14.78
06/11/2009	EST	14.37	15.34	15.97	15.17	18.40	18.91	26.62	24.42	43.51	28.70	41.83	33.80	28.50	29.58	30.73	39.17	48.15	46.58	24.45	34.65	29.58	29.65	19.94	16.24
06/12/2009	EST	16.58	14.65	13.28	15.51	15.10	24.00	24.52	70.24	25.37	31.39	25.14	33.50	28.98	36.22	37.03	70.45	23.46	39.37	20.54	20.64	29.35	28.25	31.65	13.24
06/13/2009	EST	13.65	19.29	15.26	17.53	9.73	14.34	19.63	56.36	23.33	67.65	22.35	48.50	19.75	34.98	24.06	21.34	28.49	34.10	29.52	25.26	26.91	28.34	19.47	17.11
06/14/2009	EST	13.13	11.24	10.31	-23.90	13.00	10.48	7.10	-3.68	18.33	26.55	22.49	30.59	25.90	27.90	23.53	23.40	24.66	25.13	23.64	22.88	49.08	36.85	20.04	17.02
06/15/2009	EST	-5.01	14.95	12.36	14.47	15.37	14.38	19.23	27.66	25.30	71.01	39.54	46.15	42.69	26.54	27.81	55.59	27.39	63.63	27.12	27.00	86.29	20.84	6.61	3.90
06/16/2009	EST	0.73	-17.72	-18.14	-4.49	9.24	19.29	20.51	23.68	23.17	23.10	24.40	24.04	37.11	23.71	23.73	23.48	27.91	27.57	38.17	25.78	25.26	21.60	18.48	5.51
06/17/2009	EST	16.45	12.83	14.27	15.15	16.18	19.48	19.05	20.88	34.90	42.31	37.23	27.92	35.10	60.52	37.63	28.43	33.19	30.77	24.26	23.61	30.33	25.99	19.69	6.77
06/18/2009	EST	-1.40	10.92	7.77	6.33	14.31	17.12	21.04	20.53	22.01	22.71	24.53	28.78	81.40	134.89	45.41	92.05	61.29	32.37	31.80	72.02	35.72	37.99	23.75	22.57

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
06/19/2009	EST	19.01	12.64	16.24	16.32	16.01	22.63	21.88	23.05	40.88	45.96	38.95	65.98	29.99	27.21	52.29	57.70	35.31	34.75	36.94	38.33	65.33	23.48	20.34	16.51
06/20/2009	EST	16.68	16.31	15.57	17.18	15.59	14.33	17.69	19.90	33.69	33.23	54.34	30.93	31.37	35.64	114.82	60.35	35.61	36.23	51.90	25.66	30.77	35.22	21.23	18.43
06/21/2009	EST	12.31	18.10	16.85	16.90	13.68	2.00	-5.00	18.43	22.74	26.51	63.14	31.96	32.47	25.97	24.46	28.32	38.68	103.21	29.39	62.43	132.71	60.05	19.33	21.21
06/22/2009	EST	20.79	18.85	18.00	17.26	18.57	19.14	37.76	24.44	42.16	46.11	83.19	42.32	80.42	53.42	72.23	89.09	68.70	75.20	58.85	52.06	60.71	40.37	25.09	45.06
06/23/2009	EST	18.98	16.27	15.93	16.07	17.18	17.52	32.84	31.94	29.66	66.44	34.56	51.35	84.65	65.52	62.34	94.24	55.98	46.46	64.35	42.05	35.12	41.55	30.48	35.47
06/24/2009	EST	23.57	20.06	17.45	17.49	16.78	12.20	24.32	23.12	28.35	34.58	49.86	69.13	80.93	81.16	44.91	46.38	74.07	77.32	45.45	45.40	103.94	32.71	40.49	30.63
06/25/2009	EST	26.26	20.43	19.71	20.95	18.41	17.49	30.32	33.06	37.39	43.44	49.13	61.40	94.93	59.47	48.50	48.02	55.79	63.20	46.09	50.33	31.06	33.33	24.97	25.50
06/26/2009	EST	21.34	18.95	13.57	16.64	16.24	5.21	23.28	23.67	29.33	50.46	27.10	28.44	33.13	34.65	35.77	48.02	31.74	29.16	25.63	21.58	21.39	23.70	20.41	17.23
06/27/2009	EST	17.76	15.27	12.88	9.98	12.58	10.01	-2.21	18.00	21.00	30.00	28.75	30.69	32.35	62.43	27.86	41.01	45.02	30.04	27.91	23.00	23.83	22.57	15.56	-8.81
06/28/2009	EST	22.31	15.79	15.70	-0.10	12.48	-45.03	16.19	17.07	17.06	21.44	40.42	22.72	23.79	21.25	23.94	23.10	23.59	22.24	20.80	19.30	19.51	20.34	12.05	-10.79
06/29/2009	EST	8.49	7.63	-11.14	-26.60	13.37	-5.00	16.96	30.15	23.91	24.01	26.21	24.99	25.11	26.26	25.39	25.50	25.27	22.60	20.58	18.96	20.69	18.95	14.13	15.03
06/30/2009	EST	13.90	1.41	15.05	14.97	17.31	18.91	16.84	29.10	22.82	67.28	27.27	21.15	26.91	30.56	34.65	24.02	22.33	21.07	20.37	19.91	23.83	20.89	13.71	15.82
07/01/2009	EST	14.36	15.45	15.24	14.04	15.90	16.22	11.63	22.09	28.09	22.62	36.31	40.20	22.53	23.65	25.69	22.98	22.75	21.92	22.41	19.13	24.13	19.65	17.22	7.24
07/02/2009	EST	14.78	13.64	14.15	13.26	17.40	20.46	30.71	21.44	25.11	28.97	25.81	25.30	25.80	52.31	27.67	24.60	25.66	24.27	24.59	23.35	23.72	21.81	17.37	15.43
07/03/2009	EST	15.44	13.03	12.20	3.81	-21.17	13.20	14.93	17.00	19.65	23.21	25.48	24.87	25.27	24.41	25.32	26.74	23.38	23.46	20.51	19.69	21.26	21.05	16.87	13.62
07/04/2009	EST	14.21	14.37	-5.30	9.32	13.10	12.05	12.17	14.67	17.68	17.72	19.48	18.13	18.10	16.35	16.00	15.45	15.86	14.00	16.55	16.09	17.06	14.75	16.79	6.71
07/05/2009	EST	-19.38	9.73	10.60	12.01	12.67	3.34	0.77	4.78	18.31	16.42	19.38	22.90	21.45	22.59	21.10	24.60	25.07	31.04	26.28	25.23	27.04	26.91	19.57	15.92
07/06/2009	EST	14.63	14.01	9.73	13.93	15.25	15.88	20.39	21.03	27.04	38.76	59.28	34.80	33.82	31.02	34.34	34.13	61.51	31.26	34.84	40.73	26.81	33.21	20.04	18.03
07/07/2009	EST	17.62	15.76	14.23	14.73	16.43	15.20	17.88	30.99	28.74	34.90	35.70	25.79	26.67	26.24	29.74	34.26	27.20	29.13	25.46	31.35	54.16	22.50	15.25	11.80
07/08/2009	EST	10.09	13.19	3.47	13.09	15.50	17.22	17.60	20.44	21.32	22.73	24.62	24.95	45.21	28.51	25.12	26.34	24.70	22.86	22.26	20.16	23.33	19.52	12.45	12.61
07/09/2009	EST	12.12	12.05	11.68	12.90	15.63	16.36	16.63	20.97	25.15	22.30	23.51	22.19	26.63	30.56	29.02	29.41	29.72	31.80	29.02	25.64	24.36	25.33	19.83	17.82
07/10/2009	EST	8.77	12.67	13.65	12.30	16.23	17.72	19.20	22.39	25.19	23.24	27.16	25.32	28.87	30.13	30.19	28.38	28.26	26.60	25.75	24.10	51.86	24.23	19.16	19.66
07/11/2009	EST	19.97	18.58	14.05	14.35	15.86	14.09	15.69	19.68	22.92	37.70	24.25	22.66	21.63	24.84	25.44	26.16	30.15	34.08	26.44	21.02	37.66	23.07	17.14	17.66
07/12/2009	EST	18.35	-10.24	11.67	7.87	-6.05	5.45	5.53	20.11	28.37	31.95	21.78	23.41	22.97	22.80	23.97	25.15	29.18	23.65	21.62	18.76	18.98	20.78	16.90	17.15
07/13/2009	EST	13.83	8.02	7.65	7.13	17.27	17.82	19.10	25.64	44.47	26.63	75.85	44.54	38.59	32.22	36.75	28.48	40.33	65.25	26.16	22.84	20.92	22.12	-1.93	12.34
07/14/2009	EST	15.35	13.22	11.43	-0.72	11.81	17.21	17.90	23.91	25.57	30.91	24.25	26.02	21.97	22.65	26.21	23.65	26.74	23.28	22.59	28.22	31.09	23.86	12.27	15.67
07/15/2009	EST	17.14	14.74	12.57	11.18	13.72	25.30	18.78	19.48	21.27	20.29	22.69	24.64	24.30	27.42	42.32	30.24	26.15	34.10	29.80	34.14	24.01	24.64	31.23	16.01
07/16/2009	EST	21.92	16.47	14.47	14.57	17.22	25.03	20.20	41.35	70.29	26.56	28.60	27.99	28.35	31.40	32.86	31.06	38.20	34.99	25.78	23.60	32.35	19.99	19.24	-1.46
07/17/2009	EST	7.78	-26.40	-8.69	-5.61	3.06	20.37	22.50	27.55	30.53	24.86	28.98	15.00	22.61	23.45	21.04	35.94	19.06	15.57	15.13	16.88	20.12	16.62	11.52	15.24
07/18/2009	EST	16.71	18.60	16.95	16.46	15.51	3.95	14.44	16.46	19.95	18.42	19.61	17.72	18.13	18.11	18.16	19.29	18.22	18.79	17.94	16.28	27.52	21.28	16.34	14.97
07/19/2009	EST	17.79	17.34	15.49	15.02	13.20	8.35	17.26	17.82	27.09	18.10	18.43	18.77	18.45	17.98	18.71	20.33	21.37	20.66	18.78	19.93	21.09	17.83	14.92	10.10
07/20/2009	EST	11.89	11.74	6.50	14.73	16.21	15.46	9.46	22.85	23.34	30.02	35.02	61.53	44.00	26.28	27.28	28.83	36.14	34.17	24.76	22.64	23.55	22.02	15.09	16.29
07/21/2009	EST	14.96	10.75	14.70	14.08	12.72	20.28	18.34	22.67	26.03	69.39	45.70	34.48	26.27	35.74	29.37	30.71	34.98	24.44	24.78	23.71	41.35	25.05	18.04	16.55
07/22/2009	EST	16.52	15.63	14.94	15.35	12.78	20.71	18.47	20.60	23.30	22.21	25.51	43.40	34.44	34.25	34.70	30.77	26.04	25.09	23.43	23.24	24.55	26.97	19.73	18.34
07/23/2009	EST	17.49	17.65	17.13	17.54	17.02	22.92	21.12	24.91	31.95	60.96	27.95	33.57	34.06	42.52	41.01	30.55	33.92	31.65	28.29	25.23	25.41	23.08	20.76	17.71
07/24/2009	EST	16.43	16.00	5.23	10.37	17.11	18.68	16.24	21.70	37.83	36.35	47.31	38.54	48.36	32.27	31.98	41.20	35.81	31.38	37.26	23.84	28.24	21.33	17.08	17.37

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Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
07/25/2009	EST	18.11	16.11	12.55	-4.35	13.00	11.65	14.34	18.80	18.94	20.39	21.11	25.06	27.02	23.48	26.00	38.36	34.31	24.49	22.24	29.42	23.41	20.28	14.97	15.92
07/26/2009	EST	14.17	6.97	2.27	12.97	9.28	8.90	2.65	19.66	17.62	37.41	28.08	42.12	24.55	29.89	39.38	47.65	41.70	59.49	36.09	42.43	23.77	40.27	18.79	17.20
07/27/2009	EST	15.64	10.49	9.40	13.74	14.17	17.90	21.84	22.82	22.58	29.59	28.28	46.27	39.71	31.61	37.12	63.73	64.74	42.27	68.21	43.69	43.63	22.99	19.98	7.27
07/28/2009	EST	6.57	15.77	14.72	15.46	14.82	17.20	18.00	33.68	32.88	25.39	28.59	34.20	82.35	32.96	38.09	40.97	25.44	25.02	22.97	22.86	24.27	23.05	12.58	12.18
07/29/2009	EST	17.42	15.72	10.61	9.69	15.33	18.67	25.53	20.73	25.98	22.22	24.30	27.28	29.33	25.68	25.91	25.28	27.43	32.73	32.87	23.48	28.84	20.64	15.01	15.15
07/30/2009	EST	9.89	14.66	12.62	16.13	4.63	37.31	25.54	37.09	22.54	34.37	36.47	32.05	27.39	27.64	28.92	25.26	25.24	52.50	24.44	29.25	41.93	21.22	8.64	15.71
07/31/2009	EST	-8.37	13.30	15.33	13.19	13.08	17.34	17.51	20.38	38.93	77.24	42.21	61.03	26.16	52.67	44.85	27.50	49.08	25.50	23.43	19.91	84.39	18.07	16.38	15.55
08/01/2009	EST	25.28	13.73	14.27	14.53	12.47	13.70	14.87	21.90	21.05	21.81	25.66	21.08	22.46	18.62	19.52	16.51	16.53	20.55	18.21	19.48	21.28	19.27	8.20	-10.88
08/02/2009	EST	11.25	13.52	11.42	3.20	-55.66	12.38	-34.27	4.24	17.03	18.84	19.34	21.10	21.12	19.69	20.78	20.66	20.94	19.90	21.00	19.24	20.32	15.88	11.56	-4.45
08/03/2009	EST	13.65	10.85	13.67	13.44	16.14	19.60	14.66	20.06	19.68	22.81	24.68	23.94	26.14	33.34	46.69	42.78	73.56	37.03	29.76	25.60	73.25	23.73	21.05	16.94
08/04/2009	EST	16.50	16.60	15.27	14.45	9.52	19.84	20.37	25.39	25.01	26.80	50.54	26.28	36.24	35.94	37.19	33.73	26.88	25.63	24.60	23.18	22.72	22.45	18.94	14.70
08/05/2009	EST	14.49	14.41	13.14	14.74	16.06	18.21	18.99	19.71	21.82	22.86	23.26	24.16	26.07	27.70	31.82	27.94	28.61	25.95	23.16	20.60	23.04	22.89	19.78	16.52
08/06/2009	EST	17.85	16.84	14.08	14.40	12.61	22.14	18.44	22.30	24.56	31.44	65.20	27.30	29.59	34.53	37.35	30.55	29.06	28.66	27.70	24.99	35.50	22.25	21.54	16.74
08/07/2009	EST	15.34	15.29	13.70	-4.02	14.81	12.40	17.82	21.00	23.84	23.75	36.38	41.86	27.24	27.77	25.84	26.19	25.35	22.78	23.29	29.16	23.22	20.80	18.89	5.26
08/08/2009	EST	-13.60	-32.34	-16.54	12.18	12.42	10.52	12.46	14.08	19.35	18.66	21.05	22.30	23.20	22.64	23.78	25.28	43.07	38.53	31.30	27.92	27.50	25.04	21.49	19.92
08/09/2009	EST	20.12	19.19	16.78	17.61	-9.47	11.38	15.20	26.66	51.66	26.34	38.93	254.36	52.01	35.39	34.25	59.00	45.67	39.04	36.28	25.33	28.16	34.90	23.36	17.06
08/10/2009	EST	12.30	9.54	17.89	15.91	18.45	20.77	21.76	23.01	26.30	30.80	37.65	46.62	72.92	39.16	38.35	41.41	49.18	37.69	31.64	28.82	31.66	25.50	21.04	8.68
08/11/2009	EST	15.46	14.83	14.92	6.86	9.35	20.11	25.48	26.92	26.51	70.75	37.15	68.48	31.83	49.53	110.69	36.74	39.71	64.87	31.52	24.80	25.31	19.29	18.94	16.87
08/12/2009	EST	17.02	14.90	15.54	14.42	17.99	20.47	17.98	19.66	20.83	24.55	28.68	27.92	36.23	33.06	36.93	65.35	50.45	55.61	39.23	28.74	58.51	25.05	22.46	18.10
08/13/2009	EST	11.17	15.33	14.09	14.29	15.83	19.78	18.70	24.20	24.35	24.94	27.44	28.62	38.39	72.20	50.25	35.96	41.58	87.68	33.83	26.89	25.46	24.07	20.45	16.23
08/14/2009	EST	17.43	15.52	14.85	15.67	16.50	19.13	19.18	23.66	38.32	26.69	28.24	31.98	39.69	54.69	47.66	54.75	53.12	34.14	26.79	27.38	53.06	24.96	24.51	19.29
08/15/2009	EST	19.90	18.93	17.24	16.33	15.14	14.90	12.34	19.68	25.26	25.34	58.73	25.68	42.61	137.71	32.00	45.82	70.35	28.87	24.65	25.98	50.93	22.95	23.13	5.75
08/16/2009	EST	11.81	17.15	-6.52	17.89	15.92	15.76	13.87	9.91	24.61	27.84	61.55	47.57	24.85	42.17	57.59	88.56	97.14	27.47	31.27	24.73	26.86	23.33	23.71	22.01
08/17/2009	EST	15.71	15.10	14.38	16.61	18.74	22.53	22.23	25.14	19.89	27.33	41.55	65.09	38.00	46.60	30.02	31.70	42.42	26.27	23.97	35.14	38.54	19.31	16.51	11.58
08/18/2009	EST	14.20	14.93	15.83	16.51	15.59	21.12	31.35	25.42	24.83	25.53	24.51	31.49	27.92	33.00	49.17	38.69	44.62	40.63	27.43	31.88	24.44	21.86	0.23	5.15
08/19/2009	EST	0.93	1.45	13.62	15.14	17.65	21.76	21.13	24.02	23.41	26.31	28.36	32.64	76.84	36.29	137.17	31.22	33.61	135.98	24.51	39.08	24.19	23.41	16.10	16.16
08/20/2009	EST	18.02	16.59	16.31	17.71	19.88	39.21	25.79	24.75	32.10	29.00	28.03	28.13	44.47	21.10	22.44	24.36	22.48	23.10	23.48	24.08	24.34	16.87	17.88	16.01
08/21/2009	EST	15.65	13.79	-3.39	13.95	15.12	18.93	19.88	24.59	24.36	31.35	25.41	22.26	22.84	23.47	23.02	22.95	20.79	18.89	17.61	22.11	20.83	16.62	15.51	15.21
08/22/2009	EST	16.25	6.79	2.71	15.94	15.44	17.88	15.15	17.67	23.07	19.08	17.87	18.22	18.59	17.91	18.84	18.48	19.02	17.84	17.52	24.77	19.93	17.82	16.17	3.56
08/23/2009	EST	-50.02	2.31	8.92	-8.55	11.69	12.18	-45.76	-12.83	11.94	17.58	17.84	18.05	17.52	18.21	18.32	18.79	19.58	21.46	20.61	24.43	22.75	17.07	15.16	11.73
08/24/2009	EST	12.62	12.38	11.79	6.60	10.90	20.73	17.72	21.60	42.13	33.67	22.57	24.53	28.84	25.41	24.93	31.60	63.09	25.89	26.41	23.29	25.39	20.13	17.97	16.84
08/25/2009	EST	13.72	13.82	13.92	13.60	16.48	23.51	17.93	20.18	19.15	20.43	23.07	23.25	26.49	26.37	55.31	27.37	28.80	25.83	26.56	28.42	24.43	21.05	18.60	17.29
08/26/2009	EST	14.65	15.17	14.50	8.70	13.35	22.82	25.03	22.32	34.12	26.11	23.38	23.58	29.65	26.00	51.59	38.37	26.30	24.62	34.96	72.99	23.40	22.51	22.86	17.53
08/27/2009	EST	16.38	14.99	11.79	15.02	16.91	35.13	24.61	22.69	37.51	35.26	25.41	30.45	33.42	35.80	38.40	49.78	42.39	33.16	39.50	104.52	38.45	41.42	21.25	18.72
08/28/2009	EST	6.42	16.86	17.02	17.17	19.16	54.28	34.76	32.96	23.54	26.43	34.99	25.93	24.76	23.30	23.13	47.78	24.30	21.15	20.26	28.50	20.92	19.85	13.44	20.90
08/29/2009	EST	12.43	23.39	8.30	12.40	14.27	23.55	9.20	11.68	27.69	43.45	37.72	54.55	19.76	35.43	27.13	18.76	22.24	23.91	11.63	20.41	22.64	18.87	17.29	16.85

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
08/30/2009	EST	24.50	20.29	15.66	14.96	14.01	16.13	15.37	15.22	15.57	18.81	26.60	17.66	19.42	15.23	18.91	15.54	21.44	20.06	18.91	58.89	26.96	19.83	17.64	11.22
08/31/2009	EST	10.64	14.56	13.15	14.87	10.32	31.47	30.58	18.78	22.48	31.22	23.30	25.86	24.76	25.36	24.91	23.11	22.20	19.56	19.96	20.87	21.96	18.18	13.82	6.81
09/01/2009	EST	-17.96	-8.25	11.62	12.49	12.99	8.81	21.55	18.97	17.60	18.29	18.64	19.21	19.52	18.73	19.12	18.13	17.87	18.08	15.76	17.95	17.63	8.11	13.35	11.96
09/02/2009	EST	11.23	5.75	-9.44	-5.51	15.26	27.90	17.62	18.30	22.92	22.91	24.97	23.96	24.01	21.93	22.67	24.20	61.23	22.65	20.68	28.65	22.42	16.32	16.24	11.83
09/03/2009	EST	15.38	14.31	15.75	16.08	14.37	15.47	30.64	21.73	33.45	21.84	22.44	26.20	23.97	26.93	40.21	24.64	34.18	22.36	21.29	29.86	26.95	17.11	18.39	12.82
09/04/2009	EST	14.58	13.98	11.42	4.73	4.59	16.77	19.53	18.61	34.08	22.18	22.75	25.01	23.97	25.95	23.00	22.44	25.37	21.15	17.59	20.96	19.27	20.83	17.81	14.41
09/05/2009	EST	11.64	12.75	14.74	13.70	13.79	10.41	9.87	16.74	18.54	27.79	21.20	18.93	24.42	19.79	21.89	34.74	22.72	24.29	20.55	26.90	18.48	17.52	20.02	17.15
09/06/2009	EST	15.60	13.28	14.49	11.47	13.03	13.28	12.38	14.38	28.25	17.58	20.16	24.37	25.14	22.50	19.65	19.47	20.13	22.72	21.71	21.52	23.10	21.49	16.98	17.37
09/07/2009	EST	-8.38	19.90	15.54	15.36	15.58	16.06	1.75	-5.94	39.37	35.42	31.73	34.71	26.54	29.69	26.88	45.91	22.69	48.50	22.48	66.44	21.52	17.34	9.79	16.37
09/08/2009	EST	13.54	2.67	13.98	25.03	42.31	18.80	20.65	19.91	25.08	23.72	69.21	23.96	24.19	37.84	69.69	46.19	44.71	25.12	23.65	40.06	26.19	18.25	-3.56	14.92
09/09/2009	EST	14.70	13.75	14.18	12.25	16.19	36.94	22.56	20.46	27.78	25.12	43.63	39.17	35.50	28.09	50.16	46.47	29.89	32.18	25.35	26.33	34.72	21.67	18.39	17.86
09/10/2009	EST	16.95	15.59	15.77	14.73	13.41	34.00	25.02	19.99	20.76	22.11	24.95	69.52	26.31	35.86	61.23	27.29	30.11	35.02	25.46	63.28	43.36	19.20	18.13	15.60
09/11/2009	EST	14.42	12.86	13.72	14.11	14.16	17.82	20.73	21.55	21.98	32.98	35.85	31.48	27.06	69.50	44.06	23.48	24.21	24.04	20.20	32.63	22.30	20.63	18.38	17.27
09/12/2009	EST	6.71	14.04	13.87	13.87	14.88	3.69	20.81	23.05	36.10	60.63	47.12	25.92	56.07	267.89	45.45	26.71	41.75	38.60	22.49	36.12	26.70	21.42	14.94	13.11
09/13/2009	EST	13.24	10.28	6.37	0.71	12.65	11.39	9.06	18.09	18.73	21.49	31.60	21.87	24.30	48.85	54.74	60.67	27.45	30.48	26.58	283.01	21.85	17.55	16.94	15.21
09/14/2009	EST	14.81	13.96	13.49	13.15	16.16	22.30	18.15	18.26	22.62	22.45	27.89	41.37	24.88	32.26	58.04	33.71	30.21	30.64	24.32	26.81	29.56	15.48	18.03	15.64
09/15/2009	EST	16.52	15.82	14.61	15.43	15.11	37.26	41.85	21.00	21.14	23.37	33.02	55.22	37.27	36.33	35.13	51.24	32.14	29.05	30.12	35.73	29.53	23.14	12.32	15.43
09/16/2009	EST	14.37	14.31	13.99	15.08	17.95	17.78	23.80	21.72	24.54	39.07	24.32	61.79	27.69	30.29	36.04	37.94	37.36	25.51	23.29	23.28	21.44	19.04	17.15	14.60
09/17/2009	EST	12.90	14.69	6.59	14.36	18.11	25.11	21.87	28.08	26.36	23.06	23.72	29.98	29.32	36.56	46.82	38.62	31.36	28.35	24.83	38.11	24.31	18.71	18.06	15.35
09/18/2009	EST	14.47	-24.09	2.04	5.36	4.66	22.89	32.22	23.46	21.71	24.27	29.86	29.58	30.54	41.59	43.81	29.79	44.50	27.09	23.51	23.71	21.30	19.05	17.53	15.22
09/19/2009	EST	3.03	12.37	11.49	13.46	14.48	-7.05	14.41	17.70	18.63	28.97	54.45	20.07	22.35	20.58	21.43	21.74	30.88	20.19	19.96	21.49	19.07	15.31	14.09	-23.09
09/20/2009	EST	-49.72	11.43	-19.90	11.79	10.84	11.64	13.07	16.70	16.03	16.47	18.36	17.30	18.50	11.43	18.50	18.55	18.38	20.95	64.49	21.61	18.46	13.01	13.74	13.88
09/21/2009	EST	-3.18	-13.65	10.55	10.37	19.49	48.82	71.98	24.00	24.00	23.72	24.99	27.08	32.09	27.15	25.48	28.74	26.89	22.70	52.94	32.33	22.97	20.84	18.96	15.69
09/22/2009	EST	14.98	15.47	-5.05	-1.66	15.43	36.47	27.40	27.78	22.83	24.84	28.50	30.64	32.53	35.21	28.16	30.33	30.63	24.28	31.65	29.71	32.10	23.37	18.75	15.98
09/23/2009	EST	13.98	6.91	8.07	11.76	13.82	27.50	39.16	23.64	24.87	25.42	23.45	25.23	30.93	27.77	27.77	24.23	23.56	23.16	20.12	22.73	25.57	23.36	18.43	16.15
09/24/2009	EST	15.58	16.49	15.34	14.98	16.93	23.29	23.34	23.42	21.91	21.55	23.64	28.02	44.72	23.99	21.95	22.85	23.12	22.27	37.55	29.78	24.95	21.66	17.85	19.06
09/25/2009	EST	15.80	17.04	15.55	15.52	16.23	22.48	22.66	24.05	34.29	27.30	28.90	28.86	29.94	46.19	27.25	26.17	24.81	23.67	41.94	25.56	23.40	21.11	17.03	13.61
09/26/2009	EST	4.63	14.88	12.27	13.75	16.90	16.89	17.93	19.34	22.09	22.47	39.72	36.71	26.00	23.54	25.44	25.66	25.39	24.24	76.00	61.66	20.93	17.20	4.21	-7.95
09/27/2009	EST	-30.64	14.53	13.38	-12.07	-15.18	15.28	15.22	18.32	19.46	22.51	22.11	22.17	22.37	22.64	20.79	17.18	20.29	25.77	39.08	22.15	18.66	13.22	10.91	-6.14
09/28/2009	EST	-10.01	-5.28	1.40	10.32	11.03	23.49	17.64	18.12	23.18	32.87	47.63	63.13	21.25	20.42	17.58	18.33	17.46	18.24	19.91	22.49	17.53	15.50	12.85	12.50
09/29/2009	EST	12.31	11.62	-10.75	13.01	12.81	17.46	21.69	20.35	22.95	24.05	27.01	33.43	24.84	24.33	23.78	23.10	23.55	23.25	67.75	44.46	21.77	19.44	14.29	11.31
09/30/2009	EST	15.43	14.35	14.55	15.12	18.30	61.86	87.74	22.28	23.83	26.03	48.10	26.19	40.97	23.53	24.27	20.56	23.03	21.83	101.87	48.86	22.70	38.75	16.21	7.51
10/01/2009	EST	8.71	11.24	14.51	12.00	6.84	93.07	37.53	21.29	21.30	20.64	20.47	20.90	22.90	33.03	22.59	23.88	21.83	20.97	81.03	23.44	19.44	16.44	15.69	14.76
10/02/2009	EST	15.50	15.25	15.71	15.31	-1.60	9.00	37.93	38.81	30.33	31.21	32.66	28.70	29.00	25.64	22.41	21.88	24.10	22.52	33.33	36.06	22.25	18.60	19.44	16.58
10/03/2009	EST	15.17	15.11	15.01	15.06	15.24	16.15	18.45	17.92	24.13	19.68	18.39	19.14	19.21	18.22	17.93	17.72	18.97	17.57	65.67	25.94	22.26	19.38	17.63	15.65
10/04/2009	EST	14.56	14.86	15.07	14.86	14.68	15.31	16.55	17.29	23.94	18.35	17.84	18.42	18.11	17.51	18.13	21.22	18.95	20.10	34.65	32.14	20.78	17.59	16.22	16.60

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

20100528-8062 FERC PDF (Unofficial) 05/28/2010

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
10/05/2009	EST	15.55	15.63	15.67	16.37	17.74	67.28	35.04	25.76	29.45	26.97	25.80	25.81	26.36	33.45	22.05	20.60	20.96	21.39	227.70	163.92	21.67	25.58	16.85	45.70
10/06/2009	EST	25.20	38.77	5.90	35.79	5.97	12.16	21.31	37.88	24.34	23.84	27.16	28.09	25.68	21.92	19.47	29.30	20.88	22.48	21.32	23.31	25.81	17.59	-8.93	11.44
10/07/2009	EST	23.15	12.85	15.66	15.29	7.14	19.85	36.82	23.78	23.28	45.96	25.78	24.35	23.98	20.34	17.28	19.13	18.61	18.48	22.62	21.35	19.98	3.97	7.49	6.95
10/08/2009	EST	12.71	17.97	16.70	23.97	12.84	24.91	45.38	28.51	23.89	49.13	53.33	31.68	37.25	35.21	36.66	30.41	24.96	28.11	41.17	34.22	26.95	19.55	17.63	13.27
10/09/2009	EST	16.05	9.86	17.26	2.17	22.39	24.63	46.74	53.78	38.50	41.47	44.71	40.85	28.08	45.03	29.22	64.27	37.04	23.86	58.01	36.11	44.88	22.48	18.06	17.30
10/10/2009	EST	13.16	16.45	12.02	18.04	17.36	18.39	37.59	27.92	41.72	70.07	51.06	19.55	19.22	17.60	17.27	17.28	17.84	18.41	29.94	30.74	23.25	21.11	20.42	17.38
10/11/2009	EST	15.39	16.09	14.15	15.77	16.49	17.01	19.54	20.16	23.19	38.43	32.54	31.20	36.90	23.04	19.30	21.63	24.62	26.01	92.51	40.90	33.57	25.30	24.98	17.25
10/12/2009	EST	16.47	16.13	16.39	16.39	17.17	29.46	52.18	60.45	56.49	35.29	36.10	50.41	38.28	46.27	29.43	27.70	29.50	29.48	34.84	30.74	30.52	31.18	38.32	15.68
10/13/2009	EST	21.72	27.47	24.71	20.73	16.92	20.86	34.96	35.16	28.37	28.58	26.58	26.77	28.42	35.83	23.73	24.17	23.07	26.16	66.37	33.54	25.72	47.93	25.29	19.83
10/14/2009	EST	17.75	18.02	18.27	18.09	20.34	20.34	26.53	26.69	34.91	32.52	29.02	26.29	29.11	28.70	34.92	43.61	32.18	27.90	38.17	28.22	26.55	23.87	22.35	18.74
10/15/2009	EST	18.88	18.59	18.42	18.28	26.44	63.20	43.08	74.01	46.40	38.52	60.04	39.04	49.90	41.73	44.92	40.17	34.26	35.56	41.28	40.21	37.41	28.00	26.13	21.95
10/16/2009	EST	27.68	19.91	22.06	20.70	23.39	22.34	29.83	27.86	30.51	33.32	34.00	32.83	30.27	27.88	26.82	25.70	26.30	44.46	29.17	26.48	26.70	32.98	30.58	22.77
10/17/2009	EST	23.62	22.76	37.79	19.49	32.08	22.57	24.69	29.78	44.94	25.86	26.38	29.62	25.89	23.11	22.17	25.82	22.73	27.21	91.11	38.45	26.51	35.72	40.13	20.13
10/18/2009	EST	20.41	19.19	8.83	16.64	14.66	21.67	61.32	21.71	21.87	20.93	21.28	26.36	19.09	19.61	17.70	18.84	20.01	21.63	39.17	24.47	24.26	21.65	23.14	14.39
10/19/2009	EST	13.82	13.92	14.01	17.26	31.51	57.50	28.40	24.48	25.74	32.87	34.40	46.04	29.44	27.96	25.23	25.36	26.74	24.45	43.03	33.51	29.86	26.83	19.44	18.83
10/20/2009	EST	16.88	17.29	15.24	19.34	20.23	22.66	62.96	31.26	31.20	36.10	33.18	32.32	35.99	34.87	27.49	26.13	29.32	27.80	52.08	35.83	31.95	24.52	19.49	17.90
10/21/2009	EST	20.96	35.96	19.76	19.63	21.50	27.25	33.84	40.04	35.50	61.24	51.58	25.96	46.00	38.63	30.66	27.17	27.76	29.78	30.05	32.37	28.64	27.99	12.12	16.96
10/22/2009	EST	10.18	15.44	15.31	18.08	22.23	29.42	34.55	46.59	40.72	36.13	31.22	37.18	29.35	37.71	23.55	22.92	32.25	54.07	31.26	24.12	21.66	18.46	15.84	7.46
10/23/2009	EST	12.88	11.90	10.26	16.74	16.33	24.50	30.10	82.53	31.57	57.64	35.54	39.21	69.67	31.05	35.69	32.54	33.07	35.93	29.08	30.06	25.08	22.88	18.26	18.52
10/24/2009	EST	16.38	17.72	19.25	18.79	19.65	21.61	35.65	26.03	27.89	45.63	37.66	35.75	36.71	33.21	25.73	24.23	28.26	34.12	27.71	24.34	33.77	22.74	18.86	16.25
10/25/2009	EST	18.59	16.51	15.76	17.88	18.12	20.05	19.15	27.42	34.59	22.03	25.45	23.67	21.13	21.85	19.53	20.48	22.22	47.01	53.38	28.36	24.24	21.06	19.49	17.60
10/26/2009	EST	16.63	16.81	18.09	19.91	20.41	56.19	114.80	46.93	48.54	57.73	58.88	66.38	40.16	34.40	27.77	29.12	38.74	37.38	36.35	29.36	28.06	25.02	21.73	16.71
10/27/2009	EST	16.64	15.41	16.39	16.48	17.09	20.26	26.22	55.98	25.68	49.19	30.69	29.76	42.48	26.64	25.18	25.94	26.87	84.51	33.59	25.01	23.46	21.84	19.21	18.03
10/28/2009	EST	20.14	18.74	19.18	19.04	24.56	22.08	29.91	46.80	37.39	37.34	47.06	46.61	31.68	30.76	25.62	24.65	25.52	36.10	41.41	34.15	44.28	28.33	48.56	23.65
10/29/2009	EST	19.15	19.55	10.25	16.75	18.50	25.03	32.24	36.04	81.27	36.98	32.28	34.49	39.55	29.87	31.57	28.91	27.83	62.60	27.74	60.96	28.67	21.77	17.40	17.73
10/30/2009	EST	16.86	14.78	14.81	14.48	22.44	21.89	23.93	23.52	22.94	33.18	31.25	28.83	27.59	25.20	25.62	24.25	23.70	50.05	28.23	26.70	33.94	11.83	18.00	8.25
10/31/2009	EST	17.16	13.78	13.01	14.32	15.19	16.14	18.54	24.23	51.90	40.62	35.66	23.86	23.50	22.34	21.97	22.94	23.33	39.81	42.49	84.55	24.18	23.66	21.93	17.76
11/01/2009	EST	18.42	17.22	16.53	15.42	16.40	19.53	18.50	17.89	22.55	23.68	22.82	24.40	20.67	22.17	20.62	20.27	17.79	30.81	41.74	56.42	30.84	22.33	18.78	26.40
11/02/2009	EST	15.99	3.03	16.86	16.52	14.59	16.75	24.69	62.17	102.96	62.14	26.86	56.07	25.35	26.73	25.97	46.76	39.26	24.41	80.68	30.05	27.05	24.59	25.68	28.78
11/03/2009	EST	19.08	18.32	19.09	17.98	17.08	18.45	24.35	23.65	23.58	26.44	37.25	36.38	73.55	44.64	24.66	33.46	40.34	72.94	45.06	27.45	24.13	22.56	23.78	18.00
11/04/2009	EST	16.05	19.62	17.72	16.48	17.01	19.15	48.36	25.85	26.64	27.86	26.01	24.66	24.64	28.95	23.40	22.05	21.40	32.94	54.87	31.28	28.72	26.43	23.77	23.01
11/05/2009	EST	25.18	22.48	26.72	18.55	16.51	16.10	39.05	31.32	29.23	30.06	61.84	27.57	25.75	24.16	24.75	22.29	21.06	26.98	72.52	23.86	25.39	23.64	17.71	15.92
11/06/2009	EST	15.79	13.44	13.07	6.92	13.98	16.38	20.51	37.09	24.74	24.17	24.26	23.51	22.55	25.58	22.59	23.22	18.75	52.17	27.15	22.13	20.52	19.38	17.22	12.16
11/07/2009	EST	15.61	15.31	14.74	14.45	14.39	4.82	12.31	16.71	17.55	21.00	24.35	24.14	23.35	21.54	20.60	20.97	24.72	88.71	89.76	38.20	25.20	23.30	23.56	17.95
11/08/2009	EST	16.96	12.90	13.69	13.79	14.04	13.17	9.05	2.61	8.15	19.44	18.03	19.90	19.77	19.85	18.18	18.98	18.54	41.91	23.22	25.24	22.80	21.65	18.18	15.94
11/09/2009	EST	13.76	14.32	14.37	14.48	15.00	16.46	20.72	48.18	25.06	63.00	81.25	42.58	42.58	43.65	50.01	29.30	25.32	67.57	72.07	42.44	38.39	27.77	21.97	21.03

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
11/10/2009	EST	19.80	18.25	17.92	6.56	16.79	22.17	154.57	27.80	21.75	21.65	28.40	28.07	28.07	35.05	24.39	22.48	23.63	42.20	25.43	26.87	24.80	23.84	20.51	14.70
11/11/2009	EST	2.37	13.61	17.18	18.16	14.85	13.99	25.82	42.70	23.82	24.83	27.43	22.92	24.11	25.05	23.81	22.57	19.63	36.33	27.69	33.82	37.64	27.20	20.01	19.33
11/12/2009	EST	17.51	17.58	17.93	13.26	14.62	17.54	29.23	28.66	110.85	24.70	30.98	23.88	24.15	19.96	19.88	18.83	19.35	31.22	26.40	38.75	24.26	23.13	19.48	19.51
11/13/2009	EST	16.78	13.11	13.63	16.00	17.12	17.41	27.23	22.12	25.19	25.18	44.47	34.58	38.26	28.38	45.42	26.44	22.80	62.27	36.20	26.64	24.86	25.59	22.17	19.36
11/14/2009	EST	18.82	19.17	16.08	17.31	17.34	18.64	18.04	20.03	20.37	24.05	22.97	22.16	22.69	20.78	19.65	18.98	18.99	87.63	35.62	25.88	21.38	20.91	19.83	17.59
11/15/2009	EST	17.37	13.77	16.21	15.27	13.86	16.19	15.09	17.54	18.55	19.09	20.14	20.26	21.13	21.34	19.20	18.50	18.36	22.00	22.85	23.92	25.03	25.14	20.76	18.23
11/16/2009	EST	16.65	16.85	17.87	14.90	-10.68	15.24	8.78	21.51	20.66	19.62	21.23	24.19	20.81	28.11	24.77	26.24	22.13	21.95	23.76	22.94	21.84	22.60	21.19	12.62
11/17/2009	EST	6.67	-4.44	16.00	15.75	18.64	24.67	80.47	47.03	37.03	28.58	26.51	28.16	28.48	25.71	32.85	23.96	24.02	55.92	30.96	26.29	33.27	24.14	20.47	28.23
11/18/2009	EST	22.42	17.25	10.32	17.03	17.65	15.83	31.53	49.81	26.08	88.29	28.35	33.69	28.55	32.30	59.27	22.36	26.08	35.31	38.45	31.78	42.81	31.18	28.07	19.89
11/19/2009	EST	18.40	18.53	17.94	17.49	17.15	19.46	22.26	59.93	97.66	99.38	37.12	39.08	39.68	24.35	26.47	26.68	23.13	39.46	35.56	29.75	39.42	27.82	22.81	19.02
11/20/2009	EST	17.79	18.03	17.39	17.71	17.69	16.59	18.72	23.38	22.24	24.79	27.21	61.07	22.84	25.62	35.23	22.92	22.23	28.03	47.76	26.84	25.96	22.64	21.66	19.57
11/21/2009	EST	20.14	18.42	18.02	19.14	18.57	17.73	19.31	20.32	25.32	26.63	46.58	22.93	19.92	18.38	17.44	17.06	16.45	28.93	24.22	23.38	23.00	21.09	21.77	16.78
11/22/2009	EST	19.39	21.48	17.36	19.58	17.97	18.85	17.30	17.93	19.61	19.59	21.20	20.51	20.16	19.47	18.35	18.75	17.85	83.10	24.26	42.47	51.94	24.18	28.99	15.74
11/23/2009	EST	18.03	17.80	17.30	19.03	16.86	20.10	50.16	28.27	22.65	24.67	77.63	32.09	90.80	23.57	20.80	23.06	23.14	37.61	34.23	27.28	31.35	22.49	13.79	20.42
11/24/2009	EST	22.10	18.75	24.88	17.49	17.76	16.24	4.54	21.64	32.23	32.43	23.20	51.63	35.73	28.32	21.86	20.11	19.79	25.82	25.09	21.78	21.59	25.32	20.34	13.31
11/25/2009	EST	12.35	15.69	15.77	15.71	15.07	15.21	25.24	21.50	19.84	25.93	20.56	21.28	22.40	30.43	23.65	20.25	19.65	29.36	28.67	23.00	22.30	20.92	17.45	2.07
11/26/2009	EST	18.22	14.73	12.66	12.79	13.62	14.40	14.08	16.60	18.31	22.42	36.82	24.12	20.27	16.12	17.85	17.24	17.38	21.16	20.87	20.24	35.58	26.32	18.20	13.82
11/27/2009	EST	16.07	16.99	16.22	17.31	15.98	16.83	18.85	19.01	28.34	34.81	23.76	22.36	20.60	20.99	28.83	33.04	31.05	29.15	34.35	30.10	56.79	46.09	14.72	16.46
11/28/2009	EST	13.96	12.54	18.52	15.66	13.86	18.46	19.74	32.96	46.27	21.48	21.45	45.63	19.84	18.55	18.94	18.75	18.02	74.71	23.24	19.62	19.95	18.22	18.72	14.63
11/29/2009	EST	17.99	17.21	-2.70	8.97	4.03	2.50	15.30	15.48	1.62	16.26	17.95	19.97	19.53	18.82	19.17	20.45	19.72	29.66	34.48	27.07	21.93	21.01	19.66	17.87
11/30/2009	EST	17.64	16.72	16.81	17.58	18.36	15.28	18.92	41.59	26.29	42.44	60.31	23.41	43.21	23.01	19.84	25.04	31.82	24.59	29.64	33.57	43.53	24.77	27.16	0.44
12/01/2009	EST	24.86	6.53	21.27	19.95	26.45	23.10	53.62	45.83	48.80	30.69	29.75	25.08	23.36	22.80	31.63	21.88	19.44	84.65	40.24	52.49	53.42	35.04	27.60	22.68
12/02/2009	EST	18.69	17.50	18.44	18.48	18.37	19.60	35.64	39.31	36.27	25.13	28.89	37.13	26.31	54.44	25.54	34.05	38.83	61.98	67.91	64.40	56.76	32.18	22.69	30.29
12/03/2009	EST	19.56	17.16	16.20	17.18	17.09	15.54	70.72	63.68	41.21	24.60	42.72	40.91	26.75	24.69	27.76	28.73	28.19	54.88	93.42	75.25	84.49	29.03	24.46	22.66
12/04/2009	EST	22.34	20.23	19.32	20.13	18.97	18.30	20.14	28.69	33.87	40.21	50.65	58.98	24.58	26.26	24.52	23.38	28.56	75.47	66.94	49.84	30.29	84.36	28.83	28.31
12/05/2009	EST	67.35	22.72	22.74	23.61	22.49	22.29	27.10	26.39	58.58	39.99	35.67	38.89	27.36	25.76	22.47	23.11	27.49	67.42	42.24	44.16	46.39	41.99	33.45	24.27
12/06/2009	EST	22.44	21.63	28.37	22.60	21.22	19.40	20.51	23.91	23.06	24.16	22.78	23.94	25.99	28.79	25.87	21.99	21.04	59.96	73.63	63.13	27.10	67.99	36.56	20.69
12/07/2009	EST	19.51	18.40	18.94	18.43	18.23	18.41	28.31	45.27	44.76	40.33	93.70	45.88	50.49	41.92	33.79	29.60	29.53	72.40	74.13	49.48	39.73	29.27	30.25	21.13
12/08/2009	EST	20.44	20.04	19.06	18.03	17.87	19.81	26.87	47.16	26.92	23.99	25.92	23.03	33.99	36.65	22.90	22.96	26.47	38.25	26.67	24.39	24.86	24.98	17.87	15.75
12/09/2009	EST	14.84	15.60	14.88	14.95	16.39	18.78	21.98	28.84	49.60	40.93	44.93	66.70	62.37	30.71	24.60	25.76	34.47	44.27	65.81	42.45	46.04	61.70	24.92	25.39
12/10/2009	EST	19.07	20.01	20.23	22.52	25.16	21.39	39.65	95.91	55.15	48.03	73.16	46.66	23.51	25.78	29.37	30.36	25.68	91.03	91.62	77.48	63.00	71.37	47.58	48.12
12/11/2009	EST	33.20	57.05	24.78	25.05	27.04	43.10	34.72	49.97	101.48	53.76	62.59	53.72	28.90	34.25	29.12	25.53	26.91	64.78	49.30	34.94	69.28	29.13	26.70	24.42
12/12/2009	EST	35.63	32.81	30.56	22.94	25.32	24.77	24.85	23.82	31.80	24.83	32.24	25.31	24.14	22.27	22.29	22.87	23.16	68.19	28.12	27.94	26.09	24.91	31.73	20.25
12/13/2009	EST	30.67	19.75	20.34	18.03	18.69	17.99	17.17	18.69	20.19	24.07	23.37	23.82	26.50	26.16	25.84	25.12	24.69	34.32	84.11	47.94	37.71	27.50	23.36	19.44
12/14/2009	EST	30.32	26.01	15.52	18.55	21.45	27.55	25.52	43.71	68.54	28.25	42.65	54.10	30.30	55.70	24.01	23.52	22.96	36.47	81.18	37.23	34.00	31.53	25.64	22.18
12/15/2009	EST	18.34	19.98	19.28	20.17	19.04	19.40	22.64	33.27	72.36	52.79	55.23	107.54	36.89	25.84	67.52	50.12	26.05	49.63	111.66	137.60	85.21	47.13	94.82	31.96

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2009

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

20100528-8062 FERC PDF (Unofficial) 05/28/2010

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
12/16/2009	EST	27.36	27.71	26.82	14.50	22.54	26.70	58.07	82.70	40.46	45.00	56.37	27.77	26.56	27.43	26.52	25.68	26.73	50.01	54.40	41.64	104.34	47.13	30.69	24.08
12/17/2009	EST	31.00	28.42	32.09	21.21	24.00	36.98	43.41	68.74	54.31	44.88	70.55	41.37	30.02	31.27	25.68	25.77	34.58	63.73	40.72	54.49	40.05	45.79	38.95	24.58
12/18/2009	EST	24.99	21.52	20.52	19.21	18.17	32.11	23.76	41.49	59.08	63.41	40.48	46.94	29.49	29.53	26.97	26.41	25.77	38.01	30.95	38.10	28.83	31.49	25.38	21.64
12/19/2009	EST	21.34	19.96	23.39	19.67	20.92	19.95	20.40	23.58	22.21	21.52	38.83	74.29	41.55	27.01	27.75	26.89	23.88	43.02	53.29	71.17	73.01	34.40	48.86	68.15
12/20/2009	EST	18.22	20.41	19.41	20.08	18.78	19.01	22.68	22.07	24.75	29.44	24.54	24.43	22.54	23.15	22.56	23.03	23.59	80.50	61.44	49.80	38.97	35.01	32.59	21.99
12/21/2009	EST	21.76	22.08	20.98	20.92	20.79	21.88	28.81	36.27	45.97	60.88	45.84	34.56	24.67	41.26	25.42	24.75	23.03	41.81	41.53	28.77	30.00	26.10	23.00	21.67
12/22/2009	EST	21.68	19.05	19.02	18.97	20.09	20.73	31.95	30.49	25.90	28.67	39.13	31.19	25.92	25.51	25.67	25.12	24.63	99.60	31.83	26.16	26.49	28.68	26.68	21.64
12/23/2009	EST	23.53	20.72	18.09	17.25	16.87	17.72	26.60	24.61	29.52	38.02	27.91	32.98	26.68	25.74	24.76	23.22	22.95	101.11	34.41	24.93	33.40	23.78	21.83	19.22
12/24/2009	EST	17.74	17.56	13.50	15.66	16.34	15.86	17.21	20.05	20.31	22.33	23.00	22.87	22.27	21.73	20.06	18.79	15.58	28.39	27.95	18.20	18.06	18.67	16.83	14.41
12/25/2009	EST	15.65	12.36	10.47	7.48	9.77	14.46	14.94	15.13	18.36	20.08	20.34	21.81	19.68	17.09	16.91	17.14	16.60	26.48	20.04	21.47	23.28	22.34	21.01	18.22
12/26/2009	EST	17.75	18.69	18.06	18.39	17.76	17.94	18.37	22.04	21.46	27.30	66.15	28.25	24.74	22.55	22.32	21.86	22.05	133.00	76.51	55.75	27.05	26.59	26.47	23.32
12/27/2009	EST	22.84	22.69	21.57	21.59	20.17	19.01	21.20	23.22	22.66	22.73	23.25	23.36	25.21	23.81	24.12	23.19	26.84	44.05	84.92	53.64	47.25	44.35	31.18	35.69
12/28/2009	EST	21.64	21.27	20.69	20.42	23.34	20.60	23.78	24.46	25.08	39.37	38.64	67.88	74.63	34.20	25.36	25.13	23.98	35.93	67.27	65.52	57.07	55.31	44.65	29.39
12/29/2009	EST	35.11	28.31	25.70	34.64	36.19	24.50	26.79	39.11	55.21	31.62	30.64	63.60	37.08	25.49	27.92	29.93	24.77	44.82	76.10	45.73	30.21	72.38	31.39	45.53
12/30/2009	EST	46.40	22.80	28.10	23.84	22.61	24.45	24.90	30.08	33.04	41.94	50.86	27.55	57.71	37.23	30.71	26.45	24.37	40.39	58.76	52.60	36.39	24.24	23.83	24.69
12/31/2009	EST	22.45	20.82	20.31	20.70	18.50	18.68	18.78	23.02	24.85	43.60	26.08	25.85	69.56	23.74	24.75	23.94	21.84	59.01	81.02	24.68	22.33	20.06	21.78	25.02

Federal Energy Regulatory Commission FERC Form No. 714	**Annual Electric Balancing Authority Area and Planning Area Report** **For the Year Ending December 31, 2009**	Utility Code: 0 Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Description of Economic Dispatch

Provide in writing a detailed description of how Respondent calculates system lambda. For those systems that do not use an economic dispatch algorithm and do not have a system lambda, provide in writing a detailed description of how Balancing Authority Area resources are efficiently dispatched.

The Midwest ISO does not specifically calculate System Lambda. However, the Midwest ISO is providing a System Lambda proxy on the following basis.

The Marginal Energy Component (MEC) is a component of the Locational Marginal Price (LMP) reflecting the cost of energy for the next MW that is necessary
to clear the system demand based on the available and operating generator resources. The MEC reflects the energy and operating reserve prices.The MEC is
calculated for each dispatch interval and is basically the same across the Midwest ISO footprint.The information provided is the time weighted hourly MEC and
is the real time Ex Post MEC for the Midwest ISO.

Annual Electric Balancing Authority Area and Planning Area Report

Received
November 1, 2011
Indiana Utility Regulatory Commission

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data

For balancing authority areas where demand following is primarily performed by thermal generating units, the system lambda is derived from the economic dispatch function associated with automatic generation control performed at the controlling utility or pool control center. Excluding transmission losses, the fuel cost ($/hr) for a set of on-line and loaded thermal generating units (steam and gas turbines) is minimum 1/ when each unit is loaded and operating at the same incremental fuel cost ($/MWh) 2/ with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other Balancing Authority Areas. This single incremental cost of energy is the system lambda. System lambdas are likely recalculated many times in one clock hour. However, the indicated system lambda occurring on each clock hour would be sufficient for reporting purposes. Respondents must provide the following data: the system lambda, in dollars, for each hour of the year starting with 1 a.m. January 1 as more fully described in the Form 714 instructions. In column (b) indicate the time zone and the days for which daylight savings time was observed. This schedule will have 365 rows for the report year (366 rows for a leap year).

Provide, as a footnote, an explanation describing the reason for the unavailability of system lambda information. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the balancing authority area's thermal units.

Respondents should be able to report system lambda, along with the other information reported on a Balancing Authority Area basis, that describe the operation of such areas from information that should be readily available. The Commission is not requesting Respondents to develop incremental or marginal cost (either short or long term) according to any formula. Nor is the Commission requesting "avoided cost rates" that electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
01/01/2010	EST	24.01	26.75	24.27	24.05	33.45	23.51	23.42	24.46	22.55	23.21	36.33	26.11	24.14	25.30	23.17	26.18	24.12	60.88	59.61	32.33	46.35	63.26	66.80	26.22
01/02/2010	EST	42.76	35.64	24.39	38.24	37.35	31.14	69.35	51.69	36.85	121.45	98.83	61.47	66.14	49.17	46.39	31.26	42.01	89.54	109.38	101.69	101.69	71.58	44.73	49.88
01/03/2010	EST	40.20	59.75	35.41	34.63	40.66	38.89	34.47	42.19	49.91	49.15	40.25	42.82	49.89	62.49	50.45	33.98	21.24	51.17	79.52	70.48	84.10	51.02	29.85	25.91
01/04/2010	EST	22.84	25.39	24.12	24.17	28.71	26.09	37.40	66.37	90.67	92.55	52.78	79.05	120.91	78.45	54.76	32.90	32.66	55.02	63.01	55.44	51.87	48.04	41.50	37.29
01/05/2010	EST	28.70	21.76	18.60	27.52	30.88	29.49	53.39	72.74	58.41	77.29	89.09	65.22	75.07	126.07	52.04	33.59	33.26	92.98	74.32	67.00	64.44	82.00	61.32	38.20
01/06/2010	EST	43.73	25.81	26.08	23.60	29.94	14.89	53.81	62.00	96.80	35.62	50.07	75.49	52.78	74.01	47.86	46.87	53.23	82.16	61.50	57.83	48.65	26.54	30.75	22.90
01/07/2010	EST	22.23	20.75	19.95	20.28	18.62	16.10	27.03	31.90	26.73	36.33	47.91	34.23	29.75	30.26	31.40	30.20	21.99	33.58	61.58	68.47	49.15	30.43	28.22	37.46
01/08/2010	EST	39.78	30.66	20.68	26.17	28.85	40.93	45.39	59.58	60.27	84.03	64.76	75.77	70.20	58.09	57.67	54.06	34.63	49.56	79.45	90.31	88.76	75.10	63.95	59.42
01/09/2010	EST	22.34	32.93	35.82	31.00	30.77	28.73	40.28	35.04	30.62	52.41	32.25	30.56	29.89	27.02	23.00	22.26	23.22	32.14	41.98	32.45	30.02	25.29	27.97	30.71
01/10/2010	EST	26.13	29.35	24.56	21.52	22.67	22.13	24.76	25.03	22.40	26.06	27.05	28.59	22.72	20.86	11.68	20.96	20.57	31.21	39.90	32.20	38.53	28.72	24.81	34.20
01/11/2010	EST	23.46	22.15	22.14	23.24	20.58	19.89	40.70	82.51	50.02	38.75	32.21	89.45	52.62	62.69	35.80	26.97	35.56	63.04	71.71	75.96	67.58	28.63	45.30	27.27
01/12/2010	EST	26.59	23.09	23.98	22.65	24.40	24.15	28.92	43.54	47.60	49.53	47.66	28.38	31.80	33.32	29.44	28.65	30.66	61.96	81.67	52.22	51.75	40.97	30.82	30.62
01/13/2010	EST	49.57	41.67	12.09	23.82	9.51	35.41	59.58	161.33	34.07	102.88	28.93	24.53	36.63	23.40	23.20	25.41	24.14	38.84	48.04	53.76	42.18	38.82	29.57	26.20
01/14/2010	EST	24.45	18.80	21.06	22.71	23.37	29.57	27.77	65.61	57.01	41.30	58.06	43.04	32.51	34.74	37.02	27.97	29.23	33.23	54.93	63.56	51.14	38.08	26.81	21.70
01/15/2010	EST	22.95	24.49	23.19	20.93	22.62	18.59	23.84	40.24	44.76	40.77	44.99	43.05	52.08	42.21	39.21	29.47	39.02	66.27	41.12	48.19	29.13	43.41	24.70	29.63
01/16/2010	EST	40.03	26.31	23.81	24.19	23.56	21.05	23.06	31.24	29.78	85.41	29.54	32.59	30.70	27.40	25.37	21.84	20.87	46.57	84.08	42.43	53.11	55.43	27.62	26.52
01/17/2010	EST	23.73	22.80	23.83	23.49	21.72	21.02	21.97	25.37	25.09	27.26	37.27	25.67	33.62	28.42	25.30	24.39	23.50	38.49	56.44	50.78	66.54	27.41	24.44	23.01
01/18/2010	EST	20.34	20.62	19.69	20.64	20.57	21.37	32.36	37.80	62.87	86.69	68.08	86.75	44.65	52.65	34.43	34.21	38.43	33.07	76.34	64.28	62.63	38.33	31.28	31.04
01/19/2010	EST	26.06	24.77	23.81	22.88	23.55	21.22	32.13	32.24	34.69	30.28	34.76	37.31	41.71	46.05	27.51	27.56	26.72	30.87	64.40	44.87	39.48	33.76	25.97	24.21
01/20/2010	EST	24.57	22.39	20.12	19.94	19.95	20.19	23.18	31.93	28.94	26.24	38.28	25.58	39.93	33.86	35.07	31.78	27.59	37.01	58.12	32.45	35.57	26.77	26.91	20.62
01/21/2010	EST	20.77	21.42	13.27	-5.70	21.24	47.45	51.06	56.28	39.31	36.98	33.29	35.01	46.60	54.02	31.74	29.15	27.88	35.81	53.90	47.71	36.77	32.93	30.32	22.79
01/22/2010	EST	20.68	20.13	19.75	19.14	20.19	20.95	32.39	76.54	39.45	26.96	27.50	35.89	27.21	27.57	27.95	24.25	24.11	42.37	26.89	25.75	26.42	40.61	37.10	19.96
01/23/2010	EST	19.15	14.38	16.56	16.14	17.58	20.29	20.39	29.83	22.17	21.28	59.70	26.77	46.35	25.90	23.75	21.57	23.45	42.44	24.97	32.11	24.84	23.00	22.02	21.20
01/24/2010	EST	16.64	8.68	7.20	6.21	3.49	8.14	11.67	15.89	17.72	23.66	24.62	20.90	21.08	20.95	21.96	20.04	20.68	26.10	38.94	22.12	22.79	21.44	20.21	17.37
01/25/2010	EST	16.85	14.19	15.54	17.37	17.91	19.37	25.40	67.73	48.43	45.19	49.93	35.01	136.75	27.75	39.58	27.17	30.86	32.43	64.97	59.69	52.26	35.03	27.02	25.00

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
01/26/2010	EST	20.87	25.29	22.64	21.39	20.56	6.22	33.82	75.77	51.60	36.65	32.01	32.84	34.12	39.18	37.88	31.79	27.76	31.72	64.14	58.70	43.32	43.41	34.48	34.58
01/27/2010	EST	30.71	25.57	23.93	23.75	23.44	28.33	42.91	56.45	54.55	27.36	27.62	27.54	25.93	24.65	23.87	24.24	23.07	32.78	38.82	31.98	25.87	24.19	24.03	24.55
01/28/2010	EST	20.82	21.96	20.62	21.38	21.12	14.07	22.67	27.26	31.10	36.79	34.60	32.56	34.52	32.80	37.36	30.12	26.67	35.10	77.75	67.15	54.63	56.38	59.98	30.26
01/29/2010	EST	31.74	30.23	28.07	30.16	29.75	23.52	35.80	63.34	52.43	41.14	40.06	35.32	54.45	61.82	37.15	27.90	30.42	31.64	48.20	42.25	34.14	31.70	26.36	34.92
01/30/2010	EST	74.56	31.90	34.10	37.00	32.04	28.95	27.91	37.50	37.68	45.60	49.66	40.76	28.06	30.54	23.04	23.33	23.09	23.40	42.46	39.90	46.17	33.76	45.16	26.85
01/31/2010	EST	29.42	30.25	26.10	25.73	26.42	25.00	25.06	27.51	23.71	24.90	25.13	25.15	24.22	22.73	21.16	21.37	13.04	21.94	33.00	34.30	46.83	37.18	26.93	24.30
02/01/2010	EST	23.70	25.69	26.07	25.00	20.72	20.54	27.53	35.18	38.01	32.69	32.22	33.16	32.49	29.23	31.42	25.86	26.20	28.26	53.05	41.60	34.82	30.43	27.56	28.22
02/02/2010	EST	38.82	26.21	24.71	24.67	23.91	23.38	28.12	55.14	40.30	81.51	39.37	36.47	32.24	31.46	33.50	29.76	30.28	31.33	46.78	69.97	50.92	33.94	26.34	26.30
02/03/2010	EST	27.44	26.25	25.04	26.13	26.64	28.25	39.80	77.36	59.90	52.26	48.78	33.31	37.31	39.10	27.51	27.51	26.29	24.43	54.07	34.69	46.55	33.51	26.44	29.19
02/04/2010	EST	23.67	24.94	26.11	24.82	25.69	24.54	29.59	81.55	64.55	54.19	68.56	37.47	39.42	49.14	33.52	29.52	30.98	34.33	51.43	72.46	40.52	39.05	28.33	24.12
02/05/2010	EST	25.14	23.68	23.51	23.34	25.16	22.78	23.69	32.90	36.83	37.46	38.89	35.03	38.56	44.84	98.65	32.48	32.53	32.57	34.85	36.56	40.28	28.93	29.04	29.99
02/06/2010	EST	34.13	41.56	30.27	36.23	26.27	31.10	29.73	35.45	39.47	61.92	28.67	36.88	54.58	71.82	39.52	29.39	32.54	41.70	88.07	69.54	69.62	63.37	46.08	43.28
02/07/2010	EST	30.65	52.97	30.81	31.87	28.67	33.46	46.46	35.99	25.96	24.91	25.74	28.22	29.31	28.06	26.85	28.04	22.60	24.30	30.89	25.83	31.13	27.96	29.01	25.30
02/08/2010	EST	24.36	24.54	26.89	25.48	26.64	23.50	38.57	25.43	31.62	25.90	42.47	30.29	58.55	30.30	34.98	28.51	28.51	31.85	76.77	55.52	38.14	31.32	27.49	25.93
02/09/2010	EST	28.14	25.80	23.28	24.00	25.45	28.16	84.42	34.53	43.42	42.00	46.36	42.89	37.92	42.04	46.59	31.36	27.76	31.54	56.86	63.01	53.74	35.39	34.25	29.35
02/10/2010	EST	30.38	50.78	26.80	27.56	26.82	25.24	26.46	50.60	37.20	71.75	84.59	45.28	34.86	33.04	33.24	38.16	25.90	27.64	45.65	64.83	33.06	27.23	32.17	28.54
02/11/2010	EST	24.07	25.61	24.90	24.98	24.64	25.23	28.09	77.92	43.25	38.02	30.28	33.47	31.42	33.58	31.74	29.10	28.94	27.42	45.51	38.28	42.19	37.63	42.05	27.73
02/12/2010	EST	26.49	26.39	27.92	26.53	26.78	26.97	29.92	43.26	45.68	34.03	33.80	30.96	30.45	28.75	29.07	27.61	25.50	29.31	42.50	35.53	37.47	31.57	46.08	31.96
02/13/2010	EST	34.87	52.36	61.21	31.59	28.22	29.38	39.57	27.83	79.22	34.98	30.76	30.37	27.88	29.89	27.46	37.61	25.65	24.50	49.70	42.12	41.31	56.75	27.30	24.38
02/14/2010	EST	23.72	23.71	24.55	27.16	21.49	21.70	22.43	23.70	26.52	25.12	25.71	24.55	23.24	22.18	21.54	22.60	23.95	29.22	47.90	32.17	30.26	31.13	24.49	22.93
02/15/2010	EST	23.63	22.00	22.77	22.53	23.27	24.54	27.56	55.74	86.92	90.83	54.38	156.22	46.61	50.72	30.70	30.49	52.35	64.65	51.85	55.07	48.85	47.45	27.46	23.75
02/16/2010	EST	21.46	18.98	21.18	20.57	21.34	18.67	21.90	24.17	31.01	28.57	53.12	31.10	27.88	32.75	29.82	26.32	24.42	24.88	68.30	174.86	51.64	30.53	26.45	25.61
02/17/2010	EST	23.71	23.66	26.20	24.74	28.21	23.47	28.34	46.77	54.62	49.22	50.46	37.16	29.23	28.30	26.51	25.16	24.51	26.25	48.93	35.14	30.27	31.48	38.11	27.57
02/18/2010	EST	26.40	24.80	23.34	24.44	26.42	26.09	34.45	80.08	51.58	61.35	43.51	31.66	32.47	32.79	33.77	26.20	24.28	23.41	33.52	48.13	51.51	41.61	25.92	24.71
02/19/2010	EST	29.05	25.30	25.21	25.81	24.89	25.52	35.09	49.27	44.51	38.03	37.46	29.62	26.65	26.12	25.11	24.04	23.51	24.02	60.85	28.32	27.79	28.33	31.76	25.79
02/20/2010	EST	28.39	28.28	25.23	46.44	24.66	25.37	26.16	23.09	51.31	32.96	37.58	28.09	23.72	22.75	23.24	22.53	22.80	25.01	62.44	29.77	28.85	33.12	24.97	21.30
02/21/2010	EST	25.72	26.09	23.34	23.07	21.07	21.79	21.42	23.24	23.77	25.13	28.14	27.06	24.38	24.21	23.18	23.67	23.32	27.05	89.08	30.03	36.70	47.05	25.18	20.72
02/22/2010	EST	21.19	21.56	21.49	21.52	22.75	23.12	42.99	35.34	32.73	63.57	59.28	45.65	48.76	70.61	41.51	30.91	41.06	36.57	40.67	54.36	35.93	38.98	27.79	31.96
02/23/2010	EST	29.43	28.00	26.76	25.79	27.41	29.18	24.73	23.39	26.40	35.62	44.92	43.18	43.07	35.16	26.62	27.32	26.22	28.30	56.20	76.04	64.85	68.82	37.03	26.52
02/24/2010	EST	26.15	28.48	26.16	24.97	24.88	25.28	32.54	46.09	56.27	45.90	32.17	117.33	39.99	39.46	63.71	30.99	29.40	27.69	34.40	48.46	69.38	38.63	40.20	31.57
02/25/2010	EST	69.21	35.15	35.18	28.31	28.10	26.64	33.60	39.44	40.15	37.65	31.85	31.51	32.80	31.46	30.70	29.85	27.93	27.24	32.98	50.72	38.42	38.19	30.08	30.25
02/26/2010	EST	32.25	31.56	28.75	28.61	30.83	25.85	33.72	38.08	55.87	73.77	41.98	66.72	46.10	31.74	50.98	30.41	29.51	33.60	33.16	39.40	34.25	46.50	33.55	32.77
02/27/2010	EST	41.12	61.21	31.93	30.21	29.09	28.65	30.76	34.23	59.01	55.06	51.12	53.55	64.25	28.11	28.26	31.19	26.44	38.24	45.33	98.01	54.50	40.52	34.53	39.73
02/28/2010	EST	31.64	35.79	29.21	30.75	26.82	27.31	31.38	29.86	30.88	36.32	36.25	59.84	29.88	30.56	27.13	27.49	25.24	26.59	29.47	33.55	64.47	34.59	27.33	35.49
03/01/2010	EST	23.35	25.33	25.63	25.67	24.26	24.53	28.97	33.08	29.24	31.28	38.34	48.79	38.93	41.83	45.03	33.58	34.63	32.65	34.12	45.12	41.55	35.54	28.96	31.27
03/02/2010	EST	31.52	29.29	26.92	27.66	32.52	27.88	42.10	41.78	45.43	50.95	63.34	42.64	56.03	42.41	40.80	29.26	31.18	31.75	32.28	54.61	53.30	47.45	42.28	28.07

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
03/03/2010	EST	29.89	29.64	29.21	31.11	37.96	26.83	37.80	45.86	41.56	47.28	49.02	100.56	37.09	43.22	35.22	32.23	33.54	38.36	39.14	45.08	48.74	45.80	33.77	28.34
03/04/2010	EST	31.68	29.00	35.21	29.63	25.82	24.64	46.46	42.87	51.72	27.98	27.13	25.21	25.43	25.80	23.79	22.10	20.88	21.51	30.63	29.60	27.82	27.43	36.52	39.51
03/05/2010	EST	22.58	22.52	22.06	21.83	23.93	25.56	53.01	30.68	33.59	30.27	25.71	26.37	27.24	37.38	30.82	24.41	23.65	23.97	36.63	37.43	28.65	28.82	23.99	25.47
03/06/2010	EST	16.57	42.40	23.60	23.55	28.25	41.21	58.16	26.41	27.35	29.08	39.46	25.78	25.17	22.68	20.98	20.47	20.69	21.10	43.97	36.21	29.05	27.37	24.19	21.51
03/07/2010	EST	24.16	22.47	22.06	21.17	24.17	23.26	29.00	23.67	24.76	25.92	25.22	24.30	25.19	23.83	22.80	21.67	22.26	24.29	80.20	63.82	28.11	45.72	25.34	21.71
03/08/2010	EST	21.19	19.69	20.63	20.43	21.65	28.39	46.08	35.28	33.77	28.43	29.51	27.32	30.39	28.07	27.01	25.47	22.90	24.13	47.70	29.80	27.52	26.84	21.80	17.41
03/09/2010	EST	20.65	20.10	20.20	20.02	21.82	21.37	44.52	36.73	32.00	35.29	35.84	33.53	30.63	35.56	48.50	27.90	30.13	29.38	75.40	55.88	37.00	50.15	24.57	18.87
03/10/2010	EST	19.42	19.29	18.09	18.39	14.97	20.87	26.96	92.00	25.21	29.63	27.81	25.79	27.99	30.97	30.06	29.64	26.72	25.97	26.83	37.02	38.74	32.11	25.90	18.87
03/11/2010	EST	16.67	14.87	14.53	-7.97	-42.19	8.29	16.24	23.89	35.56	25.56	26.11	25.97	27.67	29.51	27.94	26.50	25.28	23.90	43.08	38.70	30.33	30.33	22.11	19.93
03/12/2010	EST	21.42	21.86	20.88	20.86	21.33	21.68	44.44	35.81	45.54	36.36	40.95	46.94	45.10	52.22	59.73	28.48	29.84	28.48	28.46	28.48	27.06	25.92	27.20	41.81
03/13/2010	EST	22.09	21.33	10.48	18.07	19.59	20.51	23.60	22.11	28.78	30.35	42.91	33.56	32.97	31.63	27.71	26.26	26.89	27.72	27.49	25.79	29.93	33.46	42.09	24.74
03/14/2010	EST	22.88	21.48	26.53	19.27	18.94	21.88	24.95	22.72	24.00	25.41	40.55	26.21	31.62	26.54	26.35	24.66	24.60	23.27	25.50	33.57	26.10	29.17	21.96	14.37
03/15/2010	EST	20.68	15.48	8.84	0.71	19.09	23.60	31.16	64.28	27.34	29.55	56.50	63.30	29.18	30.18	29.47	27.28	23.30	23.90	23.91	28.46	33.96	23.51	21.89	21.51
03/16/2010	EST	19.79	22.52	21.08	22.70	28.79	26.21	37.25	35.15	53.38	32.88	27.15	47.78	29.18	25.75	23.91	24.06	24.82	25.20	28.22	92.61	35.61	23.51	21.22	21.46
03/17/2010	EST	22.07	20.30	21.62	18.69	23.50	31.42	128.52	38.69	53.13	59.75	29.91	31.34	32.21	32.18	35.33	32.01	26.15	25.05	30.74	38.01	34.76	24.22	20.89	19.62
03/18/2010	EST	18.74	19.83	19.72	22.02	29.34	42.28	55.90	25.35	26.80	28.10	34.25	26.00	26.07	27.08	24.19	23.34	23.81	22.97	21.07	25.26	24.22	22.32	21.37	8.73
03/19/2010	EST	17.19	18.18	18.39	18.59	21.50	26.53	30.01	28.13	24.23	24.69	29.35	24.55	25.37	24.43	23.59	22.09	21.64	21.51	22.82	29.39	27.67	22.42	22.06	20.50
03/20/2010	EST	19.30	18.37	19.86	19.87	21.46	34.27	45.42	29.89	38.66	40.47	36.21	33.30	26.01	27.32	29.40	26.23	36.78	37.49	26.35	38.27	37.00	28.27	26.01	22.82
03/21/2010	EST	21.38	21.19	21.39	19.78	21.40	22.34	23.98	48.12	25.96	32.32	29.16	38.73	62.01	25.14	22.28	21.83	24.70	25.98	24.93	33.78	25.03	22.99	28.33	21.71
03/22/2010	EST	21.68	21.75	20.92	19.27	25.90	23.38	27.52	29.15	52.19	27.31	43.69	31.98	29.09	25.83	26.96	26.52	26.17	25.66	24.38	28.37	31.40	23.28	-4.31	24.34
03/23/2010	EST	19.25	20.48	20.31	21.13	27.37	29.54	80.12	36.21	56.48	66.25	135.52	29.19	28.67	32.07	27.17	24.25	33.44	20.99	37.81	63.64	23.85	22.72	16.12	18.03
03/24/2010	EST	13.47	5.04	16.12	10.07	20.08	31.68	24.72	26.75	27.67	30.63	69.48	55.34	38.58	26.91	22.92	23.31	23.08	22.14	24.48	26.18	23.33	21.73	17.26	14.54
03/25/2010	EST	16.63	15.01	14.42	16.78	18.42	44.14	24.70	25.29	24.95	26.32	28.22	47.97	28.68	29.65	29.04	99.13	26.31	35.32	25.18	45.55	47.10	23.31	23.79	56.59
03/26/2010	EST	18.18	20.38	19.54	20.78	19.07	24.15	90.25	35.67	26.71	30.39	28.71	29.79	75.01	25.22	22.67	22.11	19.88	19.23	31.97	43.77	24.89	20.90	19.63	19.46
03/27/2010	EST	19.50	19.69	19.71	19.92	21.53	19.52	22.97	26.40	24.94	24.16	25.72	48.26	22.30	22.66	20.38	20.49	20.55	21.43	21.72	25.99	22.82	40.62	19.01	20.25
03/28/2010	EST	19.44	19.02	17.26	16.12	16.95	18.93	19.59	20.32	21.54	21.94	22.14	23.45	22.63	22.13	17.52	20.52	21.16	22.08	22.70	25.71	25.52	23.67	20.74	20.04
03/29/2010	EST	20.36	20.29	20.25	19.93	20.32	32.00	31.50	27.84	26.48	116.34	31.01	41.04	47.31	71.50	29.91	19.84	20.65	24.63	25.12	31.10	27.87	22.49	19.25	14.29
03/30/2010	EST	16.63	10.12	13.24	15.31	9.04	46.37	31.14	31.86	26.59	24.75	21.84	25.91	22.72	23.20	20.24	18.02	18.40	18.15	19.30	23.01	21.64	16.94	-12.16	2.97
03/31/2010	EST	9.84	10.52	-8.87	5.10	15.64	50.95	22.90	24.06	23.34	22.60	21.54	21.48	21.42	21.55	22.63	22.02	21.62	20.45	20.40	25.67	23.36	19.49	17.02	15.72
04/01/2010	EST	15.94	15.08	-15.56	12.22	11.94	19.07	23.02	24.93	23.21	25.01	26.93	28.12	31.96	24.87	24.58	23.11	24.85	21.36	19.28	26.39	21.53	8.95	-3.53	4.15
04/02/2010	EST	0.88	14.25	4.38	3.23	-13.86	-27.34	13.09	18.98	24.12	21.95	22.46	22.34	22.37	21.93	24.24	19.66	22.64	19.98	18.88	31.38	22.26	18.44	13.98	-1.88
04/03/2010	EST	15.41	15.15	16.79	16.37	17.21	16.72	19.24	47.25	40.26	25.64	24.39	23.68	22.59	21.90	23.01	22.22	22.45	20.51	21.43	98.62	24.62	22.38	16.51	18.57
04/04/2010	EST	10.03	13.84	14.51	15.45	9.72	18.34	16.69	12.44	28.65	20.71	22.99	20.29	19.88	17.18	20.77	19.13	19.92	18.05	18.91	27.14	22.85	22.92	20.10	16.62
04/05/2010	EST	13.95	16.41	16.43	14.89	18.87	26.48	48.33	36.93	46.89	32.12	34.28	38.08	75.89	43.74	44.39	60.76	44.16	31.46	39.44	51.03	24.71	24.56	21.44	18.68
04/06/2010	EST	19.57	14.91	15.93	17.70	19.05	19.54	26.05	30.45	31.52	64.74	34.14	87.90	67.16	42.89	29.62	30.52	32.02	28.81	22.52	68.67	24.73	16.61	16.96	19.81
04/07/2010	EST	17.78	12.56	16.98	16.01	18.97	42.85	22.66	27.05	63.34	65.08	76.44	40.60	25.89	28.75	25.04	30.00	26.84	24.19	23.52	30.75	25.89	22.41	18.74	17.56

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
04/08/2010	EST	18.16	15.75	15.95	18.74	23.13	32.01	41.41	33.59	29.80	32.51	29.41	26.72	27.24	30.68	25.01	22.47	25.22	23.56	21.56	29.42	32.38	23.81	27.11	21.52
04/09/2010	EST	19.83	16.68	17.96	19.28	20.37	21.80	32.40	35.62	43.34	68.27	31.65	29.49	31.27	31.93	28.62	24.71	24.64	22.97	22.34	58.09	48.94	25.48	40.02	30.82
04/10/2010	EST	22.39	25.66	24.73	23.13	21.10	32.70	24.19	63.33	92.66	27.93	69.16	42.71	25.39	43.22	24.76	23.43	24.77	24.48	21.22	47.45	26.41	29.97	24.36	19.42
04/11/2010	EST	21.27	20.37	20.44	20.36	23.39	23.33	16.91	21.79	38.31	26.42	26.49	25.77	26.56	26.27	35.13	25.61	44.70	25.99	24.23	119.90	52.95	24.78	22.72	18.37
04/12/2010	EST	16.09	15.01	14.64	18.58	27.67	30.27	33.62	28.96	26.11	28.51	26.58	32.89	28.89	29.71	37.48	24.68	34.12	25.03	24.80	25.43	24.19	21.28	15.11	9.11
04/13/2010	EST	14.34	13.35	13.96	10.02	16.28	64.40	91.07	27.20	26.86	40.52	38.06	44.18	58.98	67.32	40.81	40.47	42.40	43.40	25.09	58.25	34.28	25.74	19.14	19.74
04/14/2010	EST	17.13	7.90	8.33	15.78	16.12	30.35	24.91	40.01	32.49	31.81	47.73	32.50	26.56	25.37	53.64	58.77	32.10	27.58	24.58	42.39	38.33	24.67	30.86	22.69
04/15/2010	EST	22.30	19.08	20.58	20.71	23.10	24.23	27.38	50.09	39.26	59.22	51.58	30.86	36.81	66.95	69.14	24.28	27.03	31.08	25.29	25.60	43.16	24.94	33.00	26.41
04/16/2010	EST	19.92	19.77	18.95	20.22	17.89	22.25	70.48	42.55	28.44	58.91	46.62	67.88	52.85	37.00	50.85	38.76	23.74	25.98	23.34	67.07	27.02	24.24	17.38	19.17
04/17/2010	EST	21.63	19.87	20.46	20.67	20.55	19.52	19.90	20.19	24.74	25.85	23.98	26.37	76.34	23.78	23.26	24.61	23.05	24.89	21.54	44.19	32.21	29.85	23.36	32.13
04/18/2010	EST	25.75	24.33	24.57	22.12	23.56	22.89	21.46	19.37	25.41	25.32	26.68	27.76	25.39	24.71	23.46	23.79	34.69	39.77	20.42	45.81	30.31	30.04	21.74	23.60
04/19/2010	EST	26.65	22.44	21.39	21.15	22.15	25.20	42.91	36.75	29.33	37.44	31.36	32.37	29.97	42.81	55.73	29.01	30.33	29.46	27.93	31.03	30.17	27.51	23.75	22.60
04/20/2010	EST	22.01	47.10	20.13	20.99	44.55	26.55	41.86	39.90	29.55	30.82	32.45	38.72	37.71	64.56	49.84	34.40	29.73	28.67	26.43	61.83	28.38	24.97	14.96	23.01
04/21/2010	EST	20.85	20.87	19.65	31.79	30.00	24.90	25.06	64.67	44.44	34.04	46.22	37.64	32.52	43.85	33.94	48.43	51.87	31.75	24.66	56.30	27.86	26.06	23.19	19.76
04/22/2010	EST	19.86	20.85	19.42	19.23	20.17	51.11	66.36	37.75	39.36	33.32	32.77	33.64	35.65	32.22	37.75	32.59	29.62	27.07	26.01	25.17	41.29	23.81	21.52	18.61
04/23/2010	EST	20.77	18.25	6.10	15.77	17.56	21.51	23.18	38.58	26.52	26.37	37.88	25.97	27.74	27.29	26.09	40.74	24.17	22.37	20.65	30.26	23.19	20.32	14.90	16.74
04/24/2010	EST	20.38	20.11	44.47	18.55	17.48	19.17	15.99	22.33	35.24	38.35	45.36	38.36	24.20	24.71	23.50	23.29	22.97	24.74	18.86	20.08	20.74	18.88	8.62	-2.66
04/25/2010	EST	10.63	-6.70	11.41	-13.21	11.21	16.52	13.60	23.99	23.32	18.99	19.63	22.16	21.73	21.73	46.35	22.70	35.73	33.18	23.26	22.90	26.20	37.24	23.03	11.14
04/26/2010	EST	19.32	18.25	19.43	17.39	19.81	24.44	25.48	42.33	42.41	43.93	33.05	31.12	29.35	26.80	28.12	27.35	26.73	26.09	25.41	39.39	26.29	24.02	19.97	17.73
04/27/2010	EST	21.05	19.11	17.39	18.10	21.73	22.43	24.35	27.70	26.14	36.74	28.06	39.52	26.90	26.67	26.35	23.90	24.42	24.23	22.04	37.40	57.33	25.72	27.21	55.12
04/28/2010	EST	20.41	26.72	20.42	20.98	29.78	34.52	29.42	26.81	53.10	26.33	27.80	35.00	26.53	25.95	23.27	23.96	24.33	21.02	11.80	30.18	27.24	20.70	17.19	14.85
04/29/2010	EST	11.62	17.28	14.43	16.24	18.43	22.85	55.07	29.40	26.88	46.53	28.08	28.00	25.78	28.08	32.77	24.83	47.43	25.44	24.10	27.16	89.52	23.88	20.06	20.30
04/30/2010	EST	20.89	12.15	17.51	21.35	-4.63	20.53	25.84	38.66	29.50	41.38	33.52	28.88	56.91	35.54	31.03	28.47	56.33	23.33	25.12	63.37	37.82	22.41	21.38	26.08
05/01/2010	EST	31.98	19.93	18.88	19.74	35.48	19.98	18.95	22.79	24.37	24.62	24.38	24.55	24.76	23.81	14.33	22.36	22.10	21.95	22.64	23.98	38.11	24.01	21.95	21.54
05/02/2010	EST	19.26	18.19	16.72	18.51	17.78	18.79	18.56	24.61	23.83	26.41	27.25	28.69	43.05	25.04	23.85	24.28	37.10	27.38	25.44	22.85	94.10	25.56	18.31	18.60
05/03/2010	EST	38.07	19.25	19.36	19.07	19.73	22.35	29.48	91.94	155.27	28.77	43.47	61.85	39.87	61.75	68.02	38.39	48.73	45.37	47.29	107.33	57.55	27.68	23.23	20.38
05/04/2010	EST	21.18	19.14	20.11	21.40	24.00	30.66	42.22	30.18	54.43	54.44	37.33	68.68	35.62	97.32	38.14	28.66	47.53	35.59	25.62	23.82	26.34	26.92	22.63	21.27
05/05/2010	EST	18.13	15.35	18.02	7.69	18.60	20.37	24.83	24.19	24.73	31.73	32.38	28.48	27.36	33.63	51.75	50.86	28.88	28.42	33.12	22.18	23.93	24.65	22.62	19.90
05/06/2010	EST	24.13	20.47	20.27	21.69	22.22	23.16	25.69	37.28	53.49	41.38	38.98	44.66	38.14	35.73	74.04	34.56	27.84	80.00	50.18	30.40	89.26	25.70	20.58	18.94
05/07/2010	EST	19.36	18.37	20.57	21.22	22.80	84.38	24.64	29.29	64.60	33.14	29.20	49.18	36.40	39.44	37.58	41.66	51.28	38.47	27.88	24.61	24.61	21.00	20.38	19.49
05/08/2010	EST	19.77	18.22	30.91	25.14	17.81	13.48	28.27	44.01	29.86	26.87	40.15	30.32	37.84	25.91	21.82	24.03	24.71	23.64	23.34	24.12	28.93	27.68	23.23	20.76
05/09/2010	EST	19.08	20.22	18.93	20.43	19.54	19.08	21.28	21.82	25.22	23.71	22.34	21.01	19.52	18.92	18.65	19.56	19.01	18.69	19.15	19.45	21.54	24.91	13.01	12.12
05/10/2010	EST	17.35	17.31	16.56	15.58	15.73	18.11	20.83	22.46	24.01	28.21	24.49	23.37	24.84	23.83	23.96	22.57	24.34	24.68	24.07	25.12	31.21	37.39	19.42	16.10
05/11/2010	EST	23.39	17.47	18.12	18.19	38.13	71.40	23.81	25.81	75.34	62.11	49.28	38.80	40.63	38.84	30.63	142.09	49.32	41.44	33.69	29.34	32.82	27.00	44.06	31.74
05/12/2010	EST	35.73	21.72	21.33	21.87	24.04	33.65	53.50	35.10	35.17	28.83	36.22	39.68	39.42	29.94	31.16	36.98	31.19	33.17	45.81	27.11	27.40	24.33	23.44	21.39
05/13/2010	EST	20.58	20.60	19.99	24.14	24.08	24.34	26.34	85.45	27.13	36.07	33.89	34.47	36.23	31.40	31.25	29.40	28.86	24.39	24.55	26.55	29.55	23.80	24.78	20.62

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
05/14/2010	EST	20.28	19.60	18.83	20.09	20.11	21.86	34.81	39.23	103.12	59.61	73.91	49.97	56.03	55.80	48.89	39.78	100.51	32.42	26.56	24.67	45.12	27.44	20.81	20.58
05/15/2010	EST	46.98	26.68	25.52	21.97	22.54	22.23	22.88	40.33	64.99	28.66	52.64	27.30	28.28	25.42	26.62	28.79	29.67	21.46	23.21	35.12	25.49	23.59	17.90	18.12
05/16/2010	EST	28.16	-6.94	18.09	18.07	19.20	17.02	21.88	25.12	31.80	23.87	26.37	30.50	23.57	22.98	23.13	25.94	25.15	25.08	31.03	51.91	39.20	36.70	21.98	20.10
05/17/2010	EST	17.62	16.86	17.44	19.20	20.27	23.29	25.06	32.41	33.08	32.13	38.18	27.18	27.85	30.37	35.30	28.98	40.84	31.53	26.60	27.79	26.47	26.60	27.42	20.43
05/18/2010	EST	21.92	20.73	21.04	19.19	22.70	32.53	23.31	26.03	25.69	28.04	31.07	28.74	30.62	41.93	24.55	25.43	24.71	24.38	24.59	23.74	25.04	24.91	23.19	22.26
05/19/2010	EST	13.60	18.00	16.63	15.44	20.69	23.86	25.81	26.07	29.71	27.01	27.70	28.79	30.41	30.72	27.83	26.88	26.97	29.62	25.92	28.52	84.07	27.47	22.65	21.58
05/20/2010	EST	23.08	18.86	20.21	20.57	21.79	25.16	27.29	42.01	36.65	29.22	37.78	31.85	35.03	63.60	34.93	34.79	34.34	29.57	91.34	29.97	32.65	32.93	29.24	28.97
05/21/2010	EST	18.53	22.02	20.59	29.80	25.26	24.96	23.55	26.08	26.08	32.39	57.13	32.54	52.85	60.86	33.17	28.13	31.08	28.19	29.23	31.79	26.20	38.19	23.04	23.14
05/22/2010	EST	22.64	20.73	19.72	33.35	17.24	-19.19	18.94	20.76	19.32	25.47	23.25	24.19	24.44	24.94	22.55	23.42	24.80	26.82	26.82	23.33	25.07	24.10	19.97	18.61
05/23/2010	EST	4.64	17.91	14.71	15.62	16.93	-24.88	-22.41	19.49	20.43	22.62	22.57	24.69	26.61	29.13	31.78	35.07	58.41	32.43	33.29	90.76	72.78	34.33	27.85	22.65
05/24/2010	EST	33.14	19.29	17.69	19.12	20.68	27.45	26.52	33.10	79.74	62.74	99.21	63.21	69.06	88.91	81.39	75.77	184.35	179.48	53.88	42.41	153.64	40.32	30.43	31.37
05/25/2010	EST	27.68	22.10	19.27	20.60	22.26	19.82	22.04	27.16	30.36	45.38	49.63	35.13	107.76	61.86	58.00	66.02	77.74	48.40	32.05	29.55	41.02	37.94	28.33	26.86
05/26/2010	EST	36.74	20.91	27.37	29.01	21.75	26.85	47.93	56.44	30.17	69.42	69.46	60.19	70.91	60.55	60.83	59.53	56.99	49.94	32.06	42.74	37.61	29.43	23.97	20.60
05/27/2010	EST	14.03	14.66	11.80	18.00	23.28	23.49	31.41	50.27	26.90	40.10	114.67	76.47	61.53	54.57	49.39	65.14	53.94	41.90	27.93	28.50	29.00	28.74	24.93	17.92
05/28/2010	EST	19.80	19.53	13.34	13.46	21.35	20.92	24.38	25.72	37.30	26.47	70.53	32.56	59.20	123.79	61.70	60.40	50.73	40.47	42.13	30.46	65.58	24.65	24.34	19.39
05/29/2010	EST	-3.23	25.81	46.85	18.49	16.23	5.73	20.34	21.85	24.15	26.14	28.18	100.66	37.59	35.14	49.49	116.83	55.00	38.41	54.12	50.09	75.44	38.74	22.33	20.98
05/30/2010	EST	32.56	15.61	9.89	17.49	16.94	13.06	18.53	23.60	29.14	25.20	25.34	34.12	34.55	39.91	105.95	39.70	57.84	58.08	44.09	29.26	65.10	40.13	22.67	20.79
05/31/2010	EST	20.71	20.54	20.00	17.90	17.95	-31.01	19.53	29.72	28.70	47.35	125.26	34.04	26.99	26.19	29.42	33.63	28.41	28.24	29.18	28.13	25.78	26.17	20.76	18.30
06/01/2010	EST	18.67	18.06	17.54	16.05	19.63	20.91	21.51	24.48	24.66	28.53	33.30	38.40	84.03	72.98	56.40	62.16	60.67	64.80	47.91	39.31	68.27	75.35	56.90	23.15
06/02/2010	EST	23.09	20.04	20.89	20.74	23.21	24.12	37.98	24.45	24.82	24.38	24.69	28.24	32.21	41.35	43.16	35.29	31.49	25.98	25.01	26.12	26.45	32.56	36.94	27.30
06/03/2010	EST	23.04	22.31	21.87	21.36	22.22	23.56	23.18	26.26	27.63	30.32	32.85	33.79	50.05	39.81	46.59	45.82	39.67	40.49	27.96	27.40	28.30	34.05	25.52	20.83
06/04/2010	EST	20.06	18.03	18.75	18.09	21.18	21.07	28.82	38.84	37.38	40.92	57.28	49.71	47.89	58.91	55.20	75.24	70.85	62.11	73.76	75.97	53.42	43.04	40.05	26.99
06/05/2010	EST	25.67	23.13	21.14	19.19	22.86	22.29	22.25	47.07	34.23	28.42	35.14	51.23	49.78	50.85	44.80	63.57	74.04	50.26	127.43	74.27	216.03	33.42	24.99	31.74
06/06/2010	EST	25.17	49.54	6.99	-5.27	-3.63	-85.74	22.48	21.23	23.66	27.46	22.29	23.89	19.74	25.51	27.03	28.71	32.07	24.70	23.63	23.38	24.04	26.95	21.84	16.21
06/07/2010	EST	17.86	17.54	16.45	17.14	20.61	21.68	27.23	28.09	29.83	41.56	40.50	45.73	39.61	43.26	44.28	32.51	29.37	35.81	39.48	31.92	44.17	28.61	21.18	23.18
06/08/2010	EST	19.95	17.72	8.57	16.75	19.83	21.59	31.41	21.50	50.09	35.26	28.51	29.34	33.29	33.00	26.23	24.19	24.14	24.59	24.93	30.56	32.25	26.68	24.05	12.87
06/09/2010	EST	15.88	10.58	12.70	11.55	19.50	31.37	22.45	24.50	27.35	27.48	25.36	31.78	30.11	39.90	37.87	35.48	40.45	42.86	33.89	33.64	62.01	39.62	28.77	28.13
06/10/2010	EST	11.54	19.83	20.48	20.24	18.19	21.28	23.42	25.41	30.88	40.68	31.04	47.87	42.77	39.33	59.92	56.98	102.89	45.00	51.38	33.87	37.20	36.00	52.27	17.46
06/11/2010	EST	9.42	12.66	4.82	2.33	21.04	22.60	24.56	32.39	24.93	29.58	81.75	42.47	30.60	37.73	51.67	62.92	60.21	38.40	38.99	32.79	26.85	31.77	29.64	41.79
06/12/2010	EST	22.39	23.61	22.83	22.18	21.78	15.04	22.43	26.69	24.96	30.00	40.82	33.75	38.10	47.60	48.17	38.30	35.02	34.40	31.76	30.98	28.47	27.08	22.26	27.13
06/13/2010	EST	14.86	17.76	19.56	18.33	18.36	-12.31	16.01	15.54	20.90	21.46	23.71	26.02	25.43	25.65	26.96	27.46	26.13	26.50	26.84	25.03	22.95	26.48	22.68	20.21
06/14/2010	EST	19.29	20.68	19.13	19.22	21.39	21.90	26.34	27.45	36.72	46.66	81.34	117.91	91.04	87.12	109.51	65.64	60.75	40.79	31.81	64.28	37.56	37.34	24.43	23.50
06/15/2010	EST	24.14	22.75	22.51	22.70	33.95	24.39	25.52	53.47	33.68	33.07	89.04	122.20	54.63	54.92	69.91	48.96	50.81	44.59	35.45	35.38	32.46	31.15	26.91	24.18
06/16/2010	EST	43.53	20.32	18.58	18.13	59.08	19.46	23.44	25.65	34.56	33.08	30.38	44.95	46.53	55.99	68.81	64.09	57.47	40.31	33.67	24.63	27.54	27.87	22.25	-6.03
06/17/2010	EST	16.95	18.86	17.83	-2.91	14.63	19.86	24.13	21.07	22.46	23.44	24.64	26.57	30.59	35.65	42.31	71.44	47.59	40.45	24.85	23.18	24.54	26.48	23.76	23.04
06/18/2010	EST	20.42	23.28	19.26	20.24	18.47	-8.69	15.23	22.99	29.13	26.10	38.43	46.39	79.98	80.41	98.30	126.17	77.01	47.81	45.54	25.75	24.38	23.61	24.09	21.14

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
06/19/2010	EST	21.49	20.17	18.47	8.51	15.79	-2.36	-7.26	20.71	17.74	23.28	19.64	24.10	30.10	35.91	38.05	53.08	64.15	35.16	31.89	26.21	25.87	28.28	24.11	23.44
06/20/2010	EST	13.19	21.32	17.50	15.12	16.38	-1.90	17.24	24.27	27.16	28.26	49.89	38.20	52.77	33.69	63.53	54.24	46.41	58.01	89.05	61.09	115.96	54.39	20.89	25.39
06/21/2010	EST	21.22	19.62	17.92	18.49	21.78	23.03	29.07	24.71	30.43	32.25	32.87	33.33	88.89	58.01	55.89	62.64	57.99	77.66	62.09	47.85	40.42	40.20	28.92	27.37
06/22/2010	EST	27.15	20.34	20.27	19.97	22.32	23.38	20.52	22.84	28.83	38.39	39.72	38.55	53.49	66.58	73.33	81.67	73.24	78.02	76.09	56.93	51.50	38.56	29.77	24.64
06/23/2010	EST	23.90	23.03	22.15	22.25	25.24	49.96	9.22	29.55	44.01	32.06	27.01	28.51	42.94	66.71	48.37	52.28	62.83	62.75	46.05	37.60	40.83	28.41	23.23	15.31
06/24/2010	EST	30.15	21.30	19.69	18.95	19.57	26.61	26.06	28.52	41.71	56.06	33.45	37.47	65.41	53.86	73.92	64.20	64.82	60.56	37.82	33.95	28.81	32.15	23.31	20.86
06/25/2010	EST	19.67	20.42	17.55	14.96	18.42	19.40	23.27	31.54	38.17	38.88	56.43	41.71	55.94	65.85	61.11	64.47	81.39	59.87	51.59	31.21	46.64	35.72	25.67	26.92
06/26/2010	EST	25.90	24.88	26.80	19.43	20.54	22.03	29.71	26.99	27.69	27.91	31.58	33.78	47.71	57.49	50.89	65.17	66.42	53.40	39.23	32.94	43.01	37.40	29.24	30.29
06/27/2010	EST	7.50	25.14	19.69	19.85	22.99	8.15	21.27	25.06	28.89	30.30	36.82	41.18	30.14	27.17	28.05	27.39	29.88	32.78	32.39	31.19	27.34	25.19	23.62	19.47
06/28/2010	EST	22.61	-4.03	16.21	-19.65	19.93	20.15	22.27	24.65	26.35	34.48	42.63	44.83	69.53	47.19	38.16	39.27	35.30	35.30	29.42	23.84	24.14	24.17	19.85	19.25
06/29/2010	EST	18.47	18.80	16.18	16.19	17.03	21.23	56.22	30.31	39.68	47.44	38.91	36.10	48.65	39.54	42.82	42.71	38.43	29.11	31.88	27.41	27.25	26.41	19.88	18.20
06/30/2010	EST	-13.81	16.07	15.15	15.28	18.00	19.32	21.86	43.97	26.29	31.67	26.34	33.05	80.51	32.50	44.87	36.85	62.96	34.08	31.62	31.32	37.00	26.02	32.37	18.10
07/01/2010	EST	16.48	15.45	16.23	15.76	18.53	15.30	19.07	25.50	33.03	48.45	32.56	32.75	33.84	69.56	39.03	39.56	37.82	44.15	27.93	25.53	40.78	30.18	27.61	22.45
07/02/2010	EST	9.03	16.03	11.07	15.31	11.20	16.23	44.06	50.18	26.28	28.73	30.62	137.97	32.18	34.73	34.81	42.73	46.44	95.27	62.40	39.36	50.01	34.14	19.83	38.60
07/03/2010	EST	29.75	17.26	1.48	14.22	13.93	-11.16	36.38	19.48	21.47	25.01	24.93	25.97	38.61	27.56	31.48	85.34	41.60	28.08	28.33	36.04	23.20	23.81	19.43	20.22
07/04/2010	EST	18.69	15.50	14.72	-22.56	14.58	10.66	-27.75	18.12	21.27	27.37	29.16	65.31	52.69	28.06	35.14	31.18	38.13	49.59	29.20	25.15	24.38	25.10	27.60	22.08
07/05/2010	EST	55.32	20.60	20.36	19.15	18.11	15.76	20.23	23.66	66.35	52.53	178.96	43.38	43.60	51.24	48.76	56.26	55.52	45.96	50.43	38.85	52.43	39.97	26.06	26.52
07/06/2010	EST	19.35	19.16	18.77	17.53	18.28	19.12	24.45	27.31	39.01	41.81	41.46	44.73	59.14	63.78	64.20	74.09	66.61	63.90	57.15	48.06	121.33	28.32	26.09	27.73
07/07/2010	EST	27.45	23.60	22.37	22.33	21.98	21.89	27.34	26.59	44.81	32.55	96.34	72.43	71.42	72.49	79.79	64.40	75.13	60.18	45.19	50.30	111.87	35.35	36.83	24.99
07/08/2010	EST	22.95	21.90	20.47	18.78	19.64	21.48	24.90	26.99	27.78	42.25	44.76	56.71	68.03	63.56	82.89	72.14	79.62	49.42	36.81	30.32	31.53	34.57	29.09	35.00
07/09/2010	EST	24.25	13.37	12.53	22.28	22.83	21.42	28.07	28.50	38.19	49.20	48.02	49.52	61.22	69.44	63.44	72.25	69.58	62.54	53.20	40.33	32.17	51.74	25.22	25.45
07/10/2010	EST	23.20	22.16	18.40	19.87	18.40	-5.79	18.81	24.09	102.28	32.01	33.63	40.37	42.61	49.81	47.21	46.11	48.85	42.19	34.34	27.80	28.03	26.11	21.48	20.15
07/11/2010	EST	19.23	19.01	15.65	16.22	15.16	-10.60	16.14	21.12	27.19	31.45	23.80	37.07	38.58	46.45	45.47	40.36	35.32	36.49	38.22	31.31	38.66	33.00	10.58	27.09
07/12/2010	EST	21.68	19.54	18.66	20.60	18.49	43.39	31.67	23.83	26.06	34.29	43.49	73.35	75.57	68.53	57.06	65.06	64.60	60.09	48.74	36.21	90.45	27.69	25.92	23.28
07/13/2010	EST	21.54	3.30	11.92	15.40	20.01	16.20	23.51	25.26	25.48	25.16	26.39	27.23	33.23	48.89	33.80	47.83	54.90	39.33	37.06	32.03	35.48	32.27	26.29	24.58
07/14/2010	EST	21.34	20.89	19.55	18.97	19.84	20.05	22.60	25.90	26.39	161.12	30.99	41.12	41.79	148.57	53.76	60.23	145.16	55.98	56.21	50.10	343.18	65.34	25.76	29.59
07/15/2010	EST	24.47	23.63	12.88	9.75	22.14	22.41	22.16	27.81	30.51	53.67	51.30	53.08	64.33	63.81	70.34	60.46	59.41	53.03	40.79	35.50	27.50	25.17	22.48	21.75
07/16/2010	EST	15.42	5.98	15.40	16.69	17.54	19.58	24.49	25.33	34.72	32.18	44.28	43.22	93.63	83.18	95.95	106.50	68.44	50.08	45.03	38.93	27.16	28.17	25.56	29.28
07/17/2010	EST	24.53	21.68	20.75	18.56	18.33	14.90	19.80	22.76	36.14	48.19	51.09	42.84	55.10	66.24	56.87	245.89	93.54	48.37	48.38	44.24	68.06	36.50	44.07	25.88
07/18/2010	EST	27.47	22.29	21.61	20.21	18.22	16.67	19.43	24.30	22.60	22.80	23.87	25.27	25.97	29.04	33.94	40.92	49.20	46.51	45.87	39.32	25.67	31.25	26.75	18.64
07/19/2010	EST	20.66	17.74	13.75	18.28	21.32	23.24	23.72	27.78	29.86	46.10	42.55	43.53	60.75	48.02	75.12	52.83	137.12	36.31	36.88	29.58	29.38	29.74	28.02	24.64
07/20/2010	EST	23.61	20.37	20.14	20.46	22.00	24.37	35.90	27.51	27.19	41.10	35.91	42.67	69.73	61.59	145.37	192.62	69.06	78.14	110.28	46.99	57.92	37.70	30.12	27.67
07/21/2010	EST	23.69	22.29	21.79	21.85	23.00	23.04	25.26	32.81	45.36	46.97	78.25	56.32	100.70	67.45	140.22	88.78	81.34	62.29	52.78	49.46	44.88	34.82	25.70	25.13
07/22/2010	EST	21.06	23.94	20.34	20.04	20.95	21.73	24.58	61.56	63.10	27.88	49.83	83.68	36.86	53.55	73.22	69.46	50.29	56.05	58.62	59.08	51.64	53.46	34.21	34.96
07/23/2010	EST	29.28	24.94	23.83	23.74	26.64	105.49	24.41	32.76	40.36	53.90	61.40	65.25	79.07	77.96	221.11	71.63	68.13	65.27	59.80	60.52	67.93	39.00	32.45	26.64
07/24/2010	EST	28.31	25.03	24.03	12.89	22.63	21.50	18.72	20.31	26.87	27.70	32.35	50.98	53.47	56.66	66.76	60.62	72.72	59.32	38.41	34.00	34.68	40.23	26.53	28.62

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
07/25/2010	EST	27.04	37.84	10.92	18.05	19.74	19.30	17.72	20.44	21.10	50.00	55.91	34.48	35.23	58.35	31.90	75.75	35.58	36.26	42.48	32.19	36.21	27.59	23.56	23.62
07/26/2010	EST	10.17	18.77	17.92	19.46	20.15	21.04	22.66	25.95	30.37	38.39	42.62	61.74	55.75	65.60	63.62	153.42	84.17	70.59	66.28	55.96	63.03	39.67	29.27	22.37
07/27/2010	EST	20.11	21.64	20.31	19.91	20.92	23.25	24.88	28.42	31.53	37.80	56.31	59.79	69.39	65.05	64.62	64.10	60.68	62.17	59.07	61.55	64.46	43.38	34.87	34.49
07/28/2010	EST	26.90	24.47	24.01	23.86	24.71	25.68	27.79	42.47	50.00	40.85	63.30	86.42	62.03	64.95	63.19	70.62	67.45	61.14	56.16	44.89	42.67	33.26	35.89	30.98
07/29/2010	EST	32.11	25.15	16.04	23.60	23.37	23.81	23.77	33.50	34.44	57.01	59.81	47.00	55.89	77.66	87.60	61.26	92.31	50.61	52.67	34.87	38.85	30.09	31.24	29.84
07/30/2010	EST	25.35	16.44	20.79	21.91	22.67	23.35	26.93	28.02	25.91	33.25	34.99	39.12	63.05	40.76	54.98	39.21	35.47	30.95	28.32	30.85	38.53	28.69	34.78	25.21
07/31/2010	EST	23.96	22.98	22.38	22.15	25.51	21.97	22.49	24.88	26.89	28.48	33.01	27.66	27.95	29.11	34.97	46.97	46.71	30.08	30.35	31.91	30.21	26.65	24.44	26.38
08/01/2010	EST	26.21	23.62	20.72	18.84	18.47	17.28	15.43	21.54	26.16	27.59	73.42	36.33	32.03	29.70	35.35	47.04	52.61	50.04	41.26	32.08	42.41	27.39	25.51	23.35
08/02/2010	EST	20.98	11.20	17.91	17.57	20.11	20.30	23.76	28.81	30.85	33.87	41.87	49.77	67.07	56.72	56.21	60.73	59.68	58.13	60.02	50.27	71.20	40.00	38.12	32.11
08/03/2010	EST	30.44	29.25	26.33	24.29	29.58	29.34	24.31	34.20	31.94	35.35	51.96	51.51	56.84	63.08	70.11	91.32	115.19	105.95	67.22	60.56	82.90	58.25	46.24	40.29
08/04/2010	EST	39.02	28.00	29.31	27.77	27.55	30.92	30.50	30.51	54.37	49.54	51.80	65.56	71.31	66.41	65.87	81.78	73.68	67.08	59.19	44.62	34.16	38.32	36.42	25.80
08/05/2010	EST	34.89	25.66	22.87	22.79	22.84	25.93	26.71	22.60	34.42	36.48	39.01	47.19	62.77	53.71	57.14	53.77	52.62	52.84	41.46	29.32	28.46	24.93	23.88	23.76
08/06/2010	EST	22.92	21.63	20.60	19.48	19.19	21.06	22.11	26.48	30.47	58.56	30.71	36.97	41.46	43.72	77.12	52.09	51.89	42.79	36.93	31.98	34.23	28.46	24.62	23.06
08/07/2010	EST	21.05	20.04	19.08	17.81	16.04	16.25	18.64	22.60	25.12	29.11	29.95	33.15	33.42	33.44	36.05	35.19	59.73	64.26	51.81	36.96	34.32	29.10	25.95	22.20
08/08/2010	EST	22.08	20.55	17.95	17.23	13.36	16.18	17.60	21.30	25.14	27.80	30.51	42.02	48.59	41.45	39.24	47.45	73.97	67.04	51.44	44.52	53.04	39.01	28.39	32.01
08/09/2010	EST	24.04	23.45	21.16	19.76	21.60	24.67	23.55	27.35	31.25	34.07	46.21	71.62	73.89	104.26	57.65	68.55	77.87	65.56	63.88	73.53	70.69	46.31	32.37	38.02
08/10/2010	EST	31.02	25.26	23.33	23.56	23.68	26.49	26.00	31.59	40.53	45.06	90.07	66.05	71.76	90.13	97.63	345.12	69.72	72.11	68.25	70.93	71.35	47.75	38.01	29.57
08/11/2010	EST	24.48	23.24	22.78	22.58	23.51	29.35	25.53	28.96	38.10	42.42	50.62	59.66	70.45	71.21	69.83	125.57	94.08	127.70	85.22	64.48	74.98	68.82	50.71	42.02
08/12/2010	EST	28.18	25.29	23.69	23.79	25.41	29.57	27.47	37.06	53.53	42.12	63.83	66.54	64.07	65.24	58.94	67.03	66.28	60.03	66.86	54.90	48.75	48.56	42.41	26.75
08/13/2010	EST	21.85	19.62	23.22	23.56	23.65	25.28	25.43	28.92	37.99	52.02	65.32	65.29	58.10	59.05	58.75	59.60	58.36	68.05	41.84	34.03	35.14	28.61	27.07	26.43
08/14/2010	EST	28.99	26.78	23.80	23.13	23.21	23.85	23.44	25.18	40.99	29.96	35.67	72.15	48.84	51.87	48.91	43.31	48.91	39.10	31.30	28.31	29.56	25.88	25.82	61.45
08/15/2010	EST	23.33	23.88	21.27	19.79	19.56	18.65	18.52	23.39	26.08	35.40	42.20	73.07	35.18	36.96	38.62	66.35	53.21	42.15	44.02	45.17	105.51	24.70	-1.27	19.98
08/16/2010	EST	20.26	19.97	16.76	13.74	19.92	23.81	22.59	25.86	28.99	32.51	48.79	28.87	27.88	31.13	36.66	54.59	51.77	33.27	33.59	24.29	26.60	25.31	21.19	19.52
08/17/2010	EST	21.03	21.17	17.92	21.22	20.41	21.73	21.37	24.78	27.42	28.61	55.96	47.42	38.37	32.43	39.89	43.20	31.28	30.09	28.87	32.00	31.01	27.43	25.18	23.53
08/18/2010	EST	21.89	21.59	21.00	21.74	22.32	27.42	24.27	26.34	26.20	29.52	74.95	44.17	77.86	37.40	48.83	71.51	79.18	49.12	50.72	108.17	171.09	38.44	35.68	26.58
08/19/2010	EST	23.73	18.91	20.45	21.34	23.17	25.28	23.99	24.43	27.29	34.54	41.86	63.31	69.73	70.12	115.52	57.05	148.32	126.09	45.54	41.25	45.16	37.77	39.60	18.28
08/20/2010	EST	24.34	24.20	23.25	20.91	24.13	26.60	25.79	27.33	30.55	46.97	73.35	71.00	63.52	75.53	89.05	71.32	62.46	55.29	49.65	49.44	79.84	41.78	29.13	31.96
08/21/2010	EST	28.23	33.21	23.46	23.50	24.00	23.36	23.49	24.51	26.82	22.37	24.74	23.99	25.24	27.69	28.54	30.81	35.85	34.03	31.15	25.36	26.14	26.27	25.26	21.59
08/22/2010	EST	32.12	22.54	1.20	17.75	17.62	-29.89	-29.36	18.81	22.85	26.55	25.50	44.24	45.64	87.02	56.91	76.30	109.17	104.32	44.46	32.31	30.69	26.99	22.10	21.23
08/23/2010	EST	20.12	19.87	19.97	18.54	19.14	25.27	23.48	25.66	25.86	26.26	30.30	27.86	35.81	37.30	41.64	41.51	50.62	34.97	32.48	26.81	25.94	23.66	22.65	21.03
08/24/2010	EST	21.47	19.33	18.76	19.03	21.79	24.56	23.74	24.61	27.60	27.09	25.67	31.59	30.84	29.85	26.33	24.50	25.85	24.89	25.83	24.68	25.95	23.49	21.47	20.17
08/25/2010	EST	19.46	18.26	9.30	17.61	18.90	37.39	24.00	23.34	33.53	31.15	28.96	30.48	34.59	31.05	31.26	34.79	60.73	30.50	58.50	46.83	27.50	24.47	21.32	18.22
08/26/2010	EST	17.86	-8.97	-7.93	5.06	16.91	20.93	21.18	23.12	26.19	27.33	27.17	108.53	32.47	30.46	49.35	67.31	33.01	30.28	28.97	24.13	24.78	21.18	-6.91	17.30
08/27/2010	EST	8.21	1.82	-13.64	-0.17	15.81	17.90	26.33	24.38	25.55	40.01	31.73	37.90	40.34	40.42	85.30	54.90	45.30	39.54	31.41	27.51	31.21	26.02	20.41	6.22
08/28/2010	EST	18.15	0.83	13.98	14.08	10.94	15.29	15.37	19.70	23.63	24.93	28.44	38.97	27.20	52.10	29.21	65.92	39.06	32.80	30.41	32.15	35.86	30.02	22.01	15.50
08/29/2010	EST	18.91	12.65	6.13	-10.58	-16.61	15.58	15.27	16.48	51.40	42.71	88.21	55.98	290.85	39.81	56.04	38.03	49.42	62.17	44.27	41.69	43.89	30.23	30.44	22.24

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
08/30/2010	EST	19.45	20.78	20.67	20.03	18.48	53.12	26.94	31.71	31.29	46.49	52.01	45.54	60.03	69.81	75.95	83.44	74.26	69.52	59.57	54.30	45.25	37.35	39.48	31.73
08/31/2010	EST	20.96	20.36	16.59	20.03	27.04	35.61	28.13	77.69	27.14	25.64	43.79	56.19	77.77	83.10	158.63	65.09	49.68	44.28	55.66	56.03	37.96	27.90	28.20	30.10
09/01/2010	EST	21.82	20.94	18.72	20.78	21.77	28.61	30.51	25.87	27.32	37.70	25.04	39.00	62.67	42.52	47.46	64.34	52.48	37.77	32.53	37.97	30.12	23.23	23.27	14.95
09/02/2010	EST	-59.79	19.09	19.63	18.82	19.90	24.70	26.42	28.02	52.16	33.81	49.33	40.88	48.37	44.29	44.65	165.64	51.28	46.15	52.80	53.56	24.21	10.77	16.42	16.93
09/03/2010	EST	15.70	19.27	17.76	10.23	20.53	55.87	23.05	23.29	22.60	21.25	27.28	23.35	22.41	22.80	20.52	20.03	22.32	11.39	19.84	20.39	21.04	16.98	17.80	-6.87
09/04/2010	EST	-20.87	-4.89	-31.16	17.17	15.98	16.51	-0.39	5.90	26.26	22.75	22.47	22.16	21.10	21.58	21.76	22.40	22.12	22.91	21.52	25.74	23.36	19.05	16.99	-39.77
09/05/2010	EST	-13.89	-17.49	-15.78	15.32	-26.91	-0.27	-57.35	-27.31	22.14	22.01	19.95	21.60	20.81	20.32	20.51	20.58	22.39	20.91	19.52	21.02	20.05	17.00	7.18	11.86
09/06/2010	EST	-43.42	11.95	4.13	8.59	6.03	15.71	-29.15	3.20	20.03	27.03	22.11	25.40	20.90	21.23	21.76	25.69	44.33	23.02	25.55	24.73	23.73	18.89	14.75	9.75
09/07/2010	EST	-35.10	-4.76	-94.41	-16.10	12.44	32.49	21.62	29.10	22.00	39.34	29.11	25.30	51.84	52.27	63.04	53.38	29.19	18.02	23.14	28.65	25.01	22.17	16.62	15.25
09/08/2010	EST	5.76	-11.20	-9.98	-1.73	5.06	26.97	22.96	23.18	22.91	23.20	23.53	25.08	31.66	27.02	25.49	24.15	25.43	24.38	24.09	26.05	22.71	18.24	19.26	8.03
09/09/2010	EST	14.74	-0.50	2.35	15.11	12.41	21.74	22.31	21.39	22.22	53.98	42.96	23.62	24.65	24.10	23.23	26.61	22.19	22.55	25.07	27.23	46.33	20.14	15.42	12.74
09/10/2010	EST	6.93	13.00	-18.75	12.28	11.88	31.76	22.61	24.07	41.63	34.88	23.57	32.61	25.09	39.16	24.39	23.69	23.32	23.31	23.01	100.99	23.19	22.01	20.15	15.19
09/11/2010	EST	17.07	18.08	16.56	17.12	17.33	17.34	16.56	19.25	21.11	22.26	22.16	22.61	22.52	21.74	22.49	23.80	24.01	23.76	45.61	26.63	23.47	23.12	20.11	15.82
09/12/2010	EST	14.40	8.15	9.92	10.37	14.86	15.91	14.77	19.69	21.28	22.73	23.56	25.05	23.64	23.85	38.72	74.05	47.71	36.83	25.89	49.25	32.46	23.24	20.46	20.08
09/13/2010	EST	19.98	14.59	15.08	18.59	20.07	32.53	30.15	25.22	27.02	36.03	52.82	45.99	50.60	53.62	42.87	58.13	39.76	40.07	27.31	32.44	27.96	24.01	22.47	17.40
09/14/2010	EST	17.62	17.06	16.35	16.64	17.79	23.80	23.87	23.92	23.95	25.12	25.99	29.02	52.05	43.90	39.80	39.92	38.12	27.03	25.81	27.61	26.35	23.61	20.66	18.12
09/15/2010	EST	15.65	13.41	14.87	16.97	15.17	35.86	45.43	24.90	47.06	48.05	26.03	37.33	44.81	38.72	38.98	47.78	40.16	96.80	68.95	59.95	36.97	25.80	20.09	17.57
09/16/2010	EST	13.52	17.44	18.07	15.37	17.61	58.23	109.15	46.13	50.86	30.23	37.74	38.55	37.05	67.44	59.38	29.07	123.57	44.11	26.23	52.37	25.94	21.58	19.81	18.38
09/17/2010	EST	8.59	-12.23	6.34	8.09	10.98	29.83	27.19	23.62	29.99	27.91	31.73	30.72	39.45	58.86	33.80	27.96	29.37	27.67	24.76	29.32	25.72	21.04	19.82	17.04
09/18/2010	EST	20.09	17.70	16.73	11.86	13.09	18.36	19.35	20.32	34.86	72.25	24.41	32.17	25.60	36.43	26.54	47.34	31.48	67.01	31.60	38.35	29.10	24.78	19.29	17.64
09/19/2010	EST	17.62	15.98	15.82	14.32	15.12	17.25	23.00	27.10	25.63	22.64	52.35	47.10	35.79	22.68	52.44	23.80	67.08	32.46	83.49	63.49	23.82	22.08	4.47	18.51
09/20/2010	EST	14.10	10.83	16.40	17.26	18.58	28.99	24.19	25.41	25.75	27.76	74.43	29.88	83.86	39.97	60.24	53.64	28.00	70.71	31.34	79.27	26.03	24.02	21.75	18.70
09/21/2010	EST	21.04	19.32	15.46	18.40	19.54	22.69	22.49	48.50	24.43	24.24	26.02	27.46	43.72	48.28	39.83	52.20	49.33	32.46	34.29	32.56	27.22	24.72	26.02	22.19
09/22/2010	EST	21.90	19.95	20.33	20.20	20.69	24.01	25.84	26.01	28.71	29.08	27.58	29.30	25.77	32.98	25.93	25.52	24.80	23.69	25.22	27.93	24.54	22.38	19.71	18.74
09/23/2010	EST	18.10	17.54	18.60	16.64	20.00	23.63	29.78	25.72	31.24	33.82	42.20	45.82	62.76	98.01	52.48	75.79	64.09	31.86	34.19	32.48	28.75	22.53	23.12	12.70
09/24/2010	EST	5.51	15.79	12.09	-0.98	11.67	29.63	33.80	44.24	38.33	48.35	26.43	27.67	46.85	29.35	33.34	25.67	24.37	24.19	25.33	26.81	24.85	23.87	20.59	19.71
09/25/2010	EST	21.57	21.34	20.46	19.08	19.13	20.51	20.66	25.02	29.22	31.63	28.68	26.34	30.15	23.72	43.02	24.52	32.54	22.81	59.75	41.61	23.81	21.59	18.38	18.35
09/26/2010	EST	17.91	16.35	2.23	14.86	16.61	15.46	16.57	17.52	20.24	20.76	21.16	20.94	20.29	19.89	20.79	20.61	21.78	23.79	82.90	36.66	23.81	19.32	17.54	12.14
09/27/2010	EST	-43.27	12.30	14.22	11.17	53.93	36.28	55.01	58.33	38.18	70.56	30.05	64.34	27.12	26.52	26.18	26.29	25.41	37.46	105.17	48.38	31.58	20.00	16.56	13.59
09/28/2010	EST	13.08	-32.03	11.42	-28.52	15.75	28.42	24.95	23.34	28.50	27.98	50.75	32.63	43.10	39.69	26.22	25.71	25.59	21.92	20.44	29.61	29.53	22.18	17.95	15.36
09/29/2010	EST	14.28	11.08	5.79	-12.86	17.30	23.02	28.62	21.99	22.75	23.37	25.32	21.55	23.28	23.11	26.76	24.98	25.21	21.97	66.11	59.57	25.74	19.70	17.93	16.36
09/30/2010	EST	-50.05	3.14	2.98	14.83	20.63	23.62	25.10	23.33	25.85	31.15	54.71	26.50	37.52	33.62	35.82	26.63	24.88	23.64	70.02	68.08	25.90	23.91	22.80	21.74
10/01/2010	EST	19.76	20.03	19.54	19.69	20.14	23.17	24.06	37.18	31.83	25.82	26.63	27.83	27.30	41.90	30.33	25.00	23.63	0.79	13.86	22.41	22.73	21.60	20.44	16.34
10/02/2010	EST	17.97	10.16	16.58	16.81	17.86	20.98	20.93	23.84	23.92	21.70	24.18	22.38	21.86	22.08	21.63	21.35	22.18	20.45	25.00	24.42	32.62	24.39	20.02	13.76
10/03/2010	EST	0.55	7.32	3.53	3.35	14.47	18.16	19.34	20.70	23.05	24.54	52.47	22.18	22.41	21.73	21.75	22.53	25.45	21.14	32.31	36.24	23.91	23.10	18.36	-1.61
10/04/2010	EST	-47.10	22.82	25.26	-2.05	11.11	30.66	31.10	29.08	34.27	28.27	35.50	29.38	28.62	28.85	29.26	25.50	25.43	24.67	27.76	52.18	25.98	21.29	17.83	16.34

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
10/05/2010	EST	37.66	20.15	19.90	20.41	42.83	108.98	24.74	27.13	24.60	64.88	26.18	40.70	26.91	31.93	31.45	28.11	25.92	24.89	47.15	41.92	22.26	37.26	20.90	12.54
10/06/2010	EST	-27.13	-33.30	15.14	14.54	17.25	32.52	37.36	23.94	27.56	32.13	37.52	54.12	31.59	28.03	29.75	24.27	24.85	24.90	25.21	25.27	23.69	22.31	19.84	15.11
10/07/2010	EST	8.64	16.44	16.67	17.28	18.79	23.31	29.08	24.60	25.55	29.64	38.79	30.16	33.33	50.17	30.99	30.46	33.24	27.70	50.71	33.42	31.15	22.26	20.56	12.19
10/08/2010	EST	19.49	18.12	1.41	12.77	28.86	23.87	37.07	23.71	35.61	38.25	42.21	27.54	27.82	41.69	35.01	34.66	36.90	25.23	25.66	25.55	22.47	20.01	18.75	18.61
10/09/2010	EST	18.54	19.11	17.54	14.77	12.41	18.36	23.18	21.17	23.47	23.64	26.67	38.57	22.83	25.17	29.64	28.32	28.62	25.39	28.63	24.32	23.50	22.80	26.68	15.47
10/10/2010	EST	13.80	16.73	16.63	16.44	16.93	17.54	24.62	19.11	23.58	22.90	23.81	24.17	28.30	27.04	32.35	32.36	26.31	21.72	42.49	26.39	23.55	22.73	22.22	27.91
10/11/2010	EST	19.68	18.86	18.47	17.16	29.25	19.84	22.79	26.38	25.88	31.57	45.46	49.11	36.71	52.56	38.91	31.70	32.99	30.38	33.68	25.78	29.18	26.00	22.79	26.20
10/12/2010	EST	20.24	18.35	18.79	26.68	32.33	74.72	36.27	34.20	26.08	31.02	31.43	32.71	47.70	43.10	25.34	38.38	27.25	24.20	105.91	26.28	26.27	20.86	18.98	16.88
10/13/2010	EST	19.38	12.19	13.95	16.52	16.80	26.18	36.41	61.20	31.60	63.76	29.09	30.32	33.03	31.84	27.30	41.51	28.24	30.03	100.21	49.57	34.31	41.95	21.46	18.62
10/14/2010	EST	16.91	16.70	17.12	16.13	26.23	63.08	32.65	31.54	24.73	27.39	28.84	62.78	53.50	23.87	23.64	14.99	27.93	28.88	26.96	39.53	45.70	31.71	36.29	17.84
10/15/2010	EST	18.59	22.44	18.53	20.95	39.46	31.49	49.13	51.37	27.00	27.53	28.32	39.69	57.03	29.31	26.97	48.83	31.10	23.00	70.60	42.52	26.40	21.59	20.19	16.21
10/16/2010	EST	42.72	15.31	17.48	15.71	19.13	20.10	20.25	24.58	30.07	24.49	26.29	24.00	23.64	22.63	19.86	21.66	21.40	21.35	27.30	25.75	21.10	19.68	17.33	21.81
10/17/2010	EST	21.99	16.77	14.14	15.99	15.92	-0.33	36.92	21.25	23.48	25.02	23.49	22.78	23.45	23.16	23.20	22.59	24.51	23.13	31.70	24.71	22.53	19.54	46.59	16.14
10/18/2010	EST	15.35	14.39	15.80	16.67	15.71	20.46	25.81	39.38	60.40	41.52	27.45	26.16	41.28	30.27	31.53	43.83	41.74	39.18	93.41	40.40	27.33	23.20	40.70	20.93
10/19/2010	EST	18.69	18.33	18.32	19.31	16.34	32.86	80.63	29.57	25.82	25.21	26.20	24.32	24.20	34.90	62.51	26.12	58.50	34.34	32.61	26.73	24.59	22.68	18.25	21.22
10/20/2010	EST	16.38	18.15	14.14	41.32	-5.23	24.45	42.18	25.79	36.43	58.05	38.13	24.31	22.92	23.70	22.67	33.11	50.76	22.77	28.17	26.17	23.77	22.26	24.36	19.72
10/21/2010	EST	16.84	16.83	15.79	13.46	17.64	34.37	22.57	26.52	36.76	26.15	29.62	27.11	26.71	26.65	25.31	25.42	25.55	25.60	62.69	61.20	36.41	27.25	21.18	19.72
10/22/2010	EST	17.90	40.97	17.36	18.36	17.36	25.34	44.17	43.14	32.03	30.51	23.23	23.26	23.90	24.59	25.14	23.05	22.68	23.36	38.89	24.20	21.91	19.27	18.17	15.70
10/23/2010	EST	18.09	13.24	19.41	17.78	23.65	21.66	21.52	24.29	29.13	29.59	26.56	25.81	25.09	24.46	22.80	23.72	23.18	25.25	30.50	23.62	21.97	19.88	19.06	16.92
10/24/2010	EST	24.63	37.69	18.22	17.43	16.96	16.72	21.41	19.56	22.57	24.35	23.55	25.08	25.32	24.35	23.57	42.80	28.76	43.65	58.83	100.86	25.11	22.67	21.57	25.13
10/25/2010	EST	25.30	17.54	19.05	35.08	20.24	41.21	40.49	28.60	26.42	26.59	26.47	25.76	25.89	28.01	25.43	25.16	24.10	27.38	32.77	26.59	23.97	20.49	15.98	15.10
10/26/2010	EST	14.41	5.87	4.91	7.08	0.52	18.31	24.09	24.48	25.60	25.53	24.26	23.67	24.53	24.37	22.17	10.49	22.76	23.56	25.61	25.33	15.79	20.39	15.53	10.22
10/27/2010	EST	14.18	16.12	13.50	11.98	16.59	12.63	24.42	25.53	25.35	36.84	31.52	26.53	26.06	27.40	24.80	25.13	25.98	31.69	79.56	25.24	19.83	21.43	13.35	13.28
10/28/2010	EST	-0.19	8.03	10.97	12.64	7.34	22.62	36.52	29.22	26.46	39.44	30.37	41.87	28.32	27.21	28.53	24.07	23.54	29.97	29.58	42.33	27.82	24.84	23.61	22.47
10/29/2010	EST	22.21	21.67	21.50	21.84	22.24	24.90	27.84	28.28	24.42	24.94	24.67	22.82	26.97	20.33	18.59	16.87	20.43	22.44	23.77	23.48	41.05	24.25	19.22	20.39
10/30/2010	EST	21.17	19.78	19.23	24.35	22.10	34.25	32.78	32.14	35.11	33.05	36.08	28.59	22.90	21.63	22.09	22.59	23.07	24.50	25.34	28.35	22.68	21.63	19.55	19.06
10/31/2010	EST	20.57	19.27	18.95	17.86	21.39	23.89	22.64	23.43	25.29	26.21	26.05	26.07	27.02	26.62	27.56	27.12	26.86	24.62	29.83	27.50	30.36	24.04	22.17	32.56
11/01/2010	EST	36.86	19.04	19.68	21.19	24.10	32.59	65.56	30.54	31.03	36.65	31.52	34.19	33.21	29.28	28.24	26.78	26.76	72.97	43.85	34.26	26.90	24.07	22.57	18.81
11/02/2010	EST	19.10	19.39	21.02	21.75	21.63	26.80	30.78	30.85	33.59	33.84	54.87	27.82	27.85	25.00	23.13	26.20	25.19	27.96	25.97	26.70	24.66	22.92	17.82	19.43
11/03/2010	EST	26.85	21.11	21.65	51.82	21.24	74.51	40.27	51.12	75.61	27.13	32.01	23.62	24.35	24.92	22.05	27.45	25.27	41.13	26.97	66.38	45.27	20.96	9.47	-18.18
11/04/2010	EST	12.85	11.32	21.33	17.87	17.68	29.61	37.99	34.85	27.85	39.70	28.35	32.98	41.66	27.73	24.67	28.45	28.77	46.74	38.24	38.94	31.19	24.88	23.43	21.08
11/05/2010	EST	21.85	20.90	21.62	22.66	23.08	33.22	84.16	32.70	31.86	48.93	33.43	80.35	51.56	42.38	25.63	38.75	43.76	58.33	85.39	40.13	54.73	29.50	29.45	25.84
11/06/2010	EST	26.50	26.12	26.68	26.08	21.94	21.69	36.06	32.16	34.44	40.15	42.58	41.00	24.03	22.32	21.38	10.27	20.50	13.82	45.41	51.50	53.69	28.12	21.95	15.85
11/07/2010	EST	29.75	21.03	20.66	24.36	23.88	18.90	27.33	22.14	40.11	33.90	26.50	23.44	23.69	24.38	22.43	26.34	16.22	28.70	60.74	36.53	22.79	22.35	19.95	15.23
11/08/2010	EST	17.78	13.20	5.88	-0.14	-8.42	14.80	45.83	88.57	37.51	30.83	25.46	27.45	26.53	27.56	25.15	24.32	21.53	22.23	30.33	25.73	26.56	21.34	18.10	19.39
11/09/2010	EST	18.58	17.70	19.57	20.93	21.74	20.73	39.79	64.78	27.77	29.54	28.63	27.48	25.83	24.24	23.73	22.15	21.98	46.65	35.04	26.88	26.93	25.22	19.66	18.30

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
11/10/2010	EST	5.37	16.58	11.86	12.88	-1.50	13.07	60.75	28.15	30.34	29.17	30.21	27.11	33.46	32.62	25.74	24.88	23.67	49.70	73.30	44.82	23.92	23.21	21.66	23.34
11/11/2010	EST	13.00	16.32	17.55	16.16	9.84	16.69	39.71	30.64	30.03	32.65	56.57	47.33	38.81	30.60	43.27	28.31	26.32	107.42	51.88	31.25	29.45	28.69	23.03	20.68
11/12/2010	EST	17.58	18.97	16.52	17.60	21.05	16.04	89.14	40.28	27.90	27.05	28.35	29.39	43.20	27.93	25.67	24.82	22.04	25.40	24.77	23.28	23.72	23.48	16.90	18.66
11/13/2010	EST	21.55	16.67	16.45	5.05	15.12	17.50	16.26	22.18	26.42	22.90	24.53	23.59	23.30	22.60	21.50	19.24	20.90	27.39	26.02	28.31	24.50	23.31	21.02	18.29
11/14/2010	EST	16.92	17.19	17.37	16.88	17.64	18.29	19.33	20.82	27.72	28.33	26.41	26.06	25.34	24.10	23.59	22.96	23.90	70.48	48.58	130.94	31.44	26.62	29.53	21.54
11/15/2010	EST	18.54	20.09	20.49	20.60	21.86	18.96	25.71	27.53	29.49	29.23	36.15	47.48	50.69	26.75	26.69	27.58	25.64	60.41	80.41	82.32	64.21	38.50	28.62	22.64
11/16/2010	EST	21.81	20.09	22.25	20.73	19.24	19.60	25.61	30.45	31.64	35.19	29.55	28.23	30.67	31.67	29.23	27.17	26.91	35.80	39.26	34.76	38.94	29.25	24.01	22.40
11/17/2010	EST	20.57	21.02	22.02	19.66	16.83	17.77	28.51	72.90	23.71	25.60	25.86	27.12	28.94	27.06	27.07	25.55	23.53	76.03	61.95	54.62	36.23	31.64	31.68	25.61
11/18/2010	EST	21.73	21.63	22.89	21.69	22.41	20.75	34.73	35.80	47.92	45.00	28.98	28.87	29.76	30.42	27.89	25.35	25.96	57.53	37.31	59.49	29.66	27.63	25.05	21.65
11/19/2010	EST	19.96	13.91	14.00	16.96	3.55	19.77	46.60	27.77	33.28	22.90	26.18	25.57	23.47	25.86	23.82	22.30	24.16	66.75	40.43	26.14	87.39	62.53	21.12	18.80
11/20/2010	EST	20.40	20.85	20.22	20.45	20.21	20.50	22.75	23.94	37.92	76.89	30.76	24.43	23.37	22.87	21.21	20.50	18.77	135.45	25.18	26.32	27.41	23.45	98.40	57.71
11/21/2010	EST	16.52	19.60	16.94	18.76	18.89	46.90	21.59	19.47	22.54	22.18	23.33	23.55	27.03	23.89	22.41	22.77	25.70	47.31	41.72	28.81	40.51	27.04	22.82	18.95
11/22/2010	EST	27.89	18.52	18.72	18.34	15.78	-1.39	4.38	28.85	42.89	31.81	38.09	40.39	31.77	46.60	47.04	32.26	28.42	110.14	42.27	36.68	27.69	24.14	24.71	18.57
11/23/2010	EST	15.68	18.34	17.21	16.97	17.98	17.83	27.36	30.43	28.36	28.41	30.41	34.89	27.88	26.65	30.24	25.59	22.97	39.61	32.75	33.21	27.34	26.73	23.27	20.54
11/24/2010	EST	21.49	19.64	18.98	18.62	18.29	18.63	6.37	24.53	29.73	38.76	28.66	33.58	38.05	69.35	44.93	95.10	26.99	39.63	28.43	31.61	26.77	26.87	22.79	19.19
11/25/2010	EST	20.21	20.64	20.82	20.21	19.87	20.24	20.84	22.36	26.26	25.13	29.64	29.73	23.41	20.02	18.28	16.02	16.80	21.03	21.68	21.08	20.93	21.34	20.56	19.90
11/26/2010	EST	16.50	16.78	17.11	18.23	19.44	20.88	21.36	24.36	23.11	24.12	23.54	22.38	22.14	20.20	20.26	19.89	21.47	30.31	28.06	26.19	26.33	27.25	24.97	23.75
11/27/2010	EST	20.26	20.45	20.40	20.93	21.07	22.01	23.27	24.77	32.27	40.03	26.95	26.41	24.79	22.87	21.49	21.69	21.58	28.53	30.84	31.66	29.29	23.77	23.19	18.09
11/28/2010	EST	15.78	16.76	11.91	10.94	10.00	-4.28	22.19	22.61	18.03	18.92	19.30	19.56	18.96	16.50	5.63	-1.72	19.96	24.97	37.95	39.57	24.26	23.27	20.41	0.94
11/29/2010	EST	15.10	4.71	2.88	8.53	4.16	12.93	27.97	27.42	33.06	29.09	34.96	25.72	24.01	25.37	24.61	23.14	22.63	50.25	30.48	28.07	25.30	23.79	16.04	17.11
11/30/2010	EST	13.70	16.66	14.79	4.91	10.23	18.37	49.98	28.80	22.98	23.33	25.05	25.44	25.31	26.42	25.77	26.99	23.74	44.70	31.97	29.91	29.71	48.56	19.04	17.05
12/01/2010	EST	15.59	19.34	17.80	20.38	18.88	22.01	29.66	81.58	63.38	101.31	31.38	30.88	25.97	46.46	26.78	28.65	25.58	84.26	82.55	55.96	62.38	52.41	33.97	30.55
12/02/2010	EST	24.99	23.54	23.93	28.98	28.53	25.83	35.27	41.21	45.31	43.32	41.10	42.93	32.97	34.39	29.52	28.47	30.58	34.33	42.76	44.79	52.25	34.40	27.36	27.61
12/03/2010	EST	26.49	23.10	23.09	22.79	22.24	24.68	31.26	43.06	38.88	45.23	32.41	30.40	29.50	26.50	26.81	23.31	24.71	91.60	27.90	30.42	29.24	44.52	29.33	27.05
12/04/2010	EST	27.69	25.70	23.86	23.40	23.00	21.82	21.41	24.19	28.26	28.77	29.39	27.13	27.38	25.76	24.94	24.80	25.33	69.13	45.66	49.25	44.37	36.46	32.56	24.66
12/05/2010	EST	23.69	21.96	22.28	21.50	20.34	21.91	21.97	23.46	24.88	31.34	30.35	31.75	26.01	24.23	24.42	25.41	20.52	29.16	35.57	52.87	32.94	36.98	29.73	24.26
12/06/2010	EST	21.68	22.44	21.82	22.75	19.71	21.78	37.64	33.87	45.21	42.93	52.71	27.87	28.82	34.61	26.50	25.88	36.67	56.11	78.79	70.97	54.30	28.97	26.40	26.06
12/07/2010	EST	25.05	24.82	22.55	24.86	25.35	28.87	32.42	46.93	34.21	37.70	39.92	43.47	32.90	32.74	30.54	29.62	37.74	57.42	56.25	42.51	53.55	66.57	30.69	27.22
12/08/2010	EST	25.89	24.45	26.57	25.52	26.27	32.89	47.40	71.94	75.75	33.05	34.96	28.19	28.24	25.19	25.54	25.61	26.12	39.22	48.70	39.69	31.49	34.50	28.48	23.67
12/09/2010	EST	23.46	20.16	23.17	20.65	22.56	28.07	32.28	33.93	44.70	31.85	38.99	29.27	18.89	26.08	28.78	28.60	28.68	69.27	54.73	43.07	47.33	27.81	25.86	19.72
12/10/2010	EST	16.78	18.35	10.67	17.14	18.57	20.90	27.03	36.07	38.65	25.72	76.10	40.65	25.05	21.86	22.83	20.88	19.86	31.22	36.00	31.44	29.69	26.04	23.20	18.23
12/11/2010	EST	35.06	19.23	19.03	17.40	16.82	18.08	15.60	21.17	21.90	19.81	20.22	20.75	28.54	22.02	22.03	20.60	20.29	38.97	39.81	26.80	29.60	28.32	22.84	21.01
12/12/2010	EST	19.92	19.83	17.81	19.90	20.00	15.76	21.08	20.90	21.32	24.29	24.75	25.98	22.82	24.00	21.57	22.41	25.55	92.68	61.91	27.08	32.41	73.76	26.37	29.79
12/13/2010	EST	24.81	23.76	24.55	22.67	24.50	27.69	28.46	48.80	51.23	93.29	53.38	47.85	38.85	34.71	30.83	30.73	32.13	51.90	302.06	64.82	52.36	91.72	42.49	37.69
12/14/2010	EST	60.25	30.46	31.16	30.84	36.94	31.88	61.67	89.35	65.60	93.08	50.80	46.20	48.26	37.99	30.57	32.12	29.62	56.06	40.71	39.04	156.00	40.74	24.80	31.99
12/15/2010	EST	26.49	25.22	28.90	26.99	25.92	26.65	42.79	67.26	55.52	64.03	54.45	34.19	28.43	31.57	33.58	30.71	19.58	61.04	53.46	69.49	43.27	35.80	32.86	28.78

Federal Energy Regulatory Commission
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Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2010

Utility Code: 0
Utility Name: Midwest ISO (new for 2010)

Part II - Schedule 6. Balancing Authority Area System Lambda Data (continued)

Date (a)	Time Zone (b)	0100 (c)	0200 (d)	0300 (e)	0400 (f)	0500 (g)	0600 (h)	0700 (i)	0800 (j)	0900 (k)	1000 (l)	1100 (m)	1200 (n)	1300 (o)	1400 (p)	1500 (q)	1600 (r)	1700 (s)	1800 (t)	1900 (u)	2000 (v)	2100 (w)	2200 (x)	2300 (y)	2400 (z)
12/16/2010	EST	32.75	26.11	26.81	26.53	28.55	26.41	43.42	34.27	30.69	50.52	70.86	52.66	34.60	35.52	28.05	26.31	26.74	38.19	46.60	40.15	33.57	30.21	28.09	24.51
12/17/2010	EST	23.23	23.17	21.53	22.44	24.00	24.56	27.37	29.97	28.04	35.58	25.94	37.05	30.54	29.55	32.47	29.52	24.77	65.19	76.57	59.75	36.70	34.00	29.21	24.51
12/18/2010	EST	23.70	26.41	23.40	23.50	23.66	27.45	31.04	52.50	55.37	34.50	30.18	82.97	33.62	28.07	26.77	27.12	26.55	82.06	75.90	34.58	35.53	38.46	29.49	27.15
12/19/2010	EST	25.19	24.41	24.82	25.10	24.24	24.67	43.42	85.50	34.38	112.59	44.72	30.20	27.22	28.22	27.27	25.49	24.95	39.80	34.22	34.24	36.04	35.03	32.19	26.53
12/20/2010	EST	24.09	23.41	23.01	22.67	23.15	20.16	22.92	30.24	31.67	27.05	26.02	25.42	23.78	22.69	22.61	23.99	23.30	32.67	34.19	37.26	37.28	28.91	31.99	24.65
12/21/2010	EST	25.78	22.82	22.11	21.82	21.61	22.82	27.62	29.79	40.62	30.80	32.45	46.69	28.47	33.45	27.97	27.07	27.14	36.60	36.91	33.35	28.75	67.88	30.53	23.60
12/22/2010	EST	21.96	21.61	21.05	19.62	22.88	23.69	29.24	72.70	34.40	215.96	52.16	55.91	42.52	64.00	35.77	27.91	28.55	79.80	61.39	77.05	43.45	56.89	38.78	27.32
12/23/2010	EST	24.62	22.43	22.17	22.24	8.78	24.00	24.04	25.53	27.26	29.84	34.79	30.84	27.27	24.65	23.63	23.87	23.68	41.80	33.02	26.97	29.18	33.00	25.66	22.86
12/24/2010	EST	10.58	23.07	19.23	19.21	18.68	17.44	19.15	22.01	23.22	24.28	25.68	25.55	25.20	23.91	22.71	22.22	22.23	25.05	23.49	22.09	21.22	20.90	21.09	20.27
12/25/2010	EST	17.81	15.48	15.68	12.41	5.21	4.33	11.63	18.80	22.17	19.34	20.87	20.37	20.16	18.51	13.34	16.66	18.90	27.19	22.85	22.31	22.99	24.25	23.31	23.88
12/26/2010	EST	21.04	20.46	20.62	19.68	20.88	22.95	21.56	23.33	24.74	30.95	28.19	23.55	23.38	21.40	20.78	21.45	20.42	36.82	33.20	28.41	31.38	30.24	27.44	22.96
12/27/2010	EST	22.83	22.74	23.08	23.94	24.51	24.20	22.47	25.84	25.34	32.07	33.82	32.59	30.35	28.01	25.99	24.77	23.99	80.14	316.75	29.26	36.84	36.14	32.65	25.27
12/28/2010	EST	25.36	23.20	23.08	23.48	22.81	24.13	26.62	59.67	35.50	48.72	46.03	26.20	25.50	24.98	23.69	22.89	4.66	32.02	26.77	24.01	24.23	22.39	22.29	19.27
12/29/2010	EST	15.87	8.61	1.36	5.53	16.87	18.63	33.46	25.43	24.45	26.21	23.29	23.81	22.68	22.55	21.24	21.39	19.87	25.33	24.27	24.20	25.52	22.43	16.27	16.22
12/30/2010	EST	-17.65	-61.56	3.38	10.80	-13.21	7.10	20.55	24.06	23.97	23.44	26.25	23.91	23.24	22.53	21.79	21.75	22.00	32.38	28.70	29.57	24.17	22.22	20.37	13.38
12/31/2010	EST	-7.94	15.71	10.37	2.22	17.12	16.85	18.18	19.51	22.29	25.35	24.53	24.24	23.03	22.46	23.56	23.76	34.07	39.80	26.52	23.32	21.72	20.39	18.98	16.28

Part II - Schedule 6. Description of Economic Dispatch

Provide in writing a detailed description of how Respondent calculates system lambda. For those systems that do not use an economic dispatch algorithm and do not have a system lambda, provide in writing a detailed description of how Balancing Authority Area resources are efficiently dispatched.

MISO does not specifically calculate System Lambda. However, MISO is providing a System Lambda proxy on the following basis. The Marginal Energy Component (MEC) which is a component of the Locational Marginal Price (LMP) reflecting the cost of energy for the next MegaWatt(MW) that is necessary to clear the system demand based on the available and operating generation resources. MEC reflects the energy and operating reserves prices. MEC is calculated for each dispatch interval and it is basically the same across the MISO footprint. The provided time weighted hourly MEC is the MISO Real time Ex Post MEC.

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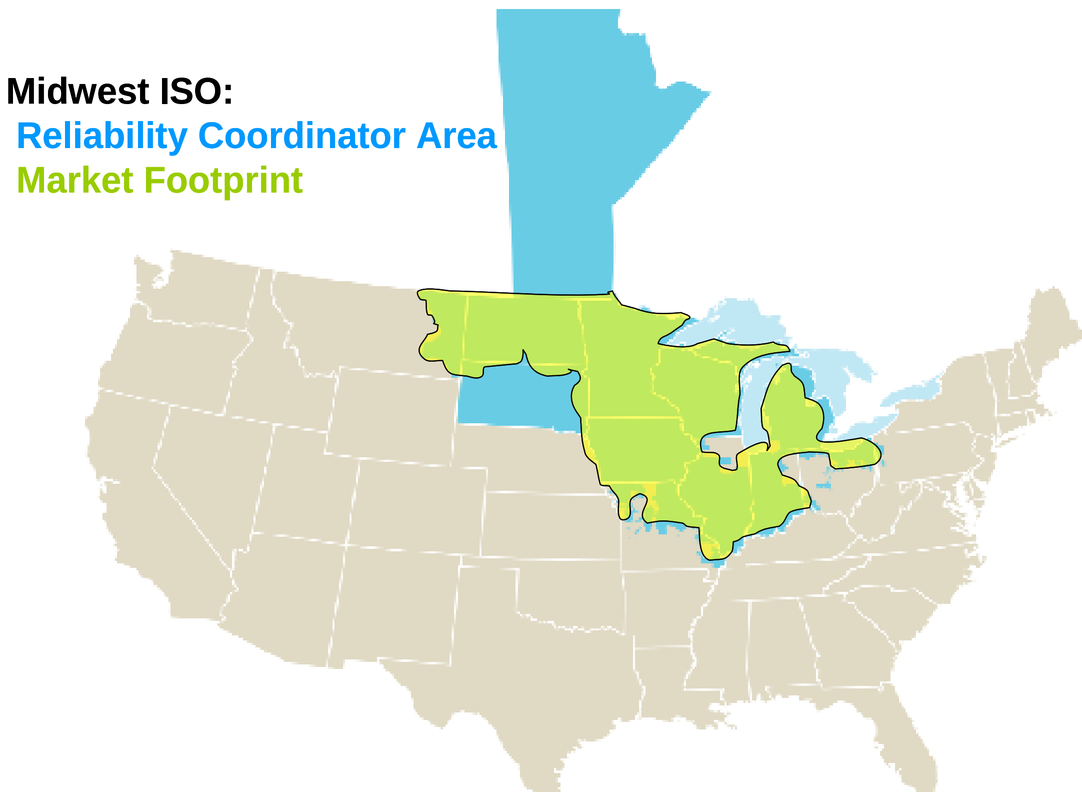
Planning Year 2011 LOLE Study Report



Midwest ISO Market Footprint
And Balance of Reliability Coordinator Area

Regulatory and Economic Studies (RES) Department

Revision History

Reason for Revision	Revised by:	Date:
Final Draft Posted	-----	1/12/11

Table of Contents

1. Executive Summary

A Planning Reserve Margin unforced capacity (PRM_{UCAP}) of 3.81% applied to Load Serving Entity (LSE) non-coincident peaks has been established for the planning year starting June 2011 and ending May 2012. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch which provided the congestion-driven zonal definitions used within MARS. The analysis resulted with one uniform Planning Reserve Margin, applicable to the Midwest ISO Market footprint as a single Planning Reserve Zone.

The goal of a Loss of Load Expectation (LOLE) study is to determine a minimum planning reserve margin that would result in the Midwest ISO system experiencing less than one loss of load event every ten years. This ten year metric, if realized uniformly over a 10 year period, would be approximately like a 10% probability for one insufficient capacity event each year. As modeled within the GE MARS software, the system would achieve this reliability level when the amount of installed capacity available is 1.174 times that of the Midwest ISO system coincident peak. The annual run for a given year at the break even 1 day in 10 criteria, achieves a 0.1 day/year solution point. The Midwest ISO Tariff states in 68.3:

68.3 The Loss of Load Expectation
The Transmission Provider will annually calculate and post the PRM such that the LOLE is equal to the one (1) day in ten (10) years, or 0.1 day per year resource adequacy criteria. The minimum PRM requirement will be determined using the LOLE analysis by stressing the Transmission System, by either adding Demand or removing Capacity, until the LOLE reaches 0.1 day per year.

Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 4.55% diversity factor. This resulted in an individual LSE reserve level of 12.06%, reduced from what would otherwise be a 17.4% reserve without accounting for diversity. Taking into account average unit availability within the Midwest ISO system a forced outage rate of 7.357% was used to arrive at an unforced capacity margin of 3.81%. An example of applying the results to LSE load is shown in Section 0.

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group (LOLEWG) was much appreciated by the Midwest ISO staff involved throughout the process.

2. PROMOD IV® Zonal Analysis

Establishing zones driven by transmission congestion for this LOLE analysis was completed using the PROMOD IV® tool to realistically model the transmission system as it is planned throughout the 2011 – 2012 planning year. This phase of the process both identified zones on the basis of congestion on the transmission system, and quantified restrictions to transfer levels in or out of the zones. This year's results concluded that the transmission system presents sufficient transfers so that congestion does not contribute to the PRM. The **red tinted boxes** on the process map in Section 2.3.6 indicate the PROMOD IV® related activities.

2.1. Usage of the word "zone"

In the context of this 2011 LOLE study report the lower case word "zone" is used extensively in reference to the congestion-driven Marginal Congestion Component (MCC) Zones derived and modeled in the study process. The Tariff has many definitions with modifiers preceding the word Zone. For example Transmission Pricing Zone. The fundamental "Zone" term 1.714 in the Tariff best reflects the essence of zone as used in this report.

1.714 Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

The GE Multi-Area Reliability Simulation (MARS) uses the term area. Therefore, narrative may transition to the 'area' term when needed to describe certain detailed steps in the LOLE analysis.

Three 'planning areas' (i.e. East, West, and Central) had been identified, before the current Resource Adequacy Requirements in Module E, as a construct for expansion planning study groups. Certain planning efforts continue to use those areas as a means to segregate sub-regional expansion planning topics. These areas should not be confused with the congestion-driven MCC Zones determined through the zonal analysis outlined in this report.

2.2. Construction of PROMOD IV® Model

Load and generating unit data was first imported from PowerBase for utilization in the PROMOD IV® zonal analysis. PowerBase is a commercially available database which is regularly updated by Midwest ISO staff to include Module E submissions such that member-reported load forecasts can be incorporated into studies. The power flow case used was the 2011 Summer Peak Pass 3 model from the 2010 MISO Collaborative Series Models. Finally, an EVENT file was created which is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. The EVENT file information was vetted through the LOLEWG to ensure that all stakeholders had a chance to offer feedback on its contents. The entire Eastern Interconnect was modeled during the PROMOD IV® analysis with non-member systems utilizing the default data from PowerBase and Florida modeled as a fixed transaction due to model limitations. The following sections outline the steps taken to construct the inputs to the PROMOD IV® software.

2.2.1. Updates to PowerBase

The PowerBase database used was originally developed for Midwest ISO Transmission Expansion Plan 2010 (MTEP 10). The demand and energy forecast information was updated using the most recent data submitted by Load Serving Entities through the Module E process.

The MTEP 10 Report can be found at the following link:
http://www.midwestiso.org/publish/Document/5648df_12c97e3f74e_-7f300a48324a?rev=1

2.2.2. Basic PROMOD IV® PowerBase Modeling Assumptions

These models were built from the Business As Usual future from MTEP10. All nuclear units that were set to retire within the study period (2011-2020) were assumed to be re-licensed and operational. Minimum capacities of coal units were changed in the following manner: Sub-critical coal to 25%, super critical coal to 40%. Supercritical units were identified from the Ventyx - Global Energy Data. Coal and nuclear units were the only type to have a must run status. The hourly profiles for wind units were obtained from the National Renewable Energy Laboratory (NREL), Department of Energy (DOE) stemming from the Eastern Wind Integration and Transmission Study (EWITS). Hydro electric units were represented in two groups, as a fixed pattern run-of-river, and as energy-limited that could respond to unit commitment.

2.2.3. Create power flow case from Model on Demand (MOD)

The power flow case used for the 2011 planning year is the 2011 Summer Peak Pass 3 of the 2010 MISO Collaborative Series Models. These collaborative models are developed using projects from the MOD database as well as the Multi-Regional Modeling Working Group 2009 models for external areas. The 2011 Summer Peak case has an effective date of July 15, 2011.

2.2.4. Event file

In PROMOD IV®, the EVENT file is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. A "base case" transmission configuration, with no outages at any lines or buses, is part of this data set.

In the events data, the user can specify single or multiple line outages and can monitor simultaneous outages in the system. Each line is matched with an outage state to analyze its impact on the system. While multiple line and outage pairs may be monitored simultaneously, the only restriction is that the user cannot define an outage state which removes every line at a generator bus. Although the program is able to monitor multiple line outages at a bus, there must be at least one line available to distribute power from a generator bus. A bus may not be isolated. There are a finite number of events that can be modeled in the EVENT file.

The original primary source of data for the EVENT file is the MISO Book of Flowgates. Over time, the Midwest ISO has updated EVENT files with the most recent information available. The EVENT file information for the 2011 Planning Year was updated using information from the LOLEWG and other Midwest ISO Studies. All information was updated and verified before PROMOD was run.

Transmission maintenance schedules were not included in the PROMOD IV® analysis of the transmission system due to the limited availability of reliable maintenance schedules and minimal impact to the results of the analysis.

2.2.5. Pool Definition

A pool is an area composed of a set of companies inside which all generators are dispatched together to meet the total pool load. Normally pools represent an energy market, like MISO or PJM. The study footprint was broken into several pools based on the structure of the energy market. In the MTEP 10 PROMOD IV® case, 9 pools were defined in the study footprint: MISO, PJM, SPP, MAPP, SERC, TVA, MHEB, NYISO, and IESO.

2.2.6. Hurdle Rates

Hurdle rates influence the capability of a pool to obtain support or sell energy to other pools. If two pools want to exchange energy, the difference of dispatch costs between the buying pool and selling pool must be greater than the hurdle rate between them.

PROMOD IV® performs the security constrained unit commitment and economic dispatch. Its solution includes two steps. The first step is unit commitment, and the second step is economic dispatch. For each step, the user can define its own hurdle rate. The hurdle rate defined for the unit commitment step is called the commitment hurdle rate, and the hurdle rate defined for the economic dispatch step is called the dispatch hurdle rate.

Normally, users will set the commitment hurdle rate to be more expensive than the dispatch hurdle rate such that the pool units will be dispatched against the pool load first in order to get the commitment order right and then allow pool interchange during the final dispatch via the dispatch hurdle rate.

There is no standard way to define the hurdle rates. Normally, hurdle rates are determined based on the filed transmission service through-and-out rates, plus a market inefficiency adder. The commitment hurdle rates are shown in Table 2-1. The dispatch hurdle rates between pools are shown in Table 2-2.

Table 2-1: Commitment Hurdle Rates

Commitment Hurdle Rate ($/MWh) Peak/Off-Peak									
To->	PJM	MISO	TVA	MAPP	SPP	SERC	IESO	MHEB	NYISO
From									
PJM	*	10/10	10/10	N/A	N/A	10/10	N/A	N/A	10/10
MISO	10/10	*	10/10	10/10	10/10	10/10	10/10	0/0	N/A
TVA	10/10	10/10	*	N/A	10/10	10/10	N/A	N/A	N/A
MAPP	N/A	10/10	N/A	*	10/10	N/A	N/A	10/10	N/A
SPP	N/A	10/10	10/10	10/10	*	10/10	N/A	N/A	N/A
SERC	10/10	10/10	10/10	N/A	10/10	*	N/A	N/A	N/A
IESO	N/A	10/10	N/A	N/A	N/A	N/A	*	10/10	10/10
MHEB	N/A	0/0	N/A	12/10	N/A	N/A	12/10	*	N/A
NYISO	10/10	N/A	N/A	N/A	N/A	N/A	10/10	N/A	*

Table 2-2: Dispatch Hurdle Rates

Dispatch Hurdle Rate ($/MWh) Peak/Off-Peak									
To->	PJM	MISO	TVA	MAPP	SPP	SERC	IESO	MHEB	NYISO
From									
PJM	*	2.5/2.5	4.8/4.8	N/A	N/A	4.8/4.8	N/A	N/A	7/7
MISO	2.5/2.5	*	7.5/5.4	7.5/5.4	7.5/5.4	7.5/5.4	7.5/5.4	0/0	N/A
TVA	6.5/4.5	8.3/8.3	*	N/A	8.3/8.3	8.4/5.7	N/A	N/A	N/A
MAPP	N/A	4.3/3.7	N/A	*	6.9/6.9	N/A	N/A	6.5/4.5	N/A
SPP	N/A	5.1/5.1	5.1/5.1	5.1/5.1	*	5.1/5.1	N/A	N/A	N/A
SERC	6.5/4.5	8.3/8.3	6.8/5.0	N/A	8.3/8.3	*	N/A	N/A	N/A
IESO	N/A	10.5/8.5	N/A	N/A	N/A	N/A	*	10.5/8.5	6.5/4.5
MHEB	N/A	0/0	N/A	11.6/7.3	N/A	N/A	11.4/7.1	*	N/A
NYISO	5/5	N/A	N/A	N/A	N/A	N/A	7/5	N/A	*

2.2.7. Losses

Load in PROMOD IV® is equivalent to the actual load plus losses as included in the 50/50 LSE forecasts. In this study, PROMOD IV® does not calculate losses, but does calculate the marginal loss component of the Locational Marginal Prices (LMPs) in an approximation method. PROMOD IV® is capable of calculating losses using a more detailed method; however this option is not used due to run time considerations.

2.2.8. Monte Carlo Outage and Auto Maintenance

For the 2011 Planning Year Study, a single draw outage library was created for use in determining zones. However, forced outages were ignored in the PROMOD IV® run that determined import and export limits of the defined zones.

PROMOD IV® generates a maintenance schedule which optimizes maintenance to minimize loss of load events. After a maintenance schedule is developed, the same schedule is maintained for all subsequent PROMOD IV® simulations.

2.3. Analysis of System

A security constrained economic dispatch (SCED) simulation was run yielding Locational Marginal Prices (LMPs) for the various load buses which were representative of the cost for energy throughout the simulated period. These LMP values contain a component representative of the cost of congestion to that bus known as Marginal Congestion Component (MCC). These MCC values can either be positive or negative to indicate if there is a shortage or surplus of generation. Trapped generation around a bus is indicated by negative MCC values and a scarcity of generation around a bus is represented by positive MCC values. The MCC metric is available in PROMOD IV® for all modeled buses. Given that there was a plethora of buses modeled within the PROMOD IV® analysis it was imperative that selection criteria be utilized to narrow down the results. This study examined the most positive and most negative MCC values present on the system during peak conditions. These positive and negative MCC values were then grouped with surrounding buses of similar values to form the zones to be utilized in the LOLE study. This bus-based information affords the ability to quantify the load and generation in each zone, as needed in the GE MARS application going forward.

2.3.1. Selection of Buses for Contour Maps

PROMOD IV® can calculate hourly LMP components for selected buses. However, it is not feasible to analyze this data for all buses in the system. This would result in over 500 million (8,760 hours x 59,900 buses) MCC values. Therefore, a smaller selection of buses from hourly output was utilized for analysis and contour map definition. The respective contour maps for 2011, 2015 and 2020 are shown on Figure 4-3, Figure 5-1 and Figure 5-4.

For a bus to be selected, it was first required that a latitude and longitude was available for plotting purposes and be in or near the study region. Then generator buses (836) and buses greater than 200kV that were not duplicate buses with the same latitude and longitude as the generator buses (495) were selected. For the 2011 Planning Year Study, 1,331 unique buses were selected.

2.3.2. Formation of Candidate Zones

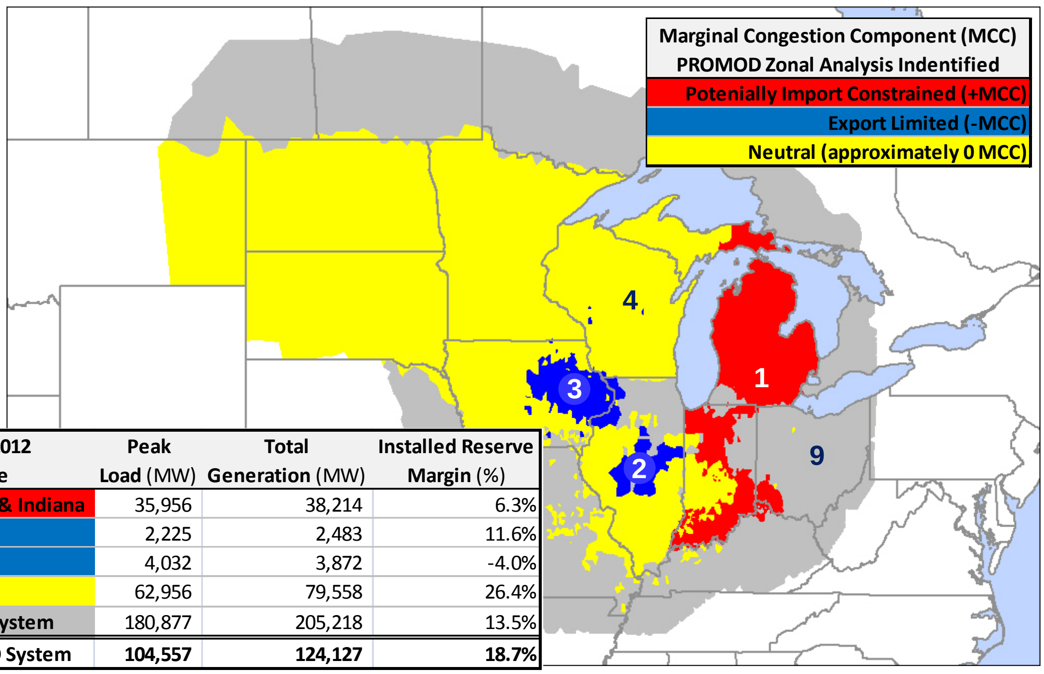
While the GE MARS model examines loss of load expectation on an hourly basis, transmission limits may only be set monthly. The fact that the GE MARS model utilizes a zonal transmission system or "ball and stick" model must also be taken into account when formulating zones. Due to these limitations a certain subset of the congestion observed during the PROMOD IV® analysis must be observed to arrive at zonal definitions which can then be used to derive monthly limits for input into the GE MARS model. The Marginal Congestion Component (MCC) value of the Locational Marginal Price (LMP) is used to identify how each bus in the transmission system is impacted by congestion on an hourly basis. The smallest time frame to reflect the congestion metrics into the GE MARS model would therefore be a particular hour, such as the peak load hour. For a single congested hour the Marginal Congestion Component for each buss would fall into one of three categories:

Be among the 30,000 most Positive MCC values (Red)
Be among the 30,000 most Negative MCC values (Blue)
Not among either of the above and defined as in the Neutral zone **(Yellow)**

Rather than model the specific congestion on the transmission system for one hour, the goal for the LOLE model is to create a more broad or diverse representation of congestion that is applicable during the most critical reliability timeframes, such as the peak hours of the peak load week. Conflicts arise as one attempts to represent long periods of time, such as a year or several months, because a unique MCC sign is not sustained for many busses. The requirement for a bus to be called Positive (RED) or Negative (BLUE) is for it to have experienced (over the hours in the shorter time period) only positive or negative MCC values with MCC values equal to zero not affecting this analysis. Busses not represented in the 30,000 most negative or 30,000 most positive sets of MCC values in the time period are not considered for zonal identification. In order to derive the most value from the PROMOD IV® simulations the time frame used for analysis must minimize the number of buses which experience both Positive and Negative MCC values. The end result is that buses are characterized as being consistently or persistently either positive or negative for the given time period. Thus, the metrics are determined using as many hours as possible. The surviving buses with their dominant MCC sign are the basis for defining the candidate zones based on congestion during the most critical reliability timeframes.

2.3.3. Zonal Filtering Criteria

At this stage of the study, candidate zones are evaluated to determine if they contained either 2000 MW of load or 2000 MW of generation. If a candidate zone did not meet the 2000 MW threshold, it was merged into the appropriate adjacent zone. A breakdown of the zones established through this process can be seen in Figure 2-1 2011 GE MARS Modeled Zones. The precursor geographically output information utilized to draw the refined Figure 2-1 is shown on Figure 4-3 in Section 4.2 Congestion Impact. Guidelines for merging smaller sized different colored areas into a larger composite area are set out in the Tariff and Business Practice documents. Zones 1, 2, 3, and 4 were found to be of sufficient size to account for the load and generation within them, and calculate their Effective Import Transmission Capability or Effective Export Transmission Capability.



2011-2012 Zone	Peak Load (MW)	Total Generation (MW)	Installed Reserve Margin (%)
1 - Michigan & Indiana	35,956	38,214	6.3%
2 - Illinois	2,225	2,483	11.6%
3 - Iowa	4,032	3,872	-4.0%
4 - Midwest	62,956	79,558	26.4%
9 - External System	180,877	205,218	13.5%
Midwest-ISO System	**104,557**	**124,127**	**18.7%**

Figure 2-1 2011 GE MARS Modeled Zones

2.3.4. Transfer Analysis

The common red or blue clusters viewed in Figure 4-3 for the year 2011, Figure 5-1 for the year 2015, and Figure 5-4 for the year 2020 are precursors to candidate zones. After same sign (same color) clusters were evaluated or merged into final zones as in Figure 2-1, PROMOD IV® was used to determine the transfer limits between zones. The prices of generation in each zone were artificially adjusted to encourage power imports into generation deficient zones (red as seen in Figure 2-1) and exports from generation rich zones (blue as seen in Figure 2-1). This was done by including penalty factors (10 for red, 0.1 for blue) that made the price of generation to be high in generation deficient zones, and the price of generation to be low in generation rich zones. The hourly zone interfaces flows were then evaluated to determine monthly limits for input into GE-MARS. The monthly limit was equal to the average of the interface flows at time of daily peak. For example, the January limit was the average of 31 flows at daily peak values.

2.3.5. Load Deliverability Analysis

After the zones are identified and the transfers are established between those zones an analysis must be performed to determine if the import limited zones (red zones in Figure 2-1 and Figure 3-1 in Section 3.1) _GE_MARS_Analysis have enough combination of resources and import capability to maintain an LOLE of 1 day in 10 years. If these zones do have enough Effective Import Transmission Capability (EITC) to maintain 1 day in 10 years then they are set at the same level of reliability as the rest of the system and can share the same Planning Reserve Margin without the need for additional short term precautions being taken. This testing of the red (i.e. positive MCC) zones is accomplished at the **purple tinted diamond** shaped activity shown on the right side of the Process Map in Section 2.2.6.

For the 2011/12 Planning Year one zone was found to be import constrained (Zone 1 in Figure 2-1) and required a load deliverability analysis to be performed. This analysis indicated that Zone 1 needed 4,868 MW of generation beyond its internal resources to meet the 1 day in 10 years criterion. The 16,977 MW level of EITC was found to be sufficient import capability to maintain 1 day in 10 years LOLE and therefore no additional precautions were recommended for Zone 1 at this time.

2.3.6. Process Map

The process map below illustrates the LOLE study data flow.
LOLE Study - Analysis Flowchart

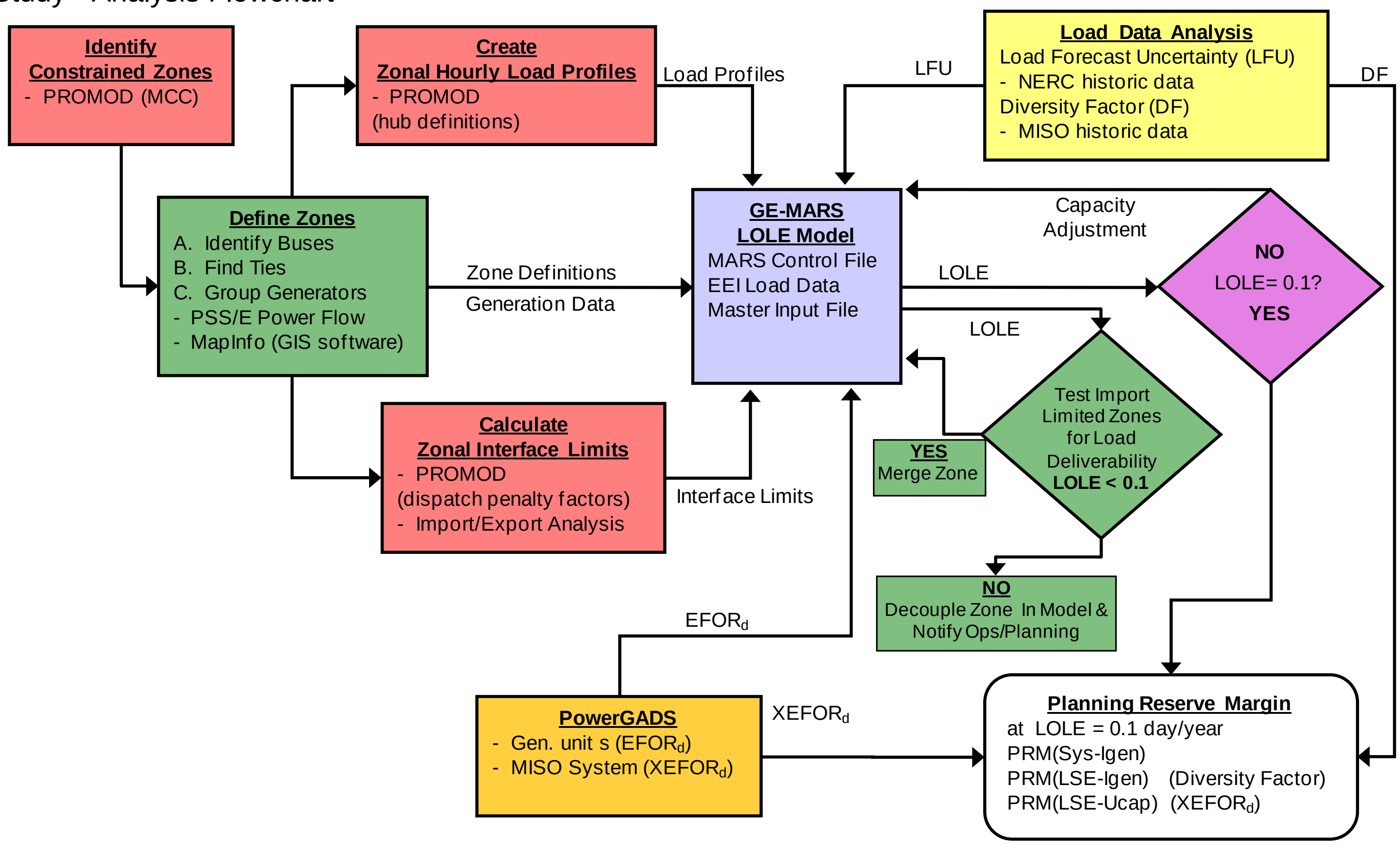


Figure 2-2: LOLE Study Analysis Flowchart

3. GE MARS Analysis

Utilizing the zones derived from the PROMOD IV® analysis, a MARS model was constructed using load, transmission and generation data from PROMOD IV® PowerBase and incorporating unit outage statistics derived from Generating Availability Data System (GADS) reporting through the Midwest ISO's PowerGADS software. The **blue shaded box** on the process map in Section 2.3.6 indicates the GE MARS activity.

3.1. Construction of GE MARS Model

The PROMOD IV® tool was used to group the buses as specified in Section 2.3 and output a single hourly load profile for each zone which included all hours within the period under scrutiny. These load profiles and zonal definitions were placed in the MARS Model where the transfer limits, also determined from the PROMOD IV® analysis, were applied. The generating units for each zone were also imported from the PROMOD IV® model; however, Forced Outage Rates (FOR) were updated with available GADS data. Each generator within a zone is assumed to be deliverable to all load within that zone. Since prices are high during peak load events and all generators are called on to serve load, all resources within the footprint were assumed to be utilized for reliability regardless of load serving obligations. The inputs garnered from the PROMOD IV® analysis are represented in Figure 3-1 as they were input to the GE MARS model.

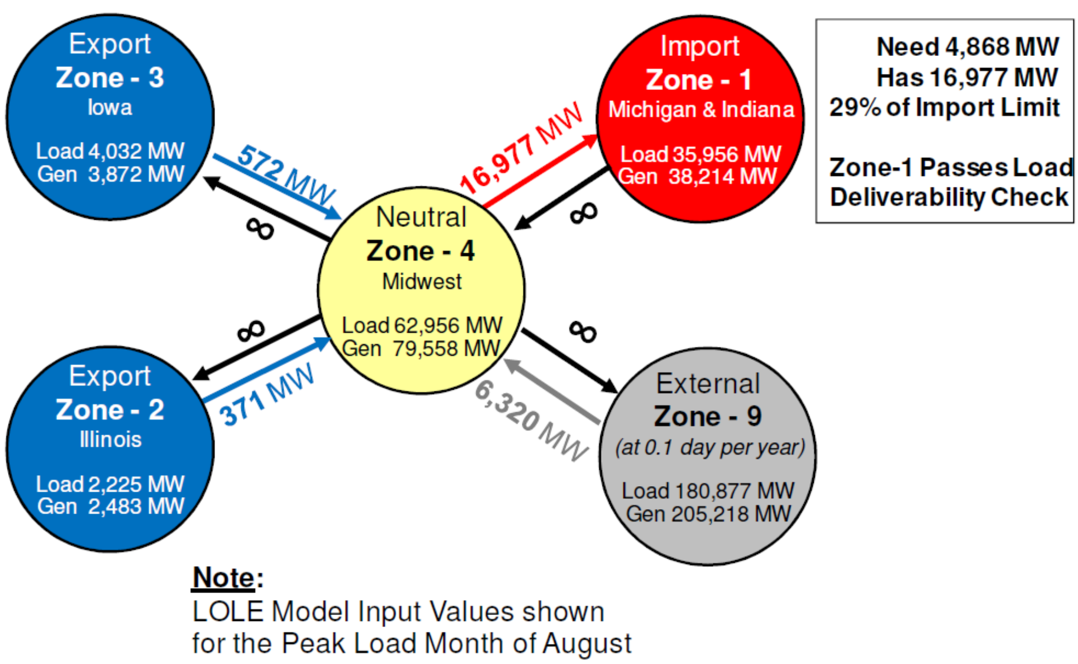


Figure 3-1: Zones and Parameters Modeled in 2011 GE MARS

Zone 1 utilized less than 30% of their total Effective Import Tie Capability (EITC) in order to maintain a 1 day in 10 year LOLE. Since the Zone met this criterion no further analysis was performed on Zone 1 which was subsequently merged into the neutral Zone 4. The merged Zones 1through 4 are illustrated in Figure 3-1 Zones 1 through 4 include all load within the Midwest ISO Reliability Coordinator footprint and the external EETC is also quantified at 6,320 MW as determined from the calculation in Table 3-1. This EETC value is down from the historically observed 11,791 MW, due to 5,471 MW of external resources committed to the Midwest ISO which are modeled in the 124,127 MW of Generation in the "Neutral Zone", in Figure 3-2. Using a Transmission Service analogy, this would be like treating the 11,791 MW as an import Total Transfer Capability (TTC), and having utilized 5,471 MW would leave an Available Flowgate Capacity (AFC) = 6,320 MW.

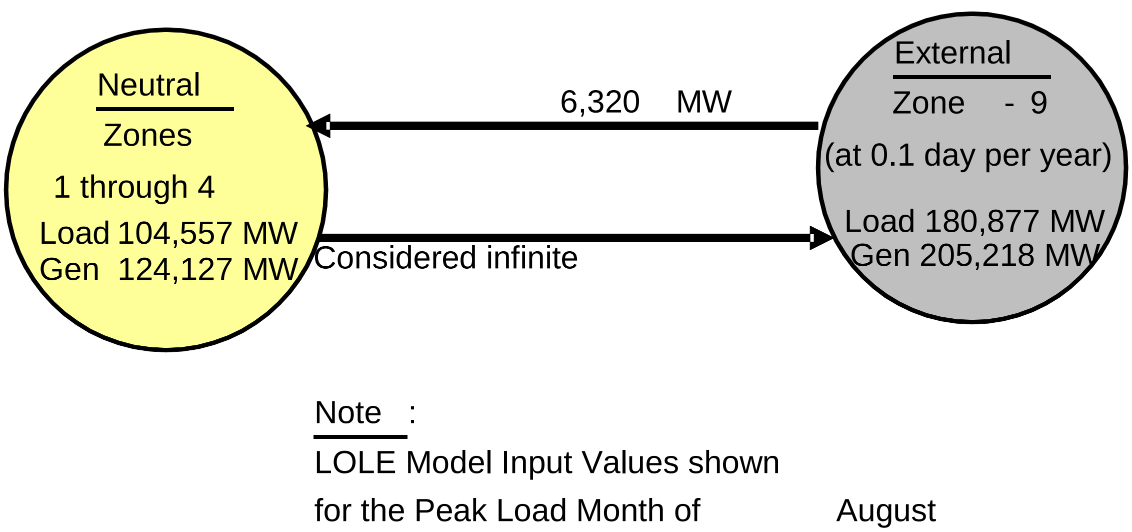


Figure 3-2: Merged Zones and Parameters Modeled in 2011 GE MARS

In the simulations the estimated 6,320 MW size of the transmission capacity is more than sufficient, and the limitations to assistance from the External Zone 9 is driven more by the probability of the resources in the External Zone 9 being able to supply assistance. The setting of the External zone's supply to the 1 day in 10 year level of performance, assumes that the external world neither exceeds nor falls short of the 1 day in 10 level of performance. For example, if higher reserves were to be actually realized, the Midwest ISO system would gain additional security over the assumption that the outside just met a 1 day in 10 level of existence.

Direct Control Load management and Interruptible Demand were accounted for by netting them from the hourly load. Therefore, no special modeling in the form of Emergency Operating Procedures was needed to further account for their impacts on the analysis.

3.1.1. Modeled External System Ties

In order to determine an appropriate level of support, the external systems were held to the same reliability level as the internal system and an external tie capacity was derived. Historical total transmission flows and contractual flows were observed to obtain an applicable external support level. The 6,320 MW value for the external Effective Import Tie Capability (EITC) is shown in Figure 3-1. This value was determined as follows:

Table 3-1: External EITC Calculations

Maximum transmission import flow from Market Externals 8/1/2007	=	11,791 MW
Less transmission capability needed to serve 2007 Summer firm deliveries into Market	=	5,471 MW
Available transmission to import into Market	=	6,320 MW

Specific contractual capacity exports were not considered during this analysis although support to external entities was allowed.

3.1.2. Migration of Resource Characteristic into Study Model

The Generating Availability Data System (GADS) provides a standardized means to collect outage information on generators. This system was used to collect data for units within the Midwest ISO for the period of January 2007 through June 2010. This historical data was then used to update the Forced Outage Rates (FOR) and seasonal maximum capacities for each specific unit within the footprint. This information was imported to the GE MARS model from the PROMOD IV® PowerBase model. If a given unit did not have outage statistics, the Forced Outage Rate was not updated and the original class average FOR from the PROMOD IV® PowerBase model was utilized. Planned outage information was also incorporated from PROMOD IV® PowerBase with the necessary maintenance time input. The MARS program allowed optimizing the scheduling of maintenance for units without specific maintenance schedules. Any retirements listed in the database were incorporated into the MARS model, but no additional retirements were assumed for the study period.

The PROMOD IV® PowerBase is updated to incorporate all units within the Midwest ISO Interconnection Queue which have a Signed Interconnection Agreement. These updates are imported to the MARS model with the unit information and all planned additions within the database are included.

Energy limitations for hydro resources and other energy limited resources are also imported from PROMOD IV® PowerBase.

Forced outage rates utilized in this study were adjusted to exclude certain outage types, deemed as outside of management control, and account for the time when a unit was in demand as outlined in Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes. These adjustments to the forced outage rates yielded an Effective Forced Outage Rate Demand (EFORd) that excluded certain outages which is known as XEFORd. While the EFORd values were utilized in the MARS simulations in order to capture all possible outages of generation, the XEFORd values were utilized in Planning Reserve Margin calculations after the simulation was run as seen in Section 3.2. A listing of the class average forced outage rates experienced within the Midwest ISO is available here:

http://www.midwestmarket.org/publish/Document/5648df_12c97e3f74e_-7fa10a48324a?rev=1

Generator Forced Outage Rate definitions:

Equivalent Forced Outage Rate Demand (EFORd): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
XEFORd: Same meaning as EFORd, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example loss of transmission outlet lines are considered as OMC relative to a units operation.

The OMC codes excluded by the Midwest ISO are itemized in Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes.

3.1.3. Load Forecast Uncertainty (LFU)

At the recommendation of the LFU Task Team, this study utilized the same NERC Bandwidths Variance Calculation as the previous LOLE Studies in order to determine a Load Forecast Uncertainty value. This method was recommended based on its historical use and its vetting through various groups. Updated NERC Bandwidths were used as they were available at the time they were necessary for inclusion in the LOLE model.

Using the NERC Bandwidths Variance Calculation, a sigma value of 4.45% was determined. This load forecast uncertainty was applied to the entire footprint. More information (including the LFU values used as input to the MARS model) on LFU can be found in Appendix A Load Forecast Uncertainty (LFU) Final Report.

3.1.4. Wind Generation

Wind generation was not modeled in the GE MARS runs for the determination of PRM, because another analysis is done to determine the equivalent UCAP capacity for wind. As UCAP capacity is “perfect” capacity with no forced outage rate, the impact of including wind would have the same effect as the capacity adjustments which are made to achieve a 1 day in 10 LOLE solution. Therefore no specific treatment of wind is needed for determining the PRM, since there is no need to assign the final adjusted block of capacity to any particular resource type. The capacity rating for the wind is discussed in Section 4.1.3 and Appendix D Wind Capacity Credit. That process handles the hourly wind generation pattern by subtracting it from the hourly load. The most recent historical hourly wind output and the historical hourly load through September 30, 2010 were simulated in GE MARS. Those results were merged with the previous years 2005 through 2009 data to determine the system wide Effective Load Carrying Capacity (ELCC) of Wind based on six years of history. The system Wide ELCC of 1,055 MW was distributed to the 129 CPnodes active as of the second quarter in 2010. The specific CPnode results are proprietary to the Market Participants associated with each CPnode (similar to proprietary treatment of GADS data for dispatchable resources). While the system wide ELCC % was 12.9%, the individual CPnode credits ranged from 0% to 31.8% of their installed capacity. Use of a CPnode's Capacity Credit as a Planning Reserve Credit (PRC) is subject to having adequate transmission service arrangements.

The method of allocating the system wide performance to individual CPnodes was accepted by the LOLEWG. The driving system wide ELCC was 12.9%, revealing a system wide capacity of 0.129 x 8,179 = 1,055 MW. The sum of the individual capacity credits calculated for each CPnode sum to same system Wide ELCC of 1,055 MW. As of the second quarter 2010, the sum of the CPnode's installed Registered Maximum capacities was 8,179 MW. The allocation is based on each CPnodes performance relative to the total performance of all CPnodes over the highest 8 daily peak hours from each year over the past 6 years (a total of 48 daily peak hours). Starting in 2010 the output of some CPnodes was adjusted upward to account for wind curtailments caused by transmission limitations. Curtailment occurred during 4 of the 8 daily peak hours in 2010. If a CPnode has less that the full complement of 48 historical days, the average performance based on the available number of days is used to calculate the CPnode's average capacity factor during peak times, relative to the total performance of all CPnodes.

3.2. Determination of Planning Reserve Margin

Once the base model with generation, load, and tie line capabilities was defined, a simulation was run to determine the Loss of Load Expectation (LOLE) value for the planning year. Capacity adjustments were then put in place to alter the available capacity in each zone to ensure that the probabilities for loss of load within the Midwest ISO system over each integrated peak hour for the planning period summed to 1 day in 10 years or 0.1 days/year. When the Midwest ISO system as a whole is at 0.1 days/year then all zones within the system will have a LOLE of 0.1 days/year or less. All external zones were modeled at the same level of reliability to ensure that they were not providing more support than would be statistically available. When capacity was appropriately adjusted in each LOLE zone to bring all systems to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the Midwest ISO yielded a reserve margin of 17.4% of the 50/50 net internal demand forecast. This value is the planning reserve margin as applied to the Midwest ISO system coincident peak. Table 5-1 expresses the base amount of generation in the model as a $PRM_{SYSIGEN}$ for each year. A reduction in generation was required in 2010, but generation additions were needed in years 2015, and 2020 to meet the 0.1 days/year LOLE target for setting the PRM. The upward adjustments were made by adding generation that had a zero forced outage rate.

Operating reserves consist of off line reserves, spinning reserves, and regulation reserves. The solved LOLE runs that determine the PRM values, such that the system ends up at the 0.1 days/year level, are arrived at on the basis of having depleted operating reserves. Alternatively, the solution could be done so that the loss of load is defined to commence at some stage of managing operating reserves that would not fully deplete these resources. For example, one could set aside the regulating amount for reserves, and reflect that requests for load shedding would start at that point in an event.

In order to account for the diversity within the system and yield a reserve margin applicable to individual LSE monthly peaks, as mandated by Module E, a diversity factor adjustment was necessary. Historical load data was available on a CPnode or Local Balancing Authority (LBA) basis. Each LSE reports their load forecasts separated into one or more CPnodes. For the purpose of this analysis the Midwest ISO calculated historical peak month diversity factors for 2005 through 2010 by comparing the Midwest ISO system peak to the sum of the CPnode Peaks for each peak month. Below is the calculation and resulting diversity factors for 2005 through 2010. For this analysis all First Energy loads were removed from the historical data in order to approximate their withdrawal from the Midwest ISO and the subsequent footprint change.

$$Diversity\ Factor = 1 - \frac{MISO\ Coincident\ Peak}{\sum^{Month} CPNode\ Peaks}$$

Table 3-2: Historical Diversity Factors

Peak Month Diversity	
Month	**w/o First Energy**
Aug-05	4.14%
Jul-06	3.07%
Aug-07	6.36%
Jul-08	6.44%
Jun-09	5.76%
Aug-10	7.13%
Mean	**5.48%**
Median	**6.06%**

The amount of diversity experienced in the Midwest ISO footprint since the start of the Energy Market in 2005 has ranged from 3.07% at its lowest in 2006 to a high of 7.13% in 2010.

A 4.55% diversity level corresponds to the lower bound of an 80% confidence interval for the mean value of Midwest ISO historical diversity with the First Energy portion of the footprint removed. This lower bound would say that there is only a 10% chance that the true mean of the historical diversity is lower than 4.55%. For more information on the diversity calculations and analysis see Appendix E Diversity Factor Task Team Report.

This value was applied to the coincident load used in the original reserve margin calculation to yield a non-coincident peak load from the system coincident peak. This increased load value was yielded a 12.06% planning reserve margin as applied to individual LSE peaks.

The final step was determination of the planning reserve margin on an unforced capacity basis. The system wide average XEFORd for generation within the Midwest ISO Market was 7.357% which was computed from the historical data for generators. The 7.357% was use in determining the Unforced Capacity Reserve Margin (PRMucap) requirement of 3.81%. The Unforced capacity for an individual unit is derived by applying a unit's XEFORd to its maximum capacity rating to arrive at a reliably provided MW value.

3.3. Example of Applying the Results

The GE MARS runs are done on the basis of the Midwest ISO Reliability Coordinator (RC) footprint, and the resulting PRM is therefore applicable to the Midwest ISO market. While the detailed formation of congestion based zones and other aspects of the LOLE study are driven by the Midwest ISO Tariff, the aspect of modeling a larger local footprint apart from the external part of the model is common practice. This means that the quantified loads and generation in Table 3-3 are greater than the Midwest ISO proper; however the PRM_{SYSGEN} percentages apply to the Midwest ISO load. The load and generation values in the various bubble diagrams throughout this report are also reflective of RC footprint quantities. From these results, the terms of UCAP capacity and diversity analysis by the Midwest ISO are unique to the market load. An analogy for modeling this way would be that prior to the Midwest ISO market, the Midwest ISO determined its PRM through a joint study with parties in the RC footprint. The group was called the Planning Reserve Sharing Group (PRSG).

Table 3-3 utilizes the load values shown in Figure 3-1 within the GE MARS model and quantifies the various values relative to the resulting PRM's, coincident and non-coincident peak load, diversity, and the XEFORd forced outage rate. The usage of IGEN, UCAP, XEFORd, etc. are exemplified in Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes

Table 3-3: For the Midwest ISO Market Planning Reserve Zones at 4.55% peak load diversity, XEFORd=7.357% and 17.40% PRMSYSIGEN

	Non-coincident Load Based		Coincident Load Based
Generator MW Basis:	UCAP	IGEN	IGEN
Total PRM $_{EFORd}$ (first column of this row is applicable to Forecast LSE Requirement)	3.81%	12.06%	17.40%
Midwest ISO Coordinator Load	109,540	109,540	104,557
Midwest ISO Coordinator Required Capacity	113,713 $_{UCAP}$	122,750 $_{IGEN}$	122,750 $_{IGEN}$

3.4. Comparison of PY 2011 to Last Year PY 2010

This section discusses the changes from the PY 2010 to the new results for PY 2011. For example, while the Midwest ISO's system Planning Reserve Margin ($PRM_{SYSIGEN}$) for the 2011/12 increased the PRM_{UCAP} decreased. The major drivers and their up versus down influence are shown in Table 3-4. In Table 3-4, the XEFORd and OMC together, are the EFORd. Therefore, only the OMC portion carries through to the PRM_{UCAP}. Detailed itemization is illustrated in Table 3-5.

Table 3-4: 2010/11 Planning Reserve Margin requirements

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM $_{UCAP}$ (%)	PRM $_{LSEIGEN}$ (%)	PRM $_{SYSIGEN}$(%)
Total PRM	3.81%	12.06%	17.40%
Driving Metrics	LFU OMC Congestion Use of Tie Load Diversity	LFU XEFORd OMC Congestion Use of Tie Load Diversity	LFU XEFORd OMC Congestion Use of Tie

2010 versus 2011 Change
Driving Metric causing an incremental PRM increase
Driving Metric causing an incremental PRM decrease

Table 3-5: LOLE model Information PY 2009 and 2010

	June2010-May2011 PY - PRM(sys-Igen)	15.4%
Senstivity	Description	Change
Congestion	Last Year: Congestion added 0.4% to the PRM This Year: The Congestion has improved and has no measurable impact on the PRM	-0.4%
Load Forecast Uncertainty (LFU)	Last Year: LFU was 4.04% This Year: LFU has increased to 4.45%	+0.8%
Forced Outage Rates	Last Year: MISO System-Wide EFORd was 7.31% This Year: MISO System-Wide EFORd is 8.02%	+0.7%
External Support	Last Year: 2,238 MW external support decreased PRM 2.0% This Year: 1,470 MW external support decreased PRM 1.4%; Net 0.6% PRM change due to less external system support	+0.6%
Membership Changes	First Energy leaving Dairyland Power Co-op and Big Rivers Electric Corp. joining	+0.2%
Modeling Improvements	Last Year, 2002 synthetic vendor hourly load shape This Year, 2005 historic hourly load shape	+0.1%
	June2011-May2012 PY - PRM(sys-Igen)	17.4%

4. Details of 2011 Results

4.1. Further Discussion of Findings

4.1.1. Monthly Distribution of Loss of Load Expectation

The accumulation of LOLE throughout the 2011 planning year reveals that 83% of the accrued annual LOLE is realized in the month of August, with 14% of the remaining 17% balance occurring in July. Figure 4-1 illustrates the distributions for PY 2009, PY 2010, and PY 2011.

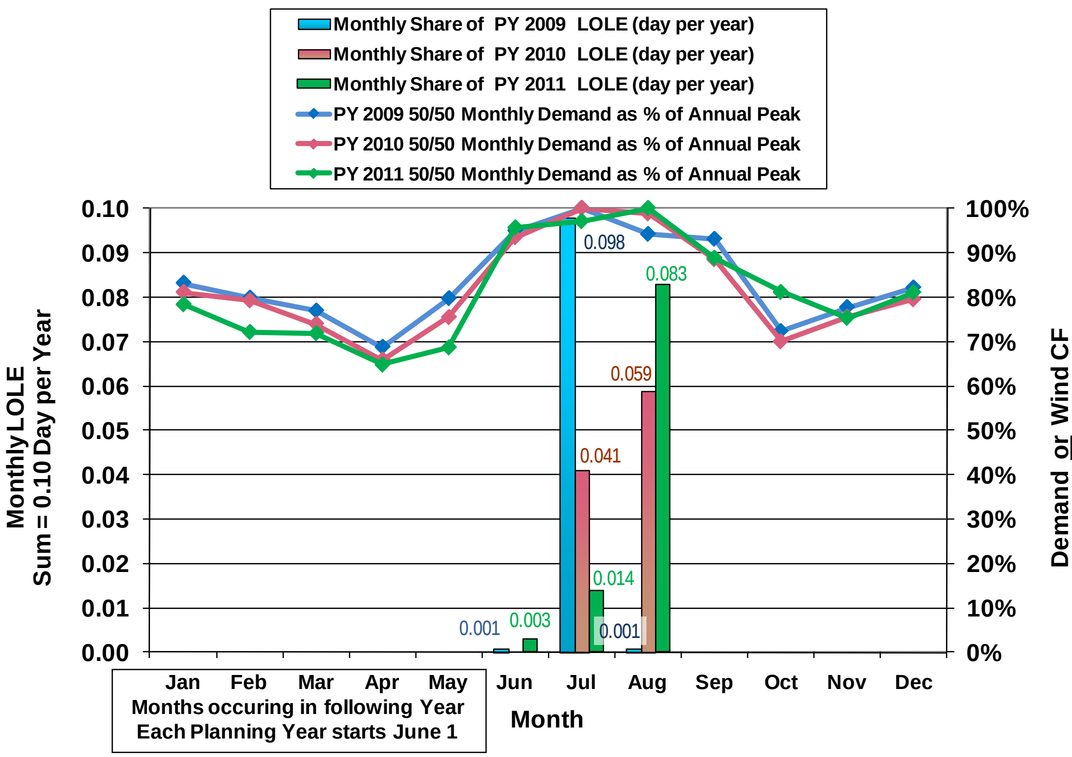


Figure 4-1 Monthly Distribution of Annual LOLE

4.1.2. Unforced Capacity (UCAP) Metric Review

Table 3-3 in Section 3.3 laid out the applicable Resource Adequacy Requirements (RAR) for the 2011 Planning Year; 17.40% $PRM_{SYSIGEN}$, 12.06% $PRM_{LSEIGEN}$, and 3.81% $PRM_{UCAP.}$ The relationship and calculation among these values for a solved LOLE case, and how they relate to the system wide average XEFORd is explained by example in Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes.

The metric of Unforced Capacity (UCAP) was utilized in this year's study in order to more equitably distribute the reserve requirement amongst a fleet of generation with varying outage rates. Through the use of Unforced Capacity all entities will utilize equivalent capacity to serve reserve margins.

4.1.3. Determination of Wind Capacity Credit for Module E

The calculation method uses a technique to determine the Equivalent Load Carrying Capacity (ELCC) of the wind generation to calculate a more precise value for wind capacity versus the comparison in Figure 4-2, or a historical median or average metric. This is required because the ELCC for Wind is dependent on the penetration level. The ELCC method is linked to using a LOLE application such as GE MARS used by the Midwest ISO. The ELCC metric is also commonly utilized by the National Renewable Energy Laboratory (NREL) when studying wind resources.

The process involves running an LOLE simulation with a historical hourly wind output pattern that is synchronized in time with the historical hourly load pattern. In a second run of the LOLE case, the wind is replaced with a fixed MW capacity adjustment, and the size of that adjust is varied until the annual LOLE result equals the LOLE level in the original wind pattern case. The resulting capacity adjustment MW divided by the Registered Max wind capacity represented in the original case is the Effective Load Carrying Capacity for the year simulated. The results for 5 years are illustrated in Figure 4-2. Tracking along a trend line of all 6 years' results, the value for the 2010 summer to date 8,179 GW Registered Max wind has an ELCC of about 12.9%, and as the capacity penetration would increases to 30 GW the ELCC decreases to about 9.2%. One would expect that the load would be somewhat higher by the time the 30 GW penetration would occur, and it is also possible that the characteristic of the base ELCC could change if the emerging future wind fleet evolved to having greater geographically diversity. Compared to some other systems, the current geographic diversity of the wind in the Midwest ISO Market is already fairly diverse.

Figure 4-2 suggests that the ELCC for wind is likely to decrease because the amount of wind capacity is a driving factor. For example the 30 GW level represents wind capacity that is on the order of one third of the system peak load. For example, if an annual median output level of about 9.2% were to occur, the effect upon LOLE analysis is as if there were a single 2,760 MW unit on the system (0.092 x 30,000 = 2,760 MW). Regardless of the driving resource (i.e. wind, coal, etc.), that size unit has greater impact than the current largest units or contingency events now in the 1,000 to 1,500 MW range. Additional discussion is provided in Appendix D Wind Capacity Credit.

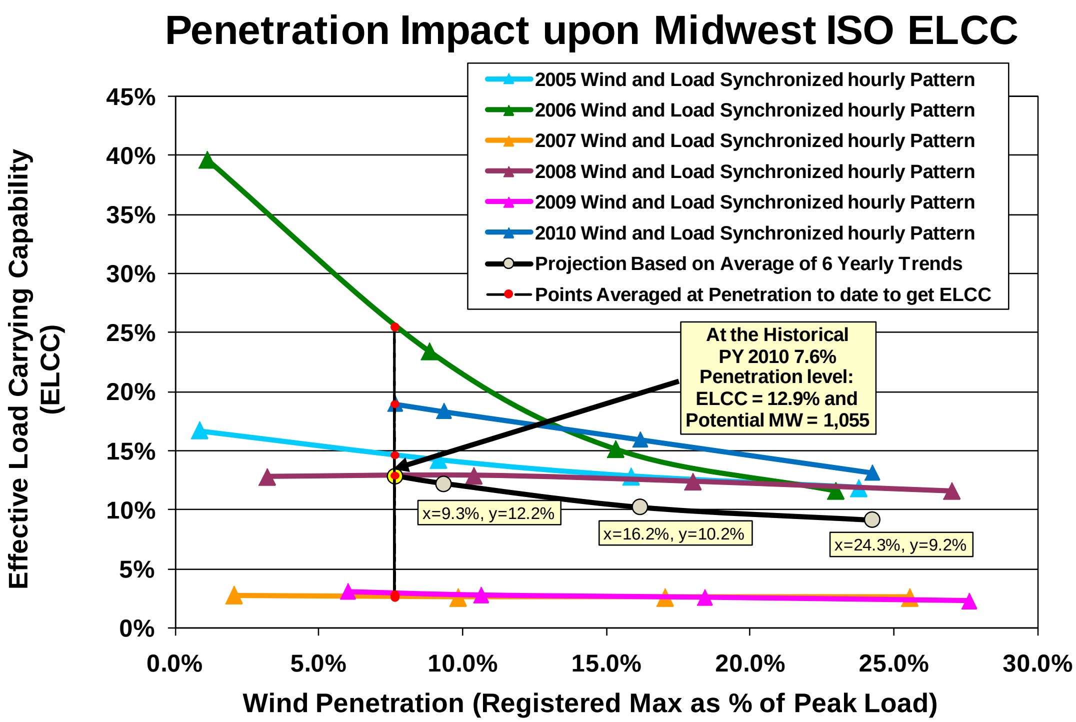


Figure 4-2: ELCC for Wind Versus Wind Capacity Penetration

4.2. Congestion Impact

Congestion incorporates the notion of aggregate deliverability impact between zones in GE-MARS, and a quantifiable MW capacity impact upon LOLE achieved by modeling the zones on a congestion-driven basis. Zones are developed from the process that utilizes two stages of PROMOD IV®. The steps are outlined in the Module E Tariff and the Resource Adequacy Business Practice Manual. This process also applies to the GE-MARS zones developed for Planning Years 2015 and 2020 in Section 5. One stage identifies the zones impacted by congestion and keys off the sign of the (MCC - $/MWh). A second stage of PROMOD IV® determines the amount of transmission support (EITC and/or EETC – MWs) that is available into or out of the zone. Figure 2-1 2011 GE MARS Modeled Zones is a geographical depiction of the resulting zones, that emerged from the raw output illustrated in Figure 4-3. Figure 4-3 is a view of the more direct information resulting from the first stage 2010 PROMOD IV® run. The blue zones indicate zones where generation resources tend to have their schedules reduced as a result of managing congestion, and the red zones are zones where generation schedules are increased in order to maintain reliable operations to serve load. The yellow areas are indifferent to congestion at time of summer peak conditions. Figure 2-1 shows the quantitative metrics (load, generation, and tie values) that were developed from the PROMOD IV® zonal analysis, and is an illustration of the input to the GE MARS LOLE program.

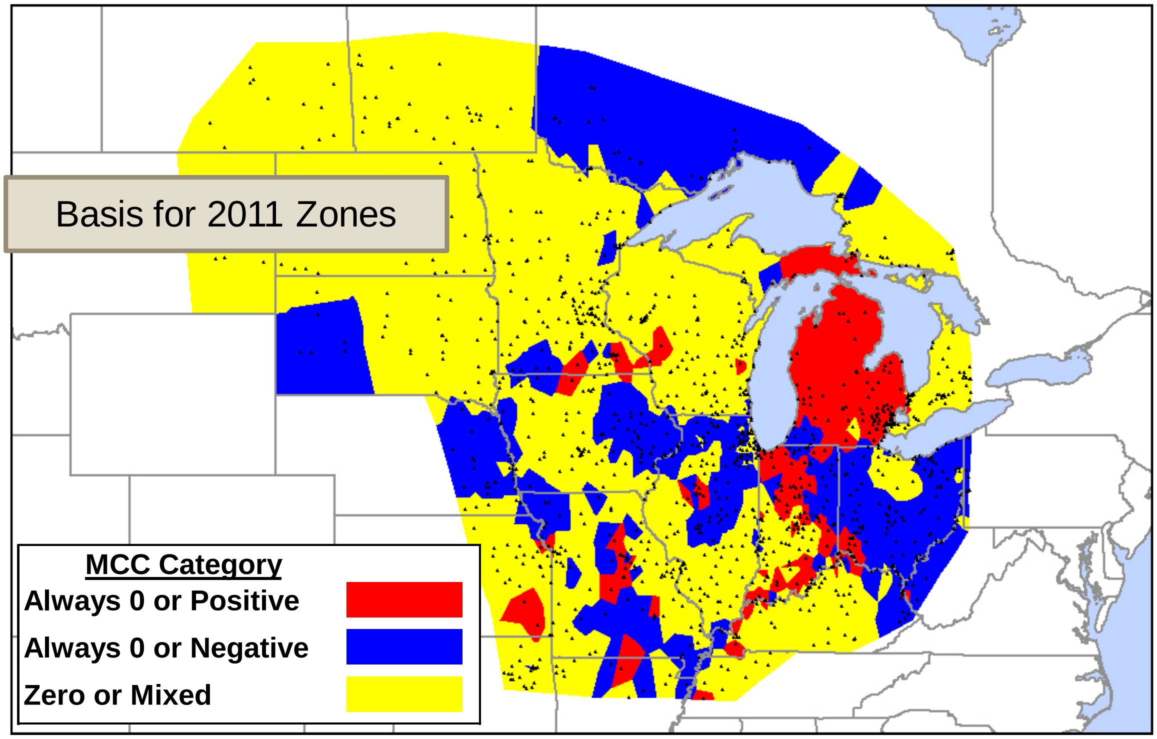


Figure 4-3: Illustration of clusters from first stage PROMOD IV® analysis results For Planning Year 2011

5. Years 2012 through 2020

5.1. GE MARS EFORd cases for 2015 and 2020

The GE MARS LOLE program was utilized again to determine planning reserve margins (PRM) for 2015 and 2020. The program utilization for these future years analysis was very similar to the assessment done previously for the 2011 planning year, but including the appropriate modeling changes in load forecast, unit additions or retirements and transmission modifications. The Load Forecast Uncertainty (LFU) was held constant for the analysis of the future years and the same value for the initial planning period was utilized. This ensures that year one and future planning years are comparable and acknowledge that when a future year is studied later as planning year one the uncertainty will decrease. In both the 2011 and 2020 cases, Equivalent Forced Outage Rate Demand (EFORd) from GADS data over the historical period 2005 through 2009 was utilized as the modeled unit forced outage rate.

Using the same process as was done for the year 2011; new internal zones were developed for years 2015 and 2020 with the specific tie limits for each year. These inputs were modeled and the planning reserve margin was calculated for a 2015 case and a 2020 case.

5.1.1. Utilize 2015 and 2020 External Equivalent zones

The same 2011 external equivalent zones configuration was utilized for the 2015 and 2020 analysis. External load growth and known unit additions and retirements where applied to the external system. The historically observed external Effective Import Tie Capacity (EITC) value of 6,320 MW was left unchanged from the 2011 model. As was done with the 2011 model, the 2015 and 2020 external systems were held to the same 0.1 day per year reliability level as the internal system, by adjusting the external load level as needed to sustain the external LOLE at 0.1.

5.1.2. 2015 Zone Analysis

Internal zones for 2015 were determined using the same process as was used to determine zones for 2011. The model and data used for this analysis was obtained by using the 2010 Midwest ISO MTEP Study - Planning Advisory Committee (PAC) Business as Usual case as a starting point. The base power flow model used was the MTEP 10 2015 Summer Peak model, which includes Appendix A and B planned and proposed projects without any Appendix B provisional projects. During the course of expansion planning hypothetical Regional Resource Forecast units are added and Transmission Overlays are developed to support these units. Regional Resource Forecast units and associated Transmission Overlays were excluded from the model utilized for the Zonal Analysis process. The first stage output of sign based MCC clusters form the PROMOD analysis is shown in Figure 5-1. Figure 5-2 shows the final GE-MARS modeled zones. All candidate zones that were found to meet the 2,000 MW size thresholds were retained as modeled zones. Transfer limits were found for the 2 export zones and 1 import zone and the results input into the GE-MARS model. The quantitative values for each zones load, generation, and tie ratings for the 2015 GE-MARS model can be found in Figure 5-3.

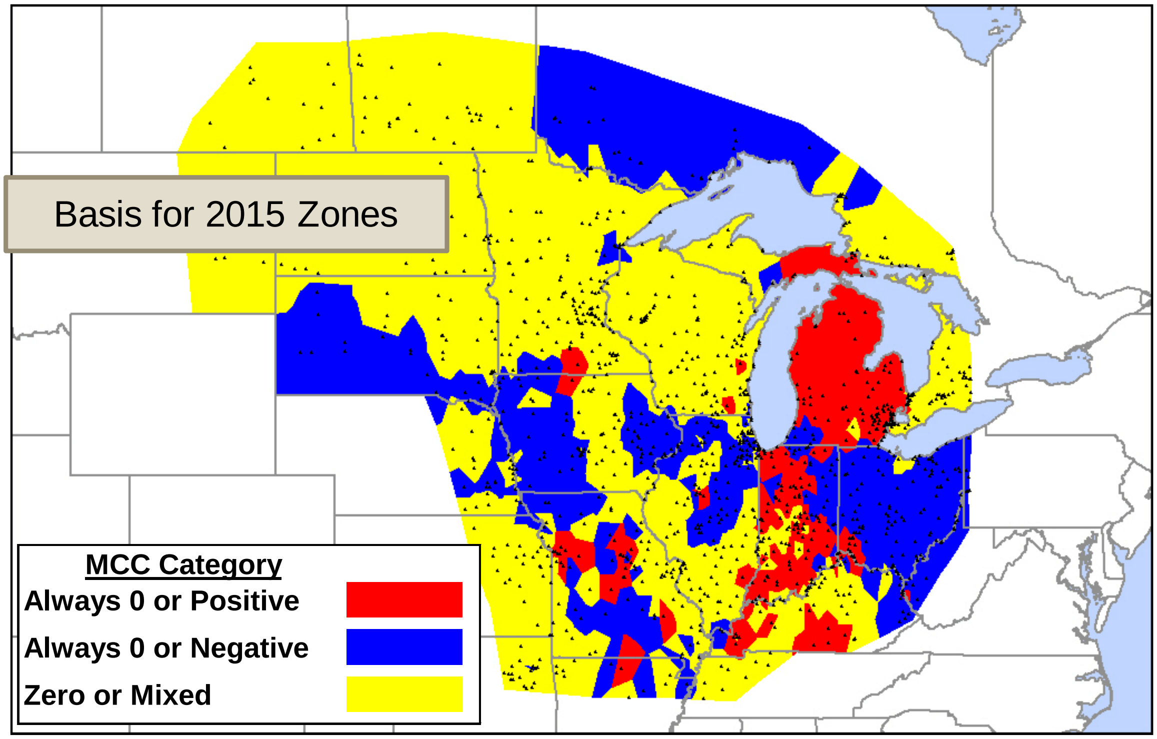
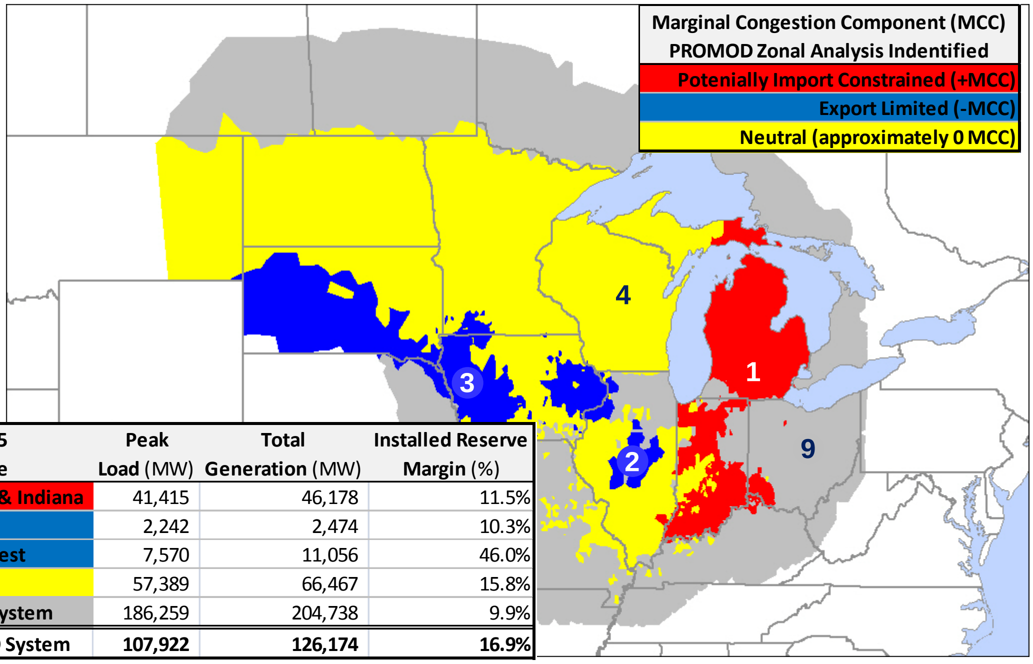


Figure 5-1 Illustration of clusters from first stage PROMOD IV® analysis results for Planning Year 2015 July 27th – Aug. 14th On Peak Hours Monday – Friday



2015 Zone	Peak Load (MW)	Total Generation (MW)	Installed Reserve Margin (%)
1 - Michigan & Indiana	41,415	46,178	11.5%
2 - Illinois	2,242	2,474	10.3%
3 - Iowa & West	7,570	11,056	46.0%
4 - Midwest	57,389	66,467	15.8%
9 - External System	186,259	204,738	9.9%
Midwest-ISO System	**107,922**	**126,174**	**16.9%**

Figure 5-2 Congestion Based Zones Modeled in 2015 After size check of results shown in

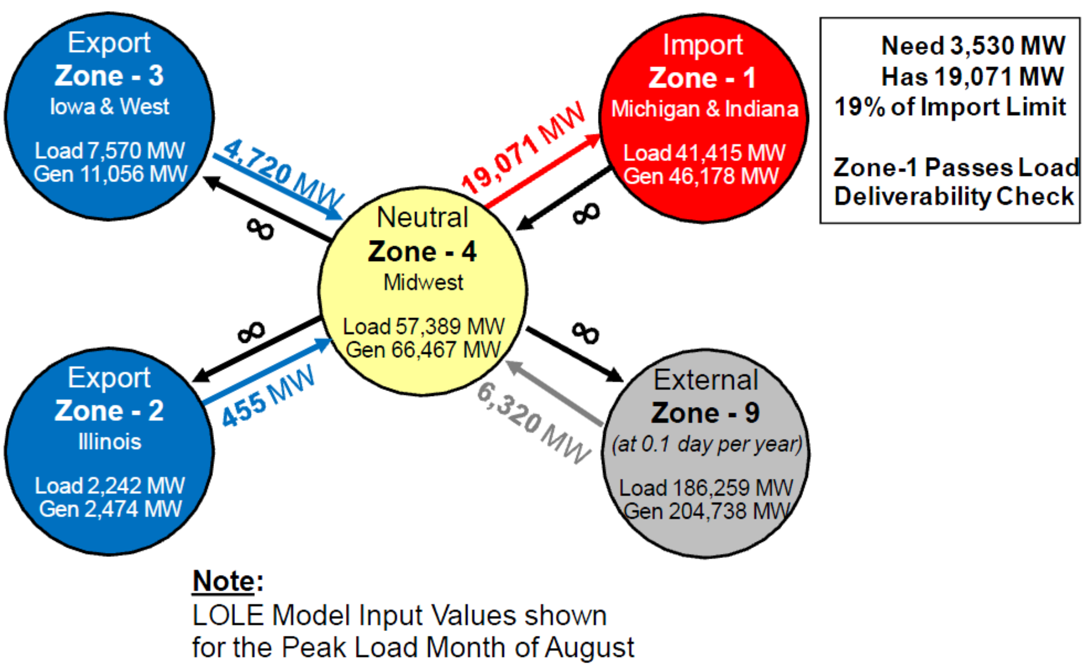


Figure 5-3: Zones and Parameters Modeled in 2015 GE MARS

5.1.3. 2020 Zone Analysis

Internal zones for 2020 were determined using the same process as was used to determine zones for 2011. The model and data used for this analysis was obtained by using the 2010 Midwest ISO MTEP Study - Planning Advisory Committee (PAC) Business as Usual case as a starting point. The base power flow model used was the MTEP 10 2015 Summer Peak model, which includes Appendix A and B planned and proposed projects without any Appendix B provisional projects. During the course of expansion planning hypothetical Regional Resource Forecast units are added and Transmission Overlays are developed to support these units. Regional Resource Forecast units and associated Transmission Overlays were excluded from the model utilized for the Zonal Analysis process. The first stage output of sign based MCC clusters form the PROMOD analysis is shown in Figure 5-4. Figure 5-5 shows the final GE-MARS modeled zones. All candidate zones that were found to meet the 2,000 MW size thresholds were retained as modeled zones. Transfer limits were found for 1 export zone and 1 import zone and the results input into the GE-MARS model. The quantitative values for each zones load, generation, and tie ratings for the 2020 GE-MARS model can be found in Figure 5-6.

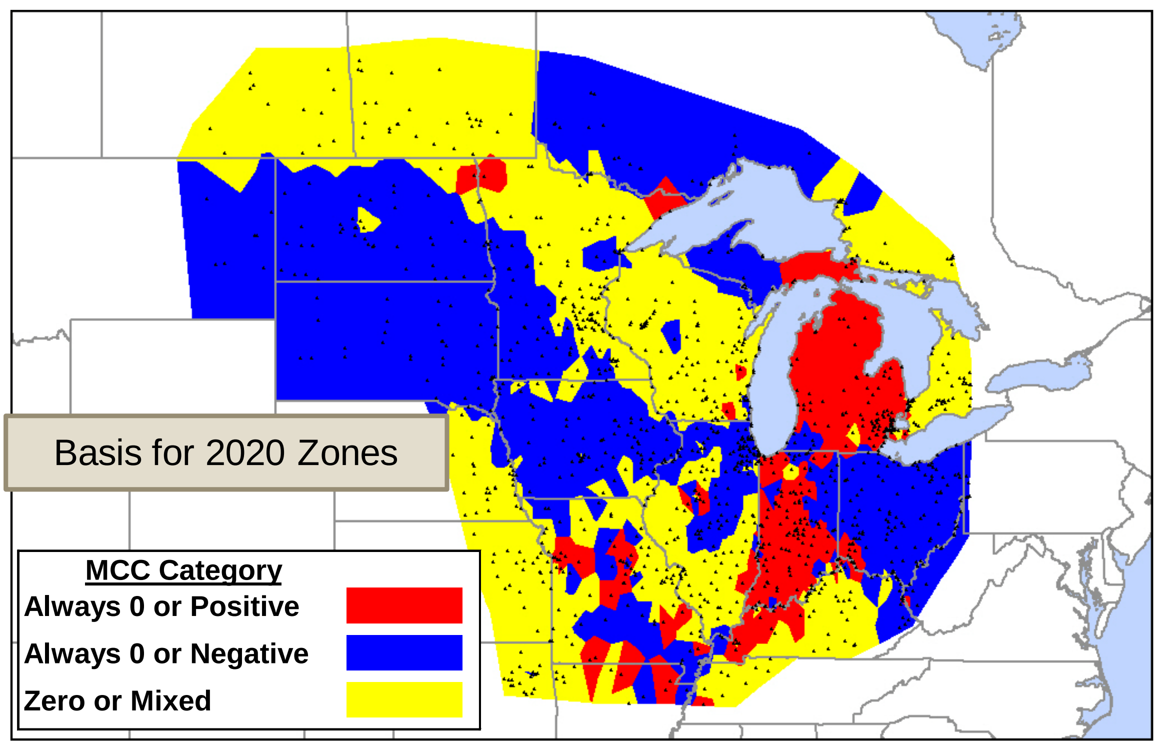
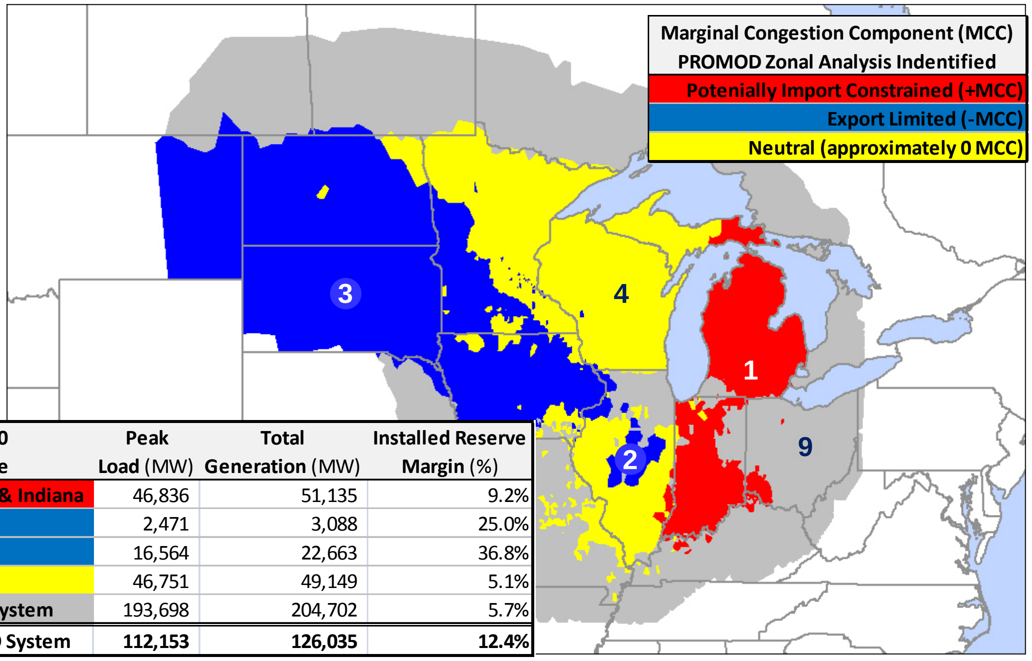


Figure 5-4: Illustration of clusters from first stage PROMOD IV® analysis results for Planning Year 2020



2020 Zone	Peak Load (MW)	Total Generation (MW)	Installed Reserve Margin (%)
1 - Michigan & Indiana	46,836	51,135	9.2%
2 - Illinois	2,471	3,088	25.0%
3 - West	16,564	22,663	36.8%
4 - Midwest	46,751	49,149	5.1%
9 - External System	193,698	204,702	5.7%
Midwest-ISO System	**112,153**	**126,035**	**12.4%**

Figure 5-5: Congestion Based Zones Modeled in 2020

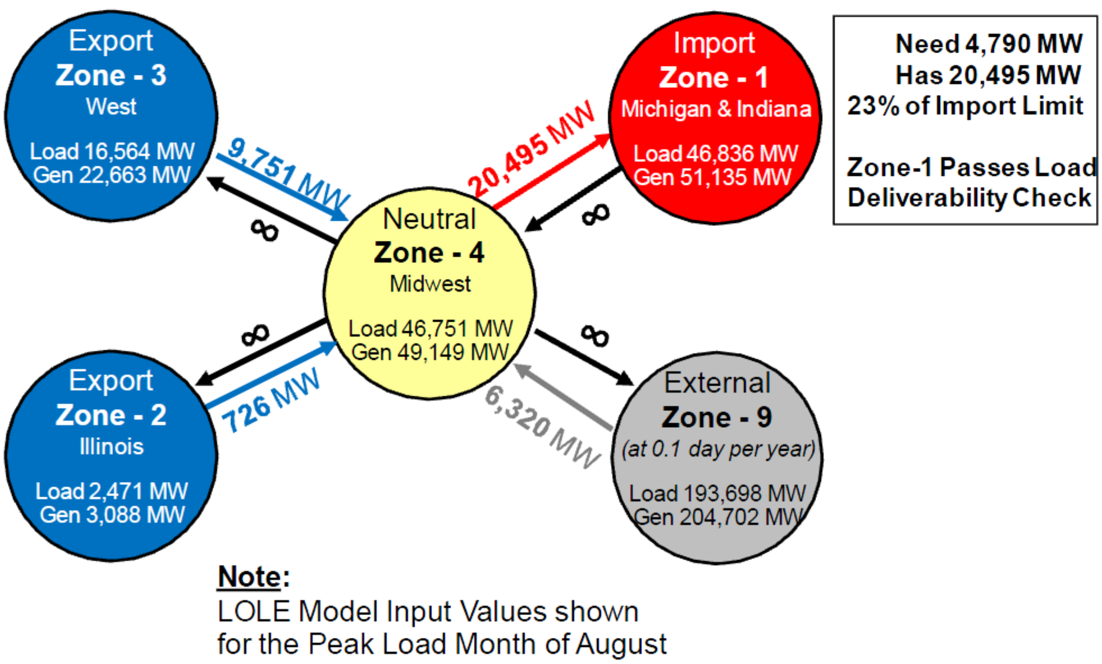


Figure 5-6: Zones and Parameters Modeled in 2020 GE MARS

5.2. Expected PRM for 2012-2020

For the two intervals of time for years 2012 through 2014, and 2016 through 2019, the planning reserve margins with no congestion, and congestion adder (top two rows in Table 5-1); were calculated by interpolating the results on a straight-line basis between the detailed cases **(red font)** that were analyzed for years 2011, 2015 and 2020. In all years the third row was determined as the sum of rows 1 and 2. The expected $PRM_{SYSIGEN}$ from these interpolations can be seen for all years in Table 5-1, where everything that was explicitly calculated is in red font, versus the interpolated values.

Table 5-1: Expected $PRM_{SYSIGEN}$ for 2011-2020

	Year									
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
$PRM_{SYSIGEN}$ (Results Ignoring Congestion)	17.4%	17.4%	17.3%	17.3%	17.2%	17.1%	17.0%	16.9%	16.8%	16.7%
$PRM_{SYSIGEN}$ (Congestion Contribution)	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.6%	0.9%	1.2%	1.5%
$PRM_{SYSIGEN}$ (Accounting for Congestion)	17.4%	17.4%	17.3%	17.3%	17.2%	17.4%	17.6%	17.8%	18.0%	18.2%
Amount of Reserve Possible from the Specific Resources represented in the GE MARS Models	18.7% ^				16.9% ^					12.4% ^
	per Figure 2-1				per Figure 5-2					per Figure 5-5

The $PRM_{SYSIGEN}$ increased over the 15.4% calculated for PY 2009 and PY 2010. The increase is attributable to the higher average EFORd rates realized among the generator fleet in addition to the other modifications detailed in Table 3-5. While the smaller congestion impact has decreased compared to the last two years and is at zero starting in 2011 and going through 2015; it is not enough to overcome the impact for the higher EFORd's. This is consistent with future transmission expansion plans. To the extent that transmission expansion plans may emerge differently in subsequent years, the effect from the current 2020 case only drives the interpolated values between 2015 and 2020 study years. The decrease apart from congestion increasing in the out years, can be explained by assuming that the new units coming online would have better than class average forced outage rates. That assumption may or may not be realized.

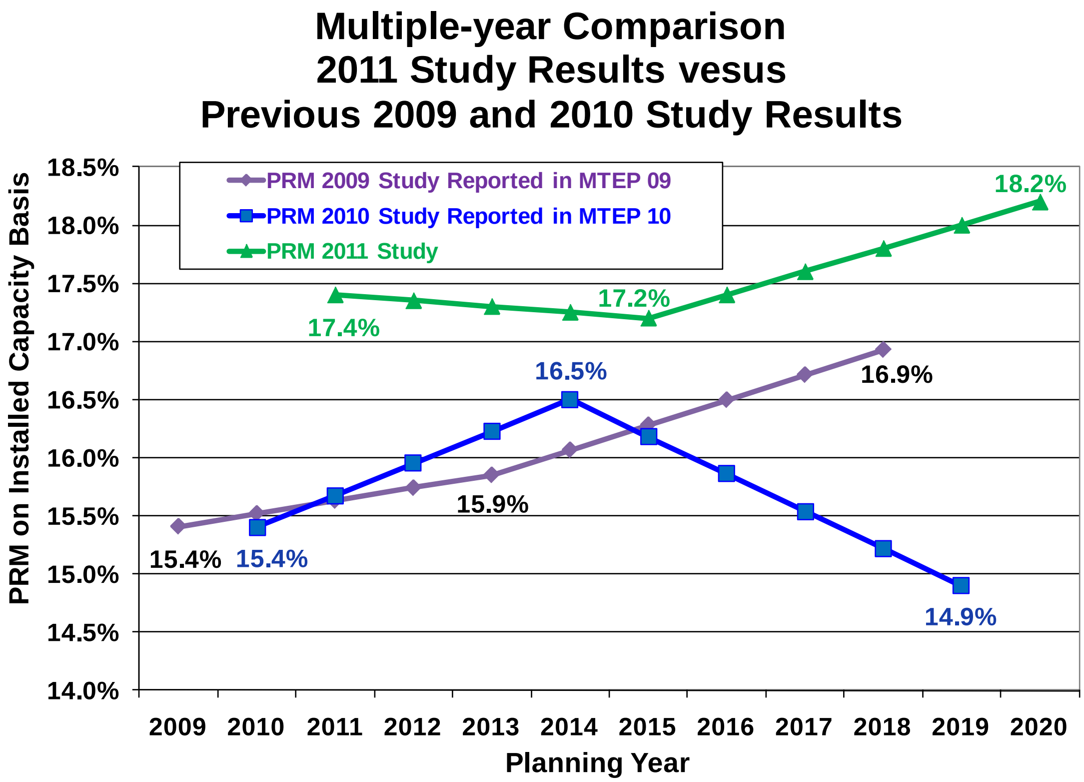


Figure 5-7: Multiple-year PRM Comparison

Table 5-2: Load and Capability for 2010-2019 (PRMSYSIGEN)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2010 Long Term RA, Reserve Margin (MW)	26,615	23,878	20,441	19,891	20,631	20,494	19,840	19,223	18,431	17,697	n/a
2010 Long Term RA, Reserve Margin (%)	25.40%	25.20%	21.90%	21.20%	21.90%	21.70%	20.90%	20.10%	19.10%	**18.20%**	n/a
Study for PY 2009, Reserve Requirement Forecast	15.59%	15.67%	15.76%	15.85%	16.13%	16.32%	16.51%	16.79%	16.98%	n/a	n/a
Study for PY 2010, Reserve Requirement Forecast	15.40%	15.68%	15.95%	16.23%	16.50%	16.18%	15.86%	15.54%	15.22%	14.90%	n/a
Study for PY 2011, Reserve Requirement Forecast	n/a	17.40%	17.35%	17.30%	17.25%	17.20%	17.40%	17.60%	17.80%	**18.00%**	18.20%

The top two rows of reserve margins shown in Table 5-2 are from Table 4.2 in the 2010 Long Term Reliability Assessment (LTRA) and are based on nameplate capacity and queue additions. The 2010 Long Term Reliability Assessment account for the associated wind capacity at 8% of its nameplate. The conclusion is that the estimate of resources in future years are sufficient to cover the range of forecasted $PRM_{SYSIGEN}$ as predicted by each of the last three LOLE studies. The most pessimistic indication of meeting Planning Reserves, indicates 0.2% headroom. The small headroom occurs with the combination of the year 2019 resources and the most recent PRM study.

The 2010 LTRA Report can be found at the following link under the Seasonal Assessments heading.

http://www.midwestiso.org/page/Regulatory+and+Economic+Studies

Appendix A Load Forecast Uncertainty (LFU) Final Report

Scope

After the initial determination of a methodology for the establishment of the Load Forecast Uncertainty (LFU) value for inclusion in the Midwest ISO Planning Reserve Margin Study the LFU Task Team will continue to meet on an annual basis to confirm the use of the established methodology.

Executive Summary

The Load Forecast Uncertainty Task Team (LFUTT) recommends the continued use of the Summation of the NERC Variances method to calculate the load forecast uncertainty value necessary for GE MARS. This method produces a sigma value of 4.45%. The Summation of the NERC Variances method has a solid methodology and the NERC Load Forecasting Working Group (LFWG) has consistent input from Midwest ISO membership. The LFUTT also recommends the use of a constant 4.45% summer LFU throughout the Loss or Load Expectation analysis for years two through ten.

Overview

The Load Forecast Uncertainty (LFU) Task Team updated the previous analysis of historical Load Forecasts submitted by Load Serving Entities and reviewed and recalculated the NERC Bandwidths methodology which will arrived at the Load Forecast Variance to be used for the LOLE study.

Updated Historical Forecast Analysis

Analysis of the Midwest ISO historical Load Forecasts as compared to historical real time loads allows for a sanity check of the Load Forecast Uncertainty (LFU) value determined through the NERC Bandwidths methodology.

Five years of real-time load data were compared to forecasts for those same periods. Load forecasts for the months of June, July and August were adjusted for the reported demand side management programs to arrive at coincident Net Internal Demand forecast values for the summer period. Those monthly forecasts were compared to the actual monthly peak loads of the same period and the differences compiled into a sample space from which to derive a standard deviation.

When all summer periods from 2005 till 2009 are considered a standard deviation of **8.0%** is derived. This is primarily driven by the 2009 data which indicated a large over forecast in July and August of roughly 20% and 10 % respectively with a significant under forecast of greater than 10% in June. This can be attributed to the very mild summer weather experienced throughout July and August causing real time loads to fall short of projections. Since these data points appear to deviate so sharply from previous analysis they can be excluded as outliers to arrive at an appropriate comparative analysis for the NERC Bandwidths methodology. Excluding 2009 a load forecast uncertainty of approximately **5.3%** for the summer was calculated.

In order to examine historical forecasts in another light, only the peak monthly forecasts for each summer period, adjusted by the reported demand response for that month, were compared to the peak historical load for that same summer period. In this manner the peak forecasts for a summer period were compared to the peak load and thus mitigating some of the effect on the assumption of when the actual peak day would occur. Since forecasts are summed on a Midwest ISO basis differing assumptions by individual LSEs on peak day will always affect total load forecasts. This new analysis produced a **4.4%** load forecast uncertainty.

Utilizing all available data resulted in a significant rise in the LFU value from previous analysis. The **8.0%** variance observed when analyzing all available summer data represents almost a **100%** shift in LFU from previous analysis which resulted in a **4.1%** LFU. This highlights the extremely sensitive nature of the historical load analysis to outlying data points due to the limited amount of available data. Until there is a significant amount of historical data available utilization of only the Midwest ISO historical data to calculate LFU values will not yield a stable result. Comparing only peak forecasts to peak loads resulted in a LFU value very close to that derived from the NERC Bandwidths methodology. This method shows promise in future analysis, but until a significant amount of historical data is available it serves as a good reasonableness test for the Bandwidths analysis. A graph of the monthly peaks is available in the appendix (Graph 1.1).

Diversity Variance within Historical Forecast Analysis

Looking at the historical forecast analysis, certain assumptions regarding diversity during the historical months had to be made. While looking at the historical months if a fixed diversity value of roughly 4% is utilized across all months the historical LFU averages roughly 0.5% higher than if actual historical diversity values are utilized. This holds true for various load adjustment assumptions and for all months or solely summer months analysis, however, this 0.5% difference in historical LFU diminishes to insignificant levels when solely comparing peak forecasts to actual peak loads.

Summation of the NERC Variances

NERC develops its uncertainty bands for each of the NERC regions through the Load Forecasting Working Group. These uncertainty bands are used with a load weighted variance calculation to determine the Midwest ISO wide sigma value and thus a LFU value. Three NERC regions have portions of themselves in the Midwest ISO: MRO US, SERC and RFC. To calculate the weights each Midwest ISO load balancing authority is assigned to its appropriate NERC regions and then the percent of the 2011 forecasted Midwest ISO load within the region is used to weight the various bandwidths. The NERC bands are stated in 90/10 and 10/90 projections and can be converted to a sigma value by dividing by 1.28.

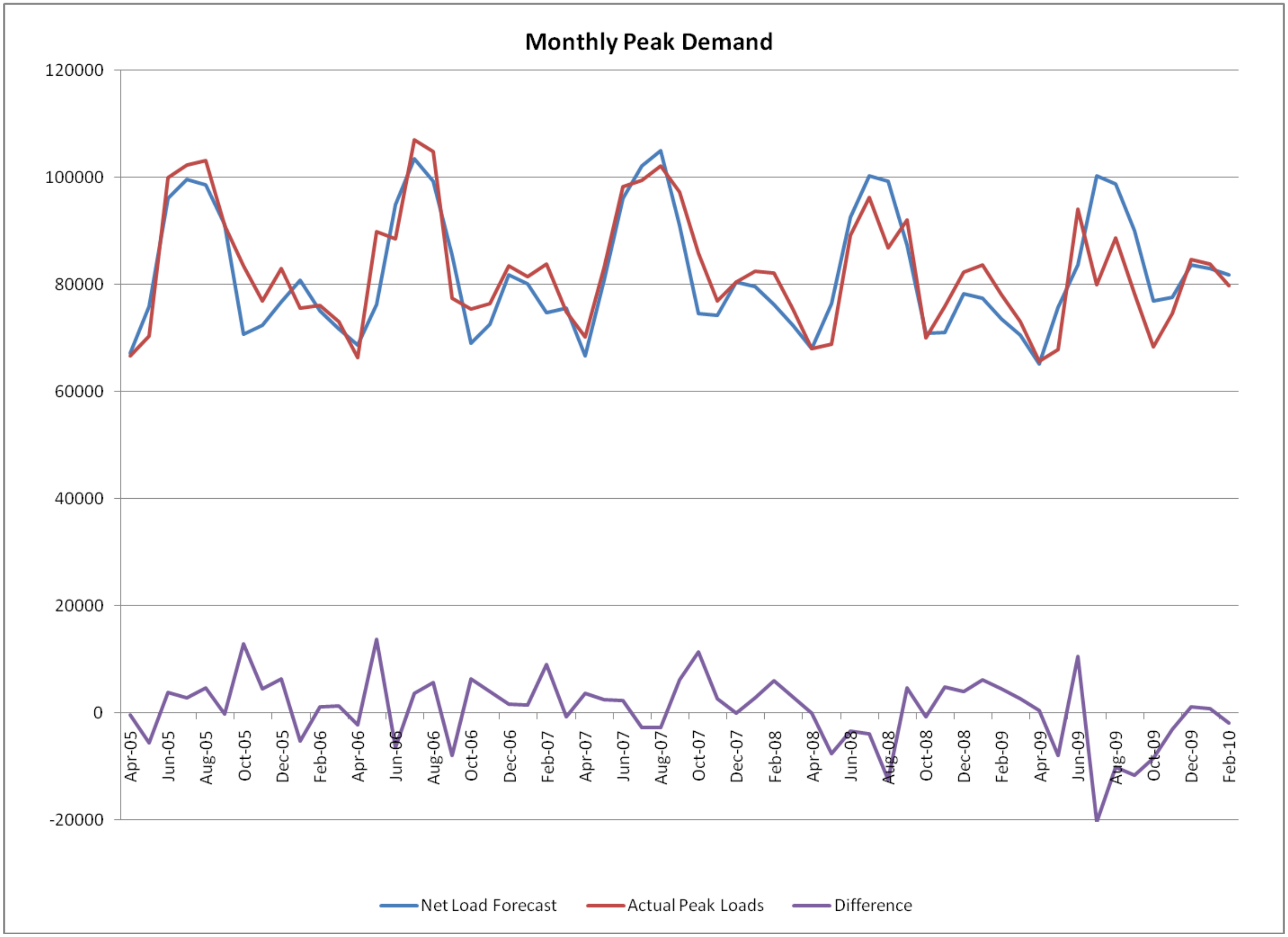
As seen in Table 2.1 (Appendix) utilizing the projected Midwest ISO footprint for the 2011/12 Planning Year and the preliminary NERC Bandwidths available July 14th assuming a 0.96 correlation results in a **4.45%** LFU value.

The work of the NERC Load Forecasting Working Group can be found at the following link:

http://www.nerc.com/filez/lfwg.html

LFU Task Team Recommendation

The LFU Task Team is recommending the use of a 4.45% LFU value determined using the Summation of the NERC Variances. This method results in a more consistent LFU value year to year and allows for vetting through two task teams before inclusion in the Planning Reserve Margin (PRM) study. This value should be used throughout the LOLE analysis for all years and all seasons as peak risk is experienced during the summer months and an increase in LFU during the out years is not conducive to an analysis of possible future PRMs.



Graph 1.1: Monthly Peak Demand

Table 2.1

Summer									
Year		WEIGHTING FACTOR	(WEIGHTING FACTOR)^2	NERC 10% band	Z α/2	σ	σ^2 or Variance	(WEIGHTING FACTOR)^2 * σ^2	(WEIGHTING FACTOR) * σ
1	RFC	0.488914	0.239036	6.35%	1.2816	4.95%	0.245%	0.000585898	0.02420534
1	SERC	0.197660	0.039070	4.26%	1.2816	3.32%	0.110%	4.3086E-05	0.006563996
1	MRO-US	0.313426	0.098236	5.84%	1.2816	4.55%	0.207%	0.000203633	0.014269994
				0.96 Correlation					
	Perfectly Correlated	4.50%	------------>	4.45%			Correlation	0.96	
	Perfectly independent	2.89%							

Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes

Appendix Item B.1
EFORd, IGEN and UCAP Relationships and Findings for 2010

1) For each generator:

IGEN (1- XEFORd $_{IGEN}$) = UCAP

Where: Installed Capacity = IGEN
Unforced Capacity = UCAP

2) For the total system results applied to an LSE with a 1,000 MW Non-coincident load:

PRM $_{IGENEFORd}$ = 12.06%, (4.55% diversity result highlighted value in Tables below)

System Average XEFORd = 7.357%

Forecast LSE Requirement = (Load) = 1,000 MW

IGEN Requirement= Forecast LSE Requirement * (1+PRM $_{IGENEFORd)}$ = 1,000 * (1+0.1206) = 1,1206 MW

UCAP Requirement = ICAP Requirement * (1 – System Average XEFORd), and substituting values gives:

UCAP Requirement = 1,1206 * (1 – 0.07357) = 1,038 MW

3) By applying the following equation to define PRM$_{UCAP}$ metric**:**

(1 – System Average XEFORd) (1+PRM$_{IGENXEFORd}$) = (1+PRM$_{UCAPXEFORd}$)

PRM$_{IGENEFORd}$= 12.06%, (4.55% diversity result highlighted value in Tables below)

System Average XEFORd = 7.357%
Then (1 – System Average XEFORd) = 0.9264

And,

0.9264 (1+0.11304) = 1+ PRM$_{UCAP}$
PRM$_{UCAPXEFORd}$ = 0.9264 (1+0.11304) – 1

$PRM_{UCAPXEFORd}$ = 0.0311 = 3.11%

The total PRM is represented by the **XEFORd** driven component **$PRM_{UCAPXEFORd}$ = %** plus the system wide average **Force Majeure** component adder for generators of **0.70%**. Therefore, the total

$PRM_{UCAPEFORd}$ = 3.11 % + 0.70% = 3.81%
0.70 is the 4.55% diversity result highlighted in Tables below

4) Amount of Capacity Required for the Modeled Market Load

Coincident Load x 117.40% = 104,557 x 1.1740 = 122,750 MW $_{IGEN}$

And within round off error:

Non-coincident Load x 112.06% = 109,540 x 1.1206 = 122,750 MW $_{IGEN}$

Table B1 - Summary of IGEN versus UCAP
At 4.55% diversity for total Model footprint:

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM_{UCAP} (%)	PRM:$_{LSEIGEN}$ (%)	$PRM_{SYSIGEN}$ (%)
With congestion XEFORd $_{\text{Generation and BTM}}$	3.11%	11.29%	16.60%
System average Generator Force Majeure adder	0.70	0.55%	0.57%
With congestion EFORd $_{\text{Generation and BTM}}$	3.81%	12.06%	17.40%
Load	109,540	109,540	104,557
Required Capacity	113,713 $_{UCAP}$	122,750 $_{IGEN}$	122,750 $_{IGEN}$

Appendix Item B.2
OMC Codes used in Midwest ISO

The term $XEFOR_d$ represents calculating the forced outage rate by excluding OMC outage causes when performing the calculation that would otherwise compute the $EFOR_d$. Currently, the Midwest ISO study utilizes 27 cause codes in its OMC set of outages and otherwise uses the NERC default set of 36 OMC cause codes . The 27 OMC Codes approved by stakeholders for use in the Midwest ISO LOLE study as listed in the BPM are shown in Table C2 below.

Table B2 - Outage Cause Codes included in the OMC set for Midwest ISO Studies

Code	Description	Midwest ISO and PJM OMC List
3600	Switchyard transformers and associated cooling systems - external	1
3611	Switchyard circuit breakers - external	1
3612	Switchyard system protection devices - external	1
3619	Other switchyard equipment - external	1
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)	1
3720	Transmission equipment at the 1st substation) (see code 9300 if applicable)	1
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)	1
9000	Flood	1
9010	Fire, not related to a specific component	1
9020	Lightning	1
9025	Geomagnetic disturbance	1
9030	Earthquake	1
9035	Hurricane	1
9036	Storms (ice, snow, etc)	1
9040	Other catastrophe	1
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels	1
9135	Lack of water (hydro)	1
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.	1
9250	Low Btu coal	1
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)	1

9320	Other miscellaneous external problems	1
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated	1
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated	1
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated	1
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated	1
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)	1
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)	1

Total 27

The accommodation of Force Majeure outage causes by using the EFORd metric as the input data to the GE MARS application is normal; however a sensitivity run with the $XEFOR_d$ metric can be done to examine the impact of the Force Majeure.

Appendix C RE Compliance Conformance Tables

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
R1. The LSE and/or its delegate(s) shall perform and possess the documentation of a planned Resource Adequacy assessment. **R1.1** Be performed annually unless a document summarizing a review of system data that concludes that changes to system data used in the assessment do not warrant such a study is provided to the MRO. A study is warranted if changes have occurred that require revisions in any key assumptions such as generation mix and transmission limitations that are not covered by a sensitivity study. **R1.1.1** The planned Resource Adequacy assessment is to be conducted for Year One through Year Ten. Year One is defined as the year that begins with the upcoming annual peak season.	**R1** The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The attached assessment is the annual Resource Adequacy Analysis for the peak season of June 2011 through May 2012 and beyond. Analysis of Year One through Year Ten can be seen in Section 5.2 Expected PRM for 2012-2020

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
R1.1.2 The annual peak season for Resource Adequacy assessment is to be determined by the LSE and/or its delegate. The peak season is defined as a period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the LSE or its Planned Reserve Sharing Group annual peak demand is expected to occur. R1.1.2.1. If the peak season is determined by the PRSG, then the peak season is to apply for the PRSG in the aggregate. If the peak season is determined by the LSE or Resource Planner, then the peak season is to apply for the LSE.		

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
R1.2 Perform the assessment with LOLP of no greater than 0.1 day in one (1) year which equals the sum of the LOLE forthe integrated daily peak hours for each year. This is done for each year of the ten year period in R1.1 to ensure meeting one (1) day in ten (10) years. Analysis to: **R1.2.3** Be performed for every day of each year throughout the period in R1.1. Expected Unserved Energy may be performed as the method to meet R1.2 provided the results of such an assessment is compared with an LOLP analysis and the comparison is documented.	**R1.1** Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.2 of this report outlines the utilization of LOLE in reserve margin determination. "Capacity adjustments were then put in place to alter the available capacity in each zone to ensure that the probabilities for loss of load within the Midwest ISO system over each integrated peak hour for the planning period summed to 1 day in 10 years or 0.1 days/year. When the Midwest ISO system as a whole is at 0.1 days/year then all zones within the system will have a LOLE of 0.1 days/year or less."

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
1.3.1.10 Available Demand-Side Management	**R1.1.1** The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.1 of this report: "Direct Control Load management and Interruptible Demand were accounted for by netting them from the hourly load. Therefore, no special modeling of these resources was needed to further account for their impacts on the analysis."
R1.4 Express the planning reserve as a percentage of the 50:50 probability forecast peak load (planning reserve margin).	**R1.1.2** The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).	Section 3.2 of this report: "When capacity was appropriately adjusted in each LOLE zone to bring all systems to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the Midwest ISO yielded a reserve margin of 17.4% of the 50/50 net internal demand forecast."
	R1.2 Be performed or verified separately for each of the following planning years:	
	R1.2.1 Perform an analysis for Year One.	In Section 4, a full analysis was performed for year 2011.
	R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	In Section 5, a full analysis was performed for the year 2015, Also outlined in Section 5 is an analysis for year 2020.

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
	R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	Analysis was performed.
R1.3 Include, at a minimum, documentation of how and why the following were/were not included in the analysis:	**R1.3** Include the following subject matter and documentation of its use:	
R1.2.1 Use loads developed from the expected 50:50 probability load forecast, **R1.2.2** Include load forecast uncertainty such as uncertainty due to load diversity, seasonal load variation, load variability due to other region economic forecasts or other factors. **R1.3.2** Load Characteristics **1.3.2.1** Load forecasts **1.3.2.2** Load forecast uncertainty **1.3.2.3** Load diversity **1.3.2.4** Seasonal load variations **1.3.2.5** Load variability due to weather, regional economic forecasts, etc. **1.3.2.6** Daily demand modeling assumptions (firm, interruptible)	**R1.3.1** Load forecast characteristics: • Median (50:50) forecast peak Load. • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	• Section 2.2.7: "Load in PROMOD IV® is equivalent to the actual load plus losses as included in the 50/50 LSE forecasts." • LFU (Load Forecast Uncertainty) use within this assessment is outlined in Section 3.1.3 and Appendix A • Section 3.1 states that an hourly load profile was utilized: "PROMOD IV® tool was used to group the buses as specified in Section 2.3 and output a single hourly load profile for each zone which included all hours within the period under scrutiny." • Section 3.1 of this report: "Direct Control Load management and Interruptible Demand were accounted for by netting them from the hourly load. Therefore, no special modeling of these resources was needed to further account for their impacts on the analysis." • Load diversity is discussed in Section 3.2 • In order to be included in the MARS model all

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
		Load Modifying Resources must first meet registration requirements through Module E.
R1.3.1 Resource availabilities **1.3.1.1** Historic resource performance and any projected changes **1.3.1.2** Seasonal resource ratings **1.3.1.3** Modeling assumptions of non-conventional resources such as wind and cogeneration **1.3.1.4** Energy limitations of hydroelectric units. **1.3.1.5** Merchant plant availabilities **1.3.1.6** Modeling assumptions of firm capacity purchases and sales of the LSE and/or its delegates	**R1.3.2** Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis	• Section 3.1.2 outlines the inclusion of historical unit performance, seasonal maximum outputs, planned outage schedules or deratings, retirements, planned additions and energy limitations in the LOLE model. • Section 3.1.1 outlines the handling of capacity purchases and sales within the assessment. • Section 3.1.4 states that wind resources are not included in the resource assessment and the reasoning for their exclusion.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves **1.3.3.2** Transmission forced outage rates **1.3.3.3** Transmission availability for emergency considering firm commitments	**R1.3.3** Transmission limitations that prevent the delivery of generation reserves	As outlined in Section 3.1: “Each generator within a zone is assumed to be deliverable to all load within that zone.”

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
	R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Section 5 states that transmission facilities included in Appendix A and B are included in the analysis.
R1.3.5 Emergency assistance from other interconnected systems including multi-area assessment considering transmission limitations	**R1.3.4** Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.1.1 shows the derivation of external assistance limitations.

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
R1.3.4 Modeling assumptions for emergency operation procedures used during unexpected resource outages. **R1.3.6** Document and justify the inclusion of market resources not committed to serving load (uncommitted resources) within the planned Resource Adequacy Assessment analysis. **1.3.1.7** Availability and deliverability of fuel **1.3.1.8** Common mode outages that effect resource adequacy **1.3.1.9** Other environmental or regulatory restrictions of resource availability **1.3.1.11** Resource maintenance outage schedules **1.3.1.12** Sensitivity to resource outage rates and resource capabilities **1.3.1.12.1** Consider impacts of extreme weather/drought conditions	**R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. •Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	• Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions were not considered separate from the historical availability characteristics as outlined in Section 3.1.2. • There are no other demand response programs save for those mentioned in R.1.3.1. • Section 3.1: "Therefore, no special modeling in the form of Emergency Operating Procedures was needed to further account for their impacts on the analysis." • Section 3.1: "Since prices are high during peak load events and all generators are called on to serve load, all resources within the footprint were assumed to be utilized for reliability regardless of load serving obligations." • The affect of resource outage characteristics on reserve margin out outlined in Section 3.2 by examining the difference between the PRM_{LSE} and the PRM_{UCAP}

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
1.3.3.1 Transmission maintenance outage schedules.	**R1.5** Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Section 2.2.4 states that "Transmission maintenance schedules were not included in the PROMOD IV® analysis of the transmission system due to the limited availability of reliable maintenance schedules and minimal impact to the results of the analysis."
R1.5 Document that the resource capacity is not counted more than once as reserve by multiple Load Serving Entities, and/or Planned Reserve Sharing Groups.	**R1.6** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	Sections 2.2 and 2.3 describe the development of the combined representation of generators and the transmission grid through use of a data base, that are the foundation for input into the probabilistic treatment in Section 3.
	R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	Section 3.1 states that: "Zones 1 through 4 include all load within the Midwest ISO Reliability Coordinator footprint…"
R2. On an annual basis, the LSE and/or its delegate(s) shall document an assessment of its Resource Adequacy by comparing its load and resource capability for the ten year period in R1.1 with the planning reserve margin benchmark in R1.4.	**R2** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis. **R2.1** This documentation shall cover each of the years in Year One through ten.	Table 5-2 illustrates the load and capability for the Midwest ISO over the next ten years relative to the Reserve Margins calculated in this assessment.

Requirements under: Standard RES-501-MRO-01	Requirements under: Standard BAL-502-RFC-02	Response
	R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	
	R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	Documentation posted with this assessment on December 6th, 2010

Appendix D Wind Capacity Credit

A Wind Capacity Credit of 12.9% of the Registered Max capacity of wind resources was set by the Midwest ISO for the Planning Year 2011. The 12.9% value was based on calculating the ELCC over 6 historical years and aligning each year to a trend. The specific value applicable for the actual 7.6% penetration in PY 2010, was then computed from the average of the values from each of the 6 year's trend. line as illustrated in Figure D3. Table D2 is a listing of the Wind Output at time of 48 Daily Peak loads over the past 6 summers.

The increase from the previous 8% Capacity Credit in PY2010 is due to three factors listed in Table D1. The more credible method developed at the LOLEWG to merge multiple ELCC historical characteristics (aside from the new year's data) accounts for 3.4% of the increase. This increase is a onetime change that can be thought of as adjusting the original 8% starting point. The wind performance for 2010 was outstanding, and when merged with the previous 5 years caused the new rolling average to go up by about 1.2%. The last change of 0.3% is due to bench marking the penetration at the after-the-fact or actual 2010 summer penetration level, driven by the ratio of actual installed wind capacity to load. The actual installed capacity was 8,179 MW through the 2nd quarter of 2010, where as the previous method applied an estimated value of 9,000 MW installed, and used a forecasted load. In subsequent years, it is expected that the 0.3% effect will become insignificant as the penetration saturates to some level. Also, subsequent merging of additional year's wind patterns should be more stable as each new addition becomes 1 among 7 years, 1 among 8 years, etc. Last, the general higher penetration causes the ELCC to decrease.

Table 1: Itemized Impacts Causing ELCC Change

Factor	Incremental	Cumulative	Cumulative Long Term
PY 2010 Base	0%	8.0%	n/a
Credible Merging of Multiple Year ELCC characteristics	3.4%	11.4%	9.2%*
Effect of 2010 Record Wind Performance	1.2%	12.6%	Approx. = 0
Effect of Setting at Most Recent Penetration versus forecasting Load and Penetration	0.3%	12.6%	Approx. = 0
PY 2010 Wind Capacity Credit	4.95	12.9%	9.2%*

Note: * Based on current wind resource geographic locations; the value may increase if any new emerging geographic foot pint of Wind resources prove beneficial.

On a formula basis the Capacity by CPnode is expressed by the following equations:

Wind UCAP Rating $_{\text{CPnode n}}$ = RMax $_{\text{n}}$ x Capacity Credit $_{\text{CPnode n}}$ %

Where:

RMax $_{\text{n}}$ = Registered Maximum capacity of a wind facility at the CPnode n
Capacity Credit $_{\text{System-Wide}}$ % = Effective Load Carrying Capacity (ELCC), and is the ratio of <u>the capacity of a 100% reliable resource</u> to <u>the sum of individual RMax CPnode capacities on the system</u> (i.e. sum of **RMAX $_{1}$** through **RMax $_{\text{n}}$**), and the size of that 100% reliable capacity resource is such that it results in the same LOLE impact as the actual summed hourly pattern of the wind outputs associated with all wind CPnodes.

Capacity Credit CPnode % = Capacity Credit $_{\text{System-Wide}}$ % x K3

Where "K3" is solved from the expression:

$$(\boldsymbol{System\ Wide\ PKmetric})\,\boldsymbol{x}\,(\boldsymbol{System\ RMax}) = \boldsymbol{K3\ x}\sum_{n=1}^{n}(\boldsymbol{PKmetric_{CPnode\ 1}\ x\ RMax_{CPnode\ 1}} + \ldots\ldots + \boldsymbol{PKmetric_{CPnode\ n}\ x\ RMax_{CPnode\ n}})$$

And the **"System Wide PKmetric"** is the average capacity factor of the total installed RMax capacity of all CPnodes during specific peak hours, and the **"PKmetric $_{\text{CPnode}}$"** is the average capacity factor of the installed RMax $_{n}$ at CPnode $_{n}$ during the same specific peak hours. The specific peak hours are the top 8 daily peaks each year, and starting with summer 2005.

Across years 2005 through 2010, the **Capacity Credit $_{\text{System-Wide}}$ % was 12.9%,** K3 was calculated to be 1.187, the **System Wide PKmetric** was 14.41%, and the individual **PKmetric's $_{\text{CPnode}}$** ranged from zero to 29.9%. The individual **Capacity Credit %** for CPnode's ranged from zero to 31.8%.
Example for the best performing CPnode through 2010 data, the Capacity Credit equals:

29.9% x 1.187 x (12.9% / 14.41%) = 31.8%, and times that CPnode's RMax would equal the UCAP rating for the best performing CPnode.

Table D2 - Wind Output for 6 years At Time of 8 top Daily Load Peaks each Year

END_TIME of Daily Peak	Wind Registerd Max (MW)	Wind Output at Daily Peak Load (MW)	Wind Output % of Registered Max at Daily Peak Load	Daily Peak Load (MW)	Year	Planning Year Daily Peak Rank
6/27/05 15:00	908	291	32.1%	105,353	2005	6
7/21/05 16:00	908	92	10.2%	104,998	2005	7
7/25/05 15:00	908	89	9.8%	108,558	2005	3
8/1/05 17:00	908	58	6.4%	106,949	2005	5
8/2/05 16:00	908	211	23.2%	109,099	2005	2
8/3/05 16:00	908	104	11.5%	109,473	2005	1
8/8/05 17:00	908	396	43.6%	104,011	2005	8
8/9/05 16:00	908	282	31.1%	107,615	2005	4
7/17/06 16:00	1,251	430	34.4%	110,011	2006	4
7/18/06 16:00	1,251	63	5.1%	102,742	2006	5
7/19/06 16:00	1,251	378	30.2%	101,744	2006	7
7/25/06 17:00	1,251	53	4.3%	100,948	2006	8
7/28/06 16:00	1,251	471	37.6%	102,161	2006	6
7/31/06 16:00	1,251	700	56.0%	113,095	2006	1
8/1/06 16:00	1,251	139	11.1%	110,947	2006	2
8/2/06 16:00	1,251	36	2.9%	110,499	2006	3
6/26/07 15:00	2,065	363	17.6%	97,413	2007	8
7/9/07 15:00	2,065	45	2.2%	98,049	2007	6
7/31/07 17:00	2,065	352	17.0%	98,955	2007	5
8/1/07 16:00	2,065	64	3.1%	101,496	2007	2
8/2/07 16:00	2,065	45	2.2%	101,268	2007	4
8/6/07 17:00	2,065	76	3.7%	97,435	2007	7
8/7/07 17:00	2,065	59	2.9%	101,306	2007	3
8/8/07 16:00	2,065	44	2.1%	101,800	2007	1
7/16/08 16:00	3,086	455	14.8%	95,982	2008	2
7/17/08 16:00	3,086	423	13.7%	95,592	2008	3
7/18/08 16:00	3,086	97	3.1%	93,144	2008	5
7/29/08 16:00	3,086	384	12.5%	96,321	2008	1
7/31/08 17:00	3,086	402	13.0%	92,544	2008	7
8/1/08 16:00	3,086	405	13.1%	93,422	2008	4
8/4/08 17:00	3,086	178	5.8%	92,245	2008	8
8/5/08 16:00	3,086	212	6.9%	93,089	2008	6
6/22/09 16:00	5,636	527	9.4%	87,846	2009	5
6/23/09 15:00	5,636	720	12.8%	91,671	2009	3
6/24/09 17:00	5,636	300	5.3%	92,402	2009	2
6/25/09 14:00	5,636	86	1.5%	94,185	2009	1
6/26/09 16:00	5,636	1,082	19.2%	87,355	2009	6
8/10/09 14:00	5,636	167	3.0%	89,039	2009	4
8/14/09 16:00	5,636	2,126	37.7%	87,023	2009	7
8/17/09 15:00	5,636	1,132	20.1%	85,593	2009	8
7/23/10 16:00	8,179	692	8.5%	102,995	2010	8
8/3/10 16:00	8,179	365	4.5%	103,646	2010	4
8/4/10 16:00	8,179	948	11.6%	103,527	2010	6
8/9/10 16:00	8,179	383	4.7%	103,571	2010	5
8/10/10 16:00	8,179	1,770	21.6%	107,171	2010	1
8/11/10 16:00	8,179	129	1.6%	104,075	2010	3
8/12/10 16:00	8,179	1,788	21.9%	106,653	2010	2
8/13/10 16:00	8,179	2,072	25.3%	102,996	2010	7

System Wide Average Peak Metric **14.41%**

Table D3 – 6 Historical Years of ELCC for Wind and Simulated Higher Penetration levels utilizing the same historical Wind and Load Patterns

Market-wide Operational Tracking			After-The -Fact ELCC % and Penetration %		ELCC % with Wind Resource Pattern Simulated at Increased Penetration					
					10 GW Penetration		20 GW Penetration		30 GW Penetration	
Peak Load (MW)	Planning Year (PY)	Registered Max MW Capacity (RMax)	Midwest ISO ELCC	Historical Penetration [1]	ELCC%	Penetration %	ELCC%	Penetration %	ELCC%	Penetration %
109,473	2005	908	**16.7%**	0.8%	14.3%	9.1%	12.9%	15.8%	11.9%	23.7%
113,095	2006	1,251	**39.6%**	1.1%	23.4%	8.8%	15.1%	15.3%	11.6%	23.0%
101,800	2007	2,065	**2.8%**	2.0%	2.6%	9.8%	2.6%	17.0%	2.6%	25.5%
96,321	2008	3,086	**12.8%**	3.2%	12.9%	10.4%	12.4%	18.0%	11.6%	27.0%
94,185	2009	5,636	**3.1%**	6.0%	2.8%	10.6%	2.6%	18.4%	2.3%	27.6%
107,171	2010	8,179	**18.9%**	7.6%	**18.3%**	9.3%	**15.9%**	16.2%	**13.1%**	24.3%

[1] Wind's capacity penetration is the 2nd quarter Installed Wind Rmax divided by the year's peak load.

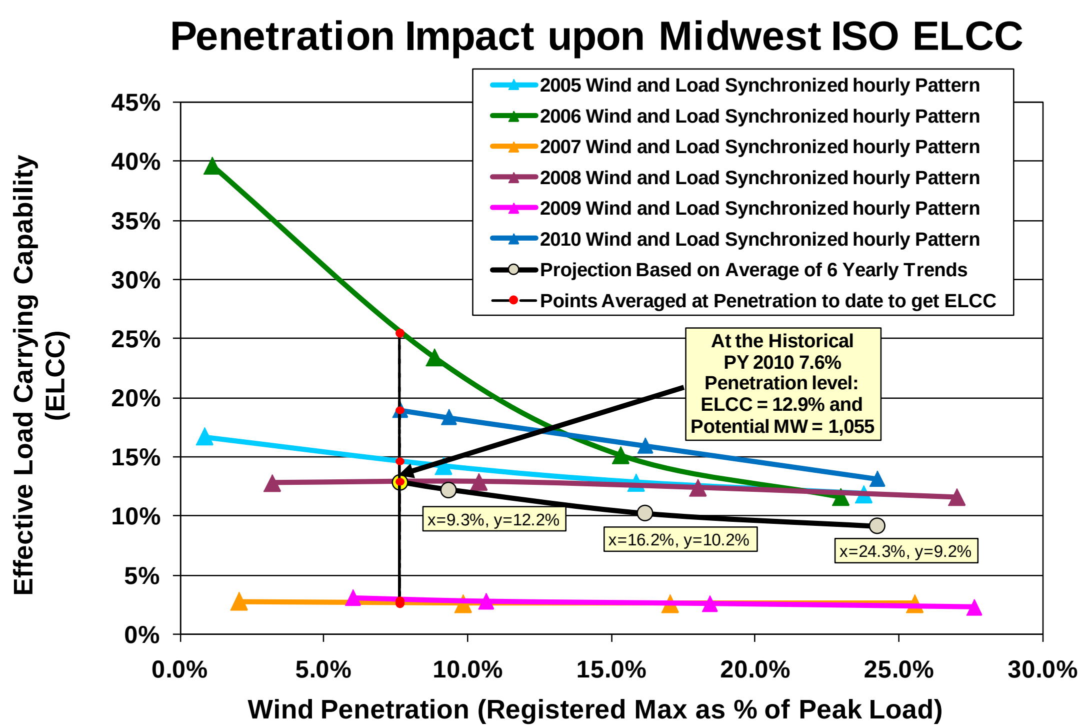


Figure D3 – Charted Values from Table D3, 6 Historical Years of ELCC for Wind and Simulated Higher Penetration levels utilizing the same historical Wind and Load Patterns

Figure D4 shows how the system wide 12.9% capacity credit percent compares with the individual capacity credit percents for the 129 2nd quarter 2010 CPnodes. This reflects implementing the formulas referred to earlier in this Appendix D. The CPnodes have been sorted by their capacity credit percentages. Figure D5 shows what a "Mock" market participant might see for their CPnodes.

Figure D6 identifies the relative amount performance history among the CPnodes. The cumulative amounts of installed RMax MW are trackted on the vertical axis, while the associated cumulative UCAP MW are tracked on the horizontal axis. The general slope is driven by the system wide average 12.9%. The large amount of CPnodes represented by only one year of history (8 peak days) is due to the acquisition of the Mid-American and Dairyland Power Cooperative wind facilities in 2010 plus the normal amount of growth from new connections. Each range of historical data shown in Figure D6 starts with lower slopes (driven by the highest ratio of incremental UCAP MW to installed RMax MW). For example the vertical slope at the right end of the 8 day data reflects 4 additions that had representative installed RMax MW while realizing no corresponding incremental UCAP MW. The less variant slopes associated with the longer data periods, indicates that a more stable and consistent rating emerges as more historical performance becomes available. It is also observed that UCAP ratings equal to zero are predominant when only short term history is available. All CPnodes with more than 2 years of data (more than16 hourly points) were able to establish a UCAP rating greater than zero.

Figure D4 – Allocation of Capacity Credit % over 129 CPnodes

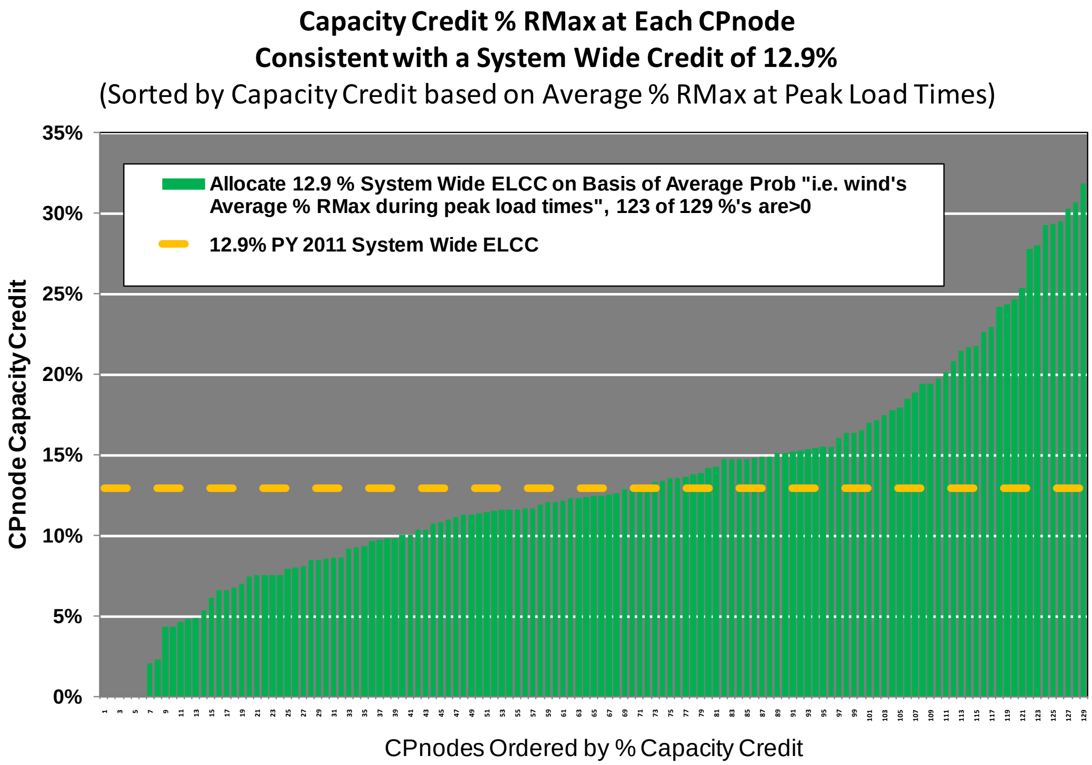


Figure D5 – Allocation of Capacity Credit % Over a Mock Market Participant's CPnodes

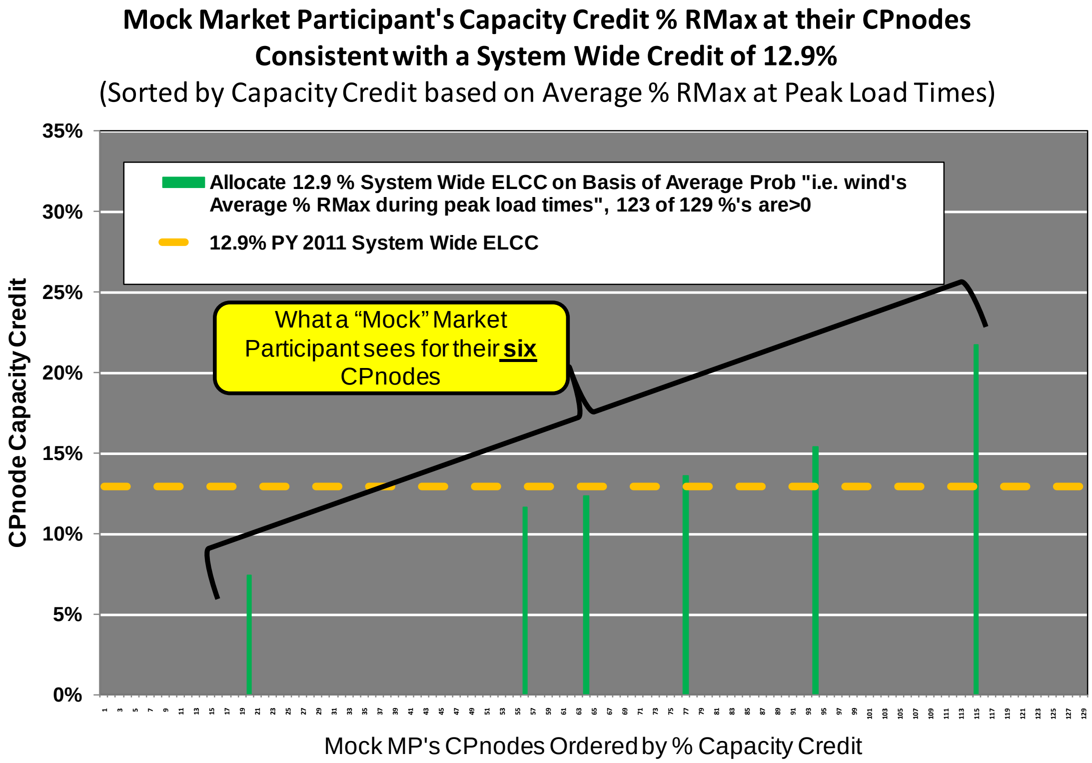
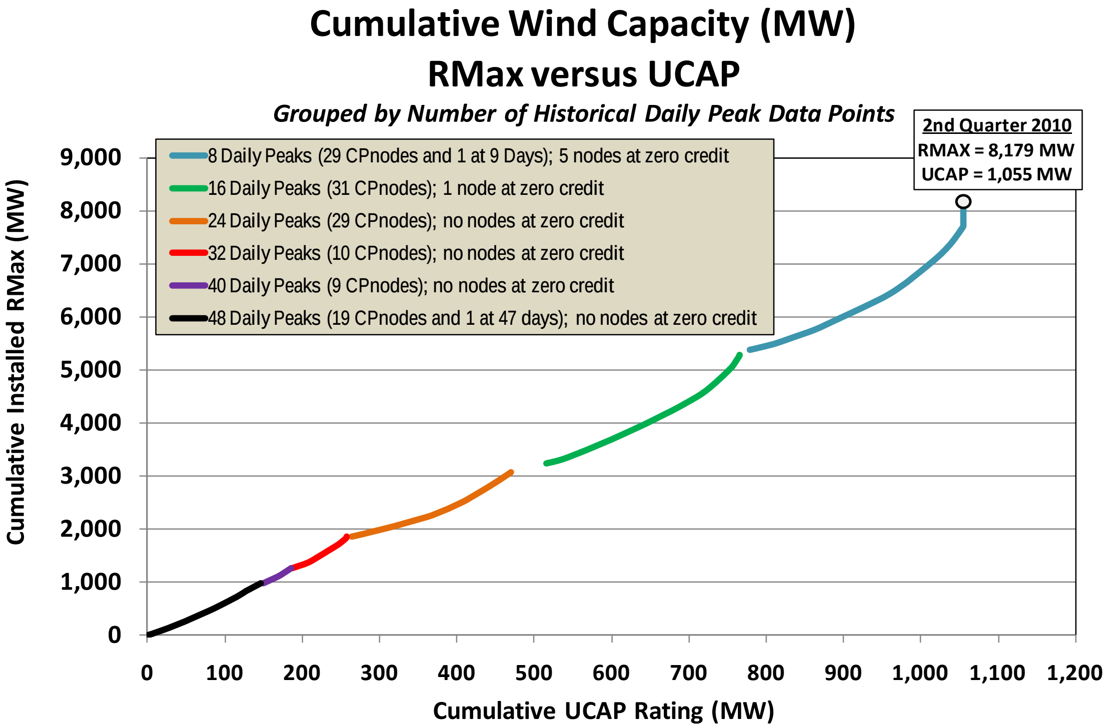


Figure D6 – Allocation of Capacity Credit %



Notes: 1. Highest Capacity Credit % CPnodes included first (left) in each Daily Peak Set
2. UCAP ratings not discounted for any applicable transmission service limitations
3. MECT entries reflect applicable transmission service limitations

Appendix E Diversity Factor Task Team Report

Scope

The Midwest ISO Diversity Factor task team shall assist in the determination of an appropriate diversity factor for the adjustment of the Planning Reserve Margin (PRM) on a system wide basis to one which can be applied to each Load Serving Entity. (LSE)

Executive Summary

A diversity value of **4.55%** was determined appropriate for the adjustment of the System Wide PRM. This value represents an estimation of the true mean of Midwest ISO historical diversity data excluding First Energy with only a ten percent chance of the true mean would be lower. Given the limited amount of available system data it was determined that utilizing an average statistic of such a small dataset would not be prudent.

Overview

During previous Diversity Factor task team analysis it was determined that the most appropriate granularity on which to determine Midwest ISO system diversity is at the Commercial Pricing Node (CP Node) level. The time frame over which to examine diversity is determined by the month during which the system coincident peak occurs for each year as most risk is experienced during the peak month. Given these determinations, diversity is calculated by summing the peak load that each CP Node experienced at any point during the peak month and comparing that to the Midwest ISO Coincident Peak value for that month. Equation 1: Diversity Factor illustrates the calculations used to determine the diversity factor.

Equation 1: Diversity Factor

$$Diversity\ Factor = 1 - \frac{MISO\ Coincident\ Peak}{\sum^{Month} CPNode\ Peaks}$$

Historical diversity factors calculated since the peak season of 2005 on a prevailing footprint basis and with all First Energy loads removed are available in

Table 0-1: Historical Diversity Factors

Table 0-1: Historical Diversity Factors

Month	Current Footprint	w/o FE
Aug-05	3.99%	4.14%
Jul-06	2.94%	3.07%
Aug-07	6.51%	6.36%
Jul-08	6.29%	6.44%
Jun-09	5.27%	5.76%
Aug-10	7.19%	7.13%
Mean	**5.36%**	**5.48%**
Median	**5.78%**	**6.06%**

Correlation Attempts

In an effort to establish a larger history of diversity values and thus derive greater certainty around the statistics associated with historical diversity correlation between diversity and historical weather data was analyzed.

Possibly due to the limited amount of data no significant correlation was found between diversity and weather data. Both monthly and daily diversity were compared to average temperatures to result in sub 0.2 R^2 values. Connections to a heat index also proved to be insignificant.

While the initial analysis proved fruitless, an increased history of diversity values would prove very useful in determination of reliable statistics.

Previously Utilized Diversity Factors

For the 2009 Planning Year a diversity value of **2.35%** was utilized for adjustment of the Planning Reserve Margin (PRM). This value corresponded to the lowest value experienced since Midwest ISO market start calculated on a Local Balancing Authority granularity.

During the 2010 Planning Year study the methodology for calculating diversity was updated to consider diversity between all Commercial Pricing Nodes within the historical data and a value of **3.00%** was used to adjust the PRM.

Stakeholder Proposal

A method for determining the appropriate diversity value to adjust the PRM was proposed by a stakeholder and presented to the LOLE Working Group as outlined below.

Based on the assumption that (a) all variation is included in the LFU for modeling purposes and the fact that (b) LSEs are required to provide load forecasts on a "50/50" basis, it was proposed that the diversity factor adjustment also be based on 50/50 history of actual diversity values at time of peak. The proposal was to use the median value of historical diversity to adjust the PRM for implementation under Module E. The outcome of this method would be to use the historical median of **6.06%**, as shown in Table 1 of this appendix.

This proposed method of adjustment was favored heavily by Load Serving Entities and when put forward as a motion to those present at the October 13th LOLEWG meeting passed with a tally of 17 for, 7 against, and 5 abstaining.

Diversity Selection Methodology

While it was determined that an average statistic could be appropriate for the determination of an appropriate diversity factor for adjustment certain considerations were necessary.

The first consideration was the level of diversity variance accounted for within the LFU. While the historical analysis of Midwest ISO forecast error as outlined in Appendix A showed that a portion of historical forecast error is due to diversity variance, that finding is not conclusive. Diversity variance in historical forecast error provides an estimation on which to analyze diversity choice, but until there is sufficient historical data a conclusion that all diversity variance is incorporated within Load Forecast Uncertainty is premature.

A second consideration was the limited amount of available data. Given that only six data points were available for analysis, taking any average statistic as canon did not seem prudent. Confidence intervals take into consideration the limited amount of available data.

Another consideration was the unknown risk associated with a diversity assumption. If not all diversity variation is contained within the LFU then there is a risk that the diversity of a planning year will be less than that of an average statistic. This risk is not quantifiable given the fact that both diversity variance within LFU and the true mean of historical diversity are unknown. The same Confidence Intervals established to account for the limited data set could account for the unknowns of diversity variance within LFU and the true mean of historical diversity.

Confidence Interval

Given the recommendation for use of an average statistic in determination of an appropriate diversity adjustment and the limited amount of available data, confidence intervals were established for the true mean of historical diversities. A Student's T-Distribution was used to determine the confidence intervals due to the 6 available data points. This distribution approximates a wider normal distribution until there are 30 data points at which point it coincides with a true normal distribution.

Table 0-2: Confidence Intervals w/o First Energy

Confidence Intervals		
Conf. Int	Upper Bound	Lower Bound
80.0%	6.42%	4.55%
90.0%	6.76%	4.20%
95.0%	7.11%	3.85%
98.0%	7.62%	3.35%
99.0%	8.04%	2.93%
99.9%	9.84%	1.13%

Table 0-2: Confidence Intervals w/o First Energy displays various confidence intervals for the mean of historical diversity values derived from the data excluding First Energy loads. These confidence intervals state that there is a given percent chance the true mean of the distribution is between the upper and lower bounds. The first confidence interval (80% in Table 0-2) illustrates that as more data becomes available there is an **80%** chance the mean will be between **4.55%** and **6.42%.** Since there is no risk associated with exceeding the diversity value the lower bound is examined when determining an appropriate adjustment. In this instance, the lower bound of the **80%** confidence interval could be deemed a **90%** confidence that the true mean of the historical diversity values is above **4.55%.**

Diversity Variance Risk Analysis

After the determination of confidence intervals around the true mean value of historical diversity an examination of the effect of a chosen diversity value could be derived. By examining the contribution of Load Forecast Uncertainty to the Reserve Margin, estimation for the effect of Diversity Uncertainty could be derived.

Utilizing historical deviation of Midwest ISO forecasts from actual loads as seen in Appendix A Load Forecast Uncertainty (LFU) Final Report, it was determined that approximately 0.5% of the Load Forecast Uncertainty (LFU) could be due to diversity variance. This was derived by first calculating the LFU of Midwest ISO historical load utilizing a fixed diversity value then comparing that to the LFU calculated using actual diversity experienced during each month of available data. The 4.45% LFU value utilized in the 2011/12 PRM calculation accounts for roughly 6.8% of the installed planning reserve margin. Assuming linearity in this relationship there is a 1.53% increase in PRM for every 1% increase in LFU. Multiplying the 0.5% LFU which could be due to diversity variance by the 1.53%/1% PRM/LFU ration arrives at a 0.765% PRM contribution due to the variance in diversity.

Removing the PRM held for diversity variance results in a 16.64% target PRM. This new target PRM is an estimation for the reserve that would need to be held if diversity was a known constant as opposed to an external variable. Using this new target PRM a look at historical diversity and its effect on the level of reserves that would have been held can be made. This analysis assumes that the current PRM was established for all historical time frames and that the current resource adequacy construct was in place.

Table 0-3: Historical Diversity Analysis

			Realized PRM		
Month	**Historical Div.**	**Target PRM**	**3% Div.**	**4.55% Div**	**5.4% Div**
Aug-05	3.99%	16.64%	18.61%	16.71%	15.67%
Jul-06	2.94%	16.64%	17.33%	15.46%	14.43%
Aug-07	6.51%	16.64%	21.80%	19.86%	18.79%
Jul-08	6.29%	16.64%	21.52%	19.58%	18.51%
Jun-09	5.27%	16.64%	20.21%	18.29%	17.24%
Aug-10	7.19%	16.64%	22.70%	20.74%	19.66%

It can be seen in Table 0-3 that if a **4.55%** diversity value is utilized to adjust the PRM the realized PRM would not meet the target in the 2006 peak season. If it is assumed that the 2006 peak season was akin to a one in ten scenario, not meeting the target reserves could be deemed appropriate for that season. It should again be noted that several assumptions were necessary in order to make this analysis and that it is simply provided as one way to look at the appropriateness of a given diversity assumption.

Conclusion

While it was seen as appropriate to utilize an average statistic the limited data set and unknown amount of diversity variance accounted for by Load Forecast Uncertainty necessitated the use of a confidence interval to mitigate any risk associated with an assumed diversity value.

Given the previous analysis it seemed prudent to assume a diversity level of **4.55%** which as mentioned previously corresponds to the lower bound of an **80%** confidence interval for the true mean of historical Midwest ISO diversity.

As a final check on the assumed diversity level, its effect on the Planning Reserve Margins can be analyzed. Table 0-4 outlines what the resultant planning reserve margins would be for the various diversity assumptions. The first and second row outline the use of confidence intervals and the two applications of those confidence intervals as used in the **previous** year's LOLE analysis and the **present** PRM establishment. The final row shows the impact if the stakeholder **proposal** would have been utilized to adjust the PRM.

Table 0-4: Diversity Impact on PRM

	Diversity	$PRM_{SYSIGEN}$	$PRM_{LSEIGEN}$	PRM_{UCAP}
Previous	3.00%	17.40%	13.88%	5.50%
Present	4.55%	17.40%	12.06%	3.81%
Proposal	6.06%	17.40%	10.29%	2.17%

Appendix F No Longer Applicable Year-to-Year Metrics

This is a discussion to illustrate why some of the comparisons between PY 2009 and PY2010 are no longer possible because some of the metrics are no longer available. The shift in metrics is due to how demand side resources are represented in the load data. Previously, it was possible to have gross load data, and that allowed for treating demand side resources similar to generators. This also was coupled with an assumption where the EFORd for the demand resources was set to zero. However, the new load data is only available on a net load basis, and therefore the demand side activity is all ready accounted for. This shift to net load does not permit some of the comparisons that were previously made. Table F1 is the comparison that was made between PY 2009 and PY 2010. Key definitions follow Table F1.

Table F2 is an illustration of what issues arise when that same type of caparison is attempted for PY 2010 versus PY 2010 where net load became the basis. For illustration purposes all three Planning Years 2009, 2010, and 2011 values are shown where applicable. The comments are applicable to PY 2010 versus PY 2011.

Table F1 Former PY 2009 to PY 2010 Comparison Metrics

Information Item	PY 2009	PY 2010	Change	Comments
$PRM_{SYSIGEN}$	15.4%	15.4%	0%	Equal off-setting effects from impact to increased PRM due to higher generator EFORd's, and decreasing PRM due to less congestion and more utilization of external ties.
$PRM_{LSEIGEN}$	12.69%	11.94%	-0.75%	Equal off-setting effects from impact to increased PRM due to higher generator EFORd's, and decreasing PRM due to less congestion and more utilization of external ties, and in addition down due to higher load diversity
PRM_{UCAP}	5.35%	4.50%	-0.85%	Decreasing PRM due to less congestion and more utilization of external ties; and down due to higher load diversity. Up slightly due to greater difference between EFORd versus XEFORd (OMC outage category)
% of Market Generation with GADS data	83.5%	99.4%	+15.9%	More units have GADS reported data, and fewer units assigned class average or used public data
System Wide Average XEFORd (Generation only)	6.75%	6.83%	+0.08%	Up due to higher forced outage history
Generation only IGEN MW	130,446	141,911	+11,465	Major increase due to Iowa companies and Dairyland Power Cooperative being included
Demand Response MW in system assigned an XEFORd=0	4,717	4,053	-664	Decrease in reported Demand Resources in Module E.
System Wide Average XEFORd (Generators and	6.514%	6.644%	+0.13%	Up due to higher forced outage history

Information Item	PY 2009	PY 2010	Change	Comments
DR)				
System Wide Average EFORd (Generation only)	7.05%	7.31%	+0.26	Reflects another year of GADS data reporting of Market resources
System Wide Average EFORd (Generators and DR blend)	6.80%	7.10%	+0.30	Reflects another year of GADS data reporting of Market resources
Sum of LSE's Load non-coincident to Market	113,287	114,205	+918	New forecast from Module E and includes new Market participants
Wind capacity credit (% of monthly Registered Max)	20%	Pending	Pending	Result of Wind Capacity Credit sensitivity study linked to LOLE on the ELCC of wind resources in the Market.
Load Diversity	2.35%	3.00%	+0.65	Result of further review utilized another historical year of data, and reflect benefits of CPnode level diversity.
System Coincident Load	110,625	110,779	+154	New forecast from Module E and includes new Market participants
Required IGEN MW	127,661	127,839	+178	New forecast from Module E, includes new Market participants, and higher $PRM_{SYSIGEN}$
Required UCAP MW	119,345	119,344	-1	New forecast from Module E, includes new Market participants and new lower PRM_{UCAP}

Definitions:

PRM – Planning Reserve Margin: An additional amount of generation above load, expressed as a % of the load. In the Tariff as: "The percentage of Capacity Resources that an LSE must maintain for RAR above its Forecast LSE Requirement to reliably be able to serve Load based upon meeting the LOLE."

IGEN – Installed Generation Capacity MW, also used as a subscript to indicate PRM on the IGEN basis

LSEIGEN – Load Serving Entity Generation MW, also used as a subscript to indicate an LSE's PRM obligation based on an LSE's non-coincident load, referred to as the LSEIGEN basis

UCAP – Unforced Capacity MW: The amount of MW credited to a generator after reducing the resources IGEN (UCAP MW = IGEN MW x (1 - XEFORd), also used as a subscript to indicate PRM on the basis of generation capacity MW not affected by XEFORd

EFORd – Equivalent demand Forced Outage Rate: A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

XEFORd - Same meaning as EFORd, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example loss of transmission outlet lines are considered as OMC relative to a units operation.

OMC – Outside Management Control: Refers to component of generator forced outages due to causes not related to prudent operation of the generator, typically these are storm or transmission related outages that cause the generation to be unavailable. This class of outages is what drives the difference between EFORd and XEFORd.

LFU – Load Forecast Uncertainty: The variance around the future forecast of demand. Represented in the LOLE model as a probability distribution around the mean (50/50) forecast.

Load Diversity – The difference on a percentage basis of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system.

Table F2 Former Year to Year Comparison Metrics Applied to PY 2010 versus PY 2011

Information Item	PY 2009	PY 2010	PY 2011	Change	Comments
$PRM_{SYSIGEN}$	15.4%	15.4%	17.4%	+2.0%	Increased PRM due to higher generator EFORd's, less use of external tie and higher LFU; and decreased due to less congestion.
$PRM_{LSEIGEN}$	12.69%	11.94%	12.06%	-0.12%	Increased PRM due to higher generator EFORd's, less use of external tie, higher LFU, and higher load diversity factor; and decreased due to less congestion.
PRM_{UCAP}	5.35%	4.50%	3.81%	-0.69%	Decreasing PRM due to less congestion; and down primarily due to higher load diversity. Slight upward effect due to less utilization of external ties, and greater difference between EFORd versus XEFORd (OMC outage category)
% of Market Generation with GADS data	83.5%	99.4%	90.7%	-8.7%	This number is difficult to track and to compare because more units report GADS data than are required to; e.g. outside the market footprint units
System Wide Average XEFORd (Generation only)	6.75%	6.83%	7.36%	+0.53%	Up due to higher forced outage history
Generation only IGEN MW	130,446	141,911	124,127	-17,784	Decrease due to First Energy leaving and unit retirements.
Demand Response MW in system assigned an XEFORd=0	4,717	4,053	0	-4,053	New Load reporting provides net load, and DR is not quantifiable in the modeled load shape. For the simulation therefore, the DR is effectively BTM
System Wide Average XEFORd (Generators and	6.514%	6.644%	n/a	n/a	New Load reporting provides net load, and DR is not quantifiable in the modeled load shape. For the simulation

Information Item	PY 2009	PY 2010	PY 2011	Change	Comments
DR)					therefore, the DR is effectively BTM
System Wide Average EFORd (Generation only)	7.05%	7.31%	8.03%	+0.72	Reflects another year of GADS data reporting of Market resources
System Wide Average EFORd (Generators and DR blend)	6.80%	7.10%	n/a	n/a	New Load reporting provides net load, and DR is not quantifiable in the modeled load shape. For the simulation therefore, the DR is effectively BTM
Sum of RC footprint Load non-coincident to total RC load	113,287	114,205	109,540	-4,665	New forecast from Module E and reflects First Energy leaving RC footprint.
Wind capacity credit (% of monthly Registered Max)	20%	8%	12.9%.	+4.9%	Result of Wind Capacity Credit driven by another year of data, and updated method to merge historical years' impacts.
Load Diversity	2.35%	3.00%	4.55%	+1.55%	Result of further review of historical data and set a new level for PY2011.
System Coincident Load	110,625	110,779	104,557	-6,222	New forecast from Module E and reflects First Energy leaving RC footprint.
Required IGEN MW	127,661	127,839	122,750	-5,089	Reflects the new lower load forecast and higher EFORD which increased the needed $PRM_{SYSIGEN}$
Required UCAP MW	119,345	119,344	113,713	-5,631	Reflects the new lower load forecast, and increased due to higher OMC and diversity which result in a net lower UCAP MW

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
P.V. UTILITY COST:	
PLANNING PERIOD	2269500.8
% DIFFERENCE	0.00%
END EFFECTS PERIOD	1041144.0
% DIFFERENCE	0.00%
STUDY PERIOD	3310644.8
% DIFFERENCE	0.00%
PLANNING PERIOD RANK	1

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
FINAL PEAK	1155.8	1155.8	1164.2	1164.2	1160.0	1151.6	1145.3	1138.9	1144.2	1149.5	1154.7	1160.0	1164.2	1170.5	1176.8
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1460.1	1363.4	1366.7	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	304.3	207.6	202.5	217.9	222.1	230.5	236.8	243.1	237.9	232.6	227.3	222.1	217.9	211.5	205.2
RESERVE MARGIN PERCENT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79	20.23	19.69	19.14	18.71	18.07	17.44
CAPACITY MARGIN PERCENT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21	16.83	16.45	16.07	15.76	15.31	14.85

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
DSM PEAK:					
7 DSM	-124.2	-128.4	-132.6	-136.8	-141.1
TOTAL DSM PEAK	-124.2	-128.4	-132.6	-136.8	-141.1
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
+ DSM ADJUSTMENTS	-124.2	-128.4	-132.6	-136.8	-141.1
FINAL PEAK	1184.2	1190.5	1198.9	1207.4	1215.8
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2027	2028	2029	2030	2031
RESERVE (MW)	197.9	191.5	183.1	174.7	166.3
RESERVE MARGIN PERCENT	16.71	16.09	15.27	14.47	13.68
CAPACITY MARGIN PERCENT	14.32	13.86	13.25	12.64	12.03

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5807.	5803.	5773.	5725.	5658.	5591.	5520.	5539.
THERM GENERATION	GWH	4677.	5320.	5356.	5588.	5846.	6095.	6258.	6423.	6700.
CONTROLLED ENERGY	GWH	1.	2.	2.	3.	3.	2.	2.	2.	2.
PAYBACK ENERGY	GWH	-1.	-1.	-2.	-2.	-2.	-2.	-2.	-2.	-2.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	487.	447.	184.	-121.	-437.	-668.	-904.	-1161.
PEAK LOAD	MW	1156.	1156.	1164.	1164.	1160.	1152.	1145.	1139.	1144.
LOAD FACTOR	PCT	57.50	57.36	56.90	56.60	56.19	56.09	55.72	55.33	55.11
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	304.	208.	203.	218.	222.	230.	237.	243.	238.
RESERVE MARGIN	PCT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79
CAPACITY MARGIN	PCT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21
ENERGY RESV MARGIN	PCT	94.04	106.76	106.91	108.49	110.78	112.72	115.28	118.03	117.87
LOSS LOAD	HOURS	3.	3.	3.	3.	4.	3.	3.	3.	3.
RENEWABLE ENERGY	PCT	4.71	4.73	4.74	4.76	4.80	4.86	4.92	4.98	4.96
FUEL BURNED 000	MBTU	52422.	58903.	59273.	61704.	64408.	67011.	68605.	70358.	73374.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157634.	146055.	149362.	162689.	175156.	187978.	199057.	211063.	227776.
VAR. O&M COST	$000	12476.	14305.	14823.	15780.	16867.	18030.	19288.	20335.	21934.
FIXED O&M COST	$000	26281.	26589.	27004.	27530.	28166.	28822.	29514.	30231.	30978.
TOTAL THERM COST	$000	196391.	186949.	191188.	205999.	220188.	234831.	247859.	261629.	280688.
THERMAL COST	$/MWH	41.99	35.14	35.70	36.86	37.67	38.53	39.60	40.73	41.90
TOTAL EMISS. COST	$000	-10829.	-9657.	-7449.	-7191.	-6847.	-6458.	-6236.	-5952.	-5170.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	37095.	13701.	14762.	3876.	-7304.	-21682.	-35230.	-49514.	-65604.
EMER ENERGY COST	$000	73.	67.	57.	65.	72.	61.	56.	54.	56.
TOTAL SYS. COST	$000	222731.	191061.	198558.	202749.	206110.	206751.	206449.	206217.	209970.
SYSTEM COST	$/MWH	38.15	32.90	34.22	35.12	36.00	36.54	36.93	37.36	37.91
AVG. MARG. COST	$/MWH	44.23	42.01	44.47	49.11	52.21	55.92	60.34	64.85	69.55
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	904.	426.	433.	272.	151.	61.	36.	11.	12.
PURCH COST	$000	26117.	11430.	12118.	8095.	4845.	2254.	1414.	576.	598.
AVE. PURCH COST	$/MWH	28.88	26.81	27.96	29.77	31.99	36.85	39.57	52.78	50.15

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	195.	391.	438.	599.	783.	1009.	1215.	1425.	1684.
SALES REV.	$000	17187.	23776.	26993.	35203.	44381.	57473.	71562.	86462.	104101.
AVE. SALES REV.	$/MWH	87.97	60.85	61.63	58.79	56.66	56.95	58.91	60.66	61.83
NET ECON ENERGY	GWH	709.	36.	-5.	-327.	-632.	-948.	-1179.	-1414.	-1672.
NET ECON COST	$000	8931.	-12346.	-14875.	-27108.	-39536.	-55219.	-70149.	-85886.	-103503.
TOTAL PURCH	GWH	1415.	937.	944.	783.	662.	572.	546.	522.	523.
TOTAL PURCH	$000	57158.	40379.	42010.	39079.	37077.	35791.	36332.	36947.	38497.
TOTAL SALES	GWH	255.	450.	497.	599.	783.	1009.	1215.	1425.	1684.
TOTAL SALES	$000	20063.	26678.	27248.	35203.	44381.	57473.	71562.	86462.	104101.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	5543.	5554.	5563.	5581.	5588.	5602.	5619.	5646.	5660.
THERM GENERATION	GWH	6759.	6821.	6875.	6965.	7088.	7158.	7207.	7294.	7310.
CONTROLLED ENERGY	GWH	2.	2.	3.	3.	3.	5.	5.	5.	5.
PAYBACK ENERGY	GWH	-2.	-2.	-2.	-2.	-3.	-4.	-4.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-1216.	-1268.	-1313.	-1385.	-1500.	-1556.	-1589.	-1649.	-1651.
PEAK LOAD	MW	1149.	1155.	1160.	1164.	1171.	1177.	1184.	1191.	1199.
LOAD FACTOR	PCT	55.05	54.90	54.75	54.57	54.50	54.34	54.17	53.99	53.89
INSTALLED CAPACITY	MW	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	233.	227.	222.	218.	212.	205.	198.	192.	183.
RESERVE MARGIN	PCT	20.23	19.69	19.14	18.71	18.07	17.44	16.71	16.09	15.27
CAPACITY MARGIN	PCT	16.83	16.45	16.07	15.76	15.31	14.85	14.32	13.86	13.25
ENERGY RESV MARGIN	PCT	117.12	116.71	116.34	116.23	115.36	114.84	114.19	113.73	112.64
LOSS LOAD	HOURS	3.	3.	3.	3.	3.	3.	3.	4.	4.
RENEWABLE ENERGY	PCT	4.96	4.95	4.94	4.93	4.92	4.91	4.89	4.87	4.86
FUEL BURNED 000	MBTU	74045.	74754.	75368.	76383.	77780.	78579.	79144.	80116.	80313.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	238518.	249135.	260376.	272890.	288223.	299740.	310308.	322548.	332562.
VAR. O&M COST	$000	22781.	23664.	24555.	25598.	26868.	27861.	28753.	29839.	30648.
FIXED O&M COST	$000	31752.	32569.	33419.	34267.	35097.	35921.	36733.	37571.	38442.
TOTAL THERM COST	$000	293051.	305367.	318349.	332755.	350188.	363523.	375794.	389958.	401652.
THERMAL COST	$/MWH	43.36	44.77	46.30	47.77	49.41	50.79	52.14	53.46	54.95
TOTAL EMISS. COST	$000	-5120.	-5058.	-5001.	-4780.	-4237.	-3991.	-3846.	-3489.	-3481.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-72566.	-79308.	-88236.	-97796.	-114747.	-124357.	-131633.	-139793.	-145446.
EMER ENERGY COST	$000	62.	65.	70.	76.	74.	75.	88.	109.	121.
TOTAL SYS. COST	$000	215427.	221067.	225182.	230256.	231279.	235249.	240403.	246785.	252845.
SYSTEM COST	$/MWH	38.86	39.81	40.48	41.26	41.39	41.99	42.78	43.71	44.67
AVG. MARG. COST	$/MWH	73.44	77.18	82.37	87.04	94.74	99.61	103.99	108.07	112.80
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	11.	10.	3.	3.	3.	3.	3.	5.	5.
PURCH COST	$000	576.	564.	332.	347.	346.	384.	446.	590.	696.
AVE. PURCH COST	$/MWH	53.12	57.32	97.25	105.04	119.30	128.29	137.02	130.04	138.30

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1737.	1789.	1827.	1899.	2014.	2070.	2103.	2164.	2166.
SALES REV.	$000	112645.	121078.	131569.	142987.	161807.	173370.	182660.	193004.	200910.
AVE. SALES REV.	$/MWH	64.83	67.69	72.02	75.30	80.34	83.75	86.86	89.19	92.74
NET ECON ENERGY	GWH	-1727.	-1779.	-1823.	-1896.	-2011.	-2067.	-2100.	-2159.	-2161.
NET ECON COST	$000	-112070.	-120514.	-131237.	-142640.	-161460.	-172986.	-182214.	-192414.	-200215.
TOTAL PURCH	GWH	522.	521.	514.	514.	514.	514.	514.	515.	516.
TOTAL PURCH	$000	40079.	41770.	43333.	45192.	47060.	49013.	51027.	53211.	55464.
TOTAL SALES	GWH	1737.	1789.	1827.	1899.	2014.	2070.	2103.	2164.	2166.
TOTAL SALES	$000	112645.	121078.	131569.	142987.	161807.	173370.	182660.	193004.	200910.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	5685.	5711.
THERM GENERATION	GWH	7360.	7419.
CONTROLLED ENERGY	GWH	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-1676.	-1709.
PEAK LOAD	MW	1207.	1216.
LOAD FACTOR	PCT	53.75	53.62
INSTALLED CAPACITY	MW	1382.	1382.
RESERVE MARGIN	MW	175.	166.
RESERVE MARGIN	PCT	14.47	13.68
CAPACITY MARGIN	PCT	12.64	12.03
ENERGY RESV MARGIN	PCT	111.70	110.76
LOSS LOAD	HOURS	4.	4.
RENEWABLE ENERGY	PCT	4.83	4.81
FUEL BURNED 000	MBTU	80904.	81594.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	344994.	359108.
VAR. O&M COST	$000	31655.	32724.
FIXED O&M COST	$000	39346.	40255.
TOTAL THERM COST	$000	415995.	432087.
THERMAL COST	$/MWH	56.52	58.24
TOTAL EMISS. COST	$000	-3276.	-2975.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-154385.	-166585.
EMER ENERGY COST	$000	118.	134.
TOTAL SYS. COST	$000	258452.	262661.
SYSTEM COST	$/MWH	45.46	46.00
AVG. MARG. COST	$/MWH	118.48	125.81
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	6.	6.
PURCH COST	$000	825.	964.
AVE. PURCH COST	$/MWH	148.02	165.01

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	2192.	2226.
SALES REV.	$000	212232.	226897.
AVE. SALES REV.	$/MWH	96.82	101.95
NET ECON ENERGY	GWH	-2186.	-2220.
NET ECON COST	$000	-211407.	-225933.
TOTAL PURCH	GWH	516.	517.
TOTAL PURCH	$000	57847.	60312.
TOTAL SALES	GWH	2192.	2226.
TOTAL SALES	$000	212232.	226897.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019	CC F(1)	LM6K(1)	LM6K(1)	CC F(1)	LM6K(1)	LM6K(1)	LM6K(1)	LM6K(1)
2020								
2021								
2022								
2023								
2024		CC F(1)	LM6K(1)		LM6K(1)	LMS (1)	LM6K(1)	LMS (1)
2025								
2026								
2027	CC F(1)			LMS (1)				
2028								
2029			CC F(1)		LM6K(1)		LMS (1)	
2030						CC F(1)		LMS (1)
2031								
P.V. UTILITY COST:								
PLANNING PERIOD	2751127.5	2751619.8	2756974.2	2760142.8	2760603.8	2766532.5	2762318.2	2769915.5
% DIFFERENCE	0.00%	0.02%	0.21%	0.33%	0.34%	0.56%	0.41%	0.68%
END EFFECTS PERIOD	1588458.5	1598035.2	1611685.8	1619819.2	1626975.2	1629455.5	1641461.2	1658032.0
% DIFFERENCE	0.00%	0.60%	1.46%	1.97%	2.42%	2.58%	3.34%	4.38%
STUDY PERIOD	4339586.0	4349655.0	4368660.0	4379962.0	4387579.0	4395988.0	4403779.5	4427947.5
% DIFFERENCE	0.00%	0.23%	0.67%	0.93%	1.11%	1.30%	1.48%	2.04%
PLANNING PERIOD RANK	1	2	3	4	5	7	6	8

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	9	10	11	12	13	14	15	16
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019	CC F(1)	LMS (1)	LM6K(1)	CC F(1)	LM6K(1)	LM6K(1)	LM6K(1)	LMS (1)
2020								
2021								
2022								
2023								
2024			CT E(1)		LM6K(1)	LM6K(1)	LMS (1)	
2025		LMS (1)						LMS (1)
2026								
2027	CT E(1)			CT F(1)				
2028								
2029			CC F(1)		CT E(1)	CT F(1)		
2030							CT E(1)	
2031		CC F(1)						LMS (1)
P.V. UTILITY COST:								
PLANNING PERIOD	2771777.0	2788828.5	2783704.5	2776840.2	2770132.2	2772267.5	2774945.0	2790359.5
% DIFFERENCE	0.75%	1.37%	1.18%	0.93%	0.69%	0.77%	0.87%	1.43%
END EFFECTS PERIOD	1657819.0	1654867.0	1664303.5	1674698.2	1681850.2	1695175.0	1696041.0	1680950.5
% DIFFERENCE	4.37%	4.18%	4.77%	5.43%	5.88%	6.72%	6.77%	5.82%
STUDY PERIOD	4429596.0	4443695.5	4448008.0	4451538.5	4451982.5	4467442.5	4470986.0	4471310.0
% DIFFERENCE	2.07%	2.40%	2.50%	2.58%	2.59%	2.95%	3.03%	3.04%
PLANNING PERIOD RANK	10	16	15	14	9	11	12	17

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	17	18	19	20	21	22	23	24
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019	LM6K(1)	LMS (1)	LM6K(1)	LMS (1)	LMS (1)	LMS (1)	CT F(1)	LM6K(1)
2020								
2021								
2022								
2023								
2024	LMS (1)		CT F(1)					CT E(1)
2025		CT E(1)		LMS (1)	CT F(1)	LMS (1)		
2026								
2027								
2028								
2029								CT E(1)
2030	CT F(1)	CC F(1)						
2031				CT E(1)		CT F(1)		
P.V. UTILITY COST:								
PLANNING PERIOD	2776157.0	2803216.0	2798326.2	2792668.8	2813281.2	2793216.2	2830490.5	2798394.0
% DIFFERENCE	0.91%	1.89%	1.72%	1.51%	2.26%	1.53%	2.88%	1.72%
END EFFECTS PERIOD	1709801.5	1683675.0	1692343.8	1714197.2	1707629.2	1728846.2	1693963.5	1743057.5
% DIFFERENCE	7.64%	5.99%	6.54%	7.92%	7.50%	8.84%	6.64%	9.73%
STUDY PERIOD	4485958.5	4486891.0	4490670.0	4506866.0	4520910.5	4522062.5	4524454.0	4541451.5
% DIFFERENCE	3.37%	3.39%	3.48%	3.85%	4.18%	4.20%	4.26%	4.65%
PLANNING PERIOD RANK	13	23	20	18	26	19	31	21

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	25	26	27	28	29	30	31	32
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019	LM6K(1)	CT E(1)	LMS (1)	LMS (1)	CT E(1)	CT E(1)	CT E(1)	LM6K(1)
2020								
2021								
2022								
2023								
2024	CT E(1)	CT E(1)			CT F(1)	CT E(1)	CT E(1)	LMS (1)
2025			CT E(1)	CT E(1)				
2026								
2027								
2028								
2029	CT F(1)	CC F(1)				CT E(1)	CT F(1)	
2030			CT E(1)	CT F(1)				BIOM(1)
2031								
P.V. UTILITY COST:								
PLANNING PERIOD	2800290.5	2836902.8	2812503.0	2813608.2	2851241.0	2852946.2	2854426.8	2819082.5
% DIFFERENCE	1.79%	3.12%	2.23%	2.27%	3.64%	3.70%	3.75%	2.47%
END EFFECTS PERIOD	1754836.5	1724787.8	1757448.5	1770226.8	1758123.0	1812483.2	1821237.2	2051229.0
% DIFFERENCE	10.47%	8.58%	10.64%	11.44%	10.68%	14.10%	14.65%	29.13%
STUDY PERIOD	4555127.0	4561690.5	4569951.5	4583835.0	4609364.0	4665429.5	4675664.0	4870311.5
% DIFFERENCE	4.97%	5.12%	5.31%	5.63%	6.22%	7.51%	7.74%	12.23%
PLANNING PERIOD RANK	22	33	25	27	35	37	38	30

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	33	34	35	36	37	38	39	40
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019	LM6K(1)	LMS (1)	LM6K(1)	LM6K(1)	CC F(1)	CC F(1)	LMS (1)	CC F(1)
2020								
2021								
2022								
2023								
2024	LM6K(1)		LMS (1)	LM6K(1)				
2025		LMS (1)					LMS (1)	
2026								
2027					BIOM(1)	BIOM(1)		COAL(1)
2028								
2029	BIOM(1)			COAL(1)				
2030			COAL(1)		CC F(1)	LM6K(1)		
2031		BIOM(1)					COAL(1)	
P.V. UTILITY COST:								
PLANNING PERIOD	2838001.8	2814249.2	2814825.2	2831953.5	2890676.5	2891789.0	2812059.2	2883442.0
% DIFFERENCE	3.16%	2.29%	2.32%	2.94%	5.07%	5.11%	2.21%	4.81%
END EFFECTS PERIOD	2036102.8	2072396.8	2085359.8	2068923.5	2013610.0	2018330.0	2108800.2	2044760.0
% DIFFERENCE	28.18%	30.47%	31.28%	30.25%	26.77%	27.06%	32.76%	28.73%
STUDY PERIOD	4874104.5	4886646.0	4900185.0	4900877.0	4904286.5	4910119.0	4920859.5	4928202.0
% DIFFERENCE	12.32%	12.61%	12.92%	12.93%	13.01%	13.15%	13.39%	13.56%
PLANNING PERIOD RANK	34	28	29	32	43	44	24	42

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1155.8	1187.4	1203.2	1225.3	1248.4	1276.8	1304.2	1332.6	1348.4	1365.3	1382.1	1398.9	1415.8	1432.6	1449.5
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
PEAK BEFORE DSM	1155.8	1187.4	1203.2	1225.3	1248.4	1276.8	1304.2	1332.6	1348.4	1365.3	1382.1	1398.9	1415.8	1432.6	1449.5
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
FINAL PEAK	1144.2	1167.4	1178.9	1191.6	1203.2	1214.7	1227.4	1238.9	1251.6	1264.2	1276.8	1290.5	1303.2	1315.8	1328.4
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 New CC F249	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
250 New CC F250	0.0	0.0	0.0	0.0	0.0	0.0	0.0	113.2	113.2	113.2	113.2	113.2	113.2	113.2	113.2
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1398.2	1398.2	1398.2	1398.2	1398.2	1398.2	1398.2	1398.2
TOTAL CAPACITY	1460.1	1363.4	1366.7	1382.1	1382.1	1382.1	1382.1	1495.3	1495.3	1495.3	1495.3	1495.3	1495.3	1495.3	1495.3

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	315.9	196.0	187.8	190.5	178.9	167.3	154.7	256.3	243.7	231.1	218.4	204.8	192.1	179.5	166.9
RESERVE MARGIN PERCENT	27.60	16.79	15.93	15.99	14.87	13.77	12.60	20.69	19.47	18.28	17.11	15.87	14.74	13.64	12.56
CAPACITY MARGIN PERCENT	21.63	14.38	13.74	13.78	12.94	12.11	11.19	17.14	16.30	15.45	14.61	13.69	12.85	12.00	11.16

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1466.3	1484.2	1502.1	1520.0	1537.9
DSM PEAK:					
7 DSM	-124.2	-128.4	-132.6	-136.8	-141.1
TOTAL DSM PEAK	-124.2	-128.4	-132.6	-136.8	-141.1
PEAK BEFORE DSM	1466.3	1484.2	1502.1	1520.0	1537.9
+ DSM ADJUSTMENTS	-124.2	-128.4	-132.6	-136.8	-141.1
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FINAL PEAK	1342.1	1355.8	1369.5	1383.2	1396.8
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
249 New CC F249	113.2	113.2	113.2	113.2	113.2
250 New CC F250	113.2	113.2	113.2	113.2	113.2
TOTAL THERMAL	1511.5	1511.5	1511.5	1511.5	1511.5
TOTAL CAPACITY	1608.5	1608.5	1608.5	1608.5	1608.5

RESERVES
========

	2027	2028	2029	2030	2031
RESERVE (MW)	266.4	252.7	239.0	225.3	211.7
RESERVE MARGIN PERCENT	19.85	18.64	17.45	16.29	15.15
CAPACITY MARGIN PERCENT	16.56	15.71	14.86	14.01	13.16

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5960.	6019.	6080.	6141.	6202.	6263.	6326.	6391.
THERM GENERATION	GWH	4677.	5320.	5356.	5588.	5846.	6095.	6258.	6901.	7248.
CONTROLLED ENERGY	GWH	2.	2.	3.	4.	4.	5.	5.	3.	3.
PAYBACK ENERGY	GWH	-1.	-2.	-3.	-3.	-4.	-4.	-4.	-2.	-3.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	639.	662.	491.	294.	106.	3.	-576.	-858.
PEAK LOAD	MW	1144.	1167.	1179.	1192.	1203.	1215.	1227.	1239.	1252.
LOAD FACTOR	PCT	58.08	58.28	58.28	58.25	58.11	58.28	58.25	58.29	58.13
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1382.	1382.	1382.	1382.	1495.	1495.
RESERVE MARGIN	MW	316.	196.	188.	190.	179.	167.	155.	256.	244.
RESERVE MARGIN	PCT	27.60	16.79	15.93	15.99	14.87	13.77	12.60	20.69	19.47
CAPACITY MARGIN	PCT	21.63	14.38	13.74	13.78	12.94	12.11	11.19	17.14	16.30
ENERGY RESV MARGIN	PCT	94.04	101.47	99.51	97.95	96.51	94.05	92.16	90.24	88.84
LOSS LOAD	HOURS	3.	4.	4.	5.	5.	6.	7.	3.	3.
RENEWABLE ENERGY	PCT	4.71	4.61	4.57	4.52	4.48	4.43	4.39	4.34	4.30
FUEL BURNED 000	MBTU	52421.	58904.	59272.	61702.	64406.	67011.	68603.	74831.	78540.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157631.	146055.	149353.	162668.	175126.	187927.	198994.	227266.	247070.
VAR. O&M COST	$000	12475.	14306.	14822.	15779.	16866.	18029.	19286.	22726.	24741.
FIXED O&M COST	$000	26281.	26589.	27004.	27530.	28166.	28822.	29514.	31761.	32546.
TOTAL THERM COST	$000	196388.	186950.	191179.	205977.	220158.	234778.	247795.	281752.	304357.
THERMAL COST	$/MWH	41.99	35.14	35.70	36.86	37.66	38.52	39.59	40.83	41.99
TOTAL EMISS. COST	$000	-10829.	-9656.	-7449.	-7190.	-6846.	-6452.	-6231.	-4263.	-3079.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	36969.	18798.	22266.	15474.	9733.	3442.	-1452.	-34136.	-49651.
EMER ENERGY COST	$000	61.	65.	78.	100.	116.	134.	159.	52.	64.
TOTAL SYS. COST	$000	222589.	196157.	206074.	214361.	223160.	231902.	240269.	243405.	251690.
SYSTEM COST	$/MWH	38.13	32.91	34.24	35.26	36.34	37.39	38.36	38.48	39.38
AVG. MARG. COST	$/MWH	44.23	42.01	44.47	49.11	52.20	55.92	60.33	65.04	69.56
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	907.	507.	553.	409.	287.	183.	153.	47.	31.
PURCH COST	$000	26127.	13919.	15894.	12817.	10042.	7557.	6875.	2139.	1695.
AVE. PURCH COST	$/MWH	28.81	27.43	28.73	31.31	35.03	41.30	44.98	45.75	54.43

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	198.	319.	342.	429.	503.	588.	660.	1133.	1400.
SALES REV.	$000	17322.	21168.	23265.	28327.	32541.	37651.	43246.	72646.	89245.
AVE. SALES REV.	$/MWH	87.63	66.26	67.98	66.03	64.67	64.06	65.50	64.12	63.75
NET ECON ENERGY	GWH	709.	188.	211.	-20.	-217.	-405.	-507.	-1086.	-1369.
NET ECON COST	$000	8804.	-7249.	-7371.	-15510.	-22499.	-30094.	-36371.	-70507.	-87550.
TOTAL PURCH	GWH	1418.	1018.	1064.	920.	797.	694.	664.	557.	542.
TOTAL PURCH	$000	57168.	42869.	45786.	43802.	42274.	41094.	41794.	38510.	39594.
TOTAL SALES	GWH	257.	379.	402.	429.	503.	588.	660.	1133.	1400.
TOTAL SALES	$000	20199.	24071.	23520.	28327.	32541.	37651.	43246.	72646.	89245.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	6453.	6518.	6583.	6649.	6716.	6782.	6851.	6919.	6988.
THERM GENERATION	GWH	7308.	7378.	7416.	7522.	7663.	7750.	8410.	8551.	8587.
CONTROLLED ENERGY	GWH	5.	5.	5.	5.	5.	5.	4.	4.	5.
PAYBACK ENERGY	GWH	-4.	-4.	-4.	-4.	-4.	-4.	-3.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-856.	-861.	-834.	-874.	-948.	-969.	-1560.	-1632.	-1600.
PEAK LOAD	MW	1264.	1277.	1291.	1303.	1316.	1328.	1342.	1356.	1369.
LOAD FACTOR	PCT	58.27	58.27	58.23	58.09	58.26	58.28	58.27	58.10	58.25
INSTALLED CAPACITY	MW	1495.	1495.	1495.	1495.	1495.	1495.	1609.	1609.	1609.
RESERVE MARGIN	MW	231.	218.	205.	192.	179.	167.	266.	253.	239.
RESERVE MARGIN	PCT	18.28	17.11	15.87	14.74	13.64	12.56	19.85	18.64	17.45
CAPACITY MARGIN	PCT	15.45	14.61	13.69	12.85	12.00	11.16	16.56	15.71	14.86
ENERGY RESV MARGIN	PCT	86.52	84.65	82.82	81.49	79.21	77.46	75.69	74.42	72.22
LOSS LOAD	HOURS	3.	3.	5.	6.	7.	7.	2.	3.	3.
RENEWABLE ENERGY	PCT	4.26	4.22	4.17	4.13	4.09	4.05	4.01	3.97	3.93
FUEL BURNED 000	MBTU	79185.	79930.	80325.	81467.	82973.	83898.	89481.	90870.	91204.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	258520.	270054.	281606.	295663.	313115.	326645.	372927.	390028.	403615.
VAR. O&M COST	$000	25686.	26700.	27632.	28872.	30379.	31614.	37248.	38975.	40221.
FIXED O&M COST	$000	33359.	34217.	35110.	36001.	36873.	37739.	40451.	41373.	42333.
TOTAL THERM COST	$000	317566.	330970.	344348.	360536.	380366.	395998.	450626.	470377.	486170.
THERMAL COST	$/MWH	43.45	44.86	46.43	47.93	49.64	51.10	53.58	55.01	56.61
TOTAL EMISS. COST	$000	-2933.	-2751.	-2740.	-2375.	-1714.	-1365.	643.	1383.	1600.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-52287.	-54839.	-57339.	-62821.	-73798.	-78917.	-137366.	-146242.	-149245.
EMER ENERGY COST	$000	75.	75.	115.	155.	176.	194.	59.	66.	92.
TOTAL SYS. COST	$000	262421.	273455.	284385.	295495.	305029.	315910.	313962.	325584.	338616.
SYSTEM COST	$/MWH	40.67	41.95	43.20	44.44	45.42	46.58	45.83	47.06	48.45
AVG. MARG. COST	$/MWH	73.45	77.17	82.33	86.98	94.64	99.52	104.36	108.29	113.02
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	30.	31.	22.	21.	18.	19.	3.	5.	5.
PURCH COST	$000	1768.	1967.	1783.	1939.	1992.	2268.	309.	504.	568.
AVE. PURCH COST	$/MWH	58.58	64.30	82.35	91.89	111.30	118.81	107.53	99.12	109.49

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1397.	1402.	1366.	1406.	1477.	1499.	2074.	2148.	2116.
SALES REV.	$000	93559.	98012.	102123.	109605.	122504.	129814.	188255.	199367.	204581.
AVE. SALES REV.	$/MWH	66.97	69.92	74.76	77.98	82.95	86.59	90.77	92.81	96.70
NET ECON ENERGY	GWH	-1367.	-1371.	-1344.	-1384.	-1459.	-1480.	-2071.	-2143.	-2110.
NET ECON COST	$000	-91791.	-96045.	-100340.	-107665.	-120512.	-127546.	-187946.	-198863.	-204013.
TOTAL PURCH	GWH	541.	541.	532.	532.	529.	530.	514.	516.	516.
TOTAL PURCH	$000	41272.	43173.	44785.	46784.	48706.	50897.	50889.	53125.	55337.
TOTAL SALES	GWH	1397.	1402.	1366.	1406.	1477.	1499.	2074.	2148.	2116.
TOTAL SALES	$000	93559.	98012.	102123.	109605.	122504.	129814.	188255.	199367.	204581.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	7058.	7128.
THERM GENERATION	GWH	8667.	8742.
CONTROLLED ENERGY	GWH	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-1610.	-1615.
PEAK LOAD	MW	1383.	1397.
LOAD FACTOR	PCT	58.25	58.26
INSTALLED CAPACITY	MW	1609.	1609.
RESERVE MARGIN	MW	225.	212.
RESERVE MARGIN	PCT	16.29	15.15
CAPACITY MARGIN	PCT	14.01	13.16
ENERGY RESV MARGIN	PCT	70.52	68.84
LOSS LOAD	HOURS	4.	4.
RENEWABLE ENERGY	PCT	3.89	3.86
FUEL BURNED 000	MBTU	91978.	92701.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	420551.	439335.
VAR. O&M COST	$000	41786.	43342.
FIXED O&M COST	$000	43328.	44329.
TOTAL THERM COST	$000	505665.	527006.
THERMAL COST	$/MWH	58.34	60.28
TOTAL EMISS. COST	$000	1992.	2400.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-157331.	-167351.
EMER ENERGY COST	$000	99.	120.
TOTAL SYS. COST	$000	350426.	362175.
SYSTEM COST	$/MWH	49.65	50.81
AVG. MARG. COST	$/MWH	118.70	126.08
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	5.	6.
PURCH COST	$000	619.	739.
AVE. PURCH COST	$/MWH	116.64	126.89

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	2126.	2131.
SALES REV.	$000	214973.	227437.
AVE. SALES REV.	$/MWH	101.10	106.71
NET ECON ENERGY	GWH	-2121.	-2125.
NET ECON COST	$000	-214353.	-226698.
TOTAL PURCH	GWH	516.	516.
TOTAL PURCH	$000	57641.	60086.
TOTAL SALES	GWH	2126.	2131.
TOTAL SALES	$000	214973.	227437.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2012								
2013								
2014								
2015	LM6K(1)	CC F(1)	LMS (1)	CT E(1)	CT F(1)	BIOM(1)	BIOM(1)	BIOM(1)
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029						CC F(1)	LM6K(1)	LMS (1)
2030								
2031								
P.V. UTILITY COST:								
PLANNING PERIOD	2570943.5	2586887.2	2613626.2	2639299.5	2681868.2	3231002.5	3232854.2	3236085.0
% DIFFERENCE	0.00%	0.62%	1.66%	2.66%	4.31%	25.67%	25.75%	25.87%
END EFFECTS PERIOD	1269416.8	1260163.2	1290564.5	1331926.8	1354286.8	1689806.0	1697356.2	1719024.0
% DIFFERENCE	0.00%	-0.73%	1.67%	4.92%	6.69%	33.12%	33.71%	35.42%
STUDY PERIOD	3840360.2	3847050.5	3904190.8	3971226.2	4036155.0	4920808.5	4930210.5	4955109.0
% DIFFERENCE	0.00%	0.17%	1.66%	3.41%	5.10%	28.13%	28.38%	29.03%
PLANNING PERIOD RANK	1	2	3	4	5	6	7	8

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	9	10	11	12
2012				
2013				
2014				
2015	BIOM(1)	BIOM(1)	BIOM(1)	BIOM(1)
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029	CT E(1)	CT F(1)	BIOM(1)	COAL(1)
2030				
2031				
P.V. UTILITY COST:				
PLANNING PERIOD	3243546.2	3247466.0	3311819.0	3307826.2
% DIFFERENCE	26.16%	26.31%	28.82%	28.66%
END EFFECTS PERIOD	1757624.8	1781806.0	2113605.0	2158105.8
% DIFFERENCE	38.46%	40.36%	66.50%	70.01%
STUDY PERIOD	5001171.0	5029272.0	5425424.0	5465932.0
% DIFFERENCE	30.23%	30.96%	41.27%	42.33%
PLANNING PERIOD RANK	9	10	12	11

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1276.9	1284.3	1292.7	1301.1	1311.6	1320.1	1329.5	1339.0	1347.4	1355.9	1366.4	1376.9
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1276.9	1284.3	1292.7	1301.1	1311.6	1320.1	1329.5	1339.0	1347.4	1355.9	1366.4	1376.9
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
FINAL PEAK	1155.8	1155.8	1164.2	1243.2	1239.0	1230.6	1224.3	1218.0	1223.2	1228.5	1233.8	1239.0	1243.2	1249.5	1255.9
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
250 New LM6K250	0.0	0.0	0.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0	1359.0
TOTAL CAPACITY	1460.1	1363.4	1366.7	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0	1456.0

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	304.3	207.6	202.5	212.8	217.0	225.4	231.7	238.1	232.8	227.5	222.3	217.0	212.8	206.5	200.2
RESERVE MARGIN PERCENT	26.33	17.96	17.40	17.12	17.51	18.32	18.93	19.55	19.03	18.52	18.02	17.51	17.12	16.52	15.94
CAPACITY MARGIN PERCENT	20.84	15.23	14.82	14.61	14.90	15.48	15.92	16.35	15.99	15.63	15.27	14.90	14.61	14.18	13.75

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1387.4	1398.0	1410.6	1423.2	1435.9
DSM PEAK:					
7 DSM	-124.2	-128.4	-132.6	-136.8	-141.1
TOTAL DSM PEAK	-124.2	-128.4	-132.6	-136.8	-141.1
PEAK BEFORE DSM	1387.4	1398.0	1410.6	1423.2	1435.9
+ DSM ADJUSTMENTS	-124.2	-128.4	-132.6	-136.8	-141.1
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FINAL PEAK	1263.2	1269.5	1278.0	1286.4	1294.8
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
250 New LM6K250	74.0	74.0	74.0	74.0	74.0
TOTAL THERMAL	1359.0	1359.0	1359.0	1359.0	1359.0
TOTAL CAPACITY	1456.0	1456.0	1456.0	1456.0	1456.0

RESERVES
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	2027	2028	2029	2030	2031
RESERVE (MW)	192.8	186.5	178.1	169.6	161.2
RESERVE MARGIN PERCENT	15.26	14.69	13.93	13.19	12.45
CAPACITY MARGIN PERCENT	13.24	12.81	12.23	11.65	11.07

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5807.	5803.	6361.	6313.	6246.	6178.	6108.	6127.
THERM GENERATION	GWH	4677.	5320.	5356.	5782.	6056.	6329.	6478.	6650.	6964.
CONTROLLED ENERGY	GWH	1.	2.	2.	4.	4.	4.	4.	3.	4.
PAYBACK ENERGY	GWH	-1.	-1.	-2.	-3.	-3.	-3.	-3.	-3.	-3.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	487.	447.	578.	257.	-84.	-300.	-542.	-838.
PEAK LOAD	MW	1156.	1156.	1164.	1243.	1239.	1231.	1224.	1218.	1223.
LOAD FACTOR	PCT	57.50	57.36	56.90	58.40	58.01	57.94	57.61	57.25	57.02
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1456.	1456.	1456.	1456.	1456.	1456.
RESERVE MARGIN	MW	304.	208.	203.	213.	217.	225.	232.	238.	233.
RESERVE MARGIN	PCT	26.33	17.96	17.40	17.12	17.51	18.32	18.93	19.55	19.03
CAPACITY MARGIN	PCT	20.84	15.23	14.82	14.61	14.90	15.48	15.92	16.35	15.99
ENERGY RESV MARGIN	PCT	94.04	106.76	106.91	89.22	91.16	92.70	94.80	97.05	96.97
LOSS LOAD	HOURS	3.	3.	3.	3.	3.	3.	3.	2.	2.
RENEWABLE ENERGY	PCT	4.71	4.73	4.74	4.32	4.35	4.40	4.45	4.50	4.49
FUEL BURNED 000	MBTU	52422.	58903.	59273.	63642.	66500.	69352.	70789.	72607.	76012.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157634.	146055.	149362.	168898.	182118.	196004.	206902.	219523.	238035.
VAR. O&M COST	$000	12476.	14305.	14823.	16394.	17546.	18808.	19977.	21055.	22820.
FIXED O&M COST	$000	26281.	26589.	27004.	28082.	28731.	29400.	30106.	30837.	31599.
TOTAL THERM COST	$000	196391.	186949.	191188.	213374.	228394.	244212.	256985.	271415.	292454.
THERMAL COST	$/MWH	41.99	35.14	35.70	36.90	37.72	38.58	39.67	40.82	42.00
TOTAL EMISS. COST	$000	-10829.	-9657.	-7449.	-6598.	-6183.	-5661.	-5462.	-5122.	-4146.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	37095.	13701.	14762.	17018.	6352.	-7172.	-19230.	-32815.	-49521.
EMER ENERGY COST	$000	73.	67.	57.	62.	58.	52.	56.	44.	45.
TOTAL SYS. COST	$000	222731.	191061.	198558.	223856.	228622.	231430.	232349.	233522.	238832.
SYSTEM COST	$/MWH	38.15	32.90	34.22	35.19	36.21	37.05	37.61	38.23	38.98
AVG. MARG. COST	$/MWH	44.23	42.01	44.47	49.36	52.45	56.11	60.55	65.05	69.66
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	904.	426.	433.	506.	314.	154.	101.	37.	22.
PURCH COST	$000	26117.	11430.	12118.	15356.	10301.	5649.	3875.	1770.	1264.
AVE. PURCH COST	$/MWH	28.88	26.81	27.96	30.36	32.85	36.79	38.22	48.47	56.16

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	195.	391.	438.	439.	567.	748.	912.	1089.	1371.
SALES REV.	$000	17187.	23776.	26993.	29322.	36181.	46358.	58024.	70957.	88684.
AVE. SALES REV.	$/MWH	87.97	60.85	61.63	66.87	63.76	61.94	63.62	65.13	64.70
NET ECON ENERGY	GWH	709.	36.	-5.	67.	-254.	-595.	-811.	-1053.	-1348.
NET ECON COST	$000	8931.	-12346.	-14875.	-13966.	-25880.	-40709.	-54149.	-69186.	-87421.
TOTAL PURCH	GWH	1415.	937.	944.	1016.	824.	664.	612.	547.	533.
TOTAL PURCH	$000	57158.	40379.	42010.	46340.	42533.	39186.	38794.	38142.	39163.
TOTAL SALES	GWH	255.	450.	497.	439.	567.	748.	912.	1089.	1371.
TOTAL SALES	$000	20063.	26678.	27248.	29322.	36181.	46358.	58024.	70957.	88684.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	6131.	6142.	6151.	6169.	6176.	6190.	6207.	6234.	6248.
THERM GENERATION	GWH	7021.	7089.	7128.	7224.	7346.	7421.	7474.	7568.	7588.
CONTROLLED ENERGY	GWH	4.	4.	5.	5.	5.	4.	4.	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.	-4.	-4.	-4.	-4.	-4.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-891.	-948.	-978.	-1055.	-1170.	-1232.	-1267.	-1335.	-1341.
PEAK LOAD	MW	1228.	1234.	1239.	1243.	1250.	1256.	1263.	1270.	1278.
LOAD FACTOR	PCT	56.97	56.83	56.67	56.49	56.43	56.27	56.09	55.90	55.81
INSTALLED CAPACITY	MW	1456.	1456.	1456.	1456.	1456.	1456.	1456.	1456.	1456.
RESERVE MARGIN	MW	228.	222.	217.	213.	206.	200.	193.	186.	178.
RESERVE MARGIN	PCT	18.52	18.02	17.51	17.12	16.52	15.94	15.26	14.69	13.93
CAPACITY MARGIN	PCT	15.63	15.27	14.90	14.61	14.18	13.75	13.24	12.81	12.23
ENERGY RESV MARGIN	PCT	96.30	95.97	95.66	95.62	94.86	94.43	93.91	93.58	92.63
LOSS LOAD	HOURS	3.	3.	3.	3.	3.	3.	4.	4.	4.
RENEWABLE ENERGY	PCT	4.48	4.47	4.47	4.46	4.45	4.44	4.43	4.41	4.40
FUEL BURNED 000	MBTU	76653.	77404.	77849.	78905.	80268.	81119.	81708.	82765.	82999.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	249008.	260094.	271077.	284197.	300104.	312396.	323608.	336841.	347624.
VAR. O&M COST	$000	23664.	24577.	25404.	26482.	27738.	28767.	29683.	30804.	31654.
FIXED O&M COST	$000	32389.	33221.	34088.	34954.	35800.	36641.	37469.	38324.	39213.
TOTAL THERM COST	$000	305061.	317893.	330569.	345633.	363642.	377804.	390761.	405969.	418490.
THERMAL COST	$/MWH	43.45	44.84	46.38	47.85	49.50	50.91	52.29	53.64	55.15
TOTAL EMISS. COST	$000	-4054.	-3916.	-3868.	-3578.	-3024.	-2722.	-2535.	-2085.	-2011.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-55376.	-61394.	-68029.	-76762.	-91860.	-100757.	-107338.	-115335.	-120392.
EMER ENERGY COST	$000	54.	53.	67.	70.	64.	74.	90.	100.	100.
TOTAL SYS. COST	$000	245685.	252636.	258739.	265363.	268821.	274399.	280977.	288649.	296187.
SYSTEM COST	$/MWH	40.07	41.14	42.06	43.02	43.52	44.33	45.27	46.30	47.41
AVG. MARG. COST	$/MWH	73.54	77.25	82.41	87.05	94.74	99.59	103.98	108.06	112.79
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	21.	19.	10.	10.	8.	8.	8.	9.	9.
PURCH COST	$000	1231.	1203.	999.	1022.	1018.	1012.	1056.	1185.	1314.
AVE. PURCH COST	$/MWH	59.73	64.11	95.64	105.19	125.40	134.18	140.65	131.87	139.22

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1422.	1477.	1499.	1576.	1689.	1750.	1786.	1855.	1861.
SALES REV.	$000	96111.	103804.	112029.	122628.	139592.	150398.	158974.	169141.	176475.
AVE. SALES REV.	$/MWH	67.59	70.27	74.74	77.82	82.66	85.93	89.03	91.20	94.82
NET ECON ENERGY	GWH	-1401.	-1458.	-1488.	-1566.	-1681.	-1743.	-1778.	-1846.	-1852.
NET ECON COST	$000	-94880.	-102600.	-111030.	-121607.	-138574.	-149386.	-157918.	-167956.	-175160.
TOTAL PURCH	GWH	531.	529.	521.	520.	519.	518.	518.	520.	520.
TOTAL PURCH	$000	40735.	42410.	44000.	45866.	47732.	49641.	51636.	53806.	56083.
TOTAL SALES	GWH	1422.	1477.	1499.	1576.	1689.	1750.	1786.	1855.	1861.
TOTAL SALES	$000	96111.	103804.	112029.	122628.	139592.	150398.	158974.	169141.	176475.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	6273.	6298.
THERM GENERATION	GWH	7646.	7713.
CONTROLLED ENERGY	GWH	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-1374.	-1416.
PEAK LOAD	MW	1286.	1295.
LOAD FACTOR	PCT	55.67	55.53
INSTALLED CAPACITY	MW	1456.	1456.
RESERVE MARGIN	MW	170.	161.
RESERVE MARGIN	PCT	13.19	12.45
CAPACITY MARGIN	PCT	11.65	11.07
ENERGY RESV MARGIN	PCT	91.86	91.09
LOSS LOAD	HOURS	4.	4.
RENEWABLE ENERGY	PCT	4.38	4.36
FUEL BURNED 000	MBTU	83662.	84418.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	361164.	376642.
VAR. O&M COST	$000	32720.	33860.
FIXED O&M COST	$000	40134.	41061.
TOTAL THERM COST	$000	434019.	451563.
THERMAL COST	$/MWH	56.76	58.55
TOTAL EMISS. COST	$000	-1725.	-1357.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-129065.	-140759.
EMER ENERGY COST	$000	110.	111.
TOTAL SYS. COST	$000	303339.	309558.
SYSTEM COST	$/MWH	48.36	49.15
AVG. MARG. COST	$/MWH	118.46	125.77
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	9.	10.
PURCH COST	$000	1418.	1570.
AVE. PURCH COST	$/MWH	151.15	163.14

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	1894.	1936.
SALES REV.	$000	187505.	201677.
AVE. SALES REV.	$/MWH	98.99	104.18
NET ECON ENERGY	GWH	-1885.	-1926.
NET ECON COST	$000	-186087.	-200107.
TOTAL PURCH	GWH	520.	520.
TOTAL PURCH	$000	58440.	60917.
TOTAL SALES	GWH	1894.	1936.
TOTAL SALES	$000	187505.	201677.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
P.V. UTILITY COST:	
PLANNING PERIOD	3778406.0
% DIFFERENCE	0.00%
END EFFECTS PERIOD	2979091.0
% DIFFERENCE	0.00%
STUDY PERIOD	6757497.0
% DIFFERENCE	0.00%
PLANNING PERIOD RANK	1

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
FINAL PEAK	1155.8	1155.8	1164.2	1164.2	1160.0	1151.6	1145.3	1138.9	1144.2	1149.5	1154.7	1160.0	1164.2	1170.5	1176.8
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1460.1	1363.4	1366.7	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	304.3	207.6	202.5	217.9	222.1	230.5	236.8	243.1	237.9	232.6	227.3	222.1	217.9	211.5	205.2
RESERVE MARGIN PERCENT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79	20.23	19.69	19.14	18.71	18.07	17.44
CAPACITY MARGIN PERCENT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21	16.83	16.45	16.07	15.76	15.31	14.85

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
DSM PEAK:					
7 DSM	-124.2	-128.4	-132.6	-136.8	-141.1
TOTAL DSM PEAK	-124.2	-128.4	-132.6	-136.8	-141.1
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
+ DSM ADJUSTMENTS	-124.2	-128.4	-132.6	-136.8	-141.1
-----------------	-------	-------	-------	-------	-------
FINAL PEAK	1184.2	1190.5	1198.9	1207.4	1215.8
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2027	2028	2029	2030	2031
RESERVE (MW)	197.9	191.5	183.1	174.7	166.3
RESERVE MARGIN PERCENT	16.71	16.09	15.27	14.47	13.68
CAPACITY MARGIN PERCENT	14.32	13.86	13.25	12.64	12.03

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5807.	5803.	5773.	5703.	5619.	5549.	5478.	5495.
THERM GENERATION	GWH	4677.	5320.	5356.	5588.	5454.	5607.	5701.	5816.	6159.
CONTROLLED ENERGY	GWH	1.	2.	2.	3.	2.	2.	2.	2.	2.
PAYBACK ENERGY	GWH	-1.	-1.	-2.	-2.	-2.	-2.	-2.	-2.	-2.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	487.	447.	184.	249.	11.	-152.	-338.	-664.
PEAK LOAD	MW	1156.	1156.	1164.	1164.	1160.	1152.	1145.	1139.	1144.
LOAD FACTOR	PCT	57.50	57.36	56.90	56.60	55.97	55.70	55.31	54.90	54.67
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	304.	208.	203.	218.	222.	230.	237.	243.	238.
RESERVE MARGIN	PCT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79
CAPACITY MARGIN	PCT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21
ENERGY RESV MARGIN	PCT	94.04	106.76	106.91	108.49	111.60	114.19	116.88	119.71	119.63
LOSS LOAD	HOURS	3.	3.	3.	3.	3.	3.	2.	2.	2.
RENEWABLE ENERGY	PCT	4.71	4.73	4.74	4.76	4.82	4.89	4.95	5.02	5.00
FUEL BURNED 000	MBTU	52422.	58903.	59273.	61704.	60376.	61986.	62878.	64093.	67566.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157634.	146055.	149362.	162689.	165226.	174923.	183548.	193598.	210575.
VAR. O&M COST	$000	12476.	14305.	14823.	15780.	16157.	17027.	17966.	18795.	20337.
FIXED O&M COST	$000	26281.	26589.	27004.	27530.	28166.	28822.	29514.	30231.	30978.
TOTAL THERM COST	$000	196391.	186949.	191188.	205999.	209550.	220772.	231029.	242624.	261890.
THERMAL COST	$/MWH	41.99	35.14	35.70	36.86	38.42	39.37	40.53	41.72	42.52
TOTAL EMISS. COST	$000	-10829.	-9657.	-7449.	-7191.	107065.	122787.	138885.	157635.	186098.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	37095.	13701.	14762.	3876.	-7325.	-23879.	-39514.	-57833.	-83647.
EMER ENERGY COST	$000	73.	67.	57.	65.	66.	64.	38.	42.	53.
TOTAL SYS. COST	$000	222731.	191061.	198558.	202749.	309356.	319743.	330438.	342469.	364393.
SYSTEM COST	$/MWH	38.15	32.90	34.22	35.12	54.24	56.90	59.54	62.52	66.32
AVG. MARG. COST	$/MWH	44.23	42.01	44.47	49.11	75.17	80.92	88.10	95.29	100.97
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	904.	426.	433.	272.	378.	283.	245.	179.	85.
PURCH COST	$000	26117.	11430.	12118.	8095.	16875.	13621.	12467.	9780.	5125.
AVE. PURCH COST	$/MWH	28.88	26.81	27.96	29.77	44.68	48.20	50.89	54.58	60.23

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	195.	391.	438.	599.	640.	782.	907.	1028.	1260.
SALES REV.	$000	17187.	23776.	26993.	35203.	56432.	71037.	86900.	103984.	126672.
AVE. SALES REV.	$/MWH	87.97	60.85	61.63	58.79	88.24	90.79	95.77	101.13	100.52
NET ECON ENERGY	GWH	709.	36.	-5.	-327.	-262.	-500.	-662.	-849.	-1175.
NET ECON COST	$000	8931.	-12346.	-14875.	-27108.	-39557.	-57416.	-74433.	-94204.	-121547.
TOTAL PURCH	GWH	1415.	937.	944.	783.	888.	793.	756.	690.	596.
TOTAL PURCH	$000	57158.	40379.	42010.	39079.	49107.	47158.	47386.	46152.	43025.
TOTAL SALES	GWH	255.	450.	497.	599.	640.	782.	907.	1028.	1260.
TOTAL SALES	$000	20063.	26678.	27248.	35203.	56432.	71037.	86900.	103984.	126672.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	5497.	5506.	5514.	5529.	5536.	5548.	5562.	5588.	5599.
THERM GENERATION	GWH	6170.	6181.	6134.	6172.	6271.	6275.	6257.	6318.	6257.
CONTROLLED ENERGY	GWH	2.	2.	3.	3.	4.	5.	5.	5.	4.
PAYBACK ENERGY	GWH	-2.	-2.	-2.	-3.	-3.	-4.	-4.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-673.	-676.	-621.	-643.	-736.	-727.	-695.	-730.	-658.
PEAK LOAD	MW	1149.	1155.	1160.	1164.	1171.	1177.	1184.	1191.	1199.
LOAD FACTOR	PCT	54.59	54.43	54.26	54.07	53.99	53.82	53.62	53.44	53.31
INSTALLED CAPACITY	MW	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	233.	227.	222.	218.	212.	205.	198.	192.	183.
RESERVE MARGIN	PCT	20.23	19.69	19.14	18.71	18.07	17.44	16.71	16.09	15.27
CAPACITY MARGIN	PCT	16.83	16.45	16.07	15.76	15.31	14.85	14.32	13.86	13.25
ENERGY RESV MARGIN	PCT	118.95	118.58	118.28	118.25	117.41	116.92	116.38	115.95	114.96
LOSS LOAD	HOURS	3.	2.	3.	2.	3.	2.	3.	3.	3.
RENEWABLE ENERGY	PCT	5.00	4.99	4.98	4.97	4.96	4.95	4.94	4.92	4.91
FUEL BURNED 000	MBTU	67705.	67854.	67454.	67888.	68947.	69016.	68853.	69475.	68847.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	218698.	226516.	233456.	242753.	255236.	262759.	269294.	278701.	283801.
VAR. O&M COST	$000	20922.	21531.	21986.	22713.	23677.	24278.	24779.	25552.	25910.
FIXED O&M COST	$000	31752.	32569.	33419.	34267.	35097.	35921.	36733.	37571.	38442.
TOTAL THERM COST	$000	271373.	280616.	288860.	299734.	314009.	322959.	330806.	341824.	348154.
THERMAL COST	$/MWH	43.99	45.40	47.09	48.56	50.07	51.47	52.87	54.10	55.65
TOTAL EMISS. COST	$000	207010.	229994.	253302.	282608.	318015.	351914.	388078.	433259.	474510.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-91135.	-98230.	-104642.	-115449.	-136949.	-146599.	-153299.	-165495.	-167372.
EMER ENERGY COST	$000	57.	56.	61.	57.	62.	63.	64.	83.	91.
TOTAL SYS. COST	$000	387305.	412436.	437581.	466951.	495137.	528336.	565650.	609671.	655383.
SYSTEM COST	$/MWH	70.46	74.90	79.36	84.45	89.44	95.22	101.70	109.10	117.05
AVG. MARG. COST	$/MWH	107.79	114.72	124.30	132.83	144.35	153.87	163.46	172.75	183.80
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	84.	87.	104.	106.	84.	88.	96.	85.	98.
PURCH COST	$000	5405.	5971.	7700.	8346.	7124.	8066.	9377.	8999.	11085.
AVE. PURCH COST	$/MWH	64.12	68.29	73.68	78.85	85.27	91.21	97.37	106.15	113.24

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1268.	1274.	1236.	1260.	1330.	1326.	1302.	1326.	1267.
SALES REV.	$000	136044.	145407.	155343.	168639.	190787.	203294.	213256.	227115.	233226.
AVE. SALES REV.	$/MWH	107.26	114.17	125.71	133.87	143.41	153.27	163.76	171.32	184.08
NET ECON ENERGY	GWH	-1184.	-1186.	-1131.	-1154.	-1247.	-1238.	-1206.	-1241.	-1169.
NET ECON COST	$000	-130639.	-139437.	-147644.	-160294.	-183663.	-195228.	-203879.	-218116.	-222140.
TOTAL PURCH	GWH	595.	598.	615.	617.	594.	599.	607.	595.	609.
TOTAL PURCH	$000	44909.	47177.	50701.	53190.	53838.	56694.	59957.	61621.	65854.
TOTAL SALES	GWH	1268.	1274.	1236.	1260.	1330.	1326.	1302.	1326.	1267.
TOTAL SALES	$000	136044.	145407.	155343.	168639.	190787.	203294.	213256.	227115.	233226.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	5622.	5646.
THERM GENERATION	GWH	6232.	6246.
CONTROLLED ENERGY	GWH	4.	4.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-610.	-601.
PEAK LOAD	MW	1207.	1216.
LOAD FACTOR	PCT	53.16	53.02
INSTALLED CAPACITY	MW	1382.	1382.
RESERVE MARGIN	MW	175.	166.
RESERVE MARGIN	PCT	14.47	13.68
CAPACITY MARGIN	PCT	12.64	12.03
ENERGY RESV MARGIN	PCT	114.07	113.16
LOSS LOAD	HOURS	3.	4.
RENEWABLE ENERGY	PCT	4.89	4.87
FUEL BURNED 000	MBTU	68617.	68789.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	290986.	300553.
VAR. O&M COST	$000	26446.	27143.
FIXED O&M COST	$000	39346.	40255.
TOTAL THERM COST	$000	356777.	367951.
THERMAL COST	$/MWH	57.25	58.91
TOTAL EMISS. COST	$000	522502.	572397.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-173218.	-184778.
EMER ENERGY COST	$000	88.	101.
TOTAL SYS. COST	$000	706149.	755672.
SYSTEM COST	$/MWH	125.60	133.83
AVG. MARG. COST	$/MWH	196.27	209.79
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	111.	114.
PURCH COST	$000	13512.	14798.
AVE. PURCH COST	$/MWH	121.31	129.82

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	1232.	1226.
SALES REV.	$000	243752.	258923.
AVE. SALES REV.	$/MWH	197.78	211.26
NET ECON ENERGY	GWH	-1121.	-1112.
NET ECON COST	$000	-230240.	-244125.
TOTAL PURCH	GWH	622.	625.
TOTAL PURCH	$000	70534.	74145.
TOTAL SALES	GWH	1232.	1226.
TOTAL SALES	$000	243752.	258923.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
P.V. UTILITY COST:	
PLANNING PERIOD	2468853.2
% DIFFERENCE	0.00%
END EFFECTS PERIOD	1190293.2
% DIFFERENCE	0.00%
STUDY PERIOD	3659146.5
% DIFFERENCE	0.00%
PLANNING PERIOD RANK	1

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-96.8	-101.1	-105.3	-108.4	-112.6	-116.8	-121.1
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FINAL PEAK	1155.8	1155.8	1164.2	1164.2	1160.0	1151.6	1145.3	1138.9	1144.2	1149.5	1154.7	1160.0	1164.2	1170.5	1176.8
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1460.1	1363.4	1366.7	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	304.3	207.6	202.5	217.9	222.1	230.5	236.8	243.1	237.9	232.6	227.3	222.1	217.9	211.5	205.2
RESERVE MARGIN PERCENT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79	20.23	19.69	19.14	18.71	18.07	17.44
CAPACITY MARGIN PERCENT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21	16.83	16.45	16.07	15.76	15.31	14.85

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
DSM PEAK:					
7 DSM	-124.2	-128.4	-132.6	-136.8	-141.1
TOTAL DSM PEAK	-124.2	-128.4	-132.6	-136.8	-141.1
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
+ DSM ADJUSTMENTS	-124.2	-128.4	-132.6	-136.8	-141.1
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FINAL PEAK	1184.2	1190.5	1198.9	1207.4	1215.8
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2027	2028	2029	2030	2031
RESERVE (MW)	197.9	191.5	183.1	174.7	166.3
RESERVE MARGIN PERCENT	16.71	16.09	15.27	14.47	13.68
CAPACITY MARGIN PERCENT	14.32	13.86	13.25	12.64	12.03

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5807.	5803.	5773.	5725.	5658.	5591.	5520.	5539.
THERM GENERATION	GWH	4677.	5324.	5376.	5609.	5867.	6117.	6252.	6401.	6654.
CONTROLLED ENERGY	GWH	1.	2.	2.	3.	3.	2.	2.	3.	2.
PAYBACK ENERGY	GWH	-1.	-2.	-2.	-2.	-2.	-2.	-2.	-3.	-2.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	483.	427.	163.	-142.	-460.	-662.	-882.	-1116.
PEAK LOAD	MW	1156.	1156.	1164.	1164.	1160.	1152.	1145.	1139.	1144.
LOAD FACTOR	PCT	57.50	57.36	56.90	56.60	56.19	56.09	55.72	55.33	55.11
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	304.	208.	203.	218.	222.	230.	237.	243.	238.
RESERVE MARGIN	PCT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.79
CAPACITY MARGIN	PCT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	17.21
ENERGY RESV MARGIN	PCT	94.04	106.76	106.91	108.49	110.78	112.72	115.28	118.03	117.87
LOSS LOAD	HOURS	3.	4.	3.	3.	4.	3.	3.	3.	3.
RENEWABLE ENERGY	PCT	4.71	4.73	4.74	4.76	4.80	4.86	4.92	4.98	4.96
FUEL BURNED 000	MBTU	52422.	58938.	59310.	61746.	64407.	67020.	68492.	70078.	72832.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157634.	149160.	155585.	172891.	189679.	207573.	223832.	241207.	264229.
VAR. O&M COST	$000	12476.	14312.	15015.	15976.	17088.	18263.	19222.	20206.	21715.
FIXED O&M COST	$000	26281.	26589.	27004.	27530.	28166.	28822.	29514.	30231.	30978.
TOTAL THERM COST	$000	196391.	190061.	197603.	216398.	234933.	254658.	272568.	291645.	316922.
THERMAL COST	$/MWH	41.99	35.70	36.76	38.58	40.05	41.63	43.60	45.56	47.63
TOTAL EMISS. COST	$000	-10829.	-9651.	-7441.	-7186.	-6856.	-6456.	-6284.	-6055.	-5361.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	37095.	13533.	14141.	2482.	-10120.	-26631.	-41850.	-58462.	-77294.
EMER ENERGY COST	$000	73.	67.	60.	66.	72.	55.	53.	56.	58.
TOTAL SYS. COST	$000	222731.	194010.	204363.	211761.	218030.	221625.	224488.	227183.	234326.
SYSTEM COST	$/MWH	38.15	33.41	35.22	36.68	38.08	39.17	40.16	41.16	42.31
AVG. MARG. COST	$/MWH	44.23	42.81	46.11	51.86	56.16	61.25	67.39	73.72	80.52
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	904.	422.	415.	256.	141.	53.	30.	10.	12.
PURCH COST	$000	26117.	11536.	12013.	8071.	4897.	2221.	1408.	660.	754.
AVE. PURCH COST	$/MWH	28.88	27.34	28.93	31.52	34.77	42.19	46.95	64.53	61.40

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	195.	390.	440.	604.	794.	1023.	1202.	1403.	1639.
SALES REV.	$000	17187.	24051.	27509.	36573.	47248.	62389.	78176.	95493.	115947.
AVE. SALES REV.	$/MWH	87.97	61.61	62.56	60.54	59.54	60.99	65.02	68.07	70.75
NET ECON ENERGY	GWH	709.	32.	-25.	-348.	-653.	-970.	-1172.	-1393.	-1626.
NET ECON COST	$000	8931.	-12514.	-15496.	-28503.	-42352.	-60168.	-76768.	-94834.	-115193.
TOTAL PURCH	GWH	1415.	933.	926.	767.	651.	563.	541.	521.	523.
TOTAL PURCH	$000	57158.	40486.	41906.	39055.	37129.	35758.	36327.	37031.	38653.
TOTAL SALES	GWH	255.	450.	499.	604.	794.	1023.	1202.	1403.	1639.
TOTAL SALES	$000	20063.	26953.	27764.	36573.	47248.	62389.	78176.	95493.	115947.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	5543.	5554.	5563.	5581.	5588.	5602.	5619.	5646.	5660.
THERM GENERATION	GWH	6703.	6757.	6811.	6902.	7014.	7085.	7134.	7211.	7226.
CONTROLLED ENERGY	GWH	3.	3.	4.	5.	5.	5.	5.	5.	5.
PAYBACK ENERGY	GWH	-2.	-3.	-4.	-4.	-4.	-4.	-4.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-1161.	-1204.	-1249.	-1321.	-1427.	-1484.	-1516.	-1565.	-1567.
PEAK LOAD	MW	1149.	1155.	1160.	1164.	1171.	1177.	1184.	1191.	1199.
LOAD FACTOR	PCT	55.05	54.90	54.75	54.57	54.50	54.34	54.17	53.99	53.89
INSTALLED CAPACITY	MW	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	233.	227.	222.	218.	212.	205.	198.	192.	183.
RESERVE MARGIN	PCT	20.23	19.69	19.14	18.71	18.07	17.44	16.71	16.09	15.27
CAPACITY MARGIN	PCT	16.83	16.45	16.07	15.76	15.31	14.85	14.32	13.86	13.25
ENERGY RESV MARGIN	PCT	117.12	116.71	116.34	116.23	115.36	114.84	114.19	113.73	112.64
LOSS LOAD	HOURS	3.	3.	3.	3.	3.	3.	4.	4.	4.
RENEWABLE ENERGY	PCT	4.96	4.95	4.94	4.93	4.92	4.91	4.89	4.87	4.86
FUEL BURNED 000	MBTU	73391.	73991.	74615.	75630.	76902.	77717.	78276.	79125.	79314.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	281363.	298811.	312830.	328182.	346472.	360881.	373866.	387928.	400088.
VAR. O&M COST	$000	22508.	23342.	24231.	25274.	26488.	27484.	28365.	29385.	30179.
FIXED O&M COST	$000	31752.	32569.	33419.	34267.	35097.	35921.	36733.	37571.	38442.
TOTAL THERM COST	$000	335624.	354721.	370480.	387724.	408057.	424286.	438964.	454884.	468710.
THERMAL COST	$/MWH	50.07	52.50	54.39	56.18	58.18	59.88	61.53	63.08	64.87
TOTAL EMISS. COST	$000	-5356.	-5342.	-5299.	-5090.	-4626.	-4394.	-4274.	-4002.	-4016.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-86717.	-96271.	-107655.	-119379.	-138985.	-150954.	-159898.	-168819.	-175661.
EMER ENERGY COST	$000	54.	58.	83.	85.	78.	85.	102.	93.	104.
TOTAL SYS. COST	$000	243604.	253166.	257610.	263340.	264523.	269024.	274893.	282156.	289137.
SYSTEM COST	$/MWH	43.95	45.59	46.31	47.18	47.33	48.02	48.92	49.97	51.08
AVG. MARG. COST	$/MWH	86.46	92.40	98.66	104.26	113.56	119.46	124.76	129.72	135.41
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	11.	10.	4.	4.	4.	4.	4.	5.	6.
PURCH COST	$000	731.	731.	459.	481.	546.	561.	627.	827.	992.
AVE. PURCH COST	$/MWH	67.94	74.91	116.69	124.87	143.36	152.95	162.68	160.71	171.80

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1682.	1724.	1764.	1836.	1941.	1998.	2030.	2081.	2083.
SALES REV.	$000	126952.	138209.	151115.	164705.	186245.	200143.	211106.	222268.	231421.
AVE. SALES REV.	$/MWH	75.47	80.16	85.68	89.71	95.95	100.16	103.98	106.80	111.10
NET ECON ENERGY	GWH	-1671.	-1714.	-1760.	-1832.	-1937.	-1995.	-2026.	-2076.	-2077.
NET ECON COST	$000	-126221.	-137478.	-150656.	-164223.	-185699.	-199582.	-210479.	-221440.	-230429.
TOTAL PURCH	GWH	521.	520.	515.	515.	514.	514.	515.	516.	516.
TOTAL PURCH	$000	40235.	41938.	43460.	45326.	47260.	49190.	51207.	53449.	55760.
TOTAL SALES	GWH	1682.	1724.	1764.	1836.	1941.	1998.	2030.	2081.	2083.
TOTAL SALES	$000	126952.	138209.	151115.	164705.	186245.	200143.	211106.	222268.	231421.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	5685.	5711.
THERM GENERATION	GWH	7275.	7328.
CONTROLLED ENERGY	GWH	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-1590.	-1618.
PEAK LOAD	MW	1207.	1216.
LOAD FACTOR	PCT	53.75	53.62
INSTALLED CAPACITY	MW	1382.	1382.
RESERVE MARGIN	MW	175.	166.
RESERVE MARGIN	PCT	14.47	13.68
CAPACITY MARGIN	PCT	12.64	12.03
ENERGY RESV MARGIN	PCT	111.70	110.76
LOSS LOAD	HOURS	4.	4.
RENEWABLE ENERGY	PCT	4.83	4.81
FUEL BURNED 000	MBTU	79892.	80518.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	415237.	432102.
VAR. O&M COST	$000	31165.	32189.
FIXED O&M COST	$000	39346.	40255.
TOTAL THERM COST	$000	485748.	504546.
THERMAL COST	$/MWH	66.77	68.85
TOTAL EMISS. COST	$000	-3836.	-3603.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-186420.	-200451.
EMER ENERGY COST	$000	117.	113.
TOTAL SYS. COST	$000	295608.	300604.
SYSTEM COST	$/MWH	52.00	52.64
AVG. MARG. COST	$/MWH	142.24	151.09
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	6.	6.
PURCH COST	$000	1084.	1308.
AVE. PURCH COST	$/MWH	184.78	201.78

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	2107.	2136.
SALES REV.	$000	244526.	261107.
AVE. SALES REV.	$/MWH	116.06	122.27
NET ECON ENERGY	GWH	-2101.	-2129.
NET ECON COST	$000	-243442.	-259799.
TOTAL PURCH	GWH	517.	517.
TOTAL PURCH	$000	58106.	60655.
TOTAL SALES	GWH	2107.	2136.
TOTAL SALES	$000	244526.	261107.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Received
November 1, 2011
Indiana Utility Regulatory Commission

PROVIEW LEAST COST OPTIMIZATION SYSTEM
STUDY PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029	CC F(1)	LM6K(1)	LMS (1)	CT E(1)	CT F(1)	BIOM(1)	COAL(1)
2030							
2031							
P.V. UTILITY COST:							
PLANNING PERIOD	2324177.2	2326000.8	2329267.0	2336802.8	2340751.2	2405162.2	2400573.0
% DIFFERENCE	0.00%	0.08%	0.22%	0.54%	0.71%	3.48%	3.29%
END EFFECTS PERIOD	1170563.5	1178170.8	1199817.5	1239682.8	1263086.0	1595364.0	1636513.8
% DIFFERENCE	0.00%	0.65%	2.50%	5.90%	7.90%	36.29%	39.81%
STUDY PERIOD	3494740.8	3504171.5	3529084.5	3576485.5	3603837.2	4000526.2	4037086.8
% DIFFERENCE	0.00%	0.27%	0.98%	2.34%	3.12%	14.47%	15.52%
PLANNING PERIOD RANK	1	2	3	4	5	7	6

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
LOADS															
=====															
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
DSM PEAK:															
7 DSM	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7
TOTAL DSM PEAK	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7
PEAK BEFORE DSM	1167.4	1175.8	1188.4	1197.9	1205.3	1213.7	1222.1	1232.6	1241.1	1250.5	1260.0	1268.4	1276.8	1287.4	1297.9
+ DSM ADJUSTMENTS	-11.6	-20.0	-24.2	-33.7	-45.3	-62.1	-76.8	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7	-93.7
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FINAL PEAK	1155.8	1155.8	1164.2	1164.2	1160.0	1151.6	1145.3	1138.9	1147.4	1156.8	1166.3	1174.7	1183.2	1193.7	1204.2
RESOURCES															
=========															
DSM CAPACITY:															
70 DLC_RES	11.5	14.8	18.2	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	49.0	52.4	55.7	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:															
2 CAP100 2	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	-12.0	-12.0	-12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	126.0	26.0	26.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:															
1 VECTMARK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:															
1 BROWN 1	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
250 New CC F250	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0	1285.0
TOTAL CAPACITY	1460.1	1363.4	1366.7	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1	1382.1

RESERVES
========

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RESERVE (MW)	304.3	207.6	202.5	217.9	222.1	230.5	236.8	243.1	234.7	225.2	215.7	207.3	198.9	188.4	177.9
RESERVE MARGIN PERCENT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.46	19.47	18.50	17.65	16.81	15.78	14.77
CAPACITY MARGIN PERCENT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	16.98	16.30	15.61	15.00	14.39	13.63	12.87

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
LOADS					
=====					
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
DSM PEAK:					
7 DSM	-93.7	-93.7	-93.7	-93.7	-94.7
TOTAL DSM PEAK	-93.7	-93.7	-93.7	-93.7	-94.7
PEAK BEFORE DSM	1308.4	1318.9	1331.6	1344.2	1356.8
+ DSM ADJUSTMENTS	-93.7	-93.7	-93.7	-93.7	-94.7
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FINAL PEAK	1214.7	1225.3	1237.9	1250.5	1262.1
RESOURCES					
=========					
DSM CAPACITY:					
70 DLC_RES	21.5	21.5	21.5	21.5	21.5
71 DLC_COM	2.5	2.5	2.5	2.5	2.5
72 INT	35.1	35.1	35.1	35.1	35.1
TOTAL DSM CAPACITY	59.0	59.0	59.0	59.0	59.0
TRANSACTIONS:					
2 CAP100 2	0.0	0.0	0.0	0.0	0.0
7 FIRMSALE 7	0.0	0.0	0.0	0.0	0.0
11 OVEC 11	30.0	30.0	30.0	30.0	30.0
14 WIND 14	3.0	3.0	3.0	3.0	3.0
15 WIND2 15	5.0	5.0	5.0	5.0	5.0
TOTAL TRANSACTIONS	38.0	38.0	38.0	38.0	38.0
SYSTEM INTERCHANGE:					
1 VECTMARK	0.0	0.0	0.0	0.0	0.0

GENERATION AND FUEL MODULE
LOADS AND RESOURCES DETAIL REPORT

	2027	2028	2029	2030	2031
TOTAL SYSTEM INTERCHANGE	0.0	0.0	0.0	0.0	0.0
THERMAL GENERATION:					
1 BROWN 1	245.0	245.0	245.0	245.0	245.0
2 BROWN 2	245.0	245.0	245.0	245.0	245.0
4 CULLEY 2	90.0	90.0	90.0	90.0	90.0
5 CULLEY 3	270.0	270.0	270.0	270.0	270.0
6 WARRICK 4	150.0	150.0	150.0	150.0	150.0
7 NORTHEST 1	20.0	20.0	20.0	20.0	20.0
8 BROADWAY 1	50.0	50.0	50.0	50.0	50.0
9 BROADWAY 2	65.0	65.0	65.0	65.0	65.0
10 BROWNCT 1	75.0	75.0	75.0	75.0	75.0
11 BROWNCT 2	75.0	75.0	75.0	75.0	75.0
39 Blakfoot 1	0.0	0.0	0.0	0.0	0.0
250 New CC F250	0.0	0.0	113.2	113.2	113.2
TOTAL THERMAL	1285.0	1285.0	1398.2	1398.2	1398.2
TOTAL CAPACITY	1382.1	1382.1	1495.3	1495.3	1495.3

RESERVES
========

	2027	2028	2029	2030	2031
RESERVE (MW)	167.3	156.8	257.4	244.8	233.2
RESERVE MARGIN PERCENT	13.77	12.80	20.79	19.57	18.48
CAPACITY MARGIN PERCENT	12.11	11.35	17.21	16.37	15.59

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ENERGY REQUIRED	GWH	5838.	5807.	5803.	5773.	5725.	5658.	5591.	5520.	5566.
THERM GENERATION	GWH	4677.	5320.	5356.	5588.	5846.	6095.	6258.	6423.	6699.
CONTROLLED ENERGY	GWH	1.	2.	2.	3.	3.	2.	2.	2.	2.
PAYBACK ENERGY	GWH	-1.	-1.	-2.	-2.	-2.	-2.	-2.	-2.	-2.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	1160.	487.	447.	184.	-121.	-437.	-668.	-904.	-1133.
PEAK LOAD	MW	1156.	1156.	1164.	1164.	1160.	1152.	1145.	1139.	1147.
LOAD FACTOR	PCT	57.50	57.36	56.90	56.60	56.19	56.09	55.72	55.33	55.23
INSTALLED CAPACITY	MW	1460.	1363.	1367.	1382.	1382.	1382.	1382.	1382.	1382.
RESERVE MARGIN	MW	304.	208.	203.	218.	222.	230.	237.	243.	235.
RESERVE MARGIN	PCT	26.33	17.96	17.40	18.71	19.14	20.01	20.68	21.35	20.46
CAPACITY MARGIN	PCT	20.84	15.23	14.82	15.76	16.07	16.68	17.13	17.59	16.98
ENERGY RESV MARGIN	PCT	94.04	106.76	106.91	108.49	110.78	112.72	115.28	118.03	116.80
LOSS LOAD	HOURS	3.	3.	3.	3.	4.	3.	3.	3.	3.
RENEWABLE ENERGY	PCT	4.71	4.73	4.74	4.76	4.80	4.86	4.92	4.98	4.94
FUEL BURNED 000	MBTU	52422.	58903.	59273.	61704.	64408.	67011.	68605.	70358.	73370.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	157634.	146055.	149362.	162689.	175156.	187978.	199057.	211063.	227759.
VAR. O&M COST	$000	12476.	14305.	14823.	15780.	16867.	18030.	19288.	20335.	21932.
FIXED O&M COST	$000	26281.	26589.	27004.	27530.	28166.	28822.	29514.	30231.	30978.
TOTAL THERM COST	$000	196391.	186949.	191188.	205999.	220188.	234831.	247859.	261629.	280669.
THERMAL COST	$/MWH	41.99	35.14	35.70	36.86	37.67	38.53	39.60	40.73	41.90
TOTAL EMISS. COST	$000	-10829.	-9657.	-7449.	-7191.	-6847.	-6458.	-6236.	-5952.	-5172.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	37095.	13701.	14762.	3876.	-7304.	-21682.	-35230.	-49514.	-64098.
EMER ENERGY COST	$000	73.	67.	57.	65.	72.	61.	56.	54.	58.
TOTAL SYS. COST	$000	222731.	191061.	198558.	202749.	206110.	206751.	206449.	206217.	211457.
SYSTEM COST	$/MWH	38.15	32.90	34.22	35.12	36.00	36.54	36.93	37.36	37.99
AVG. MARG. COST	$/MWH	44.23	42.01	44.47	49.11	52.21	55.92	60.34	64.85	69.55
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	31041.	28950.	29892.	30984.	32232.	33537.	34919.	36371.	37899.
TRANS SALES	GWH	60.	59.	59.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	2877.	2902.	255.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	904.	426.	433.	272.	151.	61.	36.	11.	13.
PURCH COST	$000	26117.	11430.	12118.	8095.	4845.	2254.	1414.	576.	637.
AVE. PURCH COST	$/MWH	28.88	26.81	27.96	29.77	31.99	36.85	39.57	52.78	50.86

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2012	2013	2014	2015	2016	2017	2018	2019	2020
ECON ENERGY SALES	GWH	195.	391.	438.	599.	783.	1009.	1215.	1425.	1657.
SALES REV.	$000	17187.	23776.	26993.	35203.	44381.	57473.	71562.	86462.	102635.
AVE. SALES REV.	$/MWH	87.97	60.85	61.63	58.79	56.66	56.95	58.91	60.66	61.95
NET ECON ENERGY	GWH	709.	36.	-5.	-327.	-632.	-948.	-1179.	-1414.	-1644.
NET ECON COST	$000	8931.	-12346.	-14875.	-27108.	-39536.	-55219.	-70149.	-85886.	-101998.
TOTAL PURCH	GWH	1415.	937.	944.	783.	662.	572.	546.	522.	523.
TOTAL PURCH	$000	57158.	40379.	42010.	39079.	37077.	35791.	36332.	36947.	38537.
TOTAL SALES	GWH	255.	450.	497.	599.	783.	1009.	1215.	1425.	1657.
TOTAL SALES	$000	20063.	26678.	27248.	35203.	44381.	57473.	71562.	86462.	102635.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ENERGY REQUIRED	GWH	5599.	5637.	5674.	5719.	5754.	5796.	5840.	5895.	5937.
THERM GENERATION	GWH	6758.	6822.	6874.	6965.	7088.	7157.	7206.	7293.	7947.
CONTROLLED ENERGY	GWH	2.	3.	4.	5.	5.	5.	5.	5.	4.
PAYBACK ENERGY	GWH	-2.	-2.	-4.	-4.	-4.	-4.	-4.	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANSACTIONS	GWH	-1160.	-1186.	-1201.	-1247.	-1335.	-1363.	-1367.	-1399.	-2011.
PEAK LOAD	MW	1157.	1166.	1175.	1183.	1194.	1204.	1215.	1225.	1238.
LOAD FACTOR	PCT	55.25	55.17	55.13	55.03	55.02	54.94	54.88	54.77	54.75
INSTALLED CAPACITY	MW	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1382.	1495.
RESERVE MARGIN	MW	225.	216.	207.	199.	188.	178.	167.	157.	257.
RESERVE MARGIN	PCT	19.47	18.50	17.65	16.81	15.78	14.77	13.77	12.80	20.79
CAPACITY MARGIN	PCT	16.30	15.61	15.00	14.39	13.63	12.87	12.11	11.35	17.21
ENERGY RESV MARGIN	PCT	114.96	113.51	112.13	111.02	109.18	107.66	106.09	104.72	102.72
LOSS LOAD	HOURS	3.	3.	4.	4.	4.	5.	6.	6.	2.
RENEWABLE ENERGY	PCT	4.91	4.88	4.84	4.81	4.78	4.74	4.71	4.66	4.63
FUEL BURNED 000	MBTU	74037.	74765.	75353.	76384.	77775.	78572.	79132.	80100.	85981.
FIXED FUEL COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL FUEL COST	$000	238489.	249167.	260312.	272875.	288176.	299689.	310220.	322432.	365381.
VAR. O&M COST	$000	22777.	23669.	24548.	25598.	26866.	27858.	28747.	29830.	35100.
FIXED O&M COST	$000	31752.	32569.	33419.	34267.	35097.	35921.	36733.	37571.	40388.
TOTAL THERM COST	$000	293019.	305404.	318279.	332740.	350138.	363469.	375701.	389832.	440869.
THERMAL COST	$/MWH	43.36	44.77	46.30	47.77	49.40	50.78	52.14	53.45	55.47
TOTAL EMISS. COST	$000	-5122.	-5054.	-5008.	-4778.	-4238.	-3993.	-3850.	-3497.	-441.
HYD VAR COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
HYD FIXED COST	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
NET TRANS COST	$000	-69294.	-74277.	-81126.	-88504.	-102659.	-109399.	-113842.	-118916.	-178528.
EMER ENERGY COST	$000	64.	69.	93.	100.	113.	124.	158.	156.	45.
TOTAL SYS. COST	$000	218666.	226143.	232238.	239559.	243355.	250202.	258167.	267576.	261945.
SYSTEM COST	$/MWH	39.05	40.12	40.93	41.89	42.30	43.17	44.21	45.39	44.12
AVG. MARG. COST	$/MWH	73.44	77.17	82.37	87.03	94.74	99.61	103.99	108.07	112.71
TRANS PURCH	GWH	511.	511.	511.	511.	511.	511.	511.	511.	511.
TRANS PURCH COST	$000	39504.	41207.	43001.	44845.	46714.	48629.	50580.	52621.	54768.
TRANS SALES	GWH	0.	0.	0.	0.	0.	0.	0.	0.	0.
TRANS SALES REV.	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
ECON ENERGY PURCH	GWH	12.	11.	5.	5.	5.	6.	7.	9.	2.
PURCH COST	$000	664.	697.	478.	561.	633.	762.	923.	1270.	171.
AVE. PURCH COST	$/MWH	55.06	60.92	96.95	105.89	121.63	130.62	138.77	140.34	113.05

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2021	2022	2023	2024	2025	2026	2027	2028	2029
ECON ENERGY SALES	GWH	1682.	1708.	1717.	1763.	1851.	1879.	1885.	1919.	2523.
SALES REV.	$000	109462.	116180.	124606.	133909.	150006.	158789.	165345.	172807.	233467.
AVE. SALES REV.	$/MWH	65.07	68.01	72.59	75.94	81.05	84.50	87.73	90.05	92.53
NET ECON ENERGY	GWH	-1670.	-1697.	-1712.	-1758.	-1846.	-1873.	-1878.	-1910.	-2522.
NET ECON COST	$000	-108798.	-115483.	-124127.	-133348.	-149373.	-158027.	-164422.	-171537.	-233296.
TOTAL PURCH	GWH	523.	522.	516.	516.	516.	517.	517.	520.	512.
TOTAL PURCH	$000	40168.	41903.	43480.	45406.	47347.	49391.	51503.	53891.	54939.
TOTAL SALES	GWH	1682.	1708.	1717.	1763.	1851.	1879.	1885.	1919.	2523.
TOTAL SALES	$000	109462.	116180.	124606.	133909.	150006.	158789.	165345.	172807.	233467.
EXTERNAL COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.
CUST. IMPACT COSTS	$000	0.	0.	0.	0.	0.	0.	0.	0.	0.

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ENERGY REQUIRED	GWH	5989.	6043.
THERM GENERATION	GWH	8019.	8096.
CONTROLLED ENERGY	GWH	5.	5.
PAYBACK ENERGY	GWH	-4.	-4.
EMERGENCY ENERGY	GWH	0.	0.
NET TRANSACTIONS	GWH	-2030.	-2054.
PEAK LOAD	MW	1251.	1262.
LOAD FACTOR	PCT	54.68	54.66
INSTALLED CAPACITY	MW	1495.	1495.
RESERVE MARGIN	MW	245.	233.
RESERVE MARGIN	PCT	19.57	18.48
CAPACITY MARGIN	PCT	16.37	15.59
ENERGY RESV MARGIN	PCT	100.94	99.16
LOSS LOAD	HOURS	2.	2.
RENEWABLE ENERGY	PCT	4.59	4.55
FUEL BURNED 000	MBTU	86725.	87533.
FIXED FUEL COST	$000	0.	0.
TOTAL FUEL COST	$000	380438.	397479.
VAR. O&M COST	$000	36429.	37828.
FIXED O&M COST	$000	41337.	42292.
TOTAL THERM COST	$000	458203.	477599.
THERMAL COST	$/MWH	57.14	58.99
TOTAL EMISS. COST	$000	-88.	347.
HYD VAR COST	$000	0.	0.
HYD FIXED COST	$000	0.	0.
NET TRANS COST	$000	-188775.	-202285.
EMER ENERGY COST	$000	51.	63.
TOTAL SYS. COST	$000	269391.	275724.
SYSTEM COST	$/MWH	44.98	45.63
AVG. MARG. COST	$/MWH	118.38	125.67
TRANS PURCH	GWH	511.	511.
TRANS PURCH COST	$000	57022.	59347.
TRANS SALES	GWH	0.	0.
TRANS SALES REV.	$000	0.	0.
ECON ENERGY PURCH	GWH	2.	2.
PURCH COST	$000	220.	289.
AVE. PURCH COST	$/MWH	127.18	142.70

GENERATION AND FUEL MODULE
SYSTEM REPORT

VECTREN SYSTEM		2030	2031
ECON ENERGY SALES	GWH	2542.	2566.
SALES REV.	$000	246017.	261922.
AVE. SALES REV.	$/MWH	96.78	102.06
NET ECON ENERGY	GWH	-2540.	-2564.
NET ECON COST	$000	-245797.	-261633.
TOTAL PURCH	GWH	512.	513.
TOTAL PURCH	$000	57242.	59637.
TOTAL SALES	GWH	2542.	2566.
TOTAL SALES	$000	246017.	261922.
EXTERNAL COSTS	$000	0.	0.
CUST. IMPACT COSTS	$000	0.	0.

Integrated Resource Plan Cost Study

Summary of Data Prepared

Below is a summary of the development of project deliverables for Vectren's Integrated Resource Planning input.

1. Summary of generation alternatives

    a. Simple Cycle combustion turbines
        i. 1-7FA.03
        ii. 1-7FA.04
        iii. 1-7FA.05
        iv. 2-7EAs
        v. 1-LMS-100
        vi. 4-LM-6000s
    b. Combined cycle combustion turbines
        i. 2x2x1 7FA.03
        ii. 2x2x1 7FA.04
        iii. 2x2x1 7FA.05
        iv. 2x2x1 7EA
    c. Biomass (wood-fired CFB)
    d. i. CFB coal plant without carbon capture
        ii. CFB coal plant with carbon capture
    e. i. Pulverized Coal Plant without carbon capture
        ii. Pulverized Coal Plant with carbon capture
    f. i. IGCC plant without carbon capture
        ii. IGCC plant with carbon capture

2. Deliverables

    a. Plant Design Basis definition
    b. Capital costs for each (separate summaries attached)
    c. O&M costs for each (summary table on Page 2)

3. Cost Definition
    a. CT based Options
    S&L maintains a database of costs for various CT options for both simple cycle and combined cycle configurations. This database is maintained through participation in various design and study assignments. The models not only have costs for the major equipment such as CT, HRSG, & ST, but commodities. For Vectren the estimates were adjusted to reflect current

economic conditions including major equipment, although the bigger adjustment downward was for the commodities.

b. Solid Fuel – CFB and PC

Similar to CT generation, S&L also maintains cost models for various CFB and PC generation alternatives. The commodity portion was adjusted to reflect current economic conditions, while for the major equipment S&L had recently received budgetary vendor pricing. These prices were adjusted to the size of units in the Vectren study and to the July 2009 price level.

c. Solid Fuel – IGCC

S&L used a combination of the Department of Energy’s IGCC model software as well as our own in-house project data. Actual costs from IGCC vendors is closely guarded, however we did compare the publicly available pricing from the Duke-Edwardsport IGCC plant.

Fixed and Variable O&M costs

O&M Costs for all Generation Options		
	Fixed Costs	**Variable Costs**
	$/net kW/Year	$/MWhr
Simple-Cycle CT		
7FA.03	$9.35	$15.09
7FA.04	$9.02	$16.01
7FA.05	$7.83	$15.17
7EA	$9.52	$18.83
LMS100	$9.88	$2.38
LM 6000PD	$6.13	$3.37
Combined-Cycle CT		
2x2x1 7FA.03	$12.89	$6.37
2x2x1 7FA.04	$12.43	$6.70
2x2x1 7FA.05	$10.80	$6.36
2x2x1 7EA	$20.03	$7.79
Biomass		
Wood-Fired CFB	$104.16	$3.07
Coal Technologies without CCS		
CFB	$34.23	$5.57
PC	$27.33	$4.01
IGCC	$27.51	$7.12
Coal Technologies with 90% CCS		
CFB	$59.46	$16.08
PC	$48.59	$13.78
IGCC	$38.07	$8.60

Plant Design Basis
Simple Cycle Options

Description	7FA.03	7FA.04	7FA.05	7EA	LMS100	LM 6000PD
Plant Description - Major parameters	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle	Simple Cycle
Location	Southern Indiana	Southern Indiana	Southern Indiana	Southern Indiana	Southern Indiana	Southern Indiana
Initial Unit or Extension	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield	Greenfield
Number of Gas Turbine	1	1	1	2	1	4
Gross kW	176,732	183,271	211,000	85,100	99,012	43,068
Station Total Gross kW	176,732	183,271	211,000	170,200	99,012	172,272
Net Output kW	174,965	181,438	208,890	168,498	98,022	170,549
NOx Control	DLN	DLN	DLN	DLN	DLE	DLE
SCR	None	None	None	None	Yes	Yes
CO/VOC	None	None	None	None	None	None
Exhaust Temperature	1114°F	1128°F	1118°F	999°F	780°F	851°F
NOx emissions						~20ppm
Allowances						
Fuel						
Primary Fuel	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas
Required inlet gas pressure						
Back-up Fuel	Not Req'd	Not Req'd	Not Req'd	Not Req'd	Not Req'd	Not Req'd
Inlet cooling	No	No	No	No	No	No
Water Injection	No	No	No	No	No	No
345kv Switchyard	Yes	Yes	Yes	Yes	Yes	Yes
Land Costs	Not included	Not included	Not included	Not included	Not included	Not included
Construction	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts

Plant Design Basis
Combined Cycle Options

	Description	2 x 7FA.03	2 x 7FA.04	2 x 7FA.05	2 x 7EAs
	Plant Description - Major parameters				
	Location	Southern Indiana	Southern Indiana	Southern Indiana	Southern Indiana
	Initial Unit or Extension	Greenfield	Greenfield	Greenfield	Greenfield
	Gas Turbine	2	2	2	2
	Gross kW per CT	174,000	180,400	207,700	83,500
	Steam Turbine	1	1	1	1
	Gross kW	178,000	184,600	212,500	100,700
	Total MW Output				
	Gross kW	526,000	545,400	627,900	267,700
	Net kW	512,850	531,765	612,203	262,500
	Main Steam Conditions	later	later	later	later
	Reheat Steam Conditions	later	later	later	later
	HRSG				
	Main Steam Conditions	later	later	later	later
	Reheat Conditions	later	later	later	later
	NOx Control	DLN / SCR	DLN / SCR	DLN / SCR	DLN / SCR
	SCR Catalyst	Yes	Yes	Yes	Yes
	CO/VOC Catalyst	Yes	Yes	Yes	Yes
	Exhaust Temperature	1114°F	1128°F	1118°F	999°F
	Fuel				
	Primary Fuel	Natural gas	Natural gas	Natural gas	Natural gas
	Required inlet gas pressure				
	Back-up Fuel	Not Req'd	Not Req'd	Not Req'd	Not Req'd
	Duct firing	No	No	No	No
	Inlet Evap. cooling	No	No	No	No
	Water Injection	No	No	No	No
	Steam turbine Cooling	Mechanical draft towers	Mechanical draft towers	Mechanical draft towers	Mechanical draft towers
	345kv Switchyard	Yes	Yes	Yes	Yes
	Make -up water source (wells/river/lake/other)	Wells	Wells	Wells	Wells
	Wastewater System	Required	Required	Required	Required
	Land Costs	not included	not included	not included	not included
	Construction	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts

Vectren
Solid Fuel Options

	100% Biomass	Without CCS			With CCS			
Description	**1 x 50MW (net)**	**1 x 600MW (net) T/G (2 x 330MW-gross CFB's)**	**1 x 750 MW (net) PC Plant**	**IGCC (2x2x1)**	**1 x 600MW (net) T/G (2 x 330MW-gross CFB's)**	**1 x 750 MW (net) PC Plant**	**IGCC (2x2x1)**	**Comments**
Estimate Number								
Plant Description - Major parameters		Circulating Fluidized Bed	Pulverized Coal	Integrated Gasification combined Cycle	Circulating Fluidized Bed	Pulverized Coal	Integrated Gasification combined Cycle	
Location	Midwest (MISO)	Midwest (MISO)	Midwest (MISO)	Midwest (MISO)	Midwest (MISO)	Midwest (MISO)	Midwest (MISO)	
Initial Unit or Extension	Greenfield Site	Greenfield Site	Greenfield Site	Greenfield Site	Greenfield Site	Greenfield Site	Greenfield Site	
Steam Turbine Gross MW(Annual Average)	55	660	820	725	660	820	725	
Number of Boilers	1	2	1	n/a	2	1	n/a	
Steam Generator Type and Cycle	Fluidized Bed (Bubbling Bed)	CFB, Sub-critical	Pulverized Coal, Supercritical	Gasifier Coombined Cycle (sub-critical)	CFB, Sub-critical	Pulverized Coal, Supercritical	Gasifier Coombined Cycle (sub-critical)	
Fuel Type(s) (Coal Type/Oil/Wood/Trash/Other)	Biomass - Wood chips	Illinois Basin Coal	Illinois Basin Coal	Illinois Basin Coal	Illinois Basin Coal	Illinois Basin Coal	Illinois Basin Coal	
Uncontrolled SO2 emissions	Depends on biomass	~7.5-lb/mmBtu	~7.5-lb/mmBtu	~7.5-lb/mmBtu	~7.5-lb/mmBtu	~7.5-lb/mmBtu	~7.5-lb/mmBtu	
Opportunity Fuels or others	none	none	none	none	none	none	none	
Start-Up Fuel (Fuel Oil or Natural Gas)	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	
Gross Plant Output (kW)	55,000	660,000	815,000	725,000	660,000	820,000	725,000	
Net Plant Output (kW)	48,385	599,421	750,800	623,000	414,500	516,500	518,000	
Steam Cycle (at the turbine Inlet)								
Main Steam Pressure (psig)	1,200	2,520	3,690	1,900	2,520	3,690	1,900	
Main Steam Temperature (°F)	950	1,050	1,100	1,050	1,050	1,100	1,050	
Hot Reheat Steam Temperature (°F)	950	1,050	1,100	1,050	1,050	1,100	1,050	
Minimum Load - %	40	40	35	70% on each CT and turn one gasifier train off	40	35	70% on each CT and turn one gasifier train off	
Common Facilities/Systems sized for 1 or 2 unit operation	1	2 unit	2 unit	2 unit	2 unit	2 unit	2 unit	
Pollution Control Equipment								
SO2	In-bed	In-bed plus "Polishing" Dry-FGD	Wet-FGD	Enhanced MDEA, Selexol, or Rectisol	In-bed plus "Polishing" Dry-FGD	Wet-FGD	Enhanced MDEA, Selexol, or Rectisol	
NOx	Combustion /SNCR	SNCR	LNB + SCR	SCR	SNCR	LNB + SCR	SCR	
PM-filterable	Baghouse	Baghouse	Baghouse	Part of each vendor's process	Baghouse	Baghouse	Part of each vendor's process	
SO3	Baghouse	Dry-FGD and baghouse	Wet-ESP or Lime injection	Part of each vendor's process	Baghouse	Wet-ESP or Lime injection	Part of each vendor's process	
Mercury	to be determined	ACI	Wet-FGD & Wet-ESP possibly ACI	Carbon Bed	ACI	Wet-FGD & Wet-ESP possibly ACI	Carbon Bed	
CO2 Capture Equipment	n/a	n/a	n/a	n/a	Yes, 90%	Yes, 90%	Yes, 90%	
CO2 Drying and Compression Station	n/a	n/a	n/a	n/a	Yes	Yes	Yes	

Vectren
Solid Fuel Options

Description	100% Biomass 1 x 50MW (net)	Without CCS 1 x 600MW (net) T/G (2 x 330MW-gross CFB's)	Without CCS 1 x 750 MW (net) PC Plant	Without CCS IGCC (2x2x1)	With CCS 1 x 600MW (net) T/G (2 x 330MW-gross CFB's)	With CCS 1 x 750 MW (net) PC Plant	With CCS IGCC (2x2x1)	Comments
Boiler Combustion Air and Flue Gas	(per boiler)	(per boiler)	(per boiler)	n/a	(per boiler)	(per boiler)	n/a	
Forced draft fans & motors	2 x 60%, single speed radial, vane controlled	2 x 60%, single speed radial, vane controlled	2 x 60%, single speed radial, vane controlled	n/a	2 x 60%, single speed radial, vane controlled	2 x 60%, single speed radial, vane controlled	n/a	
Induced draft fans & motors	2 x 60%, Axial	2 x 60%, Axial	2x 60%, Axial	n/a	2 x 60%, Axial	2x 60%, Axial	n/a	
Primary air fans & motors		2 x 60%, single speed radial, vane controlled	2 x 60%, single speed radial, vane controlled	n/a	2 x 60%, single speed radial, vane controlled	2 x 60%, single speed radial, vane controlled	n/a	
Air heater	2x 50% regenerative	2 x 50%, tubular type	2 x 50%, vertical shaft regenerative type(Tri-sector)	n/a	2 x 50%, tubular type	2 x 50%, vertical shaft regenerative type(Tri-sector)	n/a	
Material Handling								
Coal - Rail and Unloading & Storage	n/a	yes	yes	yes	yes	yes	yes	
Biomass Truck unloading and Storage	yes	n/a	n/a	n/a	n/a	n/a	n/a	
Reagent Unloading and Storage								
Limestone	yes	yes	yes	n/a	yes	yes	n/a	
Lime	n/a	yes	no	n/a	yes	no	n/a	
Ammonia	n/a	yes	yes	yes	yes	yes	yes	
Carbon	n/a	yes	yes	fixed carbon bed	yes	yes	fixed carbon bed	
IGCC Chemicals	n/a	n/a	n/a	yes	n/a	n/a	yes	
CO2 plant Chemicals	n/a	n/a	n/a	n/a	yes	yes	yes	
Make -up water source (wells/river/lake/other)	Wells	Wells	Wells	Wells	Wells	Wells	Wells	
Wastewater System	Required	Required	Required	Required	Required	Required	Required	
345 kV Switchyard	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
Land Costs	not included	not included	not included	not included	not included	not included	not included	
Construction	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Muliple Labor Contacts	Target Price with Gasifier vendor and Constructor	Target Price with Gasifier vendor and Constructor	Target Price with Gasifier vendor and Constructor	

Sargent & Lundy

12428-100
TJM - 8/26/2009

Vectren Power Supply
IRP Study Greenfield CC and SC Plants
Order of Magnitude Cost Study
Summary of Estimated Project Costs

Estimate No.	24794A	24795A	24719A	24720A	24796A	24797A	24721A	24722A	24723A	24724A
Unit Size, MW Nominal.	525	540	600	250	175	180	200	160	160	100
	Combined Cycle				**Simple Cycle**					
Configuration	2x2x1 7FA.03	2x2x1 7FA.04	2x2x1 7FA.05	2x2x1 7EA	1x 7FA.03	1x 7FA.04	1x 7FA.05	2x 7EA	4x LM6000PD	1x LMS100PB
Costs										
Combustion Turbines & Accessories.	88,434,100	94,434,100	114,434,100	58,305,732	44,217,050	47,217,050	57,217,050	58,305,732	77,951,004	39,551,820
HRSG's & Accessories.	58,128,836	59,543,292	64,293,888	30,798,255	n/a	n/a	n/a	n/a	n/a	n/a
Simple Cycle SCR w/ Stack (See note 1).	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	20,831,296	7,036,736
Simple Cycle Stack.	n/a	n/a	n/a	n/a	1,814,456	1,814,456	1,814,456	2,121,684	n/a	n/a
Steam Turbine & Accessories.	36,309,701	37,589,514	39,749,142	17,640,617	n/a	n/a	n/a	n/a	n/a	n/a
Condenser & Accessories.	3,847,928	3,961,821	4,184,976	1,714,415	n/a	n/a	n/a	n/a	n/a	n/a
Cooling Tower & Accessories.	3,607,448	3,707,448	3,907,448	2,738,596	n/a	n/a	n/a	n/a	n/a	n/a
Water Supply (See note 2).	1,500,000	1,500,000	1,500,000	1,500,000	900,000	900,000	900,000	900,000	900,000	900,000
Pumps.	5,941,372	5,971,372	6,001,372	3,974,452	838,756	838,756	838,756	838,756	804,601	777,808
Heat Exchangers.	955,287	955,287	955,287	346,605	677,364	677,364	677,364	677,364	n/a	4,374,155
Auxiliary Boiler (See note 3).	Not Included	Not Included	2,143,368	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included	Not Included
Field Erected Tanks.	1,445,000	1,445,000	1,445,000	1,090,000	590,000	590,000	590,000	590,000	590,000	590,000
Shop Fabricated Tanks.	178,144	178,144	178,144	136,177	56,703	56,703	56,703	71,014	154,062	138,211
Ammonia Storage & Forwarding Equipment.	420,946	420,946	420,946	368,729	n/a	n/a	n/a	n/a	420,946	420,946
Cranes & Hoists.	38,302	38,302	38,302	38,093	23,062	23,062	23,062	23,062	23,062	23,062
Fuel Gas Metering Station.	By Others	By Others	By Others	By Others	By Others	By Others	By Others	By Others	By Others	By Others
Fuel Gas Compressors.	-	-	-	-	-	-	-	-	1,812,837	2,012,837
Fuel Gas Conditioning.	1,799,814	1,839,814	1,979,814	1,070,946	899,907	919,907	989,907	1,196,756	1,506,418	735,473
Bulk Gas Storage Provisions.	81,907	81,907	81,907	81,907	27,302	27,302	27,302	27,302	27,302	27,302
Air Compressors & Dryers.	386,267	386,267	386,267	261,926	259,662	259,662	259,662	259,662	259,662	259,662
Chemical Feed & Sample Systems.	428,849	428,849	428,849	289,490	n/a	n/a	n/a	n/a	n/a	n/a
Water Treating (See note 4).	2,566,423	2,566,423	2,566,423	1,812,573	95,900	95,900	95,900	95,900	95,900	95,900
Fire Protection.	1,100,000	1,100,000	1,100,000	600,000	450,000	450,000	450,000	450,000	450,000	450,000
BOP Mechanical Equipment.	263,682	263,682	263,682	143,209	162,077	162,077	162,077	162,077	162,077	162,077
Critical Piping.	7,557,323	7,557,323	7,557,323	1,342,356	n/a	n/a	n/a	n/a	n/a	n/a
BOP Piping.	21,262,073	21,262,073	21,529,634	15,489,090	3,792,071	3,792,071	3,792,071	4,549,418	4,673,486	3,169,479
Valves & Specialties.	5,804,580	5,804,580	5,804,580	3,380,087	261,389	261,389	261,389	332,311	455,765	249,478
Electrical Major Equipment.	17,520,749	17,981,898	19,358,656	10,227,721	6,086,397	6,240,114	6,699,033	7,127,153	6,878,913	4,636,328
Electrical BOP.	16,029,468	16,029,468	16,029,468	10,794,828	4,367,808	4,367,808	4,367,808	5,005,934	5,954,504	3,326,731
Instrumentation & Controls.	3,705,712	3,705,712	3,705,712	2,964,549	1,210,466	1,210,466	1,210,466	1,670,707	1,634,253	1,326,403
Switchyard.	5,859,182	5,859,182	5,859,182	5,859,182	3,516,857	3,516,857	3,516,857	4,691,389	4,691,389	3,516,857
Steel.	1,275,371	1,275,371	1,275,371	982,984	260,703	260,703	260,703	277,995	379,723	215,479
Buildings (See note 5).	6,308,554	6,308,554	6,308,554	6,182,826	3,038,701	3,038,701	3,038,701	3,038,701	3,783,445	3,783,445
Foundations.	12,726,591	12,769,576	12,857,294	10,148,428	3,182,445	3,195,299	3,215,603	3,992,230	5,070,959	3,273,781
Site Preparation, Drainage, & Yard Work.	5,927,984	5,927,984	5,927,984	4,329,646	1,764,455	1,764,455	1,764,455	1,930,749	2,273,127	1,713,362
Heavy Haul Subcontracts.	1,500,000	1,500,000	1,500,000	975,000	750,000	750,000	750,000	900,000	800,000	600,000
Startup Craft Support.	2,015,500	2,015,500	2,015,500	1,612,400	403,100	403,100	403,100	564,340	483,720	403,100
Allowance to Attract Labor.	18,235,808	18,328,343	18,817,674	15,061,154	4,237,564	4,240,780	4,247,321	4,998,889	6,231,151	3,955,668
Erector G&A and Profit.	24,984,435	25,160,660	26,040,877	17,439,296	6,282,630	6,311,097	6,394,462	7,319,869	10,994,940	7,383,915
Consumables.	1,248,698	1,294,385	1,441,964	752,642	323,162	339,042	391,684	410,641	604,366	348,615
Freight.	3,741,286	3,774,466	3,932,679	2,453,778	1,018,460	1,026,374	1,050,157	1,175,772	2,019,297	947,610
Subtotal Direct Project Costs	**363,137,319**	**372,967,243**	**406,021,366**	**232,907,688**	**91,508,448**	**94,750,496**	**105,466,050**	**113,705,408**	**162,918,205**	**96,406,239**

Vectren Power Supply
IRP Study Greenfield CC and SC Plants
Order of Magnitude Cost Study
Summary of Estimated Project Costs

Estimate No.	24794A	24795A	24719A	24720A	24796A	24797A	24721A	24722A	24723A	24724A
Unit Size, MW Nominal.	525	540	600	250	175	180	200	160	160	100
	Combined Cycle				**Simple Cycle**					
Configuration	2x2x1 7FA.03	2x2x1 7FA.04	2x2x1 7FA.05	2x2x1 7EA	1x 7FA.03	1x 7FA.04	1x 7FA.05	2x 7EA	4x LM6000PD	1x LMS100PB
Costs										
Indirect Project Costs.	30,866,672	31,702,215	34,511,816	20,961,692	7,778,218	8,053,792	8,964,614	9,664,959	13,848,047	8,676,561
Contingency (15%).	59,101,000	60,700,000	66,080,000	38,080,000	14,893,000	15,421,000	17,165,000	18,506,000	26,515,000	15,762,000
Escalation.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.
Owner's Costs.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.
Interest During Construction.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.
Operating Spare Parts.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.	Not Incl.
Subtotal Project Costs	**453,104,991**	**465,369,458**	**506,613,182**	**291,949,380**	**114,179,666**	**118,225,288**	**131,595,664**	**141,876,367**	**203,281,252**	**120,844,800**
$/kW	**863**	**862**	**844**	**1,168**	**652**	**657**	**658**	**887**	**1,271**	**1,208**

Notes:

1. SCR's not considered for 7FA or 7EA simple cycles due to high C/T exhaust temperatures.
2. Allowance included for (2) new wells, higher capacity for CC's.
3. Auxiliary boiler required for 7FA.05 Rapid Response CC station. Allowance included for 150,000 lb/hr.
4. Water Treating includes permanent demineralizers for CC's and provisions for truck mounted rental unit on SC's. Sanitary waste treatment included for all.
5. All estimates assume outdoor design for major equipment, with a new control/admin building and warehouse, along with building enclosures for water treating and gas compressors if applicable.
6. The contracting scheme is assumed to be multiple lump sum. EPC contracting would warrant additional fees.
7. Switchyards Included, all assumed to be 345 KV ring bus configuration.

Sargent & Lundy
Chicago

C O S T   S U M M A R Y   R E P O R T

VECTREN
INTEGRATED RESOURCE PLANNING
CONCEPTUAL COST ESTIMATE
750 MW NET COAL-FIRED GENERATING UNIT
SUPERCRITICAL PC,SCR/BAGHOUSE/WET FGD/WET ESP

Page: 1
Estimate No: 24714B
Project No: 12428100
Prepared by: BJD/KSZ/

Price level: 2009

Estimate Date: 06JUL09

ACCT.NO.	DESCRIPTION	TOTAL EQUIPMENT COST	TOTAL MATERIAL COST	TOTAL LABOR COST	TOTAL COST
310	LAND AND LAND RIGHTS				NOT INCLUDED
311	STRUCTURES AND IMPROVEMENTS	9,391,000	55,476,000	96,146,000	161,013,000
312	BOILER PLANT	620,284,000	47,462,000	500,798,000	1,168,544,000
314	TURBINE PLANT	119,602,000	22,471,000	47,228,000	189,301,000
315	ACCESSORY ELECTRIC EQUIPMENT	26,652,000	17,260,000	50,747,000	94,659,000
316	MISC. POWER PLANT EQUIPMENT	6,632,000	1,232,000	5,464,000	13,328,000
362	345KV 4-BREAKER RING BUS SWITCHYARD INCLUDING MAIN POWER TRANSFORMER	9,570,000	1,708,000	2,377,000	13,655,000
376	INITIAL FILLS FOR TESTING & STARTUP (NOT INCLUDING FUEL AND LIMESTONE)		651,000		651,000
377	STARTUP PERSONNEL & CRAFT STARTUP SUPPORT			10,000,000	10,000,000
378	OVERTIME INEFFICIENCY AND PREMIUM TIME PAY FOR 5-10HR DAYS			93,000,000	93,000,000
379	PER DIEM			35,000,000	35,000,000
380	CONSUMABLES .5% OF MATL.		730,000		730,000
381	CONTRACTOR G&A 5%		7,500,000	42,000,000	49,500,000
382	CONTRACTOR PROFIT 10%		15,000,000	84,000,000	99,000,000
	TOTAL CONSTRUCTION COSTS	792,131,000	169,490,000	966,760,000	1,928,381,000
	INDIRECT EXPENSES				66,000,000
	ESCALATION				
	SALES/USE TAX				
	CONTINGENCY				299,157,000
	TOTAL PROJECT COST				2,293,538,000
	AFUDC				
	GRAND TOTAL COST				2,293,538,000

FINANCIAL ASSUMPTIONS:
ESCALATION RATES: Equipment 0.000%
Material 0.000%
Labor 0.000%
Indirects 0.000%
SALES/USE TAX RATES: Equipment 0.000% Material 0.000%
CONTINGENCY RATES: Equipment 15.0% Material 15.0% Labor 15.0% Indirects 15.0%

Vectren
Integrated Resource Planning Study
Greenfield Coal Fired PC Plant
Summary of Estimated Project Costs
Estimate No. 24714B

Unit Size, MW (Net)	750	516
Configuration	Supercritical PC without Carbon Capture	Supercritical PC with Carbon Capture
Land and Land Rights	not included	not included
Structures and Improvements	161,013,000	161,013,000
Boiler Plant	1,168,544,000	1,168,544,000
Turbine Plant	189,301,000	189,301,000
Accessory Electrical Equipment	94,659,000	94,659,000
Miscellaneous Power Plant Equipment	13,328,000	13,328,000
345kV Switchyard & Main Power	13,655,000	13,655,000
Initial Fills	651,000	651,000
Startup Personnel & Craft Startup Support	10,000,000	10,000,000
Overtime Inefficiency & Overtime Premium	93,000,000	93,000,000
Per Diem (Subsistence)	35,000,000	35,000,000
Consumables	730,000	730,000
Contractor' G&A	49,500,000	49,500,000
Contractor's Profit	99,000,000	99,000,000
Subtotal Direct Project Costs	**1,928,381,000**	**1,928,381,000**
Indirect Project Costs.	66,000,000	66,000,000
Contingency (15%)	299,157,000	299,157,000
Carbon Capture Costs	Not Included	675,360,000
Escalation.	Not Included	Not Included
Interest During Construction	Not Included	Not Included
Subtotal Project Costs	**2,293,538,000**	**2,968,898,000**
$/kW	**3,058**	**5,754**

Notes:
The contracting scheme is based on multiple lump sum contracts. An EPC contract could add an additional 10-15% to the cost of the plant.
All values represent 2009 overnight pricing, with no escalation included. Escalation should be included to derive the total cost.
Indirect Project Costs include engineering and construction management.
The labor cost is based on Evansville, IN union wage rates..

Sargent & Lundy
Chicago

RUN DATE: 07/06/09
TIME: 6:24:36 PM

Price level: 2009

COST SUMMARY REPORT

VECTREN
INTEGRATED RESOURCE PLANNING STUDY
CONCEPTUAL COST ESTIMATE
600 MW NET COAL FIRED GENERATING UNIT
2 X 300 NET CFB,SNCR/ACI/POLISHING DRY FGD/BAGHOUSE/MD COOL

Estimate No: 24715B
Project No: 12428100
Prepared by: BJD/KSZ/

Estimate Date: 06JUL09

ACCT.NO.	DESCRIPTION	TOTAL EQUIPMENT COST	TOTAL MATERIAL COST	TOTAL LABOR COST	TOTAL COST
310	LAND AND LAND RIGHTS				NOT INCLUDED
311	STRUCTURES AND IMPROVEMENTS	5,255,000	55,153,000	66,951,000	127,359,000
312	BOILER PLANT	490,835,000	27,207,000	406,312,000	924,354,000
314	TURBINE PLANT	92,410,000	16,217,000	33,048,000	141,675,000
315	ACCESSORY ELECTRIC EQUIPMENT	21,502,000	15,159,000	45,910,000	82,571,000
316	MISCELLANEOUS POWER PLANT EQUIPMENT	3,372,000	1,245,000	4,070,000	8,687,000
362	345KV 4-BREAKER RING BUS SWITCHYARD INCLUDING MAIN POWER TRANSFORMER	7,170,000	1,698,000	2,209,000	11,077,000
376	INITIAL FILLS FOR TESTING & STARTUP (NOT INCLUDING FUEL AND LIMESTONE)		700,000		700,000
377	STARTUP PERSONNEL & CRAFT STARTUP SUPPORT			10,000,000	10,000,000
378	OVERTIME INEFFICIENCY AND PREMIUM TIME PAY FOR 5-10 HR DAYS			74,000,000	74,000,000
379	PER DIEM			24,000,000	24,000,000
380	CONSUMABLES .5% OF MATL.		586,000		586,000
381	CONTRACTOR G&A 5%		5,900,000	33,000,000	38,900,000
382	CONTRACTOR PROFIT 10 %		11,800,000	66,000,000	77,800,000
	TOTAL CONSTRUCTION COSTS	620,544,000	135,665,000	765,500,000	1,521,709,000
	INDIRECT EXPENSES				66,000,000
	ESCALATION				
	SALES/USE TAX				
	CONTINGENCY				238,156,000
	TOTAL PROJECT COST				1,825,865,000
	AFUDC				
	GRAND TOTAL COST				1,825,865,000

FINANCIAL ASSUMPTIONS:
ESCALATION RATES: Equipment 0.000%
Material 0.000%
Labor 0.000%
Indirects 0.000%
SALES/USE TAX RATES: Equipment 0.000% Material 0.000%
CONTINGENCY RATES: Equipment 15.0% Material 15.0% Labor 15.0% Indirects 15.0%

Vectren
Integrated Resource Planning Study
Greenfield Coal Fired CFB Plant
Summary of Estimated Project Costs
Estimate No. 24715B

Unit Size, MW (Net)	600	415
Configuration	2x300 CFB without Carbon Capture	2x300 CFB with Carbon Capture
Land and Land Rights	not included	not included
Structures and Improvements	127,359,000	127,359,000
Boiler Plant	924,354,000	924,354,000
Turbine Plant	141,675,000	141,675,000
Accessory Electrical Equipment	82,571,000	82,571,000
Miscellaneous Power Plant Equipment	8,687,000	8,687,000
345kV Switchyard & Main Power	11,077,000	11,077,000
Initial Fills	700,000	700,000
Startup Personnel & Craft Startup Support	10,000,000	10,000,000
Overtime Inefficiency & Overtime Premium	74,000,000	74,000,000
Per Diem (Subsistence)	24,000,000	24,000,000
Consumables	586,000	586,000
Contractor' G&A	38,900,000	38,900,000
Contractor's Profit	77,800,000	77,800,000
Subtotal Direct Project Costs	**1,521,709,000**	**1,521,709,000**
Indirect Project Costs.	66,000,000	66,000,000
Contingency (15%)	238,156,000	238,156,000
Carbon Capture Costs	Not Included	608,000,000
Escalation.	Not Included	Not Included
Interest During Construction	Not Included	Not Included
Subtotal Project Costs	**1,825,865,000**	**2,433,865,000**
$/kW	**3,043**	**5,865**

Notes:
The contracting scheme is based on multiple lump sum contracts. An EPC contract could add an additional 10-15% to the cost of the plant.
All values represent 2009 overnight pricing, with no escalation included. Escalation should be included to derive the total cost.
Indirect Project Costs include engineering and construction management.
The labor cost is based on Evansville, IN union wage rates..

Vectren Power Supply
Integrated Resource Plan Cost Study
Greenfield IGCC without CO Capture - 623 MW Net
2x2x1 GE F-Class Gasification Facilities
Order of Magnitude Cost Estimate
-CONFIDENTIAL-

Foundation Factor = 1.00
Y

ConocoPhillips E-Gas

Estimate No.: 24726B
Project No.: 12428-100
Date: 7/1/2009
Revision No.: 1
Revision Date: 8/26/2009
Run Date: 8/26/2009
Preparer: DJS/TJM
Reviewer: PEF

Description	Total Equipment Cost	Total Material Cost	Total Labor Cost	Subtotal Installed Cost	Indirects	Contingencies		TOTAL PLANT COST	
						Process	Project	$	$/kW
1 COAL & SORBENT HANDLING	$15,019	$4,870	$22,105	$41,994	$4,199	$4,199	$4,199	$54,593	$88
2 COAL & SORBENT PREP & FEED	$0	$8,130	$29,285	$37,415	$3,742	$3,742	$3,742	$48,640	$78
3 FEEDWATER & MISC. BOP SYSTEMS	$18,296	$15,772	$18,675	$52,743	$5,274	$5,274	$5,274	$68,566	$110
4 GASIFIER & ACCESSORIES									
4.1 Gasifier, Syngas Cooler & Auxiliaries	$168,441	$45,118	$87,229	$300,788	$30,079	$45,118	$45,118	$421,104	$676
4.2 Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0
4.3 ASU/Oxidant Compression	$109,230	$18,205	$54,615	$182,050	$18,205	$27,307	$18,205	$245,767	$394
4.4-4.9 Other Gasification Equipment	$36,974	$17,162	$25,263	$79,399	$7,940	$11,910	$7,940	$107,189	$172
SUBTOTAL 4	$314,645	$80,485	$167,107	$562,237	$56,224	$84,336	$71,263	$774,060	$1,242
5A Gas Cleanup & Piping	$107,434	$7,345	$75,423	$190,202	$19,020	$28,530	$19,020	$256,773	$412
5B CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 COMBUSTION TURBINE/ACCESSORIES									
6.1 Combustion Turbine Generator	$162,411	$0	$9,945	$172,355	$17,236	$25,853	$17,236	$232,679	$373
6.2-6.9 Combustion Turbine Other	$0	$1,368	$1,646	$3,014	$301	$452	$301	$4,069	$7
SUBTOTAL 6	$162,411	$1,368	$11,591	$175,369	$17,537	$26,305	$17,537	$236,748	$380
7 HRSG, DUCTING & STACK									
7.1 Heat Recovery Steam Generator	$45,926	$0	$10,428	$56,354	$5,635	$8,453	$5,635	$76,079	$122
7.2-7.9 Ductwork and Stack	$9,320	$4,398	$6,303	$20,021	$2,002	$3,003	$2,002	$27,028	$43
SUBTOTAL 7	$55,246	$4,398	$16,731	$76,375	$7,638	$11,456	$7,638	$103,107	$165
8 STEAM TURBINE GENERATOR									
8.1 Steam TG & Accessories	$43,109	$0	$10,649	$53,758	$5,376	$2,688	$5,376	$67,197	$108
8.2-8.9 Turbine Plant Auxiliaries and Steam Piping	$19,884	$1,906	$15,517	$37,307	$3,731	$1,865	$3,731	$46,634	$75
SUBTOTAL 8	$62,993	$1,906	$26,166	$91,065	$9,107	$4,553	$9,107	$113,832	$183
9 COOLING WATER SYSTEM	$13,518	$14,604	$13,230	$41,352	$4,135	$4,135	$4,135	$53,758	$86
10 ASH/SPENT SORBENT HANDLING SYS	$36,682	$2,746	$19,485	$58,913	$5,891	$8,837	$5,891	$79,533	$128
11 ACCESSORY ELECTRIC PLANT	$27,130	$11,874	$42,822	$81,826	$8,183	$8,183	$8,183	$106,374	$171
12 INSTRUMENTATION & CONTROL	$18,716	$3,504	$13,567	$35,787	$3,579	$1,789	$3,579	$44,734	$72
13 IMPROVEMENTS TO SITE	$6,310	$3,720	$16,941	$26,971	$2,697	$1,349	$2,697	$33,714	$54
14 BUILDINGS & STRUCTURES	$0	$12,416	$15,638	$28,054	$2,805	$1,403	$2,805	$35,068	$56
TOTAL COST	$838,399	$173,139	$488,768	**$1,500,306**	**$150,031**	$194,092	$165,070	**$2,009,498**	$3,224
Relative Percents of Installed Costs	56%	12%	33%	$1,500,306	10.0%		23.9%		
Initial Fills								$0	$0
Startup Personnel & Craft Support								$9,002	$14
Consumables								$5,251	$8
Owners Costs								Not Included	
Operating Spare Parts								Not Included	
Total Project Costs								**$2,023,751**	**$3,246**

Estimate No.: 24727B
Project No.: 12428-100
Date: 7/1/2009
Revision No.: 1
Revision Date: 8/26/2009
Run Date: 8/26/2009
Preparer: DJS/TJM
Reviewer: PEF

Vectren Power Supply
Integrated Resource Plan Cost Study
Greenfield IGCC with CO Capture - 518 MW Net
2x2x1 GE F-Class Gasification Facilities w/ CCS
Order of Magnitude Cost Estimate
-CONFIDENTIAL-

Foundation Factor = 1.00
Y

ConocoPhillips E-Gas w/ CCS

Description	Total Equipment Cost	Total Material Cost	Total Labor Cost	Subtotal Installed Cost	Indirects	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1 COAL & SORBENT HANDLING	$15,297	$4,960	$22,516	$42,773	$4,277	$4,277	$4,277	$55,605	$107
2 COAL & SORBENT PREP & FEED	$0	$8,290	$29,866	$38,156	$3,816	$3,816	$3,816	$49,603	$96
3 FEEDWATER & MISC. BOP SYSTEMS	$18,740	$15,952	$19,328	$54,020	$5,402	$5,402	$5,402	$70,226	$136
4 GASIFIER & ACCESSORIES									
4.1 Gasifier, Syngas Cooler & Auxiliaries	$173,406	$46,448	$89,799	$309,653	$30,965	$46,448	$46,448	$433,514	$837
4.2 Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0
4.3 ASU/Oxidant Compression	$116,107	$19,351	$58,053	$193,511	$19,351	$29,027	$19,351	$261,240	$504
4.4-4.9 Other Gasification Equipment	$49,728	$17,414	$30,596	$97,738	$9,774	$14,661	$9,774	$131,947	$255
SUBTOTAL 4	$339,240	$83,213	$178,449	$600,902	$60,090	$90,135	$75,573	$826,700	$1,595
5A Gas Cleanup & Piping	$162,628	$6,963	$140,362	$309,953	$30,995	$46,493	$30,995	$418,436	$807
5B CO2 REMOVAL & COMPRESSION	$34,020	$0	$20,870	$54,890	$5,489	$0	$0	$60,379	$117
6 COMBUSTION TURBINE/ACCESSORIES									
6.1 Combustion Turbine Generator	$162,400	$0	$9,945	$172,345	$17,234	$25,852	$17,234	$232,665	$449
6.2-6.9 Combustion Turbine Other	$0	$1,368	$1,646	$3,014	$301	$452	$301	$4,069	$8
SUBTOTAL 6	$162,400	$1,368	$11,591	$175,359	$17,536	$26,304	$17,536	$236,734	$457
7 HRSG, DUCTING & STACK									
7.1 Heat Recovery Steam Generator	$44,356	$0	$10,428	$54,784	$5,478	$8,218	$5,478	$73,959	$143
7.2-7.9 Ductwork and Stack	$6,444	$4,536	$6,502	$17,482	$1,748	$2,622	$1,748	$23,600	$46
SUBTOTAL 7	$50,800	$4,536	$16,930	$72,266	$7,227	$10,840	$7,227	$97,559	$188
8 STEAM TURBINE GENERATOR									
8.1 Steam TG & Accessories	$40,224	$0	$8,867	$49,091	$4,909	$2,455	$4,909	$61,364	$118
8.2-8.9 Turbine Plant Auxiliaries and Steam Piping	$18,484	$1,656	$14,096	$34,236	$3,424	$1,712	$3,424	$42,795	$83
SUBTOTAL 8	$58,708	$1,656	$22,963	$83,327	$8,333	$4,166	$8,333	$104,159	$201
9 COOLING WATER SYSTEM	$12,636	$13,640	$12,100	$38,376	$3,838	$3,838	$3,838	$49,889	$96
10 ASH/SPENT SORBENT HANDLING SYS	$37,032	$2,794	$19,853	$59,679	$5,968	$8,952	$5,968	$80,566	$155
11 ACCESSORY ELECTRIC PLANT	$27,677	$13,790	$48,762	$90,229	$9,023	$9,023	$9,023	$117,297	$226
12 INSTRUMENTATION & CONTROL	$20,364	$3,812	$14,764	$38,940	$3,894	$1,947	$3,894	$48,675	$94
13 IMPROVEMENTS TO SITE	$6,416	$3,782	$17,224	$27,422	$2,742	$1,371	$2,742	$34,277	$66
14 BUILDINGS & STRUCTURES	$0	$12,130	$72,868	$84,998	$8,500	$4,250	$8,500	$106,247	$205
TOTAL COST	$945,958	$176,886	$648,444	**$1,771,288**	**$177,129**	$220,813	$187,122	**$2,356,353**	$4,547
Relative Percents of Installed Costs	53%	10%	37%	$1,771,288	10.0%		23.0%		
Initial Fills								$0	$0
Startup Personnel & Craft Support								$10,628	$21
Consumables								$6,200	$12
Owners Costs								Not Included	
Operating Spare Parts								Not Included	
Total Project Costs								**$2,373,180**	**$4,579**

Sargent & Lundy
Chicago

C O S T   S U M M A R Y   R E P O R T

VECTREN
WOOD BIOMASS FACILITY
ORDER OF MAGNITUDE COST ESTIMATE
55MW TURBINE 55MW WOOD FIRED CFB BOILER
WITH MECHANICAL DRAFT COOLING TOWER

Page: 1
Estimate No: 25085A
Project No: 12428100
Prepared by: PF / /

Estimate Date: 29JUN09

Price level: 2009

ACCT.NO.	DESCRIPTION	TOTAL EQUIPMENT COST	TOTAL MATERIAL COST	TOTAL LABOR COST	TOTAL COST
112	WOOD HANDLING EQUIPMENT	4,956,000	2,585,000	5,052,000	12,593,000
310	LAND AND LAND RIGHTS				NOT INCLUDED
311	STRUCTURES AND IMPROVEMENTS		7,868,000	4,071,000	11,939,000
312	CIRC FLUIDIZED BED STM AT 1200 PSI, 950F	28,754,000	6,786,000	13,429,000	48,969,000
314	TURBINE PLANT	16,571,000	4,777,000	5,976,000	27,324,000
315	ACCESSORY ELECTRIC EQUIPMENT	2,605,000	2,769,000	8,805,000	14,179,000
316	MISCELLANEOUS POWER PLANT EQUIPMENT	838,000	266,000	233,000	1,337,000
352	SUBSTATION, SWITCHYARD STRUCTURES AND FACILITIES		14,000	13,000	27,000
353	SUBSTATION AND SWITCHYARD EQUIPMENT	462,000		78,000	540,000
376	INITIAL FILLSFOR TESTING & STARTUP (NOT INCLUDING FUEL OR LIMESTONE)		135,000		135,000
377	STARTUP PERSONNEL			335,000	335,000
378	OVERTIME INEFFIENCY AND PREMIUM TIME			16,167,000	16,167,000
379	PER DIEM			4,127,400	4,127,400
380	CONSUMABLES		230,000		230,000
381	CONTRACTORS G & A 5%		1,155,000	1,664,952	2,819,952
382	CONTRACTORS PROFIT 10 %		2,310,000	3,329,900	5,639,900
	TOTAL CONSTRUCTION COSTS	54,186,000	28,895,000	63,281,252	146,362,252
	INDIRECT EXPENSES				10,000,000
	ESCALATION				
	SALES/USE TAX				
	CONTINGENCY				23,454,000
	TOTAL PROJECT COST				179,816,252
	AFUDC				
	GRAND TOTAL COST				179,816,252

FINANCIAL ASSUMPTIONS:
ESCALATION RATES: Equipment 0.000%
Material 0.000%
Labor 0.000%
Indirects 0.000%
SALES/USE TAX RATES: Equipment 0.000% Material 0.000%
CONTINGENCY RATES: Equipment 15.0% Material 15.0% Labor 15.0% Indirects 15.0%

VECTREN Integrated Resource Plan

Technology Options

Technology Options

Qualitative Factors			Simple Cycle Peaker - 7FA.03	Simple Cycle Peaker - 7FA.04	Simple Cycle Peaker - 7FA.05	Simple Cycle Peaker - 7EA	Simple Cycle Peaker - LMS 100	Simple Cycle Peaker - LM6000 PD	Combined Cycle - New 7FA.03	Combined Cycle - New 7FA.04
Capacity (gross), per unit	Summer	@95degF	176,732 kW/unit +2/-2	183,271 kW/unit +2/-2	211,000 kW/unit +2/-2	85,100 kW/unit +2/-2	99,012 kW/unit +2/-2	43,068 kW/unit +2/-2		
Capacity (gross), all units	ISO		176,732 kW total +2/-2	183,271 kW total +2/-2	211,000 kW total +2/-2	170,200 kW total +2/-2	99,012 kW total +2/-2	172,272 kW total +2/-2	526,000 +2/-2	545,400 +2/-2
Capacity (net)	Summer	@95degF	174,965 kW total +2/-2	181,438 kW total +2/-2	208,890 kW total +2/-2	168,498 kW total +2/-2	98,022 kW total +2/-2	170,549 kW total +2/-2	512,850 +2/-2	531,765 +2/-2
	ISO									
Number of CTs/boilers or CC config.			1	1	1	2	1	4	2 x 2 x 1	2 x 2 x 1
2009 capital dollars	direct		$91,508,170	$94,750,494	$105,466,050	$113,705,408	$96,406,239	$162,918,205	$363,137,624	$372,966,890
	indirect		$7,778,194	$8,053,792	$8,964,614	$9,664,959	$8,676,561	$13,848,047	$30,866,698	$31,702,186
	contingency		$14,893,302	$15,421,003	$17,165,000	$18,506,000	$15,762,000	$26,515,000	$59,100,669	$60,700,382
	CCS		$0	$0	$0	$0	$0	$0	$0	$0
	owners costs (not included)									
	total		$114,179,666	$118,225,288	$131,595,664	$141,876,367	$120,844,800	$203,281,252	$453,104,991	$465,369,458
Expenditure schedule	year 1		85%	85%	85%	85%	100%	100%	10%	10%
	year 2		15%	15%	15%	15%	0%	0%	55%	55%
	year 3		0%	0%	0%	0%	0%	0%	35%	35%
	year 4		0%	0%	0%	0%	0%	0%	0%	0%
	year 5		0%	0%	0%	0%	0%	0%	0%	0%
Capital	Total capital, $/gross kW, 2009$	$/kW	$646 +20/-10	$645 +20/-10	$624 +20/-10	$834 +20/-10	$1,221 +20/-10	$1,180 +20/-10	$861 +20/-10	$853 +20/-10
	Total capital, $/net kW, 2009$	$/kW	$653 +20/-10	$652 +20/-10	$630 +20/-10	$842 +20/-10	$1,233 +20/-10	$1,192 +20/-10	$884 +20/-10	$875 +20/-10
O&M	**Fixed**	**$/kW-yr**	**$9.35 +/-30**	**$9.02 +/-30**	**$7.83 +/-30**	**$9.52 +/-30**	**$9.88 +/-30**	**$6.13 +/-30**	**$12.89 +/-30**	**$12.43 +/-30**
	routine O&M labor		$4.00	$3.86	$3.35	$4.15	$7.14	$4.10	$6.24	$6.02
	maint. materials, supplies, other		$4.50	$4.34	$3.77	$4.50	$1.84	$1.47	$4.50	$4.34
	administrative and general		$0.85	$0.82	$0.71	$0.87	$0.90	$0.56	$2.15	$2.07
	fixed O&M for CSS		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Variable	**$/MWh**	**$15.09 +/-30**	**$16.01 +/-30**	**$15.17 +/-30**	**$18.83 +/-30**	**$2.38 +/-30**	**$3.37 +/-30**	**$6.37 +/-30**	**$6.70 +/-30**
	Limestone reagent	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lime	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Activated carbon	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Water	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.07	$0.07
	Mercury V O&M for IGCC	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Ammonia ($425/ton)	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01
	Bottom ash / bed ash disposal	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Fly ash disposal	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	FGD sludge disposal	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	SCR catalyst replacement	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.14	$0.14
	Bags for baghouse	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Gasifier maintenance	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Other expense	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.30	$0.30
	CT maintenance expense	$/MWh	$15.09	$16.01	$15.17	$18.83	$2.38	$3.37	$5.60	$5.94
	ST maintenance expense (for CC)	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.24	$0.23
	CCS variable cost	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net plant heat rate	Load	BTU/kWh								
	Minimum									
	50%		10,234	10,019	9,937	11,730	9,305	9,845	6,860	6,723
	75%		11,050	10,818	10,730	12,665	9,765	9,845	7,136	6,993
	100%		10,234 +2/-2	10,019 +2/-2	9,937 +2/-2	11,730 +2/-2	9,305 +2/-2	9,845 +2/-2	6,857 +2/-2	6,720 +2/-2
Nominal planned outage req'ts		weeks/yr	1	1	1	1	1	1	1	1
Overhaul cycle		yrs	13	13	13	13	9	9	9	9
Overhaul outage requirements		weeks	4	4	4	4	4	4	4	4
Equivalent forced outage rate	Existing	%	1.0% +2/-2	1.0% +2/-2	1.0% +2/-2	1.0% +2/-2	2.4% +2/-2	2.4% +2/-2	2.5% +2/-2	2.5% +2/-2
Minimum MW (of total MW in column)	Min to meet emission limits	net MW	89.2 +10/-10	92.5 +10/-10	106.5 +10/-10	85.9 +10/-10	49.0 +10/-10	85.3 +10/-10	192.3 +10/-10	199.4 +10/-10
Ramp rate (from total MW in column)	Min to Half load	MW/min	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	32.1	33.2
	Half to full load	MW/min	17.5	18.1	20.9	16.8	9.8	17.1	32.1	33.2
Startup-warm	Hours to synch	hours	0.45 +10/-10	0.45 +10/-10	0.45 +10/-10	0.45 +10/-10	0.08 +10/-10	0.08 +10/-10	0.45 for 1st CT +10/-10	0.45 for 1st CT +10/-10
	Synch to full load	hours	0.17 +10/-10	0.17 +10/-10	0.17 +10/-10	0.17 +10/-10	0.08 +10/-10	0.08 +10/-10	0.80 +10/-10	0.80 +10/-10
	Maintenance impact	$/start	$8,000	$8,800	$9,600	$9,613	$0	$0	$16,000	$17,600
	Gas consumed	mmBTU	399	406	463	441	81	150	1,519	1,544
	Coal consumed (or biomass)	mmBTU	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Supplemental fuel consumed	mmBTU	0	0	0	0	0	0	0	0
Startup-cold	Hours to synch	Hours	0.45 +10/-10	0.45 +10/-10	0.45 +10/-10	0.45 +10/-10	0.08 +10/-10	0.08 +10/-10	0.45 for 1st CT +10/-10	0.45 for 1st CT +10/-10
	Synch to full load	Hours	0.17 +20/-0	0.17 +20/-0	0.17 +20/-0	0.17 +20/-0	0.08 +20/-0	0.08 +20/-0	3.72 +20/-0	3.72 +20/-0
	Maintenance impact	$/start	$16,000	$17,600	$19,200	$19,227	$0	$0	$32,000	$35,200
	Gas consumed	mmBTU	399	406	463	441	81	150	4,866	4,945
	Coal consumed	mmBTU	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Supplemental fuel consumed	mmBTU	0	0	0	0	0	0	0	0
Water consumption	Normal year (100% CF)	AF/yr	0	0	0	0	0	0	3,452	3,580
Project schedule	Start site work, until COD	months	15	15	15	15	12	12	33	33

Note 1: For these options minimum load is equal to half load, so no ramp rate can be calculated.

VECTREN Integrated Resource Plan

Technology Options

															CCS	CCS	CCS	CCS	CCS	CCS
Qualitative Factors	**Technology Options**		**Combined Cycle - New 7FA.05**		**Combined Cycle - New 7EAs**		**Biomass**		**Circulating Fluidized Bed**		**Supercritical Pulverized Coal**		**Integrated Gasification Combined Cycle**		**Circulating Fluidized Bed**		**Supercritical Pulverized Coal**		**Integrated Gasification Combined Cycle**	
Capacity (gross), per unit	Summer	@95degF																		
Capacity (gross), all units	ISO		627,900	+2/-2	267,700	+2/-2	55,000	+2/-2	660,000	+2/-2	815,000	+2/-2	725,000	+2/-2	660,000	+2/-2	820,000	+2/-2	725,000	+2/-2
Capacity (net)	Summer	@95degF	612,203	+2/-2	262,500	+2/-2	48,385	+2/-2	599,421	+2/-2	750,800	+2/-2	623,000	+2/-2	414,460	+2/-2	516,561	+2/-2	518,000	+2/-2
	ISO																			
Number of CTs/boilers or CC config.			2 x 2 x 1		2 x 2 x 1		1		2		1		2 x 2 x 1		2		1		2 x 2 x 1	
2009 capital dollars	direct		$406,021,366		$232,907,688		$146,362,252		$1,521,709,000		$1,928,381,000		$1,494,359,000		$1,521,709,000		$1,928,381,000		$1,713,036,000	
	indirect		$34,511,816		$20,961,692		$10,000,000		$66,000,000		$66,000,000		$148,030,000		$66,000,000		$66,000,000		$169,640,000	
	contingency		$66,080,000		$38,080,000		$23,454,000		$238,156,000		$299,157,000		$354,159,000		$238,156,000		$299,157,000		$402,935,000	
	CCS		$0		$0		$0		$0		$0		$0		$608,000,000		$675,360,000		$60,379,000	
	owners costs (not included)																			
	total		$506,613,182		$291,949,380		$179,816,252		$1,825,865,000		$2,293,538,000		$1,996,548,000		$2,433,865,000		$2,968,898,000		$2,345,990,000	
Expenditure schedule	year 1		10%		10%		10%		5%		5%		5%		5%		5%		5%	
	year 2		55%		55%		55%		40%		35%		35%		40%		35%		35%	
	year 3		35%		35%		35%		45%		45%		45%		45%		45%		45%	
	year 4		0%		0%		0%		10%		15%		15%		10%		15%		15%	
	year 5		0%		0%		0%		0%		0%		0%		0%		0%		0%	
Capital	Total capital, $/gross kW, 2009$	$/kW	$807	+20/-10	$1,091	+20/-10	$3,269	(+25/-10)	$2,766	(+25/-10)	$2,814	(+25/-10)	$2,754	(+30/-10)	$3,688	(+25/-10)	$3,621	(+25/-10)	$3,236	(+30/-10)
	Total capital, $/net kW, 2009$	$/kW	$828	+20/-10	$1,112	+20/-10	$3,716	(+25/-10)	$3,046	(+25/-10)	$3,055	(+25/-10)	$3,205	(+30/-10)	$5,872	(+25/-10)	$5,747	(+25/-10)	$4,529	(+30/-10)
O&M	**Fixed**	**$/kW-yr**	**$10.80**	**+/-30**	**$20.03**	**+/-30**	**$104.16**	**+/-30**	**$34.23**	**+/-30**	**$27.33**	**+/-30**	**$27.51**	**+/-30**	**$59.46**	**+/-30**	**$48.59**	**+/-30**	**$38.07**	**+/-30**
	routine O&M labor		$5.23		$12.19		$57.87		$19.02		$15.18		$14.93		$27.51		$22.07		$17.95	
	maint. materials, supplies, other		$3.77		$4.50		$28.93		$9.51		$7.59		$8.00		$13.75		$11.03		$9.62	
	administrative and general		$1.80		$3.34		$17.36		$5.71		$4.56		$4.59		$9.91		$8.10		$6.35	
	fixed O&M for CSS		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$8.29		$7.39		$4.15	
	Variable	**$/MWh**	**$6.36**	**+/-30**	**$7.79**	**+/-30**	**$3.07**	**+/-30**	**$5.57**	**+/-30**	**$4.01**	**+/-30**	**$7.12**	**+/-30**	**$16.08**	**+/-30**	**$13.78**	**+/-30**	**$8.60**	**+/-30**
	Limestone reagent	$/MWh	$0.00		$0.00		$0.07		$1.41		$0.68		$0.00		$2.04		$0.98		$0.00	
	Lime	$/MWh	$0.00		$0.00		$0.00		$0.03		$0.36		$0.00		$0.04		$0.52		$0.00	
	Activated carbon	$/MWh	$0.00		$0.00		$1.75		$1.10		$0.00		$0.00		$1.59		$0.00		$0.00	
	Water	$/MWh	$0.07		$0.07		$0.24		$0.23		$0.24		$0.09		$0.34		$0.34		$0.09	
	Mercury V O&M for IGCC	$/MWh	$0.00		$0.00		$0.00		$0.00		$0.00		$0.20		$0.00		$0.00		$0.20	
	Ammonia ($425/ton)	$/MWh	$0.01		$0.01		$0.31		$0.22		$0.20		$0.00		$0.32		$0.29		$0.00	
	Bottom ash / bed ash disposal	$/MWh	$0.00		$0.00		$0.09		$0.65		$0.14		$0.00		$0.94		$0.20		$0.00	
	Fly ash disposal	$/MWh	$0.00		$0.00		$0.00		$0.00		$0.54		$0.00		$0.00		$0.79		$0.00	
	FGD sludge disposal	$/MWh	$0.00		$0.00		$0.21		$1.52		$1.11		$0.00		$2.20		$1.62		$0.00	
	SCR catalyst replacement	$/MWh	$0.14		$0.14		$0.00		$0.00		$0.35		$0.00		$0.00		$0.51		$0.00	
	Bags for baghouse	$/MWh	$0.00		$0.00		$0.10		$0.10		$0.10		$0.00		$0.15		$0.14		$0.00	
	Gasifier maintenance	$/MWh	$0.00		$0.00		$0.00		$0.00		$0.00		$0.73		$0.00		$0.00		$0.73	
	Other expense	$/MWh	$0.30		$0.30		$0.30		$0.30		$0.30		$0.30		$0.43		$0.44		$0.30	
	CT maintenance expense	$/MWh	$5.63		$7.01		$0.00		$0.00		$0.00		$5.60		$0.00		$0.00		$5.60	
	ST maintenance expense (for CC)	$/MWh	$0.20		$0.25		$0.00		$0.00		$0.00		$0.20		$0.00		$0.00		$0.20	
	CCS variable cost	$/MWh	$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$8.03		$7.94		$1.48	
Net plant heat rate	Load	BTU/kWh																		
	Minimum						14,730		10,525		9,976		N/A		13,682		12,969		N/A	
	50%		6,668		7,434		14,730		10,525		9,976		N/A		13,682		12,969		N/A	
	75%		6,936		7,733		13,793		9,855		9,341		N/A		12,812		12,143		N/A	
	100%		6,665	+2/-2	7,430	+2/-2	13,391	+2/-2	9,568	+2/-2	9,069	+2/-2	9,050	+10/-10	12,438	+10/-10	11,790	+10/-10	11,313	+10/-10
Nominal planned outage req'ts		weeks/yr	1		1		2		2		2		3		2		2		3	
Overhaul cycle		yrs	9		9		10		10		10		6		10		10		6	
Overhaul outage requirements		weeks	4		4		7		7		7		4		7		7		4	
Equivalent forced outage rate	Existing	%	2.5%	+2/-2	2.5%	+2/-2	3.5%	+2/-2	3.5%	+2/-2	4.6%	+2/-2	7.8%	+5/-5	3.5%	+2/-2	4.6%	+2/-2	7.8%	+5/-5
Minimum MW (of total MW in column)	Min to meet emission limits	net MW	229.6	+10/-10	98.4	+10/-10	19.4		89.9	+10/-10	300.3	+10/-10	N/A		62.2	+10/-10	206.6	+10/-10	N/A	
Ramp rate (from total MW in column)	Min to Half load	MW/min	38.3		16.4		0.8		10.0		12.5		10.4		6.9		8.6		8.6	
	Half to full load	MW/min	38.3		16.4		0.8		10.0		12.5		10.4		6.9		8.6		8.6	
Startup-warm	Hours to synch	hours	0.45 for 1st CT	+10/-10	0.45 for 1st CT	+10/-10	1.20		1.20	+10/-10	1.20	+10/-10	N/A		1.20	+10/-10	1.20	+10/-10	N/A	
	Synch to full load	hours	0.80	+10/-10	0.80	+10/-10	2.80		2.80	+10/-10	2.80	+10/-10	N/A		2.80	+10/-10	2.80	+10/-10	N/A	
	Maintenance impact	$/start	$19,200		$9,613		N/A		N/A		N/A		N/A		N/A		N/A		N/A	
	Gas consumed	mmBTU	1,762		842		111		986		1,171		N/A		986		1,047		N/A	
	Coal consumed (or biomass)	mmBTU	N/A		N/A		761		6,740		8,002		N/A		6,740		7,157		N/A	
	Supplemental fuel consumed	mmBTU	0		0				0		0		N/A		0		0		N/A	
Startup-cold	Hours to synch	Hours	0.45 for 1st CT	+10/-10	0.45 for 1st CT	+10/-10	4.10	+10/-10	4.10	+10/-10	4.10	+10/-10	N/A		4.10	+10/-10	4.10	+10/-10	N/A	
	Synch to full load	Hours	3.72	+20/-0	3.72	+20/-0	2.30	+20/-0	2.30	+20/-0	2.30	+20/-0	N/A		2.30	+20/-0	2.30	+20/-0	N/A	
	Maintenance impact	$/start	$38,400		$19,227								$38,400						$38,400	
	Gas consumed	mmBTU	5,647		2,699		316		2,797		3,321		N/A		2,797		2,970		N/A	
	Coal consumed	mmBTU	N/A		N/A		627		5,547		6,585		N/A		5,547		5,890		N/A	
	Supplemental fuel consumed	mmBTU	0		0		0		0		0		N/A		0		0		N/A	
Water consumption	Normal year (100% CF)	AF/yr	4,122		1,953		1,042		12,509		19,088		4,122		19,599		29,908		4,122	
Project schedule	Start site work, until COD	months	33		33		30		42		45		45		42		45		45	

10/13/2009

Vectren Power Supply
Integrated Resource Plan
Typical Full-Load Emissions

	Solid Fuel		Simple Cycle					Combined cycle
	Biomass	**Coal**	**LMS-100**	**LM-6000**	**7EA**	**7FA's**		**7FA's**
NOx	< 0.1lb/mmBtu	<0.07lb/mmBtu (w/SCR)	~25-ppmvd	~25-ppmvd	5 to 9-ppmvd	9-ppmvd		2 to 3.5 ppmvd after SCR
CO	< 150ppm	<150-ppm	25 to 130	~125	20 to 30 ppmvd	9-ppmvd		2 to 3 ppmvd after CO cat
VOC	5 to 10 lb/hr	15 to 20 lb/hr						1 to 2 ppmvd after CO cat
PM	< 0.015lb/mmBtu	< 0.015lb/mmBtu						18 to 20 lb/hr (w/o DF)
SO2	<0.08 lb/mmBtu	0.1 to 0.06 lb/mmBtu	nil (for Natural Gas)	nil (for Natural Gas)	nil (for Natural Gas)	nil (for Natural Gas)		nil (for Natural Gas)
Note these are "typical", each project's location will require different values depending on air modeling and site location.								

Received
November 1, 2011
Indiana Utility Regulatory Commission

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
01/01/09	595	584	573	573	569	573	583	599	587	591	582	590	574	567	564	563	561	579	625	628	616	611	591	559
01/02/09	534	520	510	506	511	520	547	579	599	605	601	594	578	571	560	554	542	572	618	617	612	601	592	565
01/03/09	541	519	498	491	492	494	498	514	521	546	556	566	562	571	560	557	555	573	594	584	574	556	536	510
01/04/09	486	463	445	444	427	429	440	446	460	476	493	513	533	552	560	563	579	607	649	646	642	638	619	591
01/05/09	565	566	557	564	572	597	651	720	744	743	747	753	747	745	741	736	725	746	768	772	757	742	707	672
01/06/09	626	606	607	592	594	608	648	713	726	723	739	729	727	731	727	729	717	736	749	752	735	714	689	648
01/07/09	611	593	588	585	577	602	651	715	721	727	738	738	739	747	743	739	739	745	766	771	751	744	704	666
01/08/09	634	618	608	611	607	631	679	746	757	753	745	753	744	756	735	725	715	724	773	784	777	776	738	702
01/09/09	668	649	640	636	636	643	682	741	758	739	727	721	697	685	667	658	635	657	678	681	666	651	626	594
01/10/09	534	518	492	486	479	488	496	514	527	558	572	585	598	612	607	615	619	643	665	655	646	635	618	591
01/11/09	573	550	541	535	534	536	546	573	581	604	597	590	589	591	587	574	565	607	645	653	648	633	613	587
01/12/09	563	568	561	569	577	609	658	733	746	744	749	750	730	712	700	692	684	688	728	733	715	700	681	634
01/13/09	592	579	565	565	565	585	633	718	751	766	777	775	774	767	769	756	736	756	812	821	808	798	774	727
01/14/09	703	679	673	662	661	680	721	782	791	793	777	762	749	748	719	733	742	763	813	838	835	829	805	765
01/15/09	735	724	727	729	730	748	806	866	875	885	872	859	842	836	811	804	797	826	866	878	887	873	852	807
01/16/09	781	777	766	760	762	779	826	877	888	868	855	827	813	793	780	779	775	790	818	813	797	795	770	728
01/17/09	690	675	660	650	643	639	653	667	676	698	708	703	677	656	625	602	594	627	646	648	631	616	601	574
01/18/09	544	539	518	519	527	519	535	545	558	578	596	597	596	598	607	605	609	632	657	666	650	651	629	601
01/19/09	576	570	566	573	584	600	660	715	738	760	753	754	750	734	736	733	724	741	793	793	788	772	750	704
01/20/09	677	665	662	660	668	684	745	807	824	814	798	781	764	762	746	732	732	743	786	804	798	795	767	737
01/21/09	703	700	696	696	699	709	752	813	817	804	793	768	751	745	718	709	688	697	757	766	758	750	717	678
01/22/09	654	628	619	616	619	637	678	729	757	741	726	717	693	672	662	642	625	630	681	707	687	686	668	620
01/23/09	584	570	568	560	557	572	614	672	677	670	655	645	636	628	621	608	601	621	668	673	664	667	650	615
01/24/09	577	562	543	543	555	564	580	606	626	640	649	650	642	625	614	614	608	625	685	689	678	685	670	645
01/25/09	621	617	611	608	607	616	619	643	647	677	679	685	676	671	670	673	683	701	735	733	732	718	699	662
01/26/09	640	634	628	631	639	660	711	771	789	790	795	794	791	770	766	753	743	751	785	789	775	760	737	694
01/27/09	663	657	644	640	630	652	680	720	745	755	777	782	789	781	765	762	731	737	765	742	713	692	668	628
01/28/09	571	492	530	460	442	436	500	571	533	460	466	491	503	500	494	496	504	517	554	567	562	557	548	524
01/29/09	526	517	497	497	488	501	527	568	582	611	624	635	644	642	638	643	626	633	661	672	664	656	644	613
01/30/09	587	566	562	555	545	564	585	636	648	670	663	667	659	658	641	642	621	621	655	680	680	672	661	631
01/31/09	585	572	563	562	560	567	589	606	611	620	628	629	626	613	587	575	564	579	622	638	625	618	592	563
02/01/09	534	512	500	498	486	500	497	516	516	519	520	531	520	523	518	518	516	534	570	593	589	588	587	560
02/02/09	543	529	530	526	539	559	605	664	700	703	693	681	677	675	669	668	659	663	712	745	737	734	705	669
02/03/09	640	620	612	611	606	627	682	754	789	819	820	823	824	830	817	817	820	809	861	870	882	846	817	775
02/04/09	731	710	692	721	728	734	765	838	842	855	842	827	808	807	782	772	754	768	820	851	846	842	812	767
02/05/09	744	736	731	734	733	747	792	850	852	837	818	808	774	764	744	728	709	714	748	772	768	759	727	685
02/06/09	650	631	616	615	614	618	665	706	713	695	679	664	646	643	623	607	597	586	630	645	628	618	592	555
02/07/09	523	492	479	470	471	473	492	508	518	531	536	539	531	522	522	516	525	535	556	564	544	536	521	485
02/08/09	467	450	431	431	421	428	438	453	470	489	498	500	491	496	491	495	495	510	549	571	569	556	540	513
02/09/09	489	485	476	480	483	499	550	613	634	636	640	637	511	630	617	607	596	588	622	654	633	629	590	544
02/10/09	516	494	486	476	481	492	532	595	624	622	629	643	648	642	636	630	618	635	655	669	650	644	601	560
02/11/09	539	510	500	498	487	504	538	611	634	647	654	651	645	654	633	616	590	607	643	662	663	652	620	586
02/12/09	556	537	529	519	529	544	581	658	663	659	651	648	635	632	610	610	588	590	626	652	655	651	623	578
02/13/09	550	538	522	531	524	543	583	648	658	662	658	656	644	640	629	612	603	606	625	646	638	624	609	564
02/14/09	525	492	481	480	472	477	499	515	538	563	576	584	573	568	562	567	566	583	601	617	603	595	585	553
02/15/09	535	523	510	511	505	522	533	547	561	565	568	556	549	544	536	528	525	539	585	626	631	627	608	582
02/16/09	562	562	561	562	576	599	649	708	723	722	707	697	683	675	659	646	625	624	684	712	712	711	681	639
02/17/09	612	603	595	601	608	618	670	731	733	723	711	721	708	705	700	688	679	687	702	727	709	692	665	622
02/18/09	580	558	549	544	541	546	593	653	659	659	657	656	651	649	642	635	634	650	682	699	685	688	661	627
02/19/09	596	595	586	581	587	606	662	730	737	750	749	748	742	738	721	711	698	703	725	772	765	759	732	689
02/20/09	660	641	644	633	638	654	698	745	745	740	733	704	693	679	662	661	634	633	664	677	673	667	646	605
02/21/09	567	550	537	527	526	529	536	554	568	590	603	622	621	620	616	604	592	600	626	648	646	636	621	599
02/22/09	580	565	556	554	556	562	573	595	601	609	607	596	593	586	579	571	574	583	622	662	668	656	642	614
02/23/09	600	592	594	604	604	633	689	746	749	743	736	719	724	680	659	651	631	636	665	720	723	718	676	636
02/24/09	605	591	581	586	583	600	643	703	708	684	692	683	661	649	630	622	617	614	657	698	694	675	651	605
02/25/09	574	559	543	538	541	552	606	655	663	664	658	666	648	653	645	642	628	634	660	680	661	652	621	577
02/26/09	546	533	523	515	510	519	565	626	634	645	644	647	639	625	627	619	611	604	627	651	645	630	590	551
02/27/09	520	501	496	478	480	489	538	598	628	642	649	659	651	654	656	659	633	638	650	670	656	647	625	593
02/28/09	563	539	527	530	523	529	548	564	583	604	617	629	614	624	612	610	608	616	635	656	641	636	617	600
03/01/09	565	561	558	561	546	570	576	586	593	603	602	603	587	590	583	584	589	609	641	689	685	684	657	639
03/02/09	616	606	612	611	624	653	706	760	766	761	756	750	737	734	710	695	687	679	716	764	765	754	730	695
03/03/09	662	655	654	651	660	677	722	785	799	770	762	745	728	720	702	706	689	696	718	754	749	735	712	670
03/04/09	641	629	607	618	607	622	676	729	728	712	706	582	673	663	648	638	614	619	629	679	676	660	627	597
03/05/09	564	548	532	532	524	540	587	644	663	655	656	654	637	638	628	622	610	609	627	656	639	629	597	557

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
03/06/09	524	503	492	482	474	486	510	565	585	592	596	600	595	602	592	582	570	563	569	591	576	576	543	505
03/07/09	460	432	416	417	405	412	422	432	448	479	503	506	505	507	489	491	490	492	501	538	528	522	493	471
03/08/09	444	423	412	401	407	405	415	427	442	467	479	496	500	504	496	499	502	501	513	550	549	527	489	471
03/09/09	445	441	442	444	460	518	595	622	630	636	639	633	621	616	602	591	576	579	594	631	618	596	554	524
03/10/09	502	485	480	470	476	533	587	607	610	620	629	633	635	636	628	617	613	612	604	640	630	607	558	493
03/11/09	483	479	464	461	472	525	596	636	652	653	662	653	658	652	634	629	619	638	646	689	678	665	621	600
03/12/09	573	572	571	573	579	627	707	724	729	729	741	717	713	702	688	677	677	669	689	710	702	682	637	602
03/13/09	583	579	570	574	574	611	676	689	680	676	663	650	637	622	602	585	582	569	585	603	605	582	553	514
03/14/09	496	480	481	473	469	486	507	527	542	557	556	551	546	535	523	519	523	519	520	554	546	526	505	472
03/15/09	458	449	436	434	442	453	468	483	493	499	488	488	486	485	476	485	477	491	505	548	545	521	497	467
03/16/09	452	455	448	459	469	519	590	621	630	631	645	628	625	613	600	595	585	582	579	621	616	592	554	524
03/17/09	495	500	485	488	496	549	611	633	635	639	633	631	630	628	616	614	602	600	595	633	618	595	556	520
03/18/09	497	492	481	483	491	533	601	624	626	637	639	634	638	634	619	620	608	601	611	638	623	594	554	527
03/19/09	497	494	484	473	481	533	599	632	627	629	638	631	624	627	607	601	583	583	594	632	628	609	571	540
03/20/09	519	517	506	502	520	566	633	648	632	630	624	612	604	601	580	566	557	545	541	575	575	562	527	497
03/21/09	474	469	458	467	464	477	500	519	530	556	559	542	519	507	497	492	483	489	467	452	460	458	429	414
03/22/09	388	389	386	395	386	405	420	429	447	465	467	476	468	457	449	447	448	460	465	506	500	484	462	442
03/23/09	428	428	422	427	436	475	519	554	575	581	588	590	579	582	570	556	549	535	540	568	561	537	496	509
03/24/09	452	437	434	431	441	466	519	557	583	596	597	603	597	603	597	590	578	560	569	609	592	569	532	498
03/25/09	479	472	459	461	466	500	534	563	576	593	599	600	597	599	586	572	564	560	559	589	587	563	533	497
03/26/09	475	471	459	465	472	508	545	581	585	598	596	599	592	598	595	577	572	558	557	592	584	564	525	498
03/27/09	468	464	456	452	463	490	534	568	574	594	589	587	581	576	563	554	541	533	532	557	540	525	495	462
03/28/09	434	432	423	413	423	434	447	469	484	518	529	524	520	514	508	504	511	507	505	525	524	518	498	470
03/29/09	457	447	446	444	446	462	478	502	527	542	554	562	574	562	559	554	564	567	558	585	593	579	544	526
03/30/09	504	503	506	517	527	592	647	663	655	650	641	628	621	610	593	589	568	575	574	606	609	586	539	514
03/31/09	496	492	487	482	496	538	598	615	624	627	636	637	639	637	631	619	613	594	592	619	620	593	553	517
04/01/09	494	493	497	496	506	561	619	628	620	612	617	607	610	605	589	581	574	569	568	598	603	578	535	507
04/02/09	483	476	473	476	486	531	584	596	595	612	615	624	621	621	614	601	601	655	609	612	604	577	534	496
04/03/09	477	464	462	464	475	515	583	601	618	616	618	610	605	598	585	568	554	548	533	564	575	551	512	477
04/04/09	462	447	452	451	451	474	491	496	510	513	498	499	486	480	474	473	477	474	476	502	516	498	462	431
04/05/09	429	415	419	405	414	424	428	445	459	475	470	484	482	490	493	499	512	512	512	541	540	519	496	465
04/06/09	451	449	451	463	483	543	625	653	677	681	695	698	695	689	677	673	659	667	664	675	673	647	606	568
04/07/09	554	543	540	545	553	607	662	670	666	664	657	655	641	639	628	613	596	596	598	628	643	618	582	551
04/08/09	535	535	530	527	547	590	652	661	650	642	626	625	615	611	600	587	576	575	571	599	610	580	548	508
04/09/09	492	491	487	490	505	562	619	631	628	615	619	607	603	603	592	584	576	581	584	587	592	561	511	471
04/10/09	454	444	446	432	444	472	509	529	540	543	543	546	543	542	526	521	523	533	521	535	530	518	484	449
04/11/09	431	419	415	417	420	439	454	467	486	493	489	483	472	468	461	477	474	472	473	498	508	496	473	445
04/12/09	425	414	414	410	419	434	441	458	480	479	469	463	449	440	429	433	437	455	464	505	512	498	473	448
04/13/09	446	437	437	442	453	513	571	602	621	621	624	622	618	611	601	585	567	564	566	591	594	566	521	487
04/14/09	471	458	460	453	476	521	584	617	627	639	641	647	644	639	631	624	618	605	620	630	624	596	552	519
04/15/09	503	489	489	488	501	542	615	636	646	652	646	647	637	622	612	595	581	578	577	603	612	577	541	506
04/16/09	480	481	479	474	491	544	598	615	631	630	624	617	615	609	600	588	567	564	555	576	597	571	526	488
04/17/09	468	465	462	463	469	513	562	570	593	586	580	587	585	589	582	575	556	546	540	543	563	534	500	449
04/18/09	437	416	417	407	411	427	424	451	472	486	497	498	495	502	499	495	496	495	493	515	523	502	473	445
04/19/09	425	413	408	399	398	403	416	430	453	471	492	494	497	497	489	493	494	511	513	539	533	513	488	458
04/20/09	449	438	445	440	455	511	571	605	633	631	640	639	631	637	622	604	579	575	576	597	608	580	539	504
04/21/09	495	479	480	478	490	543	594	628	633	634	642	637	638	636	626	612	605	591	591	606	627	600	558	528
04/22/09	507	499	494	498	517	562	620	632	629	636	631	630	636	618	620	609	592	586	581	599	619	590	547	505
04/23/09	476	476	467	466	487	535	581	601	617	617	627	625	644	648	635	619	606	589	592	607	631	597	562	513
04/24/09	493	473	466	472	473	507	548	576	598	614	628	632	637	650	644	639	627	613	593	594	617	595	541	491
04/25/09	465	450	437	430	430	435	441	471	505	529	544	558	562	572	571	584	593	596	586	584	591	579	536	494
04/26/09	461	439	434	421	413	422	410	437	473	487	521	546	558	580	592	598	611	622	610	615	637	609	562	519
04/27/09	501	478	469	474	480	531	581	624	667	687	711	728	738	753	759	742	750	729	718	724	732	689	628	579
04/28/09	544	529	518	512	521	569	627	643	678	679	688	697	708	717	714	714	703	698	691	693	705	665	614	567
04/29/09	541	527	515	509	518	566	610	640	666	686	704	713	735	754	753	755	742	725	695	694	711	668	612	565
04/30/09	539	517	512	506	517	565	623	657	676	685	689	697	711	718	717	706	682	670	668	675	670	637	597	545
05/01/09	523	515	500	501	506	551	584	632	638	665	663	700	674	715	700	691	651	624	599	591	599	572	532	480
05/02/09	457	446	428	432	431	444	437	468	481	521	500	523	509	511	503	512	503	510	507	523	534	520	492	463
05/03/09	436	428	416	415	414	424	416	441	464	487	486	507	502	501	506	505	515	524	536	551	558	534	511	483
05/04/09	468	468	457	468	471	518	573	617	637	651	659	666	661	672	663	645	640	623	619	617	637	606	563	525
05/05/09	503	497	479	484	495	528	581	623	634	657	681	692	697	701	700	699	675	667	648	654	664	640	591	546
05/06/09	518	508	499	496	507	545	605	650	659	676	677	678	678	679	664	663	642	644	634	633	643	622	570	529
05/07/09	516	506	493	489	502	542	600	638	657	676	682	701	703	708	711	722	708	698	691	684	694	671	607	562
05/08/09	532	516	506	504	507	542	592	629	663	694	703	712	701	691	661	653	640	644	638	631	632	622	570	516

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
05/09/09	484	462	452	447	436	454	459	484	505	517	528	536	529	538	535	539	547	541	533	536	553	535	509	459
05/10/09	457	424	420	414	402	417	408	439	462	480	491	497	497	499	504	509	501	521	522	532	534	535	491	466
05/11/09	468	453	449	453	466	519	564	607	634	652	662	668	675	671	678	667	649	643	624	623	645	609	561	511
05/12/09	493	484	472	472	479	518	576	615	632	650	656	666	671	685	670	671	656	645	634	634	650	630	572	508
05/13/09	503	491	479	480	486	533	597	628	610	619	675	701	709	713	724	721	712	705	686	697	699	675	629	559
05/14/09	554	542	528	523	526	557	625	662	672	684	706	717	723	735	729	739	727	713	694	678	687	660	603	550
05/15/09	524	505	492	494	491	523	567	610	640	669	698	730	751	776	782	791	777	764	737	721	719	697	644	586
05/16/09	547	524	486	478	470	472	480	510	535	563	594	612	602	603	570	566	551	548	536	524	543	537	500	464
05/17/09	446	430	420	421	420	424	420	442	471	486	490	499	504	505	504	512	518	533	531	536	565	550	518	483
05/18/09	478	470	465	468	484	522	587	617	636	652	660	672	676	677	667	760	645	634	615	620	627	610	545	510
05/19/09	460	479	415	442	460	494	540	587	606	621	633	649	656	654	662	661	658	660	654	641	654	631	576	530
05/20/09	504	490	484	479	493	518	571	615	619	663	685	706	722	728	741	744	741	726	718	696	706	677	608	556
05/21/09	525	510	498	497	501	529	591	639	671	702	729	755	772	787	807	811	806	787	774	747	755	719	658	596
05/22/09	559	541	521	507	511	528	582	629	664	702	734	762	778	796	821	818	807	785	766	755	767	752	638	530
05/23/09	499	478	457	469	474	457	453	523	553	590	629	664	695	716	737	744	748	737	709	685	675	662	613	568
05/24/09	525	500	481	471	467	465	460	487	530	553	580	604	607	606	596	596	594	595	591	588	599	590	561	516
05/25/09	492	468	462	456	458	464	465	486	526	571	601	629	645	652	660	672	681	661	652	636	647	624	588	543
05/26/09	525	510	499	492	510	547	606	659	705	734	749	760	778	774	835	825	803	802	782	763	770	742	680	634
05/27/09	584	574	549	547	554	592	643	695	740	773	815	843	880	871	929	932	914	885	845	817	806	769	691	624
05/28/09	587	559	550	537	549	584	635	683	712	750	771	789	825	840	854	836	797	755	710	690	683	649	608	557
05/29/09	531	513	508	499	515	546	590	632	669	696	718	722	736	740	734	720	701	682	659	644	647	632	576	529
05/30/09	495	472	456	454	449	450	458	494	527	550	583	605	602	611	630	659	683	695	682	663	671	658	613	565
05/31/09	531	511	492	481	466	461	459	487	527	558	586	602	629	641	660	675	697	697	685	668	665	638	591	544
06/01/09	528	509	501	500	510	545	583	648	687	725	779	824	869	901	925	937	942	948	932	892	894	859	779	706
06/02/09	663	627	611	591	592	614	662	741	800	859	909	956	987	1008	1020	1024	990	952	902	849	836	791	737	678
06/03/09	631	606	586	574	573	608	657	707	749	781	820	842	853	861	858	851	831	802	773	744	740	694	655	599
06/04/09	571	554	538	528	532	572	611	651	665	687	697	694	692	693	686	670	650	643	646	643	650	649	606	565
06/05/09	538	518	507	498	508	527	568	606	635	659	670	675	686	699	695	689	691	684	668	651	647	638	592	540
06/06/09	502	485	468	457	451	442	457	493	518	549	573	592	607	628	637	656	654	662	630	616	617	610	571	526
06/07/09	497	472	467	456	450	443	445	478	518	553	598	629	661	688	715	733	757	756	747	726	733	717	667	615
06/08/09	573	554	536	527	549	586	637	690	727	766	804	835	837	857	854	870	867	875	856	839	836	803	747	698
06/09/09	645	617	586	565	567	595	649	708	780	802	837	868	906	943	967	955	942	930	897	872	871	841	774	716
06/10/09	661	638	614	606	605	651	693	742	772	817	865	919	944	963	982	989	979	968	947	921	906	886	817	736
06/11/09	673	610	583	565	573	602	653	695	702	742	769	796	837	880	897	880	810	785	774	751	747	738	687	647
06/12/09	592	578	560	544	552	582	615	650	678	699	728	743	759	763	762	767	753	746	728	703	698	681	627	581
06/13/09	537	510	490	478	477	472	492	520	572	616	649	686	702	715	729	747	766	769	753	722	712	693	646	593
06/14/09	552	528	506	498	491	480	483	521	564	628	675	721	755	777	798	823	822	823	802	766	754	738	686	638
06/15/09	585	568	549	540	552	590	638	714	760	789	811	809	800	792	790	789	780	780	772	756	766	751	692	640
06/16/09	608	583	559	549	555	594	650	693	727	769	811	848	847	826	787	789	795	794	782	764	753	745	683	635
06/17/09	592	570	544	540	546	583	631	702	750	807	856	909	961	991	1017	996	981	986	976	949	932	894	815	746
06/18/09	695	652	631	613	604	639	710	742	763	783	805	850	894	926	959	986	989	995	987	955	939	915	847	773
06/19/09	720	685	657	633	634	646	696	771	841	905	948	990	1016	1038	1051	1054	1040	1013	972	943	929	898	835	762
06/20/09	707	680	649	631	604	601	616	635	689	752	806	854	886	911	921	940	932	928	902	859	844	814	728	671
06/21/09	622	588	592	543	535	529	537	581	633	701	774	829	872	906	922	947	957	954	927	907	900	880	821	767
06/22/09	713	688	655	633	639	691	741	823	897	961	1019	1068	1096	1130	1143	1148	1130	1063	973	914	909	891	817	757
06/23/09	707	673	650	625	632	662	721	785	855	927	979	1021	1042	1047	1085	1089	1073	1061	1032	1008	973	947	865	795
06/24/09	735	700	674	641	647	664	718	802	861	916	969	1013	1046	1073	1096	1106	1093	1079	1049	1019	992	968	889	816
06/25/09	760	725	693	669	666	693	742	819	884	952	1004	1058	1082	1114	1128	1123	1117	1091	1073	1047	1030	1000	923	855
06/26/09	808	770	735	712	713	723	770	853	921	982	1039	1080	1091	1119	1126	1121	1103	1080	1059	1008	988	965	868	790
06/27/09	741	692	662	632	616	612	608	661	718	784	837	896	919	945	963	973	978	972	945	904	884	856	799	731
06/28/09	684	643	627	615	598	592	591	614	659	698	749	778	800	819	831	834	839	831	803	769	740	710	653	604
06/29/09	559	537	516	509	520	547	605	668	713	770	808	847	884	904	929	937	935	933	911	873	834	807	734	657
06/30/09	614	580	558	550	548	567	612	683	727	771	800	826	850	889	893	919	915	897	887	845	823	796	717	650
07/01/09	606	570	546	517	528	549	603	642	673	707	730	740	755	758	763	756	752	762	756	737	740	727	672	615
07/02/09	572	545	523	508	511	546	576	631	656	676	698	708	723	732	725	735	733	720	708	680	676	662	605	546
07/03/09	502	486	465	457	454	453	458	490	530	575	610	640	657	691	703	730	736	747	718	684	674	654	614	574
07/04/09	529	503	490	468	472	470	461	478	507	537	556	566	565	553	548	544	543	546	535	530	533	524	522	504
07/05/09	481	461	459	447	441	450	450	468	495	513	530	540	557	565	572	575	575	584	575	582	591	584	567	538
07/06/09	508	490	477	472	480	515	543	617	661	714	753	795	831	847	874	870	874	865	845	820	810	786	720	647
07/07/09	602	570	550	526	525	550	589	653	699	751	799	838	879	909	931	936	942	936	920	880	861	828	759	685
07/08/09	638	612	585	572	573	607	627	696	737	787	843	888	917	924	942	942	899	883	845	822	790	758	698	646
07/09/09	616	582	565	547	555	577	611	669	715	804	815	874	924	961	986	996	983	984	956	919	894	878	798	745
07/10/09	689	653	625	602	600	616	645	700	755	816	856	893	932	968	968	958	944	931	908	876	857	825	763	691
07/11/09	641	615	592	568	558	563	572	604	630	649	666	677	694	729	748	751	744	752	728	705	711	699	658	609

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
07/12/09	579	554	528	525	515	510	520	551	612	664	713	765	786	814	816	807	772	738	695	665	673	648	619	577
07/13/09	541	532	519	509	523	557	599	645	698	740	786	823	853	884	907	918	925	919	902	862	831	796	728	656
07/14/09	616	580	560	549	557	574	610	669	716	762	805	855	887	912	921	921	886	868	841	822	818	801	736	683
07/15/09	627	597	583	570	577	611	643	693	726	743	755	772	789	795	815	856	882	880	867	841	830	817	756	709
07/16/09	659	639	611	611	614	645	667	721	771	820	861	878	913	935	970	973	974	957	936	893	878	843	785	714
07/17/09	662	632	592	585	564	607	633	674	691	726	738	749	761	763	769	760	745	731	707	676	665	661	604	554
07/18/09	520	499	477	471	464	470	475	494	520	540	560	565	566	568	572	571	589	581	570	559	571	568	541	502
07/19/09	479	465	451	441	439	447	438	467	491	519	550	572	582	596	605	625	631	628	623	612	629	613	576	537
07/20/09	519	511	495	498	503	521	574	623	659	695	732	756	785	802	817	817	821	820	801	770	765	733	676	622
07/21/09	582	555	539	538	543	573	612	659	702	736	779	811	836	855	853	815	792	777	775	764	761	731	679	634
07/22/09	604	584	568	555	565	598	648	666	711	734	737	745	758	765	758	742	727	723	724	702	718	714	663	627
07/23/09	594	576	561	554	560	587	619	669	705	754	783	820	837	854	876	878	864	873	851	835	830	792	729	665
07/24/09	631	591	582	555	568	602	639	684	728	773	821	862	895	929	937	946	943	927	907	862	847	820	750	683
07/25/09	637	614	593	567	555	548	535	564	611	659	675	711	739	721	726	762	780	788	768	738	741	720	681	649
07/26/09	573	547	521	500	496	488	489	527	579	628	674	723	734	768	782	797	803	805	788	758	745	718	667	619
07/27/09	581	565	542	541	552	588	626	700	751	805	848	884	930	948	971	980	970	973	948	905	892	846	764	701
07/28/09	658	631	608	590	595	626	669	720	765	816	850	884	891	892	864	860	860	860	852	833	837	807	741	687
07/29/09	652	631	607	597	585	632	659	724	755	791	825	870	911	929	946	951	925	901	879	850	836	812	752	701
07/30/09	658	636	619	601	604	633	692	735	769	804	830	862	884	913	928	914	883	867	845	825	805	772	717	668
07/31/09	620	604	584	578	593	615	650	703	747	794	831	858	887	902	908	892	884	868	843	805	779	739	683	621
08/01/09	580	547	528	506	498	512	506	543	577	632	679	722	749	757	760	756	740	740	714	715	704	666	626	580
08/02/09	539	523	506	497	481	490	471	505	537	576	607	651	674	699	717	737	746	747	730	712	705	676	634	583
08/03/09	552	539	527	527	538	580	613	668	722	772	820	866	901	934	964	969	967	959	962	925	922	878	815	753
08/04/09	706	680	670	662	665	698	746	793	854	920	978	1025	1014	956	937	907	870	855	847	828	802	763	706	655
08/05/09	627	606	583	575	584	616	665	705	741	762	784	793	807	821	830	846	841	853	850	822	822	797	729	675
08/06/09	642	617	599	589	588	622	661	713	752	800	834	886	921	946	964	960	959	932	910	868	854	808	745	669
08/07/09	630	606	590	574	567	591	616	668	716	756	798	838	857	906	922	926	913	902	865	837	820	790	723	661
08/08/09	617	580	558	547	534	541	538	582	644	715	774	830	861	892	906	927	930	925	899	864	847	806	744	694
08/09/09	645	619	593	574	560	563	560	593	668	738	799	856	894	916	928	950	954	949	938	905	902	863	804	760
08/10/09	716	687	668	660	672	707	758	830	890	950	996	1051	1082	1113	1137	1143	1091	1020	975	937	892	842	776	716
08/11/09	678	647	637	617	621	662	703	760	808	868	911	948	939	938	941	937	923	933	926	915	904	839	763	697
08/12/09	653	625	612	598	597	643	690	729	771	816	851	888	902	928	942	948	949	937	908	876	862	814	742	679
08/13/09	632	616	590	584	589	628	678	730	765	818	864	905	941	973	997	1011	993	971	955	921	916	859	780	715
08/14/09	673	640	616	607	594	625	668	708	760	807	856	909	944	977	986	991	986	968	920	892	871	822	749	685
08/15/09	637	606	576	559	551	557	549	599	652	709	786	831	874	919	923	933	914	915	869	843	825	783	732	676
08/16/09	638	607	579	571	557	557	560	600	664	722	781	841	872	907	928	961	948	936	915	897	897	848	777	732
08/17/09	687	669	636	635	642	689	757	806	860	915	954	999	1036	1059	1069	1077	1065	1050	1025	1003	988	923	847	787
08/18/09	737	715	677	670	666	703	756	803	848	896	940	985	1021	1047	1059	1062	1048	1037	1000	966	939	900	810	749
08/19/09	715	679	653	643	644	690	755	783	824	877	932	987	1026	1050	1049	1043	1012	1009	983	953	937	887	810	753
08/20/09	716	687	670	646	652	708	754	768	786	802	833	875	904	940	961	957	907	898	882	854	852	816	750	690
08/21/09	650	613	597	578	584	623	667	711	747	783	814	846	867	884	885	889	868	859	825	789	784	735	676	623
08/22/09	576	558	527	517	502	515	506	529	548	578	601	614	627	629	634	623	615	615	601	597	615	591	564	527
08/23/09	495	487	465	463	459	464	463	482	505	532	552	587	583	610	603	617	611	616	616	626	638	604	574	535
08/24/09	518	504	506	506	518	562	609	650	684	714	748	769	788	809	813	831	823	807	796	794	783	735	676	623
08/25/09	590	574	561	551	556	592	639	674	706	741	776	805	841	877	900	914	917	914	902	882	865	807	737	675
08/26/09	639	614	597	583	581	632	680	717	755	733	805	912	956	985	1013	1011	998	992	969	951	930	857	779	702
08/27/09	651	623	598	587	583	622	671	721	759	808	859	915	965	990	1011	1018	1012	994	965	939	914	856	779	710
08/28/09	661	630	606	593	585	624	679	711	763	809	879	919	947	957	968	961	943	915	869	840	814	778	717	666
08/29/09	626	594	575	549	548	561	559	588	621	663	688	730	747	769	785	790	792	784	738	718	708	669	614	566
08/30/09	525	508	489	475	468	480	470	492	518	550	568	591	601	621	619	634	639	650	636	644	641	613	569	538
08/31/09	509	503	504	499	507	552	619	638	667	697	714	724	758	762	757	756	739	729	712	729	723	683	624	583
09/01/09	562	546	535	534	527	564	607	635	657	679	692	713	721	743	739	747	729	728	713	720	701	676	617	577
09/02/09	548	546	518	519	529	559	607	640	673	694	714	746	760	787	811	806	802	807	787	792	781	743	676	628
09/03/09	592	578	558	548	557	593	660	683	711	732	741	766	784	791	756	749	734	739	732	737	741	700	651	604
09/04/09	570	553	531	522	527	560	612	636	679	710	737	766	787	815	817	823	808	787	753	749	725	699	631	569
09/05/09	541	516	496	486	477	478	482	489	532	583	617	641	657	677	694	701	685	655	626	622	612	588	561	522
09/06/09	502	480	471	460	462	468	476	487	514	539	545	572	595	620	638	651	665	679	656	655	652	619	559	511
09/07/09	486	476	456	451	453	457	459	463	503	539	589	617	656	682	697	719	733	734	720	720	704	667	609	565
09/08/09	540	519	507	506	510	562	627	667	695	739	778	810	842	868	886	888	872	855	834	832	807	762	694	641
09/09/09	598	583	559	549	537	581	637	675	698	747	780	816	843	869	882	887	879	865	847	846	827	766	706	646
09/10/09	616	590	567	558	554	604	652	694	720	757	802	841	880	906	908	918	903	892	860	862	844	788	719	660
09/11/09	629	601	581	558	551	591	655	688	714	761	792	836	870	886	897	894	885	860	827	816	794	753	694	639
09/12/09	590	565	542	520	513	505	514	533	557	616	637	677	705	721	738	737	734	718	687	684	673	630	586	541
09/13/09	506	488	470	466	464	465	462	475	518	556	583	620	640	666	693	702	716	699	681	688	667	626	586	540

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
09/14/09	528	517	506	508	510	566	619	659	688	726	755	787	817	850	870	881	872	849	839	841	812	760	692	643
09/15/09	621	602	582	566	573	604	665	700	710	733	765	799	808	838	869	865	867	845	829	847	824	781	712	657
09/16/09	627	601	580	560	567	608	652	693	722	755	805	839	878	909	915	927	907	892	869	876	842	787	724	662
09/17/09	624	604	577	554	563	598	646	667	692	717	746	768	803	824	824	820	805	790	784	816	793	760	703	649
09/18/09	624	602	581	566	565	605	665	685	715	734	779	812	843	855	837	839	828	812	778	781	754	717	669	601
09/19/09	567	540	513	500	489	500	504	518	541	573	609	631	668	691	704	704	710	698	675	683	659	636	586	545
09/20/09	521	495	488	477	474	483	503	517	547	573	591	617	625	630	639	647	650	663	658	688	672	648	608	579
09/21/09	558	549	544	545	549	610	687	724	737	776	805	844	877	909	922	924	911	896	884	885	851	800	734	680
09/22/09	646	626	608	587	582	607	676	707	732	766	795	806	819	821	821	819	813	812	825	837	808	779	716	669
09/23/09	636	615	603	585	587	633	707	738	753	777	792	803	811	830	837	839	817	811	826	843	811	769	715	675
09/24/09	642	619	609	597	597	639	721	748	760	787	786	799	802	798	798	776	756	753	767	784	765	736	686	647
09/25/09	617	597	583	578	585	618	692	729	741	760	776	761	769	781	774	774	759	750	749	751	732	701	644	596
09/26/09	549	538	516	502	490	500	510	534	549	582	587	612	628	642	660	665	669	653	624	613	595	575	536	503
09/27/09	474	463	450	446	444	450	450	463	488	505	521	531	555	569	582	594	608	613	616	637	630	604	567	536
09/28/09	527	527	520	504	511	553	609	630	654	678	684	694	697	707	696	687	668	657	686	700	670	638	588	560
09/29/09	539	528	508	514	509	550	613	628	648	653	662	679	666	680	663	652	634	637	658	687	662	638	597	558
09/30/09	544	528	523	512	523	552	618	639	648	667	669	677	682	686	684	676	658	650	676	692	674	639	598	562
10/01/09	542	528	523	519	516	564	617	631	644	661	666	678	677	683	675	663	654	653	678	697	679	656	611	575
10/02/09	555	543	533	525	523	561	616	635	651	664	677	677	672	676	659	658	642	631	641	660	634	615	575	533
10/03/09	512	493	479	470	465	473	490	502	514	543	544	554	539	547	536	539	537	533	538	563	552	535	508	481
10/04/09	461	448	441	437	435	446	457	467	490	500	517	524	523	527	527	530	534	539	573	591	580	557	522	501
10/05/09	493	484	481	489	498	553	618	642	653	666	676	679	684	685	687	676	666	658	616	699	685	649	599	578
10/06/09	549	532	529	528	528	569	633	663	684	695	695	706	704	710	694	679	674	673	701	700	682	662	623	575
10/07/09	555	543	528	519	521	561	630	647	651	663	679	677	685	683	688	673	651	649	660	682	667	642	600	569
10/08/09	548	546	529	525	527	558	635	663	663	685	684	691	689	694	683	686	663	672	695	689	677	658	613	581
10/09/09	569	546	538	535	527	573	628	655	672	706	700	710	703	705	695	665	646	653	660	657	644	621	578	543
10/10/09	513	500	486	477	468	491	501	517	537	564	554	559	545	543	537	532	535	528	552	567	558	544	521	487
10/11/09	469	466	453	457	454	469	481	497	513	530	517	533	528	528	527	524	530	542	572	595	580	567	532	514
10/12/09	494	496	498	498	511	558	632	662	664	672	678	681	683	689	680	682	664	655	701	706	690	663	615	576
10/13/09	554	546	536	529	530	571	643	662	668	685	681	686	691	684	680	668	663	669	709	714	693	672	625	588
10/14/09	568	562	546	536	550	588	653	686	691	703	699	705	703	699	697	690	685	690	709	721	695	672	632	584
10/15/09	569	564	548	553	548	595	655	683	686	705	697	701	706	704	696	688	684	696	719	712	704	676	634	603
10/16/09	586	569	568	557	549	598	668	682	697	706	713	717	710	708	697	690	681	685	700	694	680	666	622	592
10/17/09	560	555	540	532	532	548	570	589	608	616	610	612	605	595	589	587	582	591	622	631	621	611	584	557
10/18/09	537	524	516	519	515	533	548	559	568	569	556	563	556	558	544	547	550	568	610	611	616	596	575	546
10/19/09	542	543	538	544	564	580	689	706	705	701	702	688	697	685	684	671	660	656	697	707	688	662	624	588
10/20/09	573	561	560	551	559	601	676	686	695	693	697	696	702	696	695	672	666	666	703	709	692	667	618	583
10/21/09	569	560	552	543	549	596	660	685	690	706	693	698	692	698	684	678	659	674	706	706	691	670	619	591
10/22/09	567	553	545	540	550	581	665	672	681	693	695	700	700	699	689	683	686	675	707	707	685	671	620	595
10/23/09	570	564	545	529	502	579	658	682	692	705	700	710	708	702	686	669	647	652	669	670	642	628	583	546
10/24/09	522	503	497	491	483	495	517	539	549	517	570	563	555	555	548	547	539	551	574	585	572	557	531	505
10/25/09	492	487	477	476	482	487	499	508	516	511	503	508	512	505	498	502	500	520	553	565	554	541	505	483
10/26/09	471	473	469	473	492	539	623	645	646	677	651	653	652	654	647	636	622	626	661	669	644	622	575	537
10/27/09	516	519	498	510	502	537	608	641	643	653	661	652	649	651	645	639	633	654	665	665	637	615	574	536
10/28/09	523	506	508	503	502	542	609	634	629	638	637	647	647	640	651	629	626	629	657	664	643	615	569	540
10/29/09	523	511	509	503	501	549	615	637	638	643	648	649	651	643	631	636	623	631	662	682	657	637	588	556
10/30/09	533	525	518	516	515	544	619	648	653	669	672	677	681	681	668	657	629	640	646	641	621	608	566	534
10/31/09	503	494	478	469	458	474	486	511	528	550	558	560	544	538	529	517	517	518	540	550	536	532	509	484
11/01/09	464	463	465	460	458	476	482	497	509	509	512	517	506	510	507	501	504	518	580	582	572	558	541	519
11/02/09	499	492	500	492	504	523	584	642	659	665	666	674	664	673	669	667	655	654	686	701	683	666	631	590
11/03/09	563	542	539	530	522	540	579	637	642	660	664	677	668	666	675	654	644	645	680	691	694	669	645	611
11/04/09	580	573	559	548	549	558	593	655	677	675	676	673	664	667	672	652	648	657	685	693	685	669	641	598
11/05/09	577	553	551	547	552	554	597	657	676	664	671	671	662	664	660	646	644	645	681	688	690	671	654	619
11/06/09	582	571	567	562	567	567	606	657	674	668	651	660	654	643	652	636	627	630	645	621	641	623	612	561
11/07/09	544	512	502	496	496	492	502	513	540	554	561	573	569	564	568	559	551	560	599	598	580	570	545	516
11/08/09	494	472	456	451	434	433	435	449	457	479	490	502	509	514	522	518	519	538	576	570	564	545	535	498
11/09/09	479	467	458	464	461	486	529	596	632	643	665	671	663	675	674	661	662	659	691	689	681	663	625	583
11/10/09	543	533	527	511	511	519	551	611	636	645	653	662	665	671	670	660	650	644	682	683	670	651	630	579
11/11/09	551	533	526	514	510	526	549	606	633	643	652	659	661	655	661	649	643	636	675	684	680	658	642	597
11/12/09	573	556	546	544	536	551	591	655	669	661	661	661	650	658	649	644	631	641	678	674	681	660	633	596
11/13/09	564	554	548	543	543	555	594	651	669	669	665	663	655	645	643	626	624	623	655	656	641	626	609	559
11/14/09	521	506	498	486	481	474	498	500	515	520	525	537	527	520	517	515	517	539	551	562	553	538	519	498
11/15/09	470	449	438	429	428	429	438	451	465	476	491	506	504	507	512	509	505	547	582	577	572	547	535	498
11/16/09	486	470	462	474	469	490	529	597	631	631	654	659	653	660	654	653	643	669	683	689	673	653	628	585

Vectren Firm Load, MW	Hour Ending																						
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/17/09	562	533	531	523	518	522	561	630	656	657	678	675	676	672	670	655	665	682	696	701	693	680	641	593
11/18/09	564	538	536	524	530	531	569	637	649	650	657	657	653	628	665	659	660	684	693	686	686	668	638	591
11/19/09	562	542	535	536	529	529	567	640	660	661	664	668	655	661	654	641	628	646	673	685	681	663	642	604
11/20/09	573	552	545	551	544	560	594	646	670	664	664	657	649	641	643	634	618	629	658	654	643	632	612	581
11/21/09	550	520	522	510	509	515	530	559	570	583	586	582	580	574	567	563	548	562	597	600	591	582	573	532
11/22/09	520	497	493	480	473	474	479	491	507	523	526	535	526	529	523	522	523	561	598	607	595	593	566	544
11/23/09	516	503	507	501	505	529	579	652	674	674	679	678	673	670	672	667	672	684	702	701	694	677	648	603
11/24/09	566	542	532	526	532	534	567	629	647	652	655	659	658	655	646	639	640	673	686	690	684	672	660	598
11/25/09	562	537	542	526	530	543	567	631	661	656	657	665	644	648	648	637	638	655	670	667	653	628	616	552
11/26/09	507	479	466	449	442	447	467	473	500	521	549	560	544	516	499	479	487	507	514	524	525	522	512	489
11/27/09	474	455	458	456	465	478	503	518	528	528	526	526	512	507	492	485	487	518	556	563	556	551	540	516
11/28/09	495	472	468	457	468	472	483	496	510	510	514	513	499	491	484	479	473	512	536	539	535	526	512	489
11/29/09	461	444	434	429	433	425	446	457	467	487	498	506	505	508	511	513	514	559	589	577	575	564	545	516
11/30/09	492	489	485	477	492	512	566	653	675	684	683	687	683	690	680	669	663	692	738	746	748	732	709	663
12/01/09	623	604	602	595	598	610	649	712	722	710	697	692	681	665	667	656	650	685	720	731	729	718	685	642
12/02/09	607	581	576	566	571	573	608	674	702	698	709	712	716	707	707	697	704	726	737	739	733	719	692	641
12/03/09	612	587	582	572	577	592	627	691	711	718	728	730	717	721	716	708	719	743	764	768	777	755	727	680
12/04/09	652	625	616	619	621	636	670	745	753	739	726	717	698	684	682	675	679	717	748	746	744	742	719	678
12/05/09	644	614	616	601	608	618	636	662	680	682	673	662	643	628	613	601	597	652	692	704	704	705	683	656
12/06/09	624	605	604	595	587	590	596	616	618	624	629	615	611	616	607	600	596	638	683	681	683	669	641	599
12/07/09	562	546	546	541	553	571	621	687	713	707	716	724	705	706	703	688	687	716	745	744	748	727	696	645
12/08/09	607	583	580	567	580	590	629	696	708	712	720	721	723	715	726	713	729	742	755	734	724	700	657	611
12/09/09	573	540	534	529	532	551	592	653	675	692	721	750	747	753	751	736	753	785	814	824	827	814	787	737
12/10/09	703	684	676	669	674	693	732	802	816	814	803	788	780	764	765	747	750	791	834	840	841	830	810	752
12/11/09	724	697	694	692	689	698	739	800	803	798	782	760	743	724	703	691	682	727	764	767	762	753	740	702
12/12/09	661	626	618	619	611	621	627	649	656	663	663	669	660	647	638	624	640	673	695	685	674	663	643	609
12/13/09	570	549	524	521	510	524	523	542	556	571	589	589	590	589	572	567	566	608	660	668	672	659	628	594
12/14/09	560	542	532	525	532	553	602	681	690	692	696	691	684	682	686	675	671	698	727	729	722	711	691	636
12/15/09	613	587	581	582	592	611	649	731	747	766	767	790	773	780	786	778	763	797	837	839	845	822	800	753
12/16/09	714	698	685	690	685	707	751	821	824	806	792	784	765	742	729	722	720	757	812	814	815	808	776	735
12/17/09	692	681	677	669	672	685	740	805	806	794	770	766	742	728	731	713	716	752	785	786	783	777	749	708
12/18/09	667	640	635	616	617	639	678	747	761	759	754	752	723	704	693	684	684	709	740	736	721	725	691	654
12/19/09	612	587	575	568	563	571	591	621	651	671	694	699	701	688	695	692	703	727	752	748	744	737	713	683
12/20/09	650	619	608	594	586	589	594	618	631	649	653	652	638	640	650	656	672	698	733	731	733	723	704	665
12/21/09	639	614	612	602	605	625	661	725	753	762	766	768	757	801	740	750	744	772	799	794	787	771	746	704
12/22/09	662	645	631	619	617	633	670	715	746	754	759	763	737	718	700	697	698	729	747	742	741	723	695	653
12/23/09	616	581	568	570	557	568	597	641	662	679	692	690	687	674	667	661	647	684	696	694	683	659	639	582
12/24/09	536	500	485	467	474	477	489	517	536	557	577	586	573	553	545	542	535	556	562	554	548	535	528	514
12/25/09	482	461	449	440	433	446	433	445	466	495	517	534	552	549	541	544	544	570	587	589	583	580	571	545
12/26/09	523	509	496	492	503	507	532	541	556	561	597	609	613	596	587	576	583	628	643	649	637	636	615	583
12/27/09	553	532	525	516	522	514	539	554	568	571	593	603	613	620	625	626	634	665	690	708	708	691	673	637
12/28/09	621	602	600	592	612	585	647	680	700	715	723	738	728	740	724	716	706	720	754	748	736	727	704	670
12/29/09	639	611	602	602	598	620	644	686	708	703	693	701	676	673	666	675	663	697	729	731	725	704	690	643
12/30/09	619	588	589	568	579	583	610	648	668	670	686	691	687	687	676	670	661	686	703	698	683	667	638	607
12/31/09	565	539	527	523	518	520	536	570	588	606	625	630	637	626	628	627	637	656	667	663	646	635	628	617

Received
November 1, 2011
Indiana Utility Regulatory Commission

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
01/01/10	603	598	600	589	593	600	614	633	620	634	643	638	643	625	625	613	615	664	706	709	702	703	703	667
01/02/10	651	632	630	628	625	639	657	679	697	707	700	694	687	670	658	644	653	691	731	744	726	733	715	698
01/03/10	679	671	658	664	664	671	679	700	711	726	719	707	685	679	674	662	682	721	771	776	782	767	747	710
01/04/10	701	694	708	710	727	752	807	875	886	880	873	862	853	838	819	806	803	828	870	887	880	871	844	804
01/05/10	769	758	761	757	761	782	823	896	897	893	878	871	850	838	826	808	803	841	883	892	890	880	849	810
01/06/10	787	769	770	759	768	788	827	889	903	878	867	855	832	811	796	785	774	804	849	854	861	838	818	769
01/07/10	733	704	703	690	700	717	751	792	816	822	839	853	857	855	863	854	861	888	919	924	915	897	871	828
01/08/10	814	791	789	793	779	807	837	880	908	912	915	916	910	894	893	875	865	875	898	898	882	863	845	803
01/09/10	773	758	744	733	735	724	748	759	778	789	801	796	791	764	739	730	729	768	813	812	807	807	789	773
01/10/10	754	733	734	719	735	746	754	771	785	785	774	749	733	722	705	694	696	737	791	812	820	801	773	741
01/11/10	714	706	708	701	707	722	779	833	853	848	842	839	833	837	832	812	810	825	858	867	858	859	833	792
01/12/10	758	740	734	727	730	738	778	844	849	853	842	826	801	787	780	738	756	781	819	833	833	831	804	767
01/13/10	743	730	728	732	736	744	792	863	870	843	813	801	781	762	755	733	724	740	793	806	811	793	767	725
01/14/10	695	676	674	678	678	695	734	798	815	790	785	765	747	735	720	708	709	724	761	767	751	738	714	670
01/15/10	637	617	616	603	600	614	649	713	732	729	737	725	724	708	708	687	688	695	712	712	703	694	677	645
01/16/10	609	582	583	571	561	573	575	598	619	633	650	642	645	635	617	610	620	629	660	657	637	626	615	579
01/17/10	559	539	527	517	514	521	531	550	570	587	598	603	604	598	589	586	585	608	665	667	680	667	644	626
01/18/10	610	603	601	598	608	625	665	625	665	678	693	698	697	694	693	680	684	688	709	721	707	690	663	620
01/19/10	601	580	587	580	583	599	641	707	726	728	716	705	690	685	676	656	662	671	696	706	697	678	655	609
01/20/10	576	559	555	540	550	557	600	670	694	697	697	692	682	680	682	670	674	684	699	698	689	673	655	604
01/21/10	580	556	558	541	547	552	589	660	689	689	695	695	725	716	693	704	693	694	709	720	720	700	673	629
01/22/10	603	583	580	565	574	585	622	688	713	712	723	746	695	722	723	712	710	707	735	729	716	703	684	642
01/23/10	601	577	565	560	544	549	551	569	591	608	618	637	629	621	606	590	584	593	626	625	615	601	592	572
01/24/10	534	519	504	498	504	505	511	522	536	544	561	568	571	563	568	567	568	586	625	631	630	610	604	573
01/25/10	562	547	561	547	566	593	642	712	751	737	750	764	764	765	770	769	766	772	798	808	793	778	758	703
01/26/10	675	656	654	647	650	674	705	779	805	807	822	821	814	810	810	807	810	808	836	843	837	819	805	763
01/27/10	741	726	724	712	720	737	766	830	843	826	813	793	777	763	766	760	751	765	789	798	790	788	756	700
01/28/10	671	648	647	644	644	670	706	786	806	803	797	792	781	776	772	763	753	781	824	843	844	835	812	771
01/29/10	749	733	731	725	725	734	771	838	864	852	868	855	860	855	856	830	833	832	855	848	830	822	798	765
01/30/10	729	714	700	692	687	683	695	710	712	724	730	729	717	709	684	666	667	681	729	742	751	733	735	710
01/31/10	684	672	675	674	669	682	701	718	718	716	697	684	668	590	553	541	548	576	630	656	660	657	635	614
02/01/10	599	595	608	607	619	636	691	765	778	754	744	728	702	689	673	657	650	665	713	716	710	693	674	626
02/02/10	599	584	576	572	571	600	631	702	715	702	705	697	693	692	692	675	683	693	723	726	717	706	670	631
02/03/10	595	582	576	565	574	603	648	713	731	716	708	703	688	679	686	653	654	660	717	728	732	714	689	655
02/04/10	623	612	601	598	607	615	662	728	741	740	735	732	722	712	702	684	687	689	719	723	708	705	670	626
02/05/10	597	574	570	553	569	580	612	676	692	700	711	711	705	703	700	691	695	698	706	705	690	686	664	633
02/06/10	594	583	574	572	573	581	593	616	638	665	675	684	676	665	664	653	664	675	704	703	695	684	665	639
02/07/10	612	605	595	596	599	610	621	634	644	653	638	628	624	611	611	593	598	609	641	653	653	652	655	638
02/08/10	612	610	607	613	626	648	688	763	796	792	786	790	776	773	766	763	763	760	789	804	793	774	749	704
02/09/10	672	666	652	648	649	656	697	730	764	761	759	777	788	795	798	788	786	790	838	865	863	859	827	788
02/10/10	760	742	732	719	718	721	746	789	819	832	822	821	803	789	785	778	769	780	815	849	841	822	806	765
02/11/10	740	730	728	720	728	746	793	852	863	842	820	803	781	770	763	740	735	736	781	815	819	805	794	757
02/12/10	734	728	731	721	721	734	778	849	857	835	813	798	772	753	739	726	718	729	752	776	766	759	746	709
02/13/10	683	661	661	653	647	650	653	659	678	700	707	709	707	690	685	673	664	676	695	704	695	688	677	645
02/14/10	620	612	602	599	589	590	608	615	628	646	653	661	661	661	652	661	664	682	704	714	708	690	675	663
02/15/10	645	646	644	642	656	680	727	768	806	821	819	814	812	802	800	792	787	795	820	847	834	808	786	721
02/16/10	703	690	702	696	698	710	746	802	801	822	823	820	799	793	799	796	787	786	818	830	827	807	780	749
02/17/10	727	709	702	702	717	728	761	801	830	838	827	816	794	777	782	769	764	771	799	826	815	801	778	738
02/18/10	715	708	696	693	694	723	754	823	824	802	787	774	763	752	745	730	716	711	749	788	794	788	764	732
02/19/10	705	691	687	681	694	706	750	801	815	790	767	752	727	717	705	684	677	673	702	730	725	719	699	656
02/20/10	626	605	599	579	575	585	591	621	636	657	661	665	646	623	610	594	589	582	611	636	637	623	616	582
02/21/10	570	548	537	534	526	525	539	540	550	567	572	575	560	555	546	547	541	565	595	624	625	605	583	550
02/22/10	535	523	520	520	525	545	598	670	706	708	755	787	749	759	758	754	752	751	767	782	774	761	735	689
02/23/10	664	637	629	626	625	643	686	741	782	784	791	799	788	780	776	766	769	775	791	814	802	790	763	717
02/24/10	689	673	667	660	666	684	732	800	818	811	805	805	798	815	812	801	800	808	829	850	840	828	802	765
02/25/10	731	724	711	709	711	718	764	831	838	839	831	820	790	782	722	755	734	768	784	819	805	799	782	738
02/26/10	717	698	701	693	699	709	754	813	821	802	795	782	769	762	741	716	704	707	726	762	761	762	741	708
02/27/10	680	661	658	650	643	646	657	667	692	694	696	686	666	657	642	641	649	653	681	693	692	675	663	627
02/28/10	605	591	581	575	575	589	593	606	624	641	645	644	634	624	616	610	618	626	653	682	694	677	659	624
03/01/10	612	598	600	600	603	629	682	757	767	769	775	770	763	774	759	748	748	753	771	796	782	773	738	694
03/02/10	673	647	641	638	651	661	710	778	799	801	803	798	788	776	763	759	758	758	775	814	808	797	765	725

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
03/03/10	700	680	667	662	658	668	711	779	793	788	793	777	781	772	770	766	769	761	767	808	802	782	756	708
03/04/10	678	666	658	663	659	689	733	785	790	779	763	752	738	737	723	702	693	689	708	760	765	754	741	704
03/05/10	670	667	647	660	657	676	725	777	776	763	744	733	709	703	685	676	659	648	658	704	709	704	697	660
03/06/10	634	618	613	611	604	613	638	650	660	660	652	646	621	612	590	583	578	571	592	639	643	636	632	606
03/07/10	585	575	574	567	565	569	576	583	590	584	580	570	561	561	545	552	548	558	577	619	623	611	595	563
03/08/10	544	523	527	522	535	557	623	689	730	724	738	732	727	713	696	679	672	658	673	730	718	711	682	646
03/09/10	619	602	603	597	598	614	646	699	711	714	716	705	706	703	702	686	680	686	689	723	712	693	662	629
03/10/10	588	568	562	552	556	559	600	652	679	678	685	687	682	681	678	671	672	657	671	705	701	682	654	614
03/11/10	563	549	532	529	524	530	570	625	657	661	660	670	674	673	674	666	653	649	650	699	692	684	659	609
03/12/10	585	565	556	549	548	557	590	651	678	679	691	703	701	703	696	687	681	664	668	693	676	663	651	604
03/13/10	576	547	530	527	519	516	532	544	563	583	597	602	597	595	587	586	591	589	609	628	615	602	592	552
03/14/10	528	511	493	492	489	496	519	520	528	553	551	575	569	575	563	567	574	591	601	626	621	604	576	546
03/15/10	538	535	531	537	549	603	686	703	710	711	708	712	706	709	695	694	692	691	711	722	716	695	647	607
03/16/10	587	582	570	564	579	616	686	709	707	706	700	696	680	678	667	655	645	645	661	687	689	668	633	597
03/17/10	581	565	558	556	568	608	676	694	683	722	694	691	685	678	668	657	648	641	651	691	699	670	631	599
03/18/10	580	578	570	579	577	627	704	722	712	701	697	691	685	683	676	668	654	651	655	701	696	676	634	596
03/19/10	577	571	568	567	577	619	693	699	695	691	681	680	678	676	663	656	631	619	629	656	651	635	595	563
03/20/10	537	529	526	511	521	533	556	570	591	598	597	596	597	583	579	580	578	576	579	611	603	587	560	529
03/21/10	503	496	482	475	474	479	486	496	520	535	543	552	556	562	560	561	572	578	592	616	602	587	565	542
03/22/10	529	520	522	530	543	600	654	694	707	725	727	730	726	735	715	705	705	708	726	733	716	690	654	621
03/23/10	609	599	600	593	604	636	685	711	709	709	702	686	685	676	664	656	643	632	648	682	677	656	624	598
03/24/10	576	566	559	566	564	601	653	680	667	683	678	680	673	675	665	665	645	650	661	683	684	660	618	591
03/25/10	562	562	551	550	554	583	633	657	665	692	692	696	688	702	691	690	675	683	698	711	705	698	658	635
03/26/10	608	605	593	601	598	637	688	713	711	708	705	692	694	682	659	643	566	531	537	590	589	592	559	534
03/27/10	516	523	506	510	501	523	537	547	568	577	573	569	548	541	531	529	533	535	542	577	559	556	525	492
03/28/10	474	457	449	453	449	471	480	492	524	551	548	565	570	570	568	578	588	606	604	630	624	606	573	553
03/29/10	543	542	542	551	572	620	705	718	713	713	704	702	688	690	670	679	651	651	661	699	701	684	637	614
03/30/10	583	590	575	591	591	646	706	722	712	709	701	700	688	690	681	670	653	643	653	690	694	671	633	593
03/31/10	579	569	563	565	573	613	678	694	691	708	697	694	698	700	688	692	671	674	671	704	709	690	635	596
04/01/10	570	561	546	547	545	579	642	661	669	684	690	703	703	709	709	699	698	690	681	701	701	670	596	553
04/02/10	510	488	467	467	460	486	511	522	552	567	572	589	583	588	587	588	587	578	574	585	599	568	533	498
04/03/10	462	454	442	445	431	454	458	491	500	533	539	545	533	541	531	532	535	541	536	559	569	557	526	490
04/04/10	461	444	441	431	437	446	459	474	501	511	510	511	501	505	504	508	507	523	532	565	594	576	536	510
04/05/10	502	496	490	494	504	552	629	660	693	715	744	754	756	791	777	768	760	763	750	776	771	741	686	642
04/06/10	613	593	574	562	572	607	666	698	719	741	752	757	777	788	788	786	770	755	762	772	774	746	678	640
04/07/10	616	597	580	581	577	618	684	708	709	735	733	729	730	731	722	716	715	710	730	740	729	691	639	612
04/08/10	603	581	561	563	547	584	640	671	687	698	690	692	700	695	678	676	654	648	663	684	692	676	621	599
04/09/10	577	564	562	560	560	608	665	680	687	685	689	707	693	693	683	669	656	643	643	660	666	651	608	574
04/10/10	547	539	527	527	515	541	549	574	589	604	599	602	592	598	588	592	588	590	591	613	627	605	560	538
04/11/10	512	495	488	484	469	479	486	500	514	529	546	553	556	562	569	570	586	594	599	627	631	606	561	534
04/12/10	512	505	489	503	509	561	621	660	668	693	701	710	724	738	741	747	736	725	728	739	741	701	646	604
04/13/10	578	559	543	543	538	584	638	668	679	697	715	731	750	767	776	776	763	763	753	755	754	723	654	610
04/14/10	582	563	550	543	544	579	629	658	674	697	724	744	767	791	802	805	805	792	771	786	773	736	669	629
04/15/10	592	576	561	554	553	590	634	670	691	719	747	770	783	804	807	821	804	791	782	778	776	733	678	628
04/16/10	595	575	562	558	556	587	636	663	686	711	736	747	764	780	779	767	728	709	697	688	677	667	617	579
04/17/10	550	536	524	510	499	506	502	519	539	561	567	573	567	557	554	558	566	560	558	570	581	569	541	505
04/18/10	484	462	468	458	461	472	473	494	512	531	532	544	538	546	541	541	554	553	562	588	595	579	545	516
04/19/10	503	500	494	498	514	559	604	655	662	671	678	682	689	688	677	672	654	648	654	681	680	657	602	569
04/20/10	549	537	527	528	529	566	619	652	663	670	680	686	694	697	690	679	658	664	657	676	686	657	612	577
04/21/10	547	540	535	529	532	572	621	647	658	680	681	690	694	700	702	694	683	668	671	686	696	670	616	585
04/22/10	559	547	532	528	532	572	627	653	673	684	694	704	714	724	723	713	697	677	681	691	710	679	621	589
04/23/10	560	552	516	513	515	549	604	631	653	679	690	703	719	728	725	730	706	684	681	685	694	670	626	590
04/24/10	555	541	530	513	504	519	526	540	568	602	614	632	631	624	615	608	612	609	598	596	611	589	564	522
04/25/10	507	485	471	463	459	467	461	479	503	529	530	552	539	554	545	545	555	560	570	581	598	566	540	516
04/26/10	505	492	487	493	509	552	616	644	655	678	698	670	669	687	677	673	657	655	663	683	687	670	621	582
04/27/10	563	564	548	546	549	592	643	672	679	691	693	694	691	692	675	674	648	664	670	692	689	670	623	590
04/28/10	576	569	557	554	569	600	653	679	684	692	695	690	698	695	690	678	676	671	680	695	701	671	616	583
04/29/10	567	558	552	551	553	589	632	664	674	691	699	701	708	721	720	715	703	690	697	701	726	700	653	617
04/30/10	584	575	556	560	563	583	634	653	672	710	716	728	735	743	739	740	734	722	717	730	733	720	673	631
05/01/10	593	561	544	539	523	533	537	557	577	607	614	629	623	622	607	611	610	600	594	606	618	608	573	545
05/02/10	516	508	497	494	489	494	502	519	549	574	587	608	613	617	618	626	640	647	644	655	669	649	608	565

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
05/03/10	548	534	521	529	534	566	617	667	697	722	740	759	778	789	793	798	787	782	767	765	769	736	675	625
05/04/10	596	579	570	559	567	589	635	677	704	723	740	758	770	792	794	792	788	773	768	761	773	745	684	636
05/05/10	609	587	575	568	573	594	651	686	703	741	771	794	816	833	845	853	843	837	826	814	828	796	734	677
05/06/10	647	608	581	570	567	591	632	676	695	717	735	750	765	789	782	802	804	776	767	750	770	745	685	642
05/07/10	607	591	579	569	571	603	649	700	726	742	798	816	819	855	858	844	812	790	783	783	766	721	659	611
05/08/10	577	550	543	525	511	516	513	549	574	586	592	589	590	584	571	578	565	570	568	578	591	585	561	525
05/09/10	507	496	487	488	488	500	487	515	531	542	542	540	540	532	532	534	536	542	547	562	592	583	554	522
05/10/10	503	497	498	503	509	556	612	648	667	682	683	694	694	694	685	685	660	662	670	684	695	667	623	583
05/11/10	569	560	553	551	552	589	634	678	692	711	715	725	733	750	752	759	752	745	741	750	774	746	680	626
05/12/10	597	576	570	571	566	603	661	707	717	723	736	754	779	795	795	805	796	786	807	804	816	797	734	684
05/13/10	651	633	616	613	614	637	687	760	783	822	842	868	882	890	848	881	857	872	848	846	862	822	767	715
05/14/10	677	645	628	623	602	644	687	730	744	752	762	771	752	753	768	769	764	722	700	682	685	670	621	567
05/15/10	545	517	506	496	480	485	474	508	541	564	586	611	611	617	621	629	625	627	613	612	618	613	580	546
05/16/10	515	506	492	483	485	487	490	496	533	548	570	578	588	592	593	595	605	615	616	636	638	616	596	561
05/17/10	540	531	529	525	542	573	644	678	690	717	731	726	748	756	749	750	722	716	719	716	728	698	644	615
05/18/10	591	571	569	566	572	590	646	679	692	706	718	731	738	735	727	719	704	686	694	708	711	697	648	613
05/19/10	583	575	561	560	565	589	647	676	686	707	707	718	717	721	715	711	704	687	694	700	720	703	654	609
05/20/10	588	581	567	563	567	593	640	672	686	702	715	714	711	731	714	718	699	688	703	713	713	699	644	612
05/21/10	590	579	572	566	574	602	677	687	713	724	711	752	744	775	772	783	760	745	710	726	734	717	664	632
05/22/10	587	568	555	545	536	530	534	573	607	641	661	685	695	715	735	750	757	766	762	740	739	725	671	625
05/23/10	584	563	543	534	534	523	525	564	608	661	710	761	806	840	857	882	890	895	888	873	880	843	789	724
05/24/10	682	647	627	615	621	661	724	791	838	895	932	983	1011	1040	1044	1052	1043	1007	992	959	942	910	815	753
05/25/10	704	676	649	643	626	650	707	768	812	865	893	941	977	1008	1020	1013	975	965	937	912	903	873	791	735
05/26/10	687	660	638	623	616	641	695	769	807	856	910	944	974	1005	1041	1057	1024	1008	999	957	951	905	831	771
05/27/10	724	685	671	652	648	663	718	778	827	875	933	972	1012	1041	1045	1010	907	879	853	846	843	819	762	707
05/28/10	678	647	636	625	612	627	680	725	772	806	846	891	916	948	965	975	973	961	930	895	881	860	792	727
05/29/10	673	627	595	582	572	562	571	603	669	724	774	827	818	855	890	893	893	891	856	826	806	784	720	661
05/30/10	614	594	566	547	550	543	545	581	652	699	754	787	826	835	847	861	877	871	849	820	802	772	729	672
05/31/10	634	601	581	559	554	553	552	584	634	681	730	763	775	789	809	825	836	812	779	755	759	716	675	634
06/01/10	610	590	581	576	580	630	677	739	792	830	884	925	968	1002	1031	1040	1046	1039	1009	977	971	935	868	796
06/02/10	747	714	695	680	668	705	740	776	803	853	883	907	973	1019	1040	1009	947	917	880	857	862	841	775	720
06/03/10	677	658	643	632	630	654	695	745	783	837	884	931	973	1002	1023	1040	1030	1025	997	975	958	922	852	791
06/04/10	736	702	682	664	651	669	716	776	832	880	943	975	1009	1042	1059	1070	1052	1033	1011	971	955	930	864	801
06/05/10	753	730	698	677	657	651	660	703	757	808	853	891	917	932	947	943	915	897	874	853	853	839	794	745
06/06/10	707	675	664	638	640	632	639	659	666	686	685	711	726	745	759	778	788	793	784	759	758	740	688	646
06/07/10	610	582	571	570	566	601	656	718	770	816	855	888	921	940	941	915	891	872	850	839	831	812	756	702
06/08/10	663	646	616	611	606	623	679	737	776	816	849	888	922	966	972	978	944	920	892	868	877	849	807	749
06/09/10	716	695	682	682	676	717	751	790	820	839	849	866	877	900	926	946	950	941	942	923	916	895	821	756
06/10/10	708	672	645	637	629	640	732	760	815	866	911	960	995	1030	1051	1064	1065	1033	1002	969	960	937	872	812
06/11/10	774	740	715	697	687	710	759	810	848	897	904	915	900	919	956	1000	996	967	919	888	894	873	831	774
06/12/10	735	700	691	676	667	679	693	732	784	844	898	951	988	1016	1031	1041	1042	1032	998	980	970	941	883	826
06/13/10	781	727	689	654	630	608	620	666	722	784	848	900	942	977	995	958	1017	1030	1004	987	969	936	860	784
06/14/10	740	713	685	673	683	708	781	865	929	1001	1060	1098	1128	1156	1151	1141	1118	1099	1076	1007	954	909	840	776
06/15/10	736	706	685	666	659	677	734	816	868	936	996	1064	1108	1124	1150	1160	1148	1040	964	929	909	876	806	765
06/16/10	714	693	667	662	655	684	732	797	836	906	947	979	1008	1029	1048	1061	1053	1043	1027	995	960	924	847	775
06/17/10	720	697	665	656	647	662	715	773	815	848	878	933	961	990	983	1003	1000	1000	995	962	955	941	858	696
06/18/10	749	730	698	682	676	702	745	810	869	932	994	1056	1082	1120	1146	1167	1154	1133	1094	1069	1048	1026	954	883
06/19/10	830	804	768	735	679	652	641	662	686	757	805	856	898	930	954	982	988	981	964	924	902	864	806	746
06/20/10	683	654	627	609	596	587	594	651	719	792	864	919	962	996	1015	1035	1015	1048	1033	1001	992	962	902	845
06/21/10	794	763	735	720	723	751	807	880	959	1022	1074	1126	1171	1201	1208	1208	1201	1190	1165	1132	1112	1077	997	928
06/22/10	864	830	794	771	739	763	807	866	904	941	1008	1079	1112	1144	1158	1169	1168	1160	1129	1101	1079	1053	981	908
06/23/10	846	816	783	762	757	780	821	908	963	1026	1072	1123	1150	1175	1184	1184	1181	1163	1144	1101	1088	1057	980	912
06/24/10	860	834	804	779	770	790	838	891	936	954	968	981	1006	1038	1054	1057	1060	1037	1025	977	952	920	851	785
06/25/10	732	706	674	663	652	659	711	784	834	883	928	976	1005	1045	1059	1072	1074	1050	1025	979	955	916	851	784
06/26/10	727	697	664	647	626	625	634	677	737	803	875	938	979	1012	1036	1051	1058	1055	1026	988	970	950	887	831
06/27/10	772	744	706	675	668	653	656	698	753	793	847	906	932	964	990	1001	1018	1021	1006	973	967	940	884	781
06/28/10	717	692	662	655	659	700	755	796	846	869	895	932	983	1024	1037	1044	1038	1025	1008	971	951	925	860	793
06/29/10	732	703	664	649	648	657	714	764	823	864	905	932	962	986	982	977	967	950	939	900	884	862	788	729
06/30/10	680	646	624	614	606	609	646	711	751	789	820	847	863	889	901	913	908	904	884	838	825	793	740	684
07/01/10	644	619	598	593	585	603	638	689	729	768	795	819	830	869	883	903	896	890	879	841	822	797	738	682
07/02/10	636	614	596	586	569	591	626	679	711	751	790	814	846	863	892	899	907	904	878	842	813	792	732	662

Vectren Firm Load, MW	Hour Ending																						
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
07/03/10	601	567	538	524	513	505	516	546	596	649	704	768	806	852	880	905	926	927	900	870	842	817	760	709
07/04/10	664	633	606	590	582	578	577	619	683	743	801	852	885	910	919	938	934	924	902	865	835	798	772	712
07/05/10	668	637	597	588	577	573	583	625	698	756	822	872	895	919	934	952	965	966	949	919	889	859	788	734
07/06/10	680	652	630	618	619	646	697	761	840	905	964	1025	1063	1092	1120	1123	1123	1115	1096	1059	1032	997	927	845
07/07/10	798	752	720	700	685	701	737	806	873	941	1001	1064	1098	1123	1142	1141	1133	1130	1113	1084	1058	1021	964	891
07/08/10	844	804	771	749	742	752	798	870	934	1006	1052	1113	1129	1158	1164	1176	1162	1142	1094	1022	995	947	890	836
07/09/10	789	761	736	723	713	732	775	822	842	879	907	921	933	960	963	970	986	991	964	916	887	851	799	736
07/10/10	682	644	615	602	592	597	600	638	696	758	807	844	868	895	903	923	930	921	898	862	835	807	753	687
07/11/10	640	616	586	570	566	559	557	602	661	721	771	824	860	880	901	928	932	922	895	881	877	844	796	736
07/12/10	692	669	646	631	640	664	702	753	797	830	868	895	917	945	957	978	984	980	963	934	926	896	851	781
07/13/10	743	708	677	673	664	691	728	763	786	808	856	900	955	991	1014	1036	1037	1046	1018	988	962	926	864	797
07/14/10	745	711	685	670	668	694	733	794	865	931	983	1036	1070	1100	1113	1125	1121	1113	1092	1061	1037	1004	935	869
07/15/10	809	767	738	716	707	729	762	825	885	962	1028	1081	1122	1150	1162	1178	1162	1154	1133	1085	1064	1018	936	858
07/16/10	803	772	739	718	705	722	756	807	867	909	977	1020	1056	1087	1093	1097	1093	1079	1048	1017	1002	970	906	845
07/17/10	795	758	727	707	687	679	683	721	781	841	898	933	964	993	1019	1029	1038	1032	1017	977	967	937	879	818
07/18/10	767	743	710	689	686	673	683	718	780	808	857	904	921	885	827	830	821	826	811	806	809	799	756	699
07/19/10	683	663	650	657	661	707	744	815	870	924	984	1039	1088	1127	1150	1147	1064	972	944	884	877	852	807	750
07/20/10	716	692	683	670	672	688	740	775	823	875	912	957	987	995	1019	1054	1076	1059	1047	1015	1020	987	934	870
07/21/10	827	796	778	770	747	772	795	854	910	964	1014	985	952	950	986	1008	1032	1032	999	974	976	937	870	826
07/22/10	771	744	730	718	706	726	768	826	894	958	1024	1086	1131	1161	1177	1192	1190	1172	1152	1118	1105	1063	997	929
07/23/10	879	842	802	787	774	791	821	879	946	1004	1053	1100	1137	1170	1180	1183	1175	1162	1135	1092	1077	1049	963	909
07/24/10	846	810	771	743	712	695	700	739	818	884	944	996	1027	1062	1079	1090	1095	1093	1065	1041	1028	994	926	871
07/25/10	816	771	751	717	707	698	690	715	765	817	874	918	950	984	1012	1020	1025	1028	994	973	967	933	867	807
07/26/10	768	739	701	697	695	721	756	830	880	924	970	992	999	1014	1044	1071	1084	1080	1066	1031	1010	969	900	845
07/27/10	801	771	741	738	726	750	789	843	888	935	975	1017	1062	1091	1120	1127	1124	1107	1089	1041	1020	981	923	865
07/28/10	813	787	761	741	730	756	794	854	918	978	1040	1097	1097	1077	1032	1019	986	961	970	945	948	922	867	813
07/29/10	777	749	732	726	726	750	790	854	907	969	1025	1072	1104	1133	1139	1140	1125	1102	1074	1041	1018	976	900	838
07/30/10	787	744	713	693	678	686	719	762	825	872	922	955	992	1024	1038	1038	1012	977	950	915	909	876	814	761
07/31/10	719	686	665	648	640	628	633	653	703	733	798	855	910	951	985	998	1011	1007	993	970	955	919	860	802
08/01/10	743	708	676	643	622	624	619	636	661	689	725	769	800	837	860	884	905	912	895	870	864	826	782	727
08/02/10	679	647	637	634	638	673	710	783	835	911	968	1021	1069	1098	1114	1131	1117	1097	1076	1048	1018	972	903	840
08/03/10	787	749	723	703	683	718	751	815	859	909	979	1059	1125	1181	1210	1227	1224	1219	1199	1177	1165	1116	1037	970
08/04/10	920	870	840	810	800	825	853	919	992	1070	1136	1197	1238	1264	1276	1280	1260	1242	1226	1187	1173	1126	1056	984
08/05/10	941	907	867	843	828	840	887	911	922	917	926	933	978	1033	1066	1083	1090	1084	1073	1025	1019	972	896	836
08/06/10	786	752	733	714	696	716	745	809	848	898	944	980	1016	1047	1051	1061	1038	1021	983	943	916	874	809	739
08/07/10	688	658	628	607	600	596	586	606	653	711	760	801	845	878	908	924	940	935	909	869	848	806	755	697
08/08/10	650	621	595	581	576	582	568	604	660	719	779	840	894	937	964	994	1010	1002	987	957	953	913	844	782
08/09/10	746	713	688	681	684	725	776	828	883	972	1047	1118	1155	1198	1217	1231	1224	1207	1188	1149	1139	1087	1004	938
08/10/10	890	847	820	801	789	822	855	917	984	1039	1128	1184	1215	1235	1244	1260	1242	1240	1218	1192	1176	1125	1037	987
08/11/10	922	895	865	842	829	867	906	956	1011	1071	1131	1174	1216	1242	1261	1265	1264	1245	1221	1185	1179	1126	1032	975
08/12/10	929	889	851	837	821	848	896	943	1002	1075	1140	1204	1239	1248	1195	1127	1079	1064	1043	1038	1023	981	903	846
08/13/10	801	776	747	741	743	767	819	865	920	981	1032	1090	1138	1180	1203	1225	1208	1201	1171	1136	1110	1065	991	918
08/14/10	863	822	798	772	751	751	744	773	796	855	898	969	1006	1042	1062	1090	1099	1086	1047	1018	1007	961	902	844
08/15/10	792	751	722	700	682	678	677	685	712	753	815	876	947	991	1018	1046	1044	1049	1030	1021	997	938	878	816
08/16/10	762	733	699	686	686	722	763	801	855	892	924	969	998	1028	1043	1067	1066	1048	1028	985	969	908	828	767
08/17/10	722	696	670	662	652	683	717	753	792	859	899	947	982	1028	1059	1080	1051	1037	1005	984	974	915	840	785
08/18/10	745	715	703	685	691	732	772	802	815	859	927	977	1039	1072	1091	1111	1103	1102	1073	1059	1038	984	904	837
08/19/10	785	759	734	712	708	743	766	817	853	914	973	1026	1082	1114	1143	1148	1140	1121	1101	1070	1055	993	910	842
08/20/10	792	750	730	704	705	729	777	814	857	920	966	1021	1071	1111	1133	1148	1128	1109	1070	1029	1000	957	886	828
08/21/10	782	754	729	716	698	693	703	717	750	780	808	837	889	936	968	998	1005	999	967	946	924	877	823	757
08/22/10	710	685	656	641	634	633	631	665	728	790	845	894	925	966	981	1003	1016	1006	976	940	936	870	804	742
08/23/10	698	673	652	643	646	693	738	785	821	880	920	963	1001	1032	1053	1067	1055	1035	1021	989	969	916	832	773
08/24/10	723	699	669	668	665	686	724	777	825	870	915	957	978	1005	1026	1042	997	984	957	952	946	901	827	761
08/25/10	720	690	669	660	660	689	749	773	794	827	865	910	959	979	996	1012	990	989	959	923	900	836	757	705
08/26/10	667	645	629	614	614	646	683	716	740	778	809	841	872	903	913	933	927	920	888	864	860	802	681	681
08/27/10	647	624	605	598	595	632	667	696	729	762	796	827	857	887	912	927	939	925	887	870	841	794	735	674
08/28/10	637	611	587	572	563	571	563	589	637	689	738	798	859	912	955	973	979	973	949	922	907	864	815	751
08/29/10	704	679	650	629	623	623	617	645	710	775	830	886	927	951	952	964	941	948	907	899	880	838	780	731
08/30/10	698	679	658	657	667	720	783	828	850	887	923	979	1011	1039	1060	1086	1063	1037	1021	1000	978	923	846	790
08/31/10	741	712	684	667	664	694	747	778	825	871	927	971	1018	1056	1085	1096	1090	1077	1043	1034	997	939	859	796
09/01/10	753	711	689	671	673	699	756	799	841	886	924	950	986	1018	1062	1085	1082	1074	1043	1026	1000	935	857	791

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
09/02/10	759	726	698	677	677	704	756	800	831	882	926	954	997	1021	1031	1040	1024	1013	990	983	972	911	856	780
09/03/10	749	731	720	701	693	725	761	775	785	829	839	851	879	889	882	884	871	847	798	778	765	722	675	617
09/04/10	584	550	530	520	507	512	510	522	551	579	603	608	620	631	645	652	666	652	638	630	625	594	565	532
09/05/10	506	489	484	481	472	474	473	486	515	537	554	577	591	613	634	650	678	680	663	663	646	627	585	555
09/06/10	523	506	496	491	489	492	492	502	538	583	624	668	702	735	770	804	826	834	812	810	808	747	697	645
09/07/10	610	586	578	566	587	640	697	752	812	870	924	976	1039	1082	1108	1102	1070	1041	989	972	930	877	809	743
09/08/10	705	677	658	642	638	672	713	738	764	796	820	846	865	888	898	900	908	894	877	865	842	787	721	667
09/09/10	634	620	599	591	588	619	665	691	718	738	765	773	794	804	798	798	788	782	778	792	792	761	703	663
09/10/10	634	628	605	605	594	628	680	706	713	730	743	745	749	753	740	736	711	709	709	736	717	712	669	634
09/11/10	614	599	592	586	588	590	612	636	658	694	714	713	732	763	788	804	802	799	782	786	757	720	684	635
09/12/10	607	579	558	549	526	526	523	531	573	589	639	676	697	733	744	767	781	782	760	759	743	705	662	608
09/13/10	584	575	552	556	563	615	653	697	723	768	797	832	870	904	931	965	953	951	921	917	862	799	738	679
09/14/10	647	617	603	588	583	616	668	691	715	760	799	842	873	887	915	936	937	921	889	889	847	789	719	671
09/15/10	606	584	566	557	558	592	637	661	702	737	786	833	879	926	958	969	950	917	905	901	869	822	758	706
09/16/10	667	651	641	629	614	641	696	716	738	766	774	812	838	873	898	914	908	883	841	838	792	744	680	619
09/17/10	579	560	548	532	529	559	602	623	653	681	702	724	751	774	797	815	813	796	752	744	708	673	617	562
09/18/10	529	506	493	479	465	472	478	491	520	559	596	627	658	702	742	769	789	783	746	726	685	645	587	545
09/19/10	509	486	466	460	460	461	456	476	504	541	576	608	639	663	684	711	720	721	711	721	699	661	600	556
09/20/10	533	522	501	506	515	568	629	656	685	746	789	840	896	930	964	991	993	971	948	933	894	819	755	694
09/21/10	655	627	597	594	586	612	668	699	740	799	857	908	967	1007	1025	1011	1006	981	958	938	886	836	766	698
09/22/10	656	626	602	587	585	618	672	695	742	794	852	903	923	944	947	943	924	907	881	885	839	787	705	658
09/23/10	615	593	570	561	569	592	645	674	711	769	827	890	932	987	994	1010	990	967	941	939	903	832	766	702
09/24/10	660	634	602	598	590	623	676	706	733	795	846	871	854	842	851	881	864	831	790	779	748	705	635	572
09/25/10	530	509	489	468	457	463	478	499	521	558	573	588	612	629	649	642	634	606	608	621	590	566	532	496
09/26/10	468	449	433	420	405	416	410	421	441	454	464	468	470	476	471	483	478	488	494	531	519	500	471	448
09/27/10	431	421	419	418	432	474	529	549	558	587	592	602	618	629	631	635	624	617	620	645	604	586	537	499
09/28/10	478	460	460	451	456	481	539	554	564	595	600	603	618	628	624	618	617	601	608	631	603	575	525	491
09/29/10	467	463	453	451	442	491	536	553	568	585	605	618	624	643	652	654	654	638	640	655	624	587	541	496
09/30/10	486	458	453	455	447	483	542	560	570	601	619	637	653	682	683	686	679	663	653	672	636	603	548	508
10/01/10	478	468	453	454	448	480	541	540	567	586	596	601	610	624	628	628	615	596	588	591	565	543	505	457
10/02/10	421	420	410	400	392	399	415	417	445	465	475	473	471	467	470	451	461	456	471	492	474	457	427	404
10/03/10	385	375	365	360	362	368	383	390	402	420	430	441	438	445	442	436	446	457	482	508	495	473	446	425
10/04/10	411	412	402	412	428	477	550	572	576	592	583	593	597	591	590	578	560	559	575	602	582	549	517	483
10/05/10	462	463	455	454	460	500	558	577	574	578	583	592	595	592	589	582	572	567	587	600	585	552	518	487
10/06/10	467	468	458	449	455	490	554	573	569	595	598	596	608	618	609	610	594	589	601	628	604	569	525	494
10/07/10	476	463	461	459	458	491	550	568	581	603	619	629	645	654	668	659	659	636	642	654	622	588	547	513
10/08/10	485	475	464	461	458	480	540	554	574	601	621	623	642	656	667	671	662	642	636	632	609	569	537	489
10/09/10	464	451	432	430	419	431	454	469	495	517	540	559	576	681	704	713	708	706	695	697	572	548	512	475
10/10/10	449	438	422	407	403	398	409	405	436	458	483	525	540	578	600	611	627	619	629	622	599	563	517	485
10/11/10	460	448	441	440	451	490	556	576	597	630	645	680	699	735	745	749	734	716	723	718	680	637	584	553
10/12/10	520	512	496	491	496	518	588	607	619	642	670	692	696	727	718	699	690	670	696	688	669	625	588	550
10/13/10	521	500	497	486	496	520	584	608	611	630	649	655	672	679	687	662	650	653	662	661	644	608	558	522
10/14/10	503	488	482	474	477	511	569	594	593	610	624	625	630	639	634	626	614	605	621	639	623	588	549	512
10/15/10	497	486	482	476	479	499	561	585	591	606	610	615	613	619	614	600	586	574	588	590	568	550	517	474
10/16/10	463	448	433	427	423	431	459	468	488	505	504	512	520	515	515	519	521	522	538	580	626	598	483	458
10/17/10	432	432	417	412	416	428	426	439	456	469	489	500	506	522	531	545	558	564	589	599	579	555	521	494
10/18/10	478	461	463	466	471	511	582	593	612	636	645	668	685	698	702	702	689	675	705	703	674	634	595	552
10/19/10	521	511	494	487	497	521	588	604	608	621	630	629	634	636	628	622	614	607	637	637	626	586	555	514
10/20/10	503	497	489	497	500	533	597	613	610	625	629	635	640	646	640	645	634	619	656	661	637	609	563	537
10/21/10	508	511	489	487	493	526	583	599	604	617	627	629	633	644	643	628	625	622	651	655	638	610	574	531
10/22/10	514	509	504	506	510	548	608	635	646	654	657	655	658	660	658	658	631	631	650	645	629	614	575	537
10/23/10	517	500	498	491	486	494	506	516	533	549	562	570	562	570	574	567	569	571	598	595	576	556	542	501
10/24/10	483	467	463	454	454	460	470	493	509	517	542	557	564	568	568	577	584	594	623	624	611	590	560	527
10/25/10	511	509	499	503	509	557	632	660	668	686	694	708	717	727	721	712	713	718	745	735	707	677	636	609
10/26/10	582	582	566	573	582	610	680	713	702	699	695	692	689	686	686	671	671	663	699	698	671	645	602	567
10/27/10	550	533	531	537	538	563	629	645	655	655	676	682	689	702	702	699	679	684	711	711	684	658	622	583
10/28/10	556	545	537	536	535	571	637	651	653	662	664	670	661	670	660	664	661	667	693	698	689	657	618	595
10/29/10	568	565	559	560	574	606	673	693	689	688	675	674	662	672	652	640	642	629	663	665	653	637	605	575
10/30/10	563	554	538	544	538	551	567	580	587	599	592	583	567	560	567	554	549	557	587	591	574	561	533	505
10/31/10	486	481	466	470	471	483	498	506	522	532	531	541	533	541	531	536	534	541	570	585	575	558	539	510
11/01/10	495	486	491	486	508	563	636	665	668	667	674	668	668	667	660	660	659	668	702	699	676	657	624	583

Vectren Firm Load, MW	Hour Ending																							
Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/02/10	571	564	556	553	564	607	662	688	675	682	674	673	663	674	655	653	638	662	704	696	680	650	612	578
11/03/10	563	552	550	542	542	570	646	676	670	675	668	671	674	660	662	656	652	654	699	698	687	655	612	584
11/04/10	571	565	554	560	556	592	649	685	678	686	675	668	671	674	666	669	664	674	713	711	707	676	642	612
11/05/10	595	580	579	571	579	617	689	704	706	700	699	698	687	689	671	671	676	675	715	708	698	683	658	622
11/06/10	606	604	599	587	597	617	648	670	674	672	661	647	632	622	603	599	597	607	659	665	659	649	635	612
11/07/10	595	581	579	571	568	570	588	595	603	602	596	583	575	570	564	562	575	588	644	641	633	630	602	570
11/08/10	550	551	534	540	541	565	618	681	686	690	684	688	682	692	676	684	672	670	709	711	697	680	654	616
11/09/10	593	571	567	570	574	581	618	672	677	677	679	686	682	689	686	694	685	684	711	721	695	685	653	612
11/10/10	598	585	569	565	569	576	611	669	681	684	688	694	686	692	697	689	690	678	712	713	697	682	655	609
11/11/10	585	570	559	548	554	562	598	647	656	666	666	674	683	687	697	697	733	682	705	713	692	676	647	601
11/12/10	583	560	550	548	549	552	587	644	663	660	666	679	684	689	693	678	676	656	683	687	669	652	639	590
11/13/10	557	548	529	519	511	512	522	534	543	559	581	591	592	589	589	593	598	615	622	620	601	588	582	544
11/14/10	526	507	503	502	499	514	520	536	543	557	561	564	553	561	556	554	558	585	640	637	643	633	608	593
11/15/10	568	558	555	558	561	592	638	707	717	722	721	708	700	697	690	692	686	691	738	743	728	724	698	658
11/16/10	632	618	611	600	605	611	646	704	715	721	727	738	734	733	731	733	744	743	759	749	732	735	690	655
11/17/10	627	606	596	592	581	600	627	686	698	693	699	693	679	689	675	677	674	677	724	726	725	704	686	641
11/18/10	616	598	584	583	592	587	633	683	711	720	727	717	717	722	717	720	718	736	745	744	736	721	695	654
11/19/10	617	609	613	593	585	594	635	686	698	705	708	700	703	700	689	687	677	686	709	708	696	687	678	635
11/20/10	602	596	587	577	585	586	597	608	608	624	632	632	626	617	597	594	595	623	653	649	639	630	621	585
11/21/10	568	545	533	528	517	527	532	539	552	566	570	578	577	578	578	577	580	603	642	641	629	623	597	568
11/22/10	538	529	517	512	517	529	571	636	650	665	666	684	676	683	684	680	669	693	717	717	707	688	665	612
11/23/10	587	566	554	542	534	543	597	677	713	676	686	692	685	681	680	674	664	684	725	741	729	707	696	658
11/24/10	626	615	600	602	590	591	633	700	724	737	748	760	751	749	730	728	714	718	731	710	699	672	646	581
11/25/10	530	491	465	449	440	441	443	465	475	508	542	549	544	514	496	483	486	506	521	525	533	532	531	509
11/26/10	495	489	484	490	492	509	534	550	559	561	566	570	559	554	545	546	542	576	623	619	614	612	595	571
11/27/10	547	515	510	505	506	523	526	542	556	571	573	579	568	573	572	568	573	598	632	638	628	626	612	599
11/28/10	572	559	555	546	550	555	576	583	587	595	576	574	565	559	549	548	555	597	647	662	661	646	619	590
11/29/10	574	551	549	552	553	579	627	699	712	691	704	707	701	707	702	703	698	716	731	749	732	717	683	638
11/30/10	604	590	577	567	563	573	605	668	695	689	710	723	725	739	746	750	758	775	800	814	788	788	759	712
12/01/10	679	669	648	646	646	652	695	759	786	782	789	791	784	789	776	765	761	794	831	832	832	817	792	743
12/02/10	712	696	693	692	693	699	739	794	800	803	790	794	766	761	767	764	726	777	805	820	804	792	759	722
12/03/10	689	677	669	662	670	682	724	793	791	786	774	769	744	733	732	732	725	752	776	770	753	752	729	684
12/04/10	649	629	619	608	611	616	637	666	682	702	698	696	695	711	701	717	723	740	759	758	752	742	729	692
12/05/10	669	645	632	621	615	613	616	635	648	670	682	691	701	705	701	705	711	746	775	779	779	763	737	703
12/06/10	671	664	660	662	672	688	738	814	832	833	833	829	822	805	797	789	796	832	865	871	871	850	814	766
12/07/10	733	720	709	713	722	737	786	847	849	834	835	813	799	799	788	783	793	824	876	890	878	867	839	794
12/08/10	762	748	739	746	745	769	803	874	868	893	831	821	797	777	773	778	771	807	843	860	851	848	829	779
12/09/10	747	741	729	728	733	744	780	852	860	831	828	812	798	781	781	781	785	810	836	835	826	811	783	739
12/10/10	695	679	665	661	658	665	706	766	776	770	767	752	731	712	720	694	697	729	747	758	760	741	725	686
12/11/10	652	634	625	617	604	611	606	628	641	663	672	680	677	672	671	681	686	705	707	701	675	676	665	655
12/12/10	633	620	609	611	620	633	647	663	672	698	705	715	721	718	718	719	741	793	836	848	835	832	809	777
12/13/10	745	741	739	737	752	781	821	874	888	902	899	896	880	875	869	871	862	901	951	954	951	934	906	862
12/14/10	826	812	811	800	816	822	869	917	943	931	897	883	859	848	832	821	829	865	885	900	891	880	846	806
12/15/10	772	751	746	743	741	751	788	856	861	861	855	852	831	827	829	832	832	865	883	884	868	844	819	766
12/16/10	741	711	707	698	692	698	725	775	792	808	808	833	833	839	830	840	837	859	868	872	861	850	817	768
12/17/10	734	710	703	700	691	708	745	800	817	833	827	825	820	815	814	806	802	830	844	832	830	812	795	758
12/18/10	711	696	680	670	672	672	681	708	721	742	729	718	707	698	677	677	685	722	770	763	760	760	749	725
12/19/10	698	683	678	679	679	682	704	716	729	726	733	724	715	700	683	688	693	734	764	769	761	752	730	697
12/20/10	665	655	642	652	653	692	733	786	815	815	820	815	793	788	794	783	790	817	827	828	818	799	771	722
12/21/10	689	660	659	644	645	659	685	745	750	775	772	785	771	773	769	760	758	774	790	793	785	771	743	704
12/22/10	664	641	630	626	631	648	677	739	763	777	788	801	801	808	802	808	803	821	835	836	823	816	777	732
12/23/10	693	670	650	653	651	667	697	752	759	766	752	741	725	705	696	677	680	726	766	760	751	742	721	679
12/24/10	632	608	581	571	568	574	580	604	614	641	648	658	654	647	646	650	645	667	678	671	654	653	647	622
12/25/10	600	585	562	563	558	564	582	594	608	625	627	633	618	613	588	590	598	626	655	660	656	660	654	625
12/26/10	606	587	582	575	585	591	606	625	633	647	650	651	643	639	629	640	653	685	716	720	710	702	683	645
12/27/10	628	604	607	597	608	622	643	682	705	711	726	727	729	712	712	713	711	742	772	765	762	754	727	700
12/28/10	672	666	660	658	671	684	712	759	767	770	753	739	711	692	689	672	670	702	737	736	729	709	690	657
12/29/10	637	613	603	601	603	616	638	670	689	706	713	720	716	715	708	698	693	708	726	713	697	677	653	612
12/30/10	584	556	547	540	537	550	569	602	627	633	638	650	633	622	611	610	599	626	644	637	626	619	600	567
12/31/10	540	520	496	493	489	494	509	521	534	545	563	567	568	566	555	557	557	584	602	588	568	552	534	514

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Vectren South
Electric DSM Action Plan:
Final Report

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EXECUTIVE OVERVIEW

This document presents a long-term Demand Side Management (DSM) Action Plan for residential and commercial electric customers in the Vectren South service area. The DSM Action Plan was prepared by Forefront Economics Inc. and H. Gil Peach and Associates with consultation and review by an Advisory Board consisting of representatives from Vectren Energy Delivery (South), Citizens Action Coalition (CAC) and the Indiana Office of Utility Consumer Counselor (OUCC). The design, implementation, oversight and cost effectiveness of electric DSM programs are addressed in the DSM Action Plan. Key findings from the DSM Action Plan are summarized in Table 1.

Table 1. Annual Usage and DSM Potential for Residential and Commercial Customers

	kWh (millions)	Percent of Total
Total Usage	2,624	100%
Technical Potential	936	36%
Economic Potential (@ $0.06/kWh)	460	18%
Recommended DSM Programs (after 5 years)	84	3.2%

The technical potential shows that if the electric saving technologies identified in this report were applied across all applicable customers, without regard to market or economic constraints, weather normalized annual kWh usage could be reduced by 36 percent. Economic potential considers the cost of these technologies compared to the marginal cost of energy supply and shows that about half of the technical potential is cost effective (18% of total usage). These findings compare favorably to similar studies from across the U.S. A review of eleven studies of potential found median technical potential of 33 percent and median economic potential of 20 percent.[1]

Estimated savings from the DSM programs recommended for implementation provides an estimate of realistically achievable energy savings. These programs ramp up over a five-year implementation schedule reaching 84 million kWh of annual savings after the fifth year, a 3.2 percent reduction from current total usage. This level of savings represents 9 percent of technical potential and 18 percent of economic potential.

The approach used to develop the set of recommended DSM programs consisted of the following steps:

(1) conduct a market assessment for determining electric usage and characteristics across customer groups,
(2) review a comprehensive list of DSM technologies for saving energy,
(3) consider the appropriateness of selected technologies for Vectren South's service territory in terms of markets, cost effectiveness and accessibility to products,
(4) group the highest potential technologies into logical sets for marketing and outreach,
(5) design program strategies to promote the technologies based on industry best practices,
(6) consider the cost effectiveness of the designed program, including costs to Vectren and to participating customers, and
(7) describe a final set of recommended program designs that make the most sense for the utility and have a strong potential for delivering cost effective energy savings.

[1] Nadel, Steven, Anna Shipley and R. Neal Elliott. *The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies.* 2004 ACEEE Summer Study in Energy Efficiency in Buildings.

The following DSM programs are recommended for implementation:

- Residential and Commercial Direct Load Control
- Energy Star Lighting
- Energy Star Appliances and Programmable Thermostats
- Old Refrigerator Pick-Up and Recycling
- Low and Moderate Income Weatherization Enhancement
- New Residential Construction – Beyond Energy Star
- Flow Efficient Fixtures
- Commercial Incentives
- Commercial New Construction
- Controls, Lights and Signs

These programs are expected to reduce the cost of providing energy by a net present value of $10 million over the life of the program measures including the cost of a general public education and awareness campaign. All of the recommended programs were found to be cost effective from a total resource cost (TRC) perspective.

Table 2. Energy Savings and Annual Budget for Recommended Programs

	All Programs	Recommended Programs	Percent
Annual kWh Savings (millions - Year 5)	103.5	83.8	81%
Average Annual Program Budget (millions)	$ 5.8	$ 3.8	65%
Percent of Revenue ($207.5 million)	2.8%	1.8%	
Program Dollars per Customer	$ 41.95	$ 27.23	

Average annual program budgets are estimated at $5.8 million for all programs considered in this report and $3.8 million for recommended programs. Compared to the $207.5 million in residential and commercial customer revenues, these levels of program expenditures amount to 2.8 percent and 1.8 percent for all programs and recommended programs, respectively. This equates to spending of nearly $27 per customer for program delivery cost and incentives. Based on recent data from the US Department of Energy on DSM program spending at 14 utilities with comparable customer counts to Vectren South, spending at $27 per customer is higher than average but well within the range of spending. Spending per customer by the comparable utilities ranged from less than 50 cents to $46, averaging $21.[2] Spending as a percent of revenue averaged 1.4 percent with a wide range.

[2] See Table 58.

MARKET ASSESSMENT

Energy efficiency planning needs to be based on a sound understanding of customer characteristics. The purpose of this section is to provide a foundation for the DSM planning and analysis presented in subsequent sections. We begin with a description of the Vectren South service territory in terms of households, businesses and customer data.[3] A description of the customer base precedes the presentation of energy usage models. These models are used to estimate the electric sales by end-uses; such as, space heat, water heat, lighting, cooking, dryers, process energy, and miscellaneous plug loads. The detailed energy usage models also provide a basis for estimating the technical potential, energy savings and cost effectiveness of a wide variety of demand side measures and programs.

Electric energy use estimates presented in this report are normalized to long-term weather conditions by using the energy usage models applied to a typical or normal year. All energy use and end-use estimates in the report have been normalized to the 30-year monthly temperature averages for Evansville. Though the energy use estimates are for a normal year, the models were developed using actual usage and weather data from October 2005 through September 2006.

Overview of Market Sectors

The focus of this study is on the nearly 140 thousand residential and commercial electric customers in the Vectren South service territory.[4] These customers account for over 2.6 million MWh annually, as shown in Table 3.

Table 3. Vectren South Customers and Weather Normalized Annual Usage by Sector

Sector	Customers	Annual Usage (MWh/year)	Percent of Total	Use per Customer (kWh/year)
Residential	121,058	1,444,524	55%	11,932
Commercial	17,933	1,179,939	45%	65,797
Total	138,991	2,624,463	100%	

Source: Unique premise counts and billing data from CIS extract (October 2005 - September 2006).

With over 120 thousand customers, the residential sector is far larger in terms of customer count than the commercial sector. Although there are far fewer commercial customers than residential, the average commercial customer uses nearly five times more electricity than the average residential customer. The commercial sector accounts for 45 percent of the energy consumption considered in this study.

[3] When using secondary data sources to describe the Vectren South service area, we have included the following six counties in the greater Evansville Indiana area; Gibson, Pike, Posey, Spencer, Vanderburgh and Warrick.
[4] Customer data for the following rate codes were included in this study: Residential (SE01, SE02, and SE03) and Commercial (SCTR, SE04, SE06, SE08, SE10, SE11, SE13, and SE19).

Monthly electric loads for both sectors are shown in Figure 1. Residential and commercial loads follow a nearly identical seasonal pattern with an obvious summer peak. Although not as predominant as the summer peak, there is also clearly a notable winter peak, especially for residential. It is clear from the monthly loads in Figure 1 that Vectren South is a summer peaking electric utility.

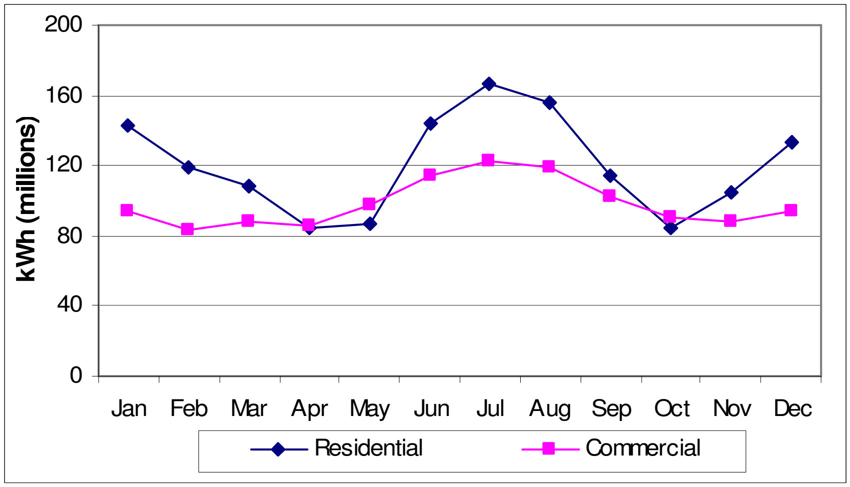

Figure 1. Total Vectren South Electric Sales by Rate Class

Detailed energy usage analysis by sector and end-use will be presented later in this section. An overview of monthly loads by end-use is presented here for the residential and commercial sectors combined as an overview of the components of electric consumption. End-use models were estimated for each sector allowing loads to be disaggregated by major end-use. Monthly loads by end-use estimated from the models are shown in Figure 2.

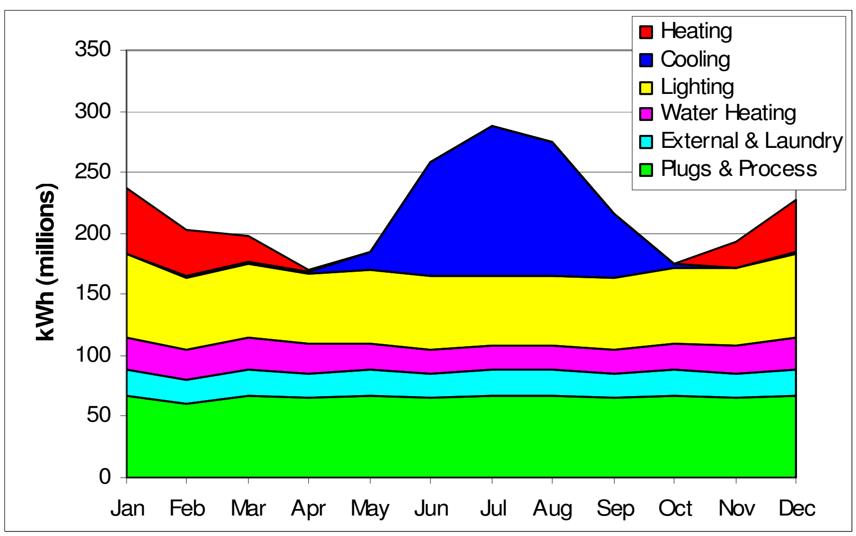

Figure 2. Total Vectren South Electric Sales by End-Use

Monthly shapes are characterized by a large base load with a prominent summer peak for cooling. Winter heating contributes to an obvious winter peak, although lower than the monthly summer peak by approximately 50 million kWh. Base loads include end-uses that are not highly weather dependent such as lighting, water heating, and miscellaneous plug loads. Annual data are shown for these same end-uses in Table 4. Base loads comprise over 75 percent of total annual usage.

Table 4. Vectren South Total Annual Electric Use by End-Use

End-use	Millions kWh	Percent
Plugs and Process	789.7	30%
Lighting	732.0	28%
Cooling	404.2	15%
Water Heating	274.1	10%
Heating	178.1	7%
External and Laundry	246.3	9%
Total	2,624.5	100%

Source: Analysis of monthly usage

Energy and demand are both important considerations when planning DSM programs. A map of MW demand in the residential and commercial sectors by month and time of day is shown in Figure 3.

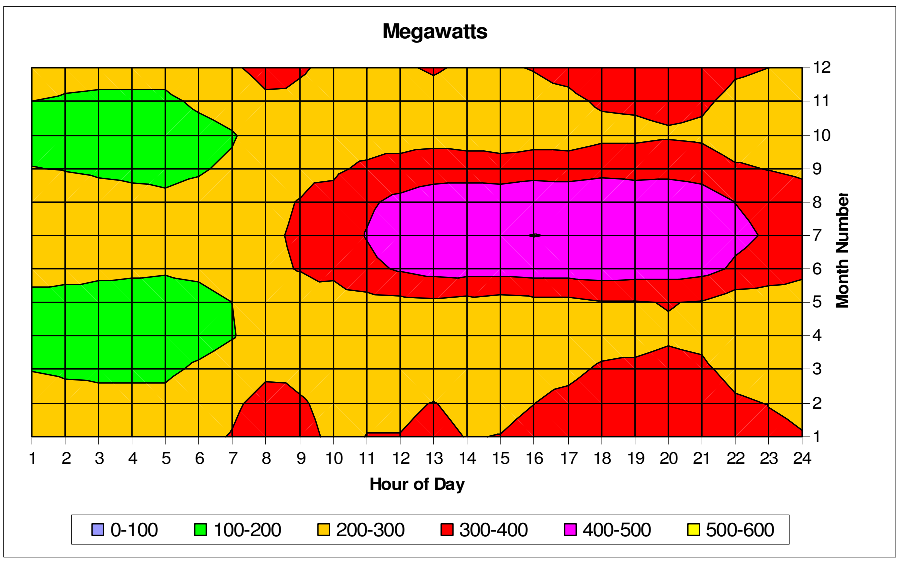

Figure 3. Vectren South Hourly Demand Map

Demand was modeled using several sources of information, including an hourly load profile analysis completed by Vectren in 2005. A detailed discussion of the methodology is presented in Appendix A. Demand is highest between 10AM and 10PM, June through August. DSM technologies and programs with impact during these periods will save peak and energy.

Residential

The market assessment presented in this section begins with a high-level view of residential housing in the Vectren South service area, followed by a detailed analysis of residential electric loads. Table 5 shows estimates of housing stock by type of construction and tenancy.

Table 5. Housing Units by Occupancy and Vacancy

	Total	Percent
Total Housing Units	143,340	
Occupied Housing Units	127,787	100%
By Construction Type		
Single Family	102,695	80%
Multi Family	25,092	20%
By Tenancy		
Owner Occupied	93,361	73%
Renter Occupied	34,426	27%

Source: 2000 Census Data for Counties in Vectren South Service Area; adjusted for percent change in Vanderburgh county between 2000 and 2005

Of the nearly 128 thousand occupied housing units in the Vectren South service area most (80%) of the housing stock is single family. The overall owner-occupancy rate is 73 percent.

Residential construction estimated from housing permit data for the Vectren South service area is shown in Figure 4. Data shown in Figure 4 are based on monthly permit data lagged to approximate the timing of construction and better align temporally with actual electric service installations. Residential construction adds between 1,500 and 2,000 dwellings annually in the Vectren South service area. Although the mix of construction varies from year-to-year, about 80 percent of new housing stock is single family units. An estimated 110 manufactured homes are placed in Vectren South service territory annually. This is based on US Census data for statewide placements of manufactured homes and the percentage of statewide single family construction that takes place within the service territory.

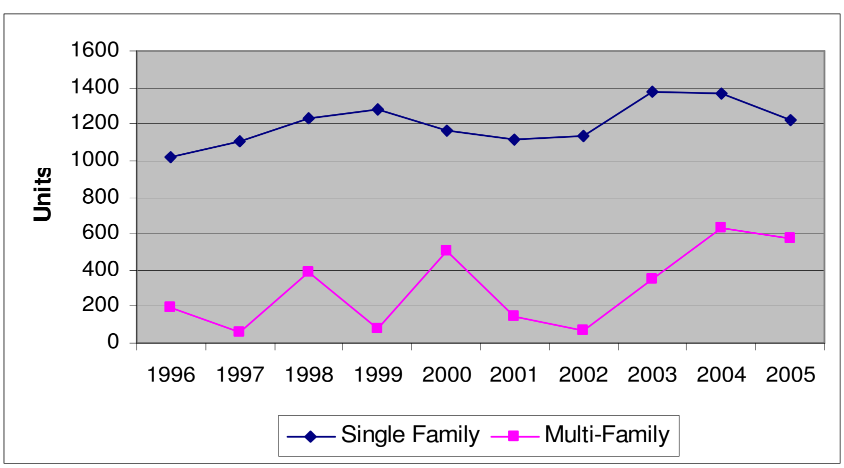

Figure 4. Residential Housing Units Permitted for Construction, Vectren South Service Area

Data for Figure 5 through Figure 7 was derived from Vanderburgh county assessor records.[5] Assessor records provide valuable housing attribute details useful for understanding the nature of the housing stock and, therefore, the DSM opportunities. Since these data pertain to a tax parcel, their greatest value comes from the information on single family housing. Most single family dwellings were built between 1940 and 1960, comprising 30 percent of homes. Nearly 80 percent of the housing stock is over 25 years old.

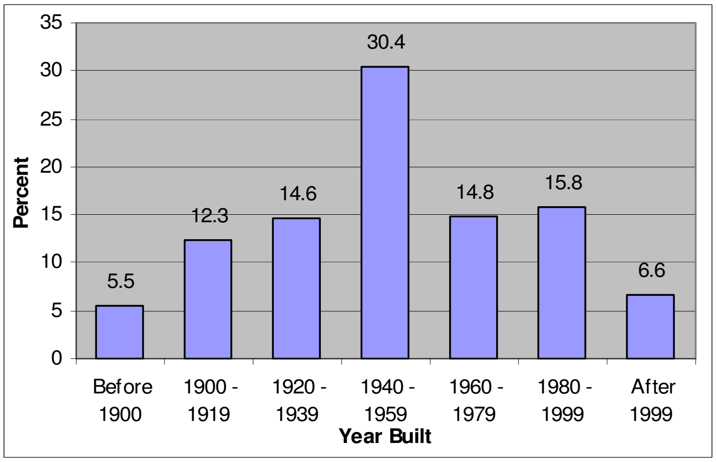

Figure 5. Percent of Single Family Dwellings by Year Built, Vanderburgh County

An average single family home has 1,620 square feet. The distribution of homes by square footage is shown in Figure 6. Most single family dwellings have square footage between 800 and 1600, with the largest number in the 800 to 1200 square footage category.

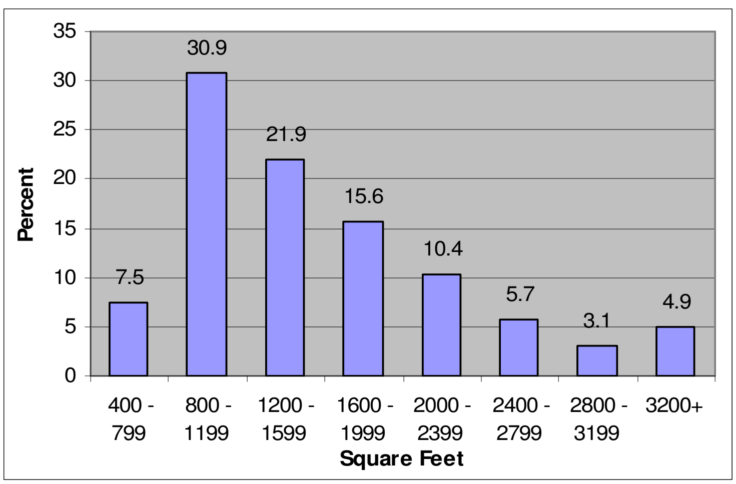

Figure 6. Percent of Single Family Dwellings by Square Feet, Vanderburgh County

Homes built before 1960, accounting for over 60 percent of the housing stock, are much smaller than other homes, averaging 1,403 square feet. Homes built after 1960 got progressively larger until leveling off in the 1980s and 1990s. Somewhat surprisingly, homes built in the last six years are not significantly different in size to homes built in the 1980s and 1990s.

[5] Vanderburgh County accounts for over half of all occupied housing in the Vectren South service territory. Attempts to acquire housing data from the Warrick and Gibson county assessor office were unsuccessful.

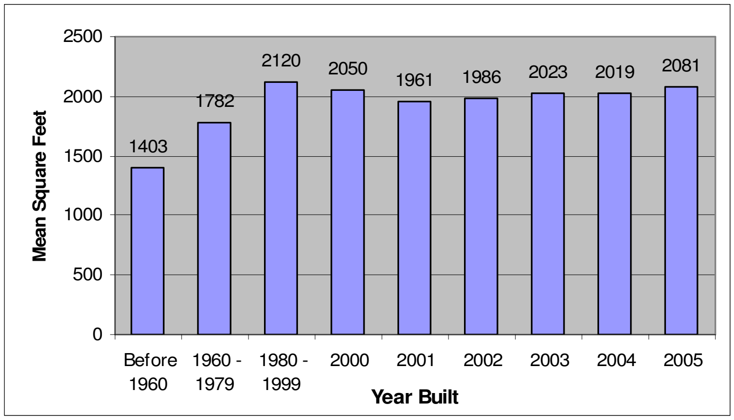

Figure 7. Single Family Mean Square Feet by Year Built, Vanderburgh County

Customer Description

A market segmentation strategy was adopted to describe the residential customer class in greater detail. The segments were also selected to better describe cost effective DSM opportunities which can vary significantly by type of housing and vintage of construction.[6]

Table 6. Number of Residential Customers by Segment

	Single Family	Multifamily	Total
	(thousands)		
Existing Construction	99.2	12.3	111.5
New Construction	7.7	1.8	9.5
Total	106.9	14.1	121.0

Source: Vectren South CIS Data

Residential customers are segmented by vintage of construction and type of housing. There are typically many important differences between older and newer homes that have large impacts on energy use and conservation potential. Differences in the thermal integrity of the building shell and appliance penetration rates, for example, can lead to large differences in annual usage between older and newer homes. Existing construction is defined as all homes with meters installed prior to 2002. New construction consists of all homes with meters installed in 2002 and after. Using 2002 as a cutoff is somewhat arbitrary and less important than having a group of homes to model and contrast the differences between existing and new housing stock.

The type of construction (single family and multifamily) also enters into the segmentation approach. Single family and multifamily units exhibit many differences that impact electric consumption and conservation potential. These differences include size of unit, appliance penetration, building shell integrity and lifestyle attributes. The housing

[6] There is a slight discrepancy between the Census count of occupied homes of nearly 128,000 and the CIS count of residential premises of 121,000. Although Census and CIS are completely different sources, it is reasonable to expect them to be close and the numbers are within 3% of each other. The real value of the Census data in Table 5 is that they provide an estimate of the split between single family and multifamily housing and between owner and renter occupied housing. Possible explanations for the discrepancy between the two sources include the process used to adjust 2000 Census to 2005 and the use of central metering on multifamily buildings, more common in older construction. Use of central metering on multifamily buildings would cause CIS numbers to be lower than Census.

type was determined from the unit number portion of the service address. Premises with unit numbers were classified as multifamily while units with no unit number were classified as single family buildings.[7]

A large share (88 percent) of residential customers fell into the single family segment. This is higher than the 80 percent single family found in the Census data and is most likely a result of our imperfect methodology for classifying customers from address information. Multifamily units that do not have unit numbers, some duplexes and triplexes, for example, would be classified as single family customers.

Electricity Usage Analysis

Our analysis of customer usage took advantage of a residential survey Vectren fielded in the summer of 2005. A report was issued by the market research firm dated September 21, 2005, describing the survey results, including appliance installation rates. A total of 351 customers responded. Since the results in the report were specific to the Vectren South service area, the results were used directly without re-weighting the figures. Given the small number of multifamily households represented in the survey (35), survey results were not analyzed by housing type. Appliance installation rates and other information from the survey results are summarized in Table 7.

Table 7. Appliance and End-Use Installation Rates from Residential Survey

	Percent (n=351)
Programmable Thermostat	23
Primary Heat is Electric	24
Secondary Heat is Electric	9
Primary Heating System is Heat Pump	4
Primary Heating System is Electric Furnace	19
Central AC	92
Window AC Units	16
Electric Water Heat	40
More than One Refrigerator	28
Electric Cooking	68
Electric Clothes Dryer	76
Dishwasher	61
Take Measurers to Reduce Energy	40
Of Respondents Taking Measures to Reduce Energy, Specific Measure Taken:	
Installed Ceiling or Attic Insulation	32
Installed Energy Star Furnace	25
Installed Energy Star AC	27
Installed Energy Star Water Heater	20
Installed Energy Star Dryer	16
Installed Insulated Windows	47
Installed Low Flow Shower and Water Faucet	24
Installed Compact Fluorescent Lights	23

Source: Vectren South Market Research Survey (2005)

[7] Frequency tables of unit number were examined for entries unrelated to unit number such as “NA”, “None”, or “BOD” (beware of dog) that could bias the classification. These sorts of entries were not found in the data.

Monthly billing data at the premise level was aggregated by the four residential customer segments used in this report. An end-use energy and demand model was then estimated using the aggregated billing data, residential survey results, detailed hourly load profiles and weather data. Model assumptions were refined to provide the best empirical fit to the actual customer billing data. The table below shows annual usage for each residential segment.

Table 8. Annual Usage by Residential Segment

Segment	Premises	Average Annual kWh per Premise	Total Usage (millions of kWh)
Single Family Existing	99,241	12,334	1,224
Multifamily Existing	12,317	8,067	99
Single Family New	7,683	13,826	106
Multifamily New	1,817	8,205	15
Total Residential	**121,058**	**42,432**	**1,445**

Source: Energy model results using monthly billing data from Vectren CIS

The monthly load profiles resulting from the energy models are shown by segment in Figure 8.

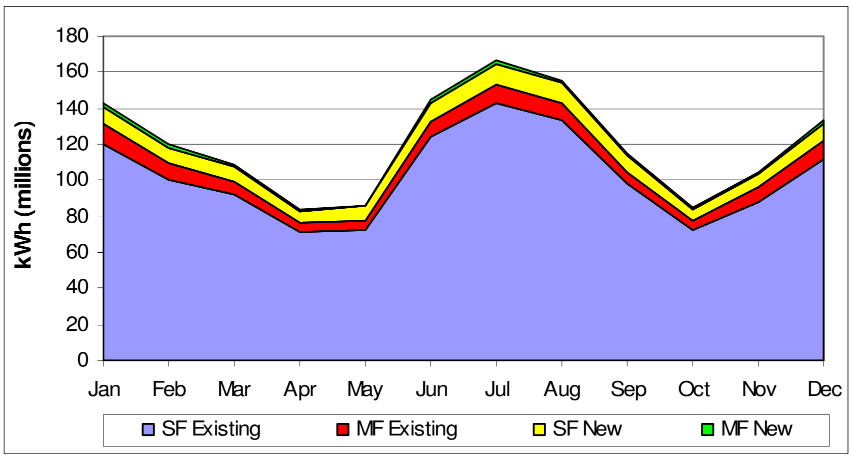

Figure 8. Residential Electric Usage by Housing Type

Because of the large number of homes, the existing stock of single family homes is by far the largest segment, accounting for 85 percent of the residential sectors energy usage. All segments follow a similar monthly load pattern, as expected. This pattern is shown by major end-use in Figure 9 and Table 9

.

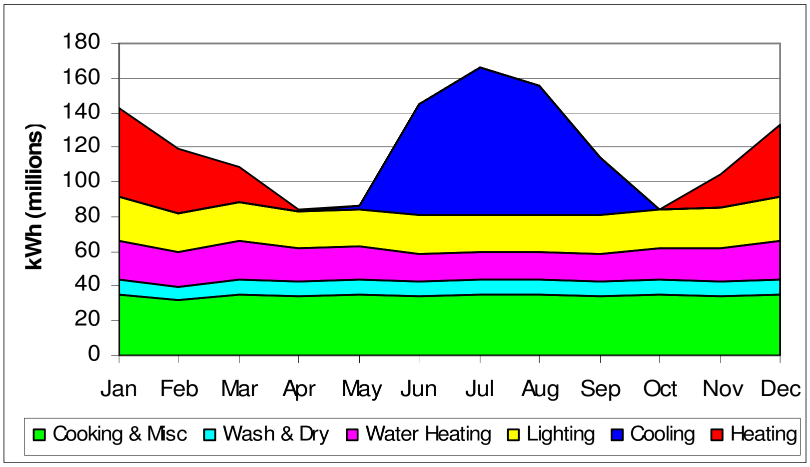

Figure 9. Monthly Residential Loads by End-Use

Table 9. Residential Sector Monthly Usage by End-Use (millions of kWh)

	Cooking & Misc	Wash & Dry	Water Heating	Lighting	Cooling	Heating
Jan	34.8	8.8	22.8	25.2	0.0	51.5
Feb	31.5	7.9	20.6	22.2	0.0	37.5
Mar	34.8	8.8	21.9	22.6	0.0	20.8
Apr	33.7	8.5	19.8	21.4	0.0	0.6
May	34.8	8.8	18.7	22.3	1.8	0.0
Jun	33.7	8.5	16.7	22.1	63.4	0.0
Jul	34.8	8.8	16.4	21.1	85.0	0.0
Aug	34.8	8.8	16.3	21.5	74.0	0.0
Sep	33.7	8.5	16.3	22.0	34.0	0.0
Oct	34.8	8.8	18.2	22.7	0.0	0.1
Nov	33.7	8.5	19.5	23.3	0.0	19.7
Dec	34.8	8.8	22.1	25.5	0.0	41.8
Annual	410.0	103.4	229.3	271.7	258.3	171.8

Commercial

The commercial market is far less homogenous than residential. There are a greater number of basic customer types (segments) and the variation in size of building is much larger in commercial. For these reasons it is useful to describe the commercial sector not only in terms of number of businesses but also in terms of square footage. Analysis of DSM opportunities in the commercial segment also benefits from an understanding of the square footage of commercial space in the service territory.

Square footage estimates were developed using site-specific data for all businesses in the service territory. Business attributes included NAICS code and estimated employment. These two pieces of information were used along with estimates of employment density (employees per square foot) by type of business to estimate the square footage of each business record in the secondary data. The results of this analysis, summarized by segment, are shown in Table 10.

Table 10. Business Counts and Estimated Square Footage by Segment

Segment	Number	Percent	Total SqFootage	SqFootage Distribution	SqFt per Business
Commercial					
Grocery	245	2.8%	2,141,970	2.0%	8,743
Hospitals	39	0.5%	1,880,540	1.8%	48,219
Lodging	70	0.8%	3,175,540	3.0%	45,365
Office	2,229	25.7%	13,490,210	12.8%	6,052
Other	2,114	24.4%	18,195,950	17.2%	8,607
Other Health	870	10.0%	9,622,730	9.1%	11,061
Restaurants	644	7.4%	7,147,460	6.8%	11,099
Retail	1,414	16.3%	9,058,330	8.6%	6,406
Schools	281	3.2%	8,368,780	7.9%	29,782
Wholesale & Warehouse	756	8.7%	32,402,520	30.7%	42,860
Total Commercial	**8,662**	**100.0%**	**105,484,030**	**100.0%**	
Other Non-Residential					
Ag, Mining, Util., & Const	1,269	67.2%	10,300,490	30.5%	8,117
Manufacturing	620	32.8%	23,504,220	69.5%	37,910
Total Other Non-Residential	**1,889**	**100.0%**	**33,804,710**	**100.0%**	
Total Non-Residential	**10,551**		**139,288,740**		

Source: InfoUSA data for Vectren South territory. Forefront Economics estimate of square footage based on employment and employment denisty by NAICS

The estimated number of businesses compares favorably to the 2004 Census count of business establishments in the Evansville MSA of 8,800 total and 7,200 commercial. Establishments without payroll are excluded from the Census count. The six-county Evansville MSA includes the four largest counties in the Vectren South service area plus Henderson and Webster counties in Kentucky.

Wholesale and Warehouse is the commercial segment with the largest amount of floor space, accounting for 30 percent of all commercial area. Office floor space accounts for nearly 13 percent of total floor space and over a quarter of all commercial businesses. The Other segment accounts for 17 percent of commercial floor space. This segment primarily consists of general public assembly facilities (e.g. churches and museums), services not else where classified, and government buildings.

It is not uncommon for Other to be a fairly large component in commercial segmentation results. Other accounts for just over 20 percent of all commercial floor space in the NW Power Planning Council's 2004 floor space model and 22 percent of the floor space in the 2003 Commercial Building Energy Consumption Survey. This is due to the highly diverse nature of the commercial segment. The challenge is that when we try to break out a business type from Other we end up with a very small segment without significantly reducing the size of Other. This is also true of the Vectren South service area.

Customer Description

Commercial customer data were segmented using the same NAICS code classification scheme used to describe the business data acquired for the service territory. Number of premises and annual usage is shown by segment in Table 11 along with other descriptive information about the commercial sector.

Table 11. Number of Premises and Annual Usage by Segment

Segment	CIS Premises	Average Annual kWh Per Premise	Customer Sites	Avgerage Annual kWh Per Site	Total Usage (Millions of kWh)	Applicable Square Feet (thousands)	EUI (kWh per Sq Ft)	EUI From NBECS
Commercial								
Groceries	216	338,647	191	382,972	73	1,934	37.8	49.4
Hopitals	76	217,182	69	239,215	17	322	51.3	27.5
Lodging	103	281,111	82	353,103	29	3,176	9.1	13.5
Office	4,547	41,343	3,275	57,401	188	8,191	22.9	17.3
Other	3,457	53,027	2,453	74,731	183	15,100	12.1	22.5
Other health	577	114,081	508	129,576	66	9,176	7.2	16.1
Restaurant	494	179,675	462	192,120	89	7,115	12.5	38.4
Retail	1,201	104,384	1,008	124,370	125	8,265	15.2	14.3
Schools	302	248,552	253	296,691	75	7,166	10.5	11.0
Wholesale & Warehouse	1,095	69,653	798	95,577	76	10,010	7.6	7.6
Total Commercial	12,068	76,333	9,099	101,241	921	70,455	13.1	
Other Non-Residential								
Ag, Mining, Util., & Const	5,221	28,925	2,903	52,021	151	7,276	20.8	
Manufacturing	644	167,282	518	207,972	108	3,298	32.7	
Total Other Non-Residential	5,865	196,207	3,421	75,635	259	10,574	24.5	
Total Non-Residential	**17,933**	**272,540**	**12,520**	94,244	**1,180**	**81,029**	14.6	

Source: Energy model results using monthly billing data from Vectren CIS. NBECS is the Non-residential Building Energy Consumption Survey (2003, US Census)

The number of premises was found to include many non-building types of electrical services (e.g. billboards and railroad controls). An alternative measure was developed to better approximate the number of actual buildings. This measure is shown in Table 11 as Customer Sites and only includes premises with at least 3,600 kWh of annual usage.[8] Although the distinction between premises and customer sites does not impact the energy modeling results, customer sites is a better measure of the number of customers available to participate in DSM programs. Applicable square feet shown in Table 11 is the total square footage found for that segment in the service area, shown in Table 10, multiplied by the ratio of kWh included in this study to total kWh. All of the kWh sales to

[8] Although arbitrary, this level of usage was thought to effectively screen non-building premises and resulted in a count of commercial customer sites that approximated the count of commercial businesses from the secondary data.

Lodging customers, for example, are included in the rate schedules encompassed by this study. Accordingly, all of the square footage of the Lodging segment is shown in Table 11. Likewise, only a small amount of the kWh sales to Hospital are included in this study (17%) so we limit square footage estimates to 17 percent of the service area. The energy utilization index (EUI) is calculated using the estimate of applicable square footage. Energy utilization index results from the 2003 NBECS are also shown for comparison purposes. Although they follow the same general pattern, there are a few notable differences in EUI estimates. Energy utilization indices serve a descriptive purpose in this report and are not used for the energy savings estimates.

Hospitals and grocery stores are the most energy intensive of commercial buildings but only account for a small amount of the applicable floor space. Offices have a large amount of square footage along with a moderately high EUI.

Electricity Usage Analysis

Annual energy usage by segment has already been presented in Table 11. Commercial energy usage by end-use is shown in Figure 10. Commercial load is characterized by a large percentage of base load with a prominent summer cooling peak.

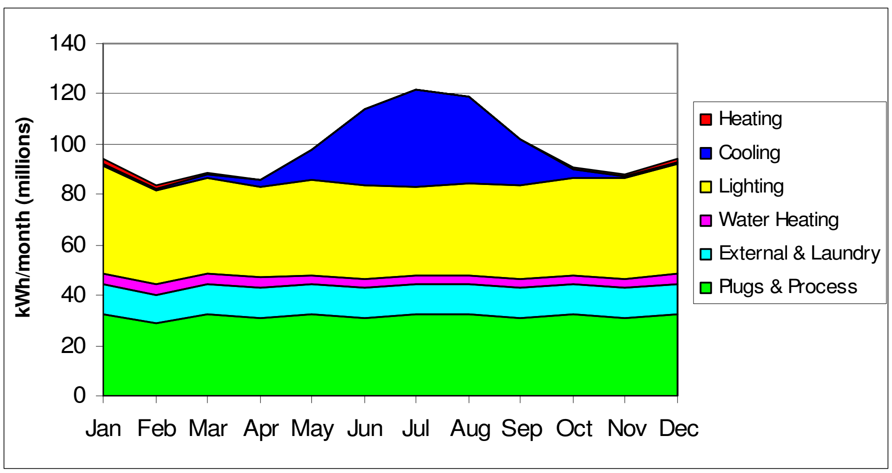

Figure 10. Monthly Commercial Usage by End-Use

ENERGY CONSERVATION MEASURES AND POTENTIAL SAVINGS

In this section we present our estimates of the energy savings potential in the Vectren South service area. This work builds off on the energy modeling results presented in Appendix A by applying energy efficiency technologies to the model parameters. These technologies, referred to as Energy Conservation Measures (ECMs), cause a reduction in the load profiles of the end-uses presented in the prior section. In this section we derive estimates of technical and economic potential.

Technical Potential

Technical potential refers to the amount of energy efficiency that could be obtained if all ECMs were adopted without regard to costs. This level of savings represents the upper limit of energy conservation opportunity. Our estimate of technical potential assumes that all customers in each sector use the most efficient available electric technology for each end-use.

We have restricted our analysis to technologies meeting existing electric end-uses more efficiently. The technical potential derived in this analysis does not consider fuel switching technologies, but there are significant interactions between electric efficiencies and gas usage. In particular, envelope or equipment efficiencies intended to reduce cooling energy will also often reduce the use of gas for space heating. Interior lighting efficiencies and appliance efficiencies can actually increase the use of gas for space heating. In estimating the technical potential, the gas effects resulting from electric efficiency are not quantified. However, the relevant and significant natural gas effects have been incorporated in our estimate of cost effective potential.

At the outset it is important to recognize two fundamental patterns in the Vectren residential and commercial stock:

1. Most Vectren electric customers are also Vectren gas customers, and
2. Seventy-five percent (75%) of the Vectren electric customers heat with gas. These customers tend to live in older, less insulated housing stock. They also tend to have less efficient central air conditioning.

It is apparent that in this service territory the residential electric and gas savings potential is closely interactive. And it is probable that the most efficient program delivery mechanism will be an all-energy approach.

For the purpose of estimating technical potential we have expressed the energy modeling results in terms of two planning elements; large buildings and small buildings. This is simply another way to consider the total energy load and has advantages for modeling the ECM impacts when estimating technical potential. These two groups are compared in Table 12.

Table 12. Comparison of Planning Elements

Planning Element	Premises	Average Energy Use (kWh/year)	Fraction of Sales
Small Buildings	134,200	14,645	75%
Large Buildings	4,700	139,732	25%

Note in Table 12 that the annual usage of the small buildings is of the same scale as residential usage, and that the annual usage of the large buildings is about ten times as much. This is the most obvious distinction between the two groups. The groups also differ in terms of energy end-uses as shown in Table 13.

Table 13. End-Use Fractions

Planning Element	Water Heating	Lighting	Cooling	Heating	Interior
Small Buildings	13%	31%	16%	9%	31%
Large Buildings	1%	53%	13%	1%	32%

The small building planning element is predominantly residential but it also includes small offices, agriculture, and other uses which have energy usage in the same scale. This element comprises 75 percent of total residential and commercial electric sales and more than 95 percent of the customer accounts. These electric sales are to a functionally homogenous array of electric forced air furnaces and air conditioners, tank style water heaters, and residential appliances. This planning element accounts for most of the electric heating in the form of resistance heat, and most of the cooling is in the form of small scale air conditioners. In this planning element, electric hot water heating is almost as large as cooling. It will be important to include hot water heating efficiency measures in programs for this planning element.

Also, in this planning element, about 38 percent of the residential and commercial electric sales pass through accessible heaters, coolers, and hot water heaters. Another 31 percent is used in reasonably accessible lighting. The remainder of the energy is used in a diverse array of electrical appliances. The principal theme of this element is small structures with residential-scale heating, cooling, hot water and lighting.

The large building planning element is comprised of the top 4,700 commercial accounts. But the average large building energy use is ten times the average small building usage. The largest component of this energy use is commercial lighting, both interior and exterior. This component is populated by about 5,000 medium scale customers. Yet this small pool of customers uses more than 50 percent of electricity for internal and external lighting, and most of this use is during Vectren's peak periods. Luckily, lighting retrofits are quite modular and reasonably easily managed. This is a rich planning situation because significant savings are concentrated into relatively few large scale jobs. The scale of the retrofit jobs is large enough to be economically viable and attractive to specialty lighting contractors. This planning element has been the workhorse of most utility commercial DSM programs.

After lighting, the next largest component of large building energy use pertains to building systems: ventilation, cooling, and computers (Other). These systems comprise about 20 percent of large building energy use. There are a few homogenous niches in this component, such as, variable speed drives applied to ventilation, roof top unit tune-up, and computer power supplies. But most applications will need to be specifically engineered. This energy use component is characterized by a diverse array of energy management type issues, such as, control of complex HVAC and interior loads.

The Technical Potential by Planning Element

The technical potential for each of the planning elements was derived by applying all the efficiency measures at once in the energy model, so that interactions between efficiency measures and load reduction measures are properly accounted for. In later stages of the program planning, various measures will be screened individually for cost effectiveness, but for estimating the total technical potential, all the measures are applied as a package. For ease in discussion, we will discuss technical potential in terms of the market sectors the planning elements most closely represent, residential and commercial.

In developing technical potential, we apply ECMs, such as, the replacement of electric furnaces by heat pumps shown in Figure 11. This figure is used to illustrate the derivation of technical potential and shows the energy use pattern for customers with electric furnaces, about 20 percent of the residential sector.

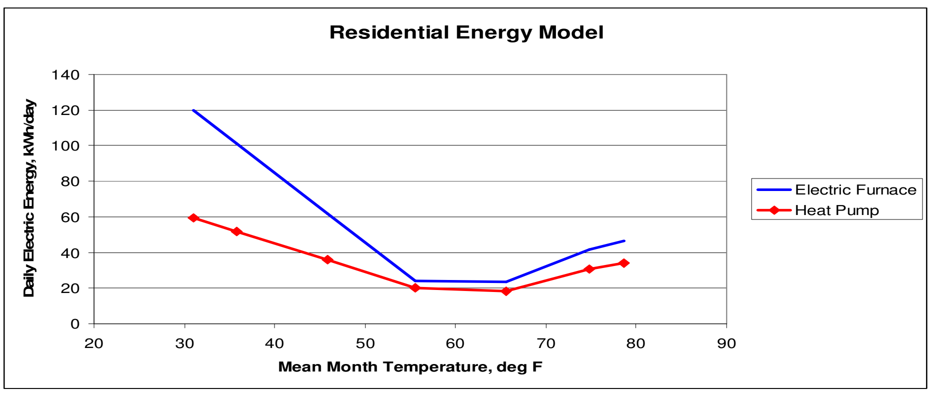

Figure 11. Residential Technical Potential Models

Figure 11 shows the building energy use model for a single average building in the residential sector. In an energy use model of this sort, the line designated as the model specifies the average daily electric usage given a particular average monthly outdoor temperature. The model can then be changed to represent physical changes to the building. Typically these models will be used to estimate the normal annual energy use by evaluating the model at each of the average monthly temperatures in a normal year.

In this illustration, the blue line is the current building energy performance model of a residential customer with an electric furnace. It shows a minimum electric energy use of about 23 kWh per day when the mean month temperature is in the 55-65°F range. In this temperature range, the building is neither heating nor cooling so this minimum is taken as the base load usage including lights, electronics, refrigeration, and all other electricity uses. As it gets colder, the electric usage for heating increases to about 120 kWh per day when it is on average 30°F outside. As the monthly temperature increases in the summer, the energy usage for cooling increases until it is about 50 kWh per day when the average monthly temperature is 80°F.

The red line shows what happens as the electric furnace is replaced by a heat pump and more efficient showerheads, lighting, and appliances are used. This more efficient building shows a lower base load energy use due to the efficient showerheads and more efficient lights and appliances. In addition, it shows significantly lower temperature sensitivity due to a more efficient space heating and cooling. In this example, the initial electric energy use of 20,600 kWh per year is reduced to 12,500 kWh per year. As is evident in Figure 11, most of the savings are associated with the improved heating efficiency.

Note in Figure 11 that for purposes of illustration, the model is expressed for a single average residential building. Expressed thus, as single building performance, the technical potential models can be readily collaborated by reference to only a few single building case studies. However, the subsequent estimate of technical potential has been expressed as a model of the whole population for convenience in the calculations.

Residential Technical Potential

There is a well developed community of interest and capability directed at residential space heat and water heating efficiency. In most retrofit programs, heating efficiency is approached in the same treatment from its three logical avenues: better thermal conversion and distribution efficiency, lower thermal and infiltration losses, and better controls. The water heating savings potential is made up of savings from lower flow fixtures and lower tank standby losses.

One of the largest components of the potential is the use of a higher thermal conversion efficiency afforded by efficient heat pumps and air conditioners coupled to a leak tested duct system. The next largest component is lighting savings followed closely by the improved thermal shell of the structure and hot water heating savings.

Commercial Technical Potential

These buildings have more complex controls than typical residential applications. Usually, there will be a boiler. Often there will be a designated energy manager. This type of situation has been the objective of energy management contractors because there are large enough energy flows to create significant dollar savings.

The largest elements of savings for this group is associated with improved lighting efficiency and improved controls. The thermal integrity of the shell in this group is subject to improvement especially with respect to infiltration.

Total Technical Potential

Ultimately, all the diverse improvements to residential and commercial building energy use resolve into a change in base load and a change in the temperature slope. Figure 12 shows the model of the aggregated residential and commercial electric energy use in blue, and the model of the same population with all technical savings options employed in red.

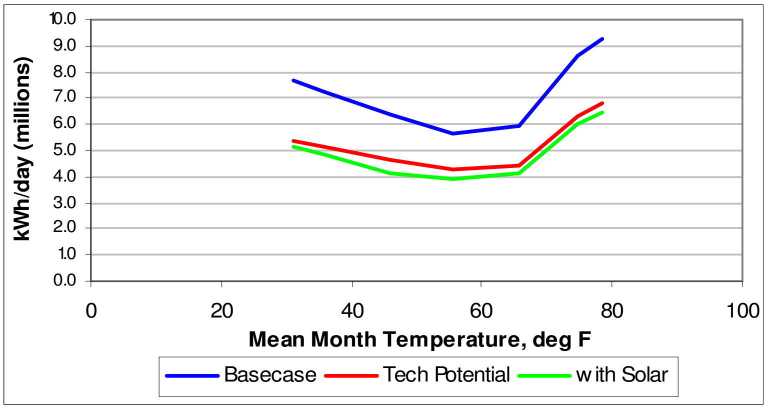

Figure 12. Technical Potential by Temperature

Figure 12 shows the effect of applying maximum reasonable improvements to every residential and commercial building. This reasonably aggressive application of efficiency technology leads to a technical potential with a 28 percent reduction in electric energy use.

The green line in Figure 12 shows the even lower energy use, representing 36 percent reduction. This line corresponds to the addition of a maximum application of solar thermal and solar electric technology. This line represents a very aggressive application of solar technology, with solar water heat on half the buildings and a 2 kW solar electric array on one-third of the buildings.

It should be noted that solar electric technology is technically fully mature. In principle, it could be maximally applied without regard for cost to create a technical potential savings of 100 percent. While this argument is technically accurate, we have resisted carrying the argument this far. Nevertheless, the solar potential noted here is for a very aggressive solar deployment.

Another perspective on the same technical potential is the energy use per month graph shown in Figure 13.

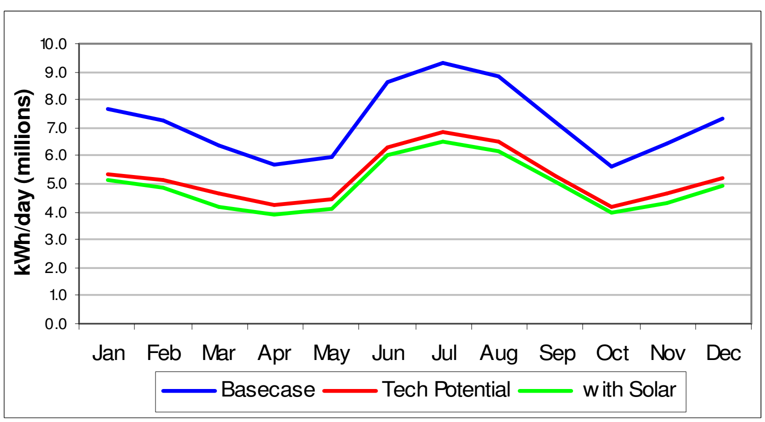

Figure 13. Technical Potential by Month

For an electric utility the second aspect of the technical potential pertains to changes in demand proceeding from the efficiency measures. In general, changes in demand will vary from hour to hour and month to month. We have estimated an hourly demand curve for each month for the base case and for the technical potential case. Figure 14 shows the hourly demand curves for July when the demand savings are greatest; while Figure 15 shows January when the hourly demand savings are the least.

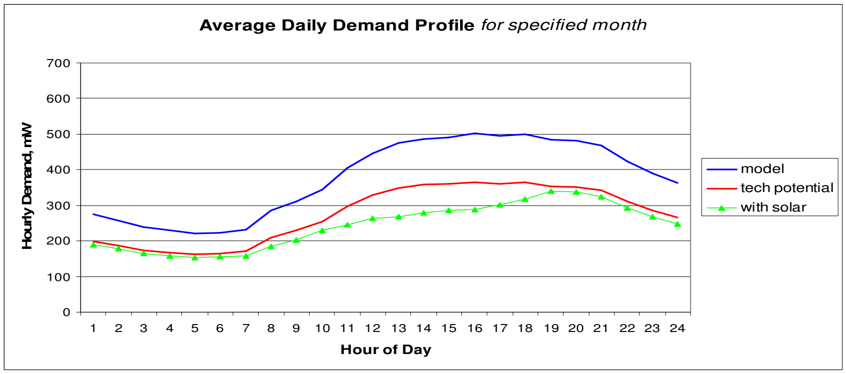

Figure 14. Technical Potential for Demand Reduction – July

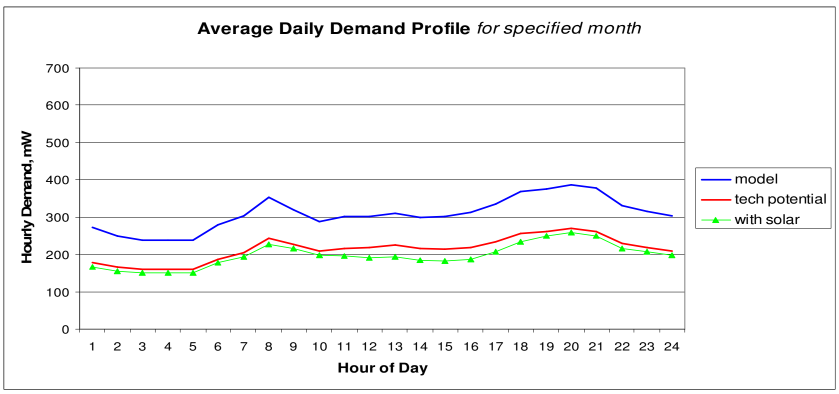

Figure 15. Technical Potential for Demand Reduction – January

A summary of the technical potential is presented in Table 14 below. Our analysis of technical potential shows that it is technically possible to cut usage and demand significantly. However, these estimates are not realistic estimates of actual reductions because they are unconstrained by market, behavioral and budget considerations.

Table 14. Summary of Technical Potential

Case	Total Energy Use (MWh/year)	Technical Potential		
		Energy Savings (%)	Average July Peak Demand Savings (MW)	Energy Savings (MWh/year)
Base Case	2,624,500		NA	
Technical Potential Case	1,883,800	28%	114	740,700
Technical Potential w/Solar	1,688,900	36%	170	935,600

Source: Analysis of monthly usage data and applicable technologies.

Conservation Measure Assessment

In order to evaluate technologies for their potential in electric DSM programs it is necessary to compile detailed information at the ECM level of detail. An ECM is a device or action that causes a drop in energy usage. The objective of ECM assessment or screening is to determine the likely set of cost effective measures which can then be used to populate DSM programs that deliver savings through standalone or bundled ECMs. An important by-product of this screening is the information necessary to construct a conservation supply curve for determining economic potential.

Our list of ECM measures and assumptions was developed through an integrated approach that combined an extensive review of industry literature, the detailed analysis of Vectren loads described earlier, and our own expert opinion. These assumptions and sources are documented in the appendixes. The assumptions required to calculate ECM cost effectiveness are shown in Table 15 for residential and Table 16 for commercial. Each of these tables uses a standard layout to present the assumptions used to calculate real levelized cost (RLC) per kWh. A discussion of the cost effectiveness approach used to evaluate ECMs follows these two tables.

Descriptions of the columns presented in Table 15 and Table 16 are presented below.

End Uses	Energy Conservation Measures are grouped by the end-use they address.
ECM Description	Brief description of the ECM. See Appendix D and Appendix E for a more detailed description.
Application	For residential measures only, describes the segment of residential sector where the ECM assumptions are applicable. For example, the same ECM may have different assumptions for single family and multifamily applications.
ECM Reference	Code to uniquely identify an ECM in this project.
Annual kWh Savings	Annual kWh savings per customer site.
Annual Therm Savings (Table 15 only)	Annual therm savings per customer site when ECM involves a technology with dual fuel impacts. Not applicable to large buildings.
Incremental Cost	The incremental cost of installing the ECM at the typical customer site, including any incremental equipment and labor expenses. Note: "Incremental" refers to the costs over and above what would have been expended for a standard efficiency measure. All costs are in 2006 dollars.
Annual O&M	Annual operation and maintenance expenses over and above the O&M expenses incurred for standard efficiency measures. Most ECMs have zero incremental O&M expenses.
Measure Life	The average expected life of the measure.
Real Levelized Cost ($/kWh)	The Installed cost expressed as a constant annual payment over the life of the measure and then divided by the annual savings. Real levelized cost provides a way of comparing ECMs with different attributes such as measure life on the same scale.

Table 15. DSM Technology Assessment, Residential

End Uses	ECM Description	ECM Reference	Application	Annual kWh Savings	Annual Therm Savings	Incremental Cost (dollars)	Annual O&M	Measure Life	Real Levelized Cost ($/kWh)
1. Customer-Sited Generation	Solar Photovoltaic	R-1	All	2,200	NA	16,000	10	25	0.6063
2. Residential Space Conditioning	Resist to Seer 13 Heat Pump	R-2	Elec SF	6,000	NA	10,000	20	10	0.2363
	Resist to Seer 13 Heat Pump	R-3	Elec MF	4,800	NA	10,000	20	10	0.2953
	SEER 8 to Seer 13 CAC	R-4	Gas SF	1,400	NA	3,500	20	10	0.3637
	SEER 8 to Seer 13 CAC	R-5	Gas MF	1,200	NA	3,500	20	10	0.4243
	Refrig Charge/Duct Tune-Up	R-6	Elec	1,200	NA	300	NA	5	0.0603
	Refrig Charge/Duct Tune-Up	R-7	Gas	300	47	300	NA	5	0.1592
	SEER 13 to Seer 15 Heat Pump	R-8	SF Elec New	800	NA	1,000	20	20	0.1393
	SEER 13 to Seer 15 Heat Pump	R-9	MF Elec New	700	NA	1,000	20	20	0.1593
	SEER 13 to Seer 15 CAC	R-10	SF Gas New	400	NA	800	20	20	0.2330
	SEER 13-Seer 15 CAC	R-11	MF Gas New	350	NA	800	20	20	0.2662
	Efficient Window AC	R-12	All	200	NA	150	10	13	0.1377
	Cool Attic	R-13	Elec	400	NA	500	NA	12	0.1540
	EE Windows	R-14	Elec	1,334	NA	2,500	NA	25	0.1550
	Programmable Thermostats	R-15	Elec	500	NA	120	NA	10	0.0335
	Ceiling Insulation (R6-R30)	R-16	Elec	1,800	NA	750	NA	25	0.0345
	Ceiling Insulation (R6-R30)	R-17	Gas	300	100	750	NA	25	0.0910
	House Sealing using Blower Door	R-18	Elec	1,000	NA	300	NA	10	0.0419
	House Sealing using Blower Door	R-19	Gas	200	42	300	NA	10	0.0964
	Ground Source Heat Pump	R-20	Elec	3,300	NA	7,000	20	25	0.1816
	Wall Insulation (R3-R11)	R-21	Elec	2,100	NA	1,400	NA	25	0.0552
	Wall Insulation (R3-R11)	R-22	Gas	400	100	1,400	NA	25	0.1926
	Solar Siting/Passive Design	R-23	New Elec	1,500	NA	500	NA	25	0.0276
	Energy Star Manufactured Home	R-24	New	3,000	NA	1,500	NA	25	0.0414
	Energy Star Construction	R-25	New Elec	3,555	NA	2,017	NA	25	0.0469
3. Load Management	Eliminate Old Refrigerators	R-26	All	700	NA	100	NA	5	0.0345
	Set Back HVAC	R-27	All	1,000	NA	5	NA	2	0.0028
4. Residential Appliances	Energy Star Clothes Washers	R-28	All	400	NA	400	NA	18	0.0966
	Energy Star Dish Washers	R-29	All	75	NA	50	NA	10	0.0932
	Energy Star Refrigerators	R-30	All	100	NA	200	NA	18	0.1931
	Pool Pumps	R-31	All	648	NA	180	NA	10	0.0388
5. Residential Lighting	Compact Fluorescent	R-32	All	800	NA	150	NA	5	0.0452
	Daylighting Design	R-33	New Elec	750	NA	500	NA	25	0.0552
	Occupancy Controlled Outdoor	R-34	All	250	NA	100	NA	10	0.0559
6. Water Heating	Tank Wrap, Pipe Wrap, Water Temp Setpoint	R-35	All	200	NA	50	NA	10	0.0349
	Low Flow Fixtures	R-36	All	500	NA	25	NA	10	0.0070
	Heat Pump Water Heaters	R-37	All	2,000	NA	2,500	NA	18	0.1207
	Tankless Water Heaters	R-38	All	400	NA	1,500	NA	18	0.3621
	Solar Water Heaters	R-39	All	2,500	NA	6,000	20	25	0.2066
	Efficient Plumbing	R-40	New Elec	500	NA	500	NA	25	0.0827

Note: Dollar amounts are expressed in 2006 dollars.

Table 16. DSM Technology Assessment, Commercial

End Uses	ECM Description	ECM Reference	Annual kWh Savings	Incremental Cost (dollars)	Annual O&M	Measure Life	Real Levelized Cost ($/kWh)
1. Customer-Sited Generation	Solar Photovoltaic	C-1	44,000	320,000	25	25	0.6023
2. C&I Space Conditioning	Small HVAC Optimization and Repair	C-2	7,000	1,417	50	5	0.0560
	Commissioning - New	C-3	14,000	5,191	NA	5	0.0895
	Re/Retro-Commissioning	C-4	14,000	5,191	NA	5	0.0895
	Low-e Windows 1500 ft2 New	C-5	11,200	4,500	NA	25	0.0332
	Low-e Windows 1500 ft2 Replace	C-6	11,200	30,000	NA	25	0.2216
	Premium HVAC Equipment	C-7	4,200	1,947	250	15	0.1091
	Large HVAC Optimization and Repair	C-8	4,200	1,436	NA	5	0.0825
3. Design	Integrated Building Design	C-9	28,000	9,486	NA	25	0.0280
4. Motors & Drives	Electrically Commutated Motors	C-10	2,800	935	NA	15	0.0357
5. Data Processing	Efficient AC/DC Power	C-11	2,100	156	NA	5	0.0179
	Network Computer Power Management	C-12	2,800	322	NA	2	0.0633
6. Lighting	New Efficient Lighting Equipment	C-13	14,000	3,682	NA	18	0.0254
	Retrofit Efficient Lighting Equipment	C-14	14,000	4,603	NA	18	0.0317
	LED Exit Signs	C-15	1,470	270	NA	10	0.0257
	LED Traffic Lights	C-16	5,000	2,000	NA	10	0.0559
	Perimeter Daylighting	C-17	4,200	3,568	NA	18	0.0820
7. Water Heating	Low Flow Fixtures	C-18	6,000	1,000	NA	10	0.0233
	Solar Water Heaters	C-19	2,500	6,000	20	25	0.2066
	Heat Pump Water Heaters	C-20	2,000	2,500	20	18	0.1307
8. Cooking and Laundry	Energy Star Hot Food Holding Cabinet	C-21	4,100	1,100	NA	15	0.0287
	Energy Star Electric Steam Cooker	C-22	2,200	5,000	NA	15	0.2433
	Pre-Rinse Spray Wash	C-23	7,000	177	NA	15	0.0027
	Restaurant Commissioning Audit	C-24	14,000	1,300	NA	5	0.0224
9. Refrigeration	Grocery Refrigeration Tune-up	C-25	14,000	2,654	NA	5	0.0457
10. Other	VendingMiser®	C-26	1,000	215	NA	10	0.0300
Note: Dollar amounts are expressed in 2006 dollars.							

Cost Effectiveness[9]

Cost effectiveness of each ECM is measured by the real levelized cost per kWh. Real levelized cost expresses the total incremental cost and any annual operation and maintenance expense as a constant annual payment over the life of the measure divided by annual savings.[10] The advantage of RLC is that it normalizes for differences in measure life and other ECM attributes to provide a means of comparing ECMs in terms of their relative cost effectiveness. As will be demonstrated in the next section, RLC also provides a convenient method for determining economic potential.

Assumptions on average annual savings, installed cost and measure life come from many sources, including the energy modeling work conducted as part of this project using segment-specific billing data for Vectren South customers.[11] In other words, our annual savings estimates are linked and consistent with the modeled loads reported in the Market Assessment section of this report. Incremental cost for the ECM screening step includes the incremental costs of installing the measure. Depending on the measure, this could be simply the cost of the high

[9] Two types of cost effectiveness analysis are presented in this report. This section deals only with technology assessment using levelized cost. More comprehensive analysis is required at the program level. See Appendix B in the final report for a discussion of each type of cost effectiveness analysis.
[10] The formula for this calculation is presented in Appendix B. A discount rate of 6.6% was used based on Vectren's weighted cost of capital. The total incremental cost of measures with both electric and gas savings has been prorated between the two fuels. The gas share of cost is limited to $0.50 per therm (real levelized).
[11] The modeling is described in more detail in Appendix A and ECM assumptions are described in Appendix D.

efficiency measure over and above the standard efficiency option. In other cases installation labor and site modifications may also be required for the high efficiency model and, hence, would be included in incremental cost. At this stage of analysis, ECM screening, the costs do not include the program costs or the cost of participant recruitment.

It should be pointed out that program design may have an impact on some of the ECM screening assumptions. An owner-installed delivery option, for example, may result in lower installed cost than a contractor installation but come at the possible loss of useful measure life. Such tradeoffs are important program design considerations but beyond the scope of ECM analysis. For the purposes of this stage of analysis the ECM assumptions provide a reasonable starting point for our assessment of energy efficiency options.

Energy conservation measures in Table 15 and Table 16 have been grouped by major end-use categories. Measures considered in the screening include combined heat and power (cogeneration) and solar electric. In principle these measures can provide very large energy savings, but they are usually not cost effective. They are included in this screening to keep a broad perspective in the analysis and to reach toward a more full understanding of the possibilities and physical limits of potential.

Cost Effectiveness Rankings

The residential and commercial measures are ranked by cost effectiveness in Table 17 and Table 18, respectively. Descriptions of the columns in these tables are presented below.

ECM Reference	Unique ECM reference number.
ECM Description	Brief description of the ECM. See Appendix D and Appendix E for a more detailed description.
Application	For residential measures only, describes the segment of residential sector where the ECM assumptions are applicable. For example, the same ECM may have different assumptions for single family and multifamily applications.
Real Levelized Cost ($/kWh)	The incremental cost and annual O&M expressed as a constant annual payment over the life of the measure and then divided by the annual savings. Entries in the ECM ranking table are sorted from least cost (lowest RLC) to highest cost measures.
Annual Savings Per Site (kWh)	Annual kWh savings per customer site.
Potential Sites	An estimate of the potential number of customer sites that could have the ECM installed without regard to cost. See Appendix D and Appendix E for more information on determining this estimate for each measure.
Potential Annual Savings (MWh)	Total annual energy savings potential in MWh derived by multiplying the annual savings per site by the number of potential sites.

It is apparent in Table 17 that the most cost effective measures are retrofit measures applied to electrically heated residences, and some efficient appliances (notably washers and lighting). Some measures with large technical potential are shown to have relatively high cost (e.g. replacing resistance heat with a heat pump).

Table 17. Ranked Measures, Residential

ECM Reference	ECM Description	Application	Real Levelized Cost ($/kWh)	Annual Savings per Site (kWh)	Potential Sites	Potential Annual Savings (MWh)
R-27	Set Back HVAC	All	0.003	1000	13,420	13,420
R-36	Low Flow Fixtures	All	0.007	500	33,550	16,775
R-23	Solar Siting/Passive Design	New Elec	0.028	1500	13,420	20,130
R-15	Programmable Thermostats	Elec	0.034	500	33,550	16,775
R-26	Eliminate Old Refrigerators	All	0.034	700	26,840	18,788
R-16	Ceiling Insulation (R6-R30)	Elec	0.034	1800	6,710	12,078
R-35	Tank Wrap, Pipe Wrap, Water Temp Setpoint	All	0.035	200	33,550	6,710
R-31	Pool Pumps	All	0.039	648	5,368	3,478
R-24	Energy Star Manufactured Home	New	0.041	3000	13,420	40,260
R-18	House Sealing using Blower Door	Elec	0.042	1000	6,710	6,710
R-32	Compact Fluorescent	All	0.045	800	67,100	53,680
R-25	Energy Star Construction	New Elec	0.047	3555	13,420	47,708
R-21	Wall Insulation (R3-R11)	Elec	0.055	2100	6,710	14,091
R-33	Daylighting Design	New Elec	0.055	750	13,420	10,065
R-34	Occupancy Controlled Outdoor	All	0.056	250	13,420	3,355
R-6	Refrig Charge/Duct Tune-Up	Elec	0.060	1200	13,420	16,104
R-40	Efficient Plumbing	New Elec	0.083	500	13,420	6,710
R-17	Ceiling Insulation (R6-R30)	Gas	0.091	300	13,420	4,026
R-29	Energy Star Dish Washers	All	0.093	75	46,970	3,523
R-19	House Sealing using Blower Door	Gas	0.096	200	40,260	8,052
R-28	Energy Star Clothes Washers	All	0.097	400	46,970	18,788
R-37	Heat Pump Water Heaters	All	0.121	2000	4,026	8,052
R-12	Efficient Window AC	All	0.138	200	26,840	5,368
R-8	SEER 13 to Seer 15 Heat Pump	SF Elec New	0.139	800	13,420	10,736
R-13	Cool Attic	Elec	0.154	400	6,710	2,684
R-14	EE Windows	Elec	0.155	1334	6,710	8,952
R-7	Refrig Charge/Duct Tune-Up	Gas	0.159	300	53,680	16,104
R-9	SEER 13 to Seer 15 Heat Pump	MF Elec New	0.159	700	13,420	9,394
R-20	Ground Source Heat Pump	Elec	0.182	3300	2,684	8,857
R-22	Wall Insulation (R3-R11)	Gas	0.193	400	6,710	2,684
R-30	Energy Star Refrigerators	All	0.193	100	80,520	8,052
R-39	Solar Water Heaters	All	0.207	2500	6,710	16,775
R-10	SEER 13 to Seer 15 CAC	SF Gas New	0.233	400	13,420	5,368
R-2	Resist to Seer 13 Heat Pump	Elec SF	0.236	6000	5,368	32,208
R-11	SEER 13-Seer 15 CAC	MF Gas New	0.266	350	13,420	4,697
R-3	Resist to Seer 13 Heat Pump	Elec MF	0.295	4800	1,342	6,442
R-38	Tankless Water Heaters	All	0.362	400	2,684	1,074
R-4	SEER 8 to Seer 13 CAC	Gas SF	0.364	1400	20,130	28,182
R-5	SEER 8 to Seer 13 CAC	Gas MF	0.424	1200	1,342	1,610
R-1	Solar Photovoltaic	All	0.606	2200	46,970	103,334

Note: Dollar amounts are expressed in 2006 dollars.
* Refrig Charge/Duct Tune-Up refers to HVAC Refrigerant Charge and Duct Tune-Up.
** Resist to SEER 13 Heat Pump refers to replacing an electric resistance furnace with an efficient heat pump.

Another energy saver with poor cost effectiveness is the replacement of poorly performing central air conditioners on a gas heated residence by more efficient ones. This poor cost effectiveness relates to the high initial cost of the equipment, and to the relatively low cooling savings. Generally measures that pertain to efficient new construction are reasonably cost effective because ECMs can be installed at the time of construction with low incremental cost impacts.

The commercial measures are ranked in Table 18 by cost effectiveness. As with residential, measures pertaining to building efficient new stock are generally cost effective. Also, measures associated with tuning and properly maintaining HVAC and refrigeration equipment are generally cost effective.

The real "stand out" measures are the lighting measures that are both cost effective and large. Another favored category is small HVAC Optimization and Repair; it is also cost effective and large. As in the case of residential, the least cost effective measures are efficient glazing, solar water heat and solar photovoltaic.

Table 18. Ranked Measures, Commercial

ECM Reference	ECM Description	Real Levelized Cost ($/kWh)	Annual Savings Per Site (kWh)	Potential Sites	Potential Annual Savings (MWh)
C-23	Pre-Rinse Spray Wash	0.003	7,000	329	2,303
C-11	Efficient AC/DC Power	0.018	2,100	2,820	5,922
C-24	Restaurant Commissioning Audit	0.022	14,000	1,410	19,740
C-18	Low Flow Fixtures	0.023	6,000	470	2,820
C-13	New Efficient Lighting Equipment	0.025	14,000	470	6,580
C-15	LED Exit Signs	0.026	1,470	3,995	5,873
C-9	Integrated Building Design	0.028	28,000	470	13,160
C-21	Energy Star Hot Food Holding Cabinet	0.029	4,100	329	1,349
C-26	VendingMiser®	0.030	1,000	1,175	1,175
C-14	Retrofit Efficient Lighting Equipment	0.032	14,000	3,995	55,930
C-5	Low-e Windows 1500 ft2 New	0.033	11,200	470	5,264
C-10	Electrically Commutated Motors	0.036	2,800	2,820	7,896
C-25	Grocery Refrigeration Tune-up	0.046	14,000	188	2,632
C-16	LED Traffic Lights	0.056	5,000	940	4,700
C-2	Small HVAC Optimization and Repair	0.056	7,000	3,290	23,030
C-12	Network Computer Power Management	0.063	2,800	470	1,316
C-17	Perimeter Daylighting	0.082	4,200	1,410	5,922
C-8	Large HVAC Optimization and Repair	0.082	4,200	3,525	14,805
C-3	Commissioning - New	0.089	14,000	470	6,580
C-4	Re/Retro-Commissioning	0.089	14,000	3,525	49,350
C-7	Premium HVAC Equipment	0.109	4,200	940	3,948
C-20	Heat Pump Water Heaters	0.131	2,000	1,175	2,350
C-19	Solar Water Heaters	0.207	2,500	1,175	2,938
C-6	Low-e Windows 1500 ft2 Replace	0.222	11,200	1,410	15,792
C-22	Energy Star Electric Steam Cooker	0.243	2,200	329	724
C-1	Solar Photovoltaic	0.602	44,000	1,175	51,700
Note: Dollar amounts are expressed in 2006 dollars.					

Economic Potential

Economic potential is defined as the total energy savings available at a specified long term avoided cost of energy. Technologies with levelized costs that are lower than the avoided cost of energy are included in estimates of economic potential. A conservation supply curve provides a flexible framework for presenting economic potential that reflects the direct relationship between the long term marginal cost of energy supply and conservation potential. Unlike point estimates, conservation supply curves show the economic potential at several levels of marginal supply cost.

The conservation supply curve for residential is shown in Figure 16 which shows the cumulative kWh savings from all measures listed in Table 17 with a levelized cost less than the corresponding point on the graph. For example, there are approximately 250,000 MWh of annual savings available at a cost $0.05 per kWh or less. Estimated residential economic potential increases to 300,000 MWh annually at a cost of $0.06 per kWh or less.

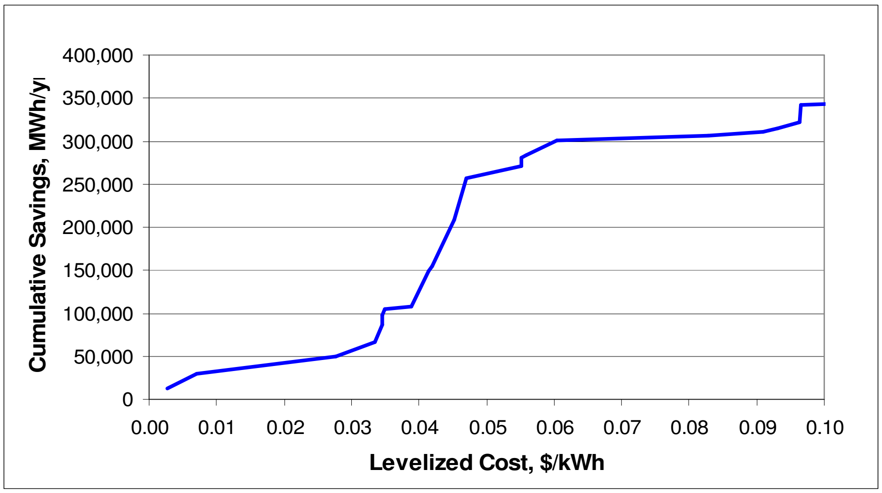

Figure 16. Residential Conservation Supply Curve

Since Figure 16 is constructed from the information in Table 17, it is possible to see exactly which measures are responsible for changes along the conservation supply curve. If marginal supply costs increase from $0.04 to $0.05 per kWh, for example, we would pick up 150,000 MWh annually with efficient new construction and compact fluorescents responsible for most of the increase. Vectren South's marginal cost of supply depends on the load shape and longevity of savings.[12] Using $0.06 per kWh as an approximate average, residential economic potential is estimated at 300,000 MWh annually.

The conservation supply curve for commercial is shown in Figure 17 and, like residential, represents an alternate format for the information in Table 18.

[12] As will be evident in the Cost Effectiveness section of this report, marginal cost of supply vary by time of day and season and the amount of avoided peak load. Since different measures have different load shapes, they also have different marginal supply cost. When measures are grouped into programs, these differences are reflected in the breakeven marginal cost of energy supply for that program which represents the cost that the program must fall under in order to be cost effective.

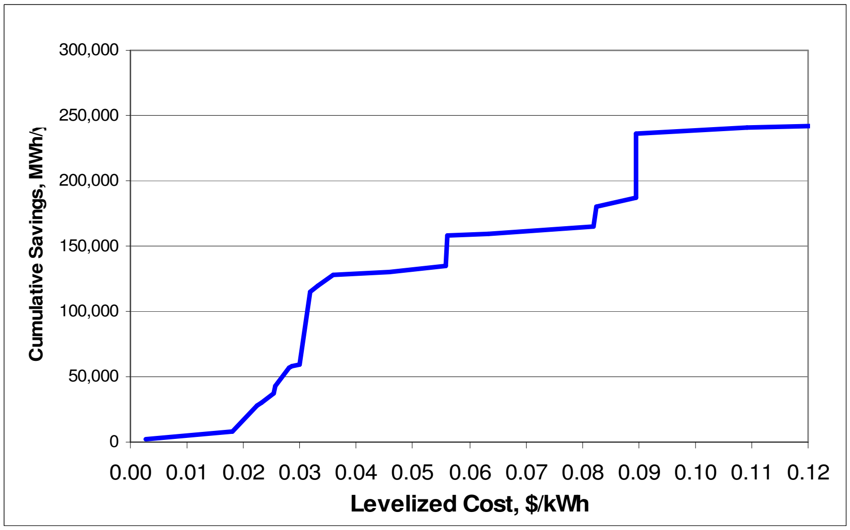

Figure 17. Commercial Conservation Supply Curve

Figure 17 shows that most of the commercial efficiency savings are available at levelized costs of less than $.09 per kWh. One characteristic of the commercial conservation supply curve is the relatively large amount of energy savings available at less than $0.04 per kWh. Using an average marginal cost of $0.06 we estimate annual economic potential in the commercial sector to be approximately 160,000 MWh.

Both the residential and commercial conservation supply curves show a diminishing return as the levelized cost rises above $.10 per kWh. About one-half of the full technical potential is available at levelized costs of less than $.06 per kWh. Our estimate of total economic potential in both segments is 460,000 MWh annually.

Further perspective on the residential and commercial savings is developed by classifying the technologies by type of measure and cost. Figure 18 and Figure 19 show the residential and commercial savings potential, respectively, classified by type of measure and cost. Figure 18 shows that about half of the residential savings costing less than $.06/kWh are associated with efficient new construction and appliances (efficient lighting). The other half is associated with site modifications such as efficient showerheads and ceiling insulation. The more expensive savings predominantly involve the more comprehensive site modifications, such as, wall insulation and higher efficiency heat pumps and central air conditioners.

In Figure 18 the savings noted as Life Style consist of voluntary usage reductions including thermostat set back and elimination of old or second refrigerators.

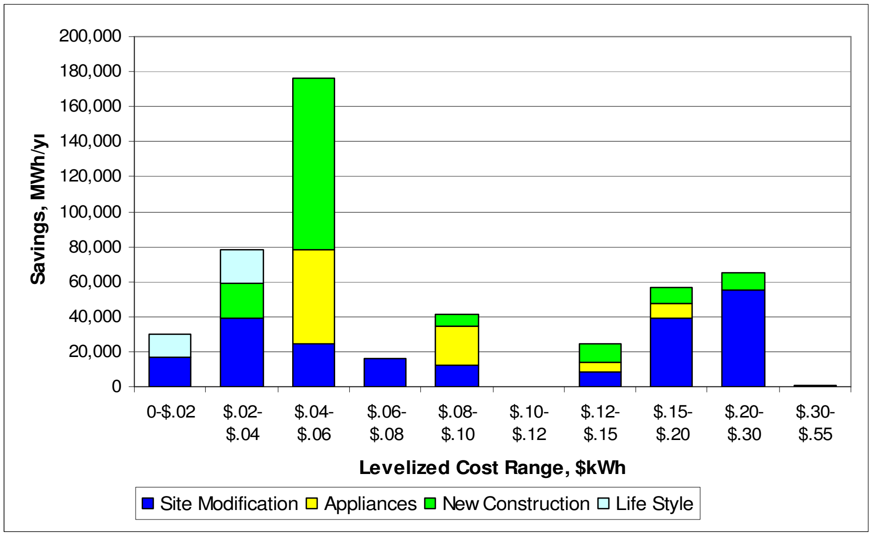

Figure 18. Residential Savings by Type and Cost

On the other hand, in Figure 19 note that most of the commercial savings costing less than $0.06 are associated with site modifications, principally more efficient lighting and improved HVAC maintenance. Commercial site modifications consist of retrofit lighting and HVAC maintenance which require a higher level of site effort than residential site modifications.

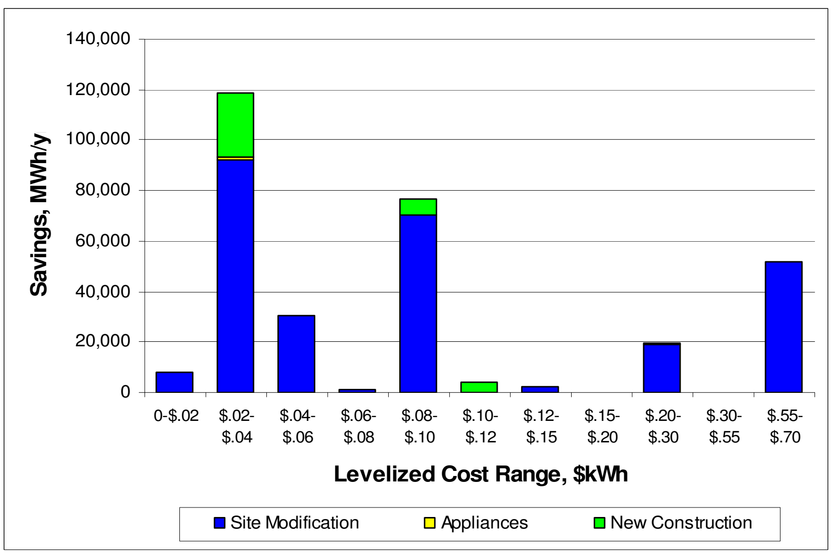

Figure 19. Commercial Savings by Type and Cost

RECOMMENDED DSM PROGRAM PLANS

Various DSM programs designed to capture the cost-effective opportunities from the energy conservation measures (ECMs) identified earlier in this report were considered for implementation. Development of DSM program plans involves combining the technological elements of the ECMs addressed by the program with program implementation and evaluation assumptions. All of these elements come together in the DSM program plans. Once preliminary program plans were in place, they were analyzed for their cost effectiveness. Cost effectiveness results are presented for all of the programs considered as part of this study in the next section of this report.

Those programs that were found to be cost effective from a Total Resource Cost (TRC) perspective are recommended for implementation along with the low income weatherization program. Detailed program plans for these recommended programs are included in this section of the report. Plans for DSM programs not recommended because of cost effectiveness considerations are presented in Appendix C. Table 19 provides a summary of all the DSM programs considered and the technologies that would be promoted to the associated market segments.

Each of the program plans presented in this section contains information on program design, participation, expected savings and an implementation budget. This information is organized as follows:

- Description of program design including measures and incentives. This description leads off each program plan.
- Rationale for Program. A brief description of the logic for the program including market and technology considerations.
- Average Annual Expected Savings. Presents the number of participants and expected annual kWh and kW savings through the first five years of program operations.
- Marketing Plans. Provides a description of the suggested marketing efforts specific to the program.
- Detailed Budget Plans. Annual program implementation budgets through the first five years of program operations. Costs for incentive payments, startup expenses, program administration, and evaluation costs.

Prior to presenting the detailed program plans, a description of recommended customer communication effort is included. The budget for this communications effort is included in the discussion below but is not allocated back to the budgets and cost-effectiveness of individual programs. Instead we show the impact of overarching communications spending on the overall cost effectiveness results in the Program Cost Effectiveness section, beginning on page 75.[13]

[13] Allocation of general education expenses back to programs is arbitrary and may involve circular logic if the arbitrary allocation algorithm causes a program to become non-cost effective requiring the reallocation of these expenses over the remaining cost effective programs.

Table 19. Program Recommendations and Technology Groupings

#	Program Name	Rec.	Target Market	End-Uses	DSM Technologies
Residential and Commercial					
1	Residential and Small Commercial PV	No	Small PV Applications	PV and non-recreational water heating	Photovoltaic
2	Residential and Commercial Direct Load Control	Yes	Residential and Commercial with Compatible Loads	Cooling, Water Heaters, Pools	Direct Load Control
Residential					
3	Energy Star Lighting	Yes	All residential	Lighting	Bulbs & Fixtures
4	Energy Star Appliances and Programmable Thermostats	Yes	All residential	Dishwashing, Clothes washing, Cooling Refrigeration	Household Appliances, Programmable Thermostat
5	Energy Efficient Pool Pumps	No	Residential with pools	Swimming pools	Pool Pumps
6	Old Refrigerator Pick-Up and Recycling	Yes	All residential	Refrigeration	Remove Load
7	Cool Attics	No	Residences with heating/cooling ducts or cooling equipment in attics	Cooling	Radiant Barrier Insulation Ventilation
8	Heat Pump Tune-Up	No	Residential with Heat Pump	Heating, Cooling	Tune-up
9	Low and Moderate Income Weatherization Enhancement	Yes	All Residential, Income Limited	Heating Cooling Health & Safety	Building shell and related Weatherization Measures
10	Energy Star Residential New Construction	Yes	New Stick-Built Homes	All end-uses	Home Constructed to ES standards
11	Energy Star Residential Manufactured Home	No	New Manufactured Homes	All end-uses	Home Constructed to ES standards
12	Flow Efficient Fixtures	Yes	Electric Water Heat Customers	Water Heat	Showerheads, Aerators
Commercial					
13	Commercial Incentives	Yes	All Commercial	Lighting, Cooling, Motors, Refrigeration, Vending	EE lights, motors, refrigeration, VendingMisers®
14	Commercial New Construction	Yes	New Commercial	Heating, Cooling	Building Measures
15	Controls, Lights, and Signs	Yes	Motels, Hotels, Traffic Lights	LEDs, AC Controllers, Occupancy Sensors	Signals, LEDs, Programmable Thermostats, Lighting, Sensors

Energy Efficiency Marketing and Communications

In addition to the recommended DSM programs, we are also recommending an Energy Efficiency Marketing and Communications effort to support energy efficiency objectives. Energy Efficiency Marketing and Communications includes an overarching cross-program effort to build customer awareness of energy-efficiency technologies and practical possibilities for conserving energy and reducing electrical demand. A first goal is building awareness. A second goal is communicating Vectren's support of customer energy efficiency needs. A third goal is communicating resources Vectren will provide to help customers to become more energy-efficient, including information on the specific residential and commercial energy-efficiency programs described in this section of the report. Marketing, communications and promotion are the key to attaining participation in each of the DSM programs.

This effort will provide funding for cross-program public education activities, outreach, marketing and promotion to raise awareness of the benefits and methods of improving energy efficiency in homes and commercial businesses. Beyond energy efficiency education an objective will be to motivate participation in the programs.

This communications effort differs from typical DSM programs in that there are no estimates of participants, savings, costs and cost-effectiveness tests. Such estimates are considered impractical for these types of overarching efforts to educate consumers. The California Standard Practice Manual (p. 5) addresses this issue as follows:

> *"For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts."*

Types of activities that will be included in this effort are:

- General mass media campaign for the public on pending gas price increases and ways to help control utility bills through energy efficiency measures and actions.
- Development (update) of the Vectren South website to include the latest energy efficiency information for residential and commercial use.
- Targeted educational campaign for businesses to support the programs.
- Targeted educational campaign for residences to support the programs.
- Targeted training and educational program for trade allies.
- Distribution of federal Energy Star and other national organization materials in the service territory.

Targeted educational efforts toward segments of the market may also be appropriate for these general purpose public education and awareness efforts. For example, builder education through the Home Builders Association and specific educational offerings through the Purdue Technology Center may provide opportunities to leverage local expertise and funding.

Rationale for Campaign

The key to greater energy efficiency is convincing the families and businesses making housing, appliance and equipment purchases to opt for greater energy efficiency. The first step in convincing the public and businesses to invest in energy efficiency is to raise their awareness.

Since nearly all of Vectren's programs will be new to the marketplace, it is imperative that a broad public education and outreach campaign be launched to not only raise awareness of what consumers can do to save energy and control their energy bills, but to prime them for participating in the various DSM program offerings that will be implemented over the next several months following regulatory approval. Without a significant public outreach campaign, it would be difficult to achieve the levels of participation represented in this Plan as reasonable targets for the programs.

This effort will address markets by sector–general public, businesses and institutions, trade allies and school children and teachers. There would be no "participants" per se, although for direct contact activities, feedback forms and other means of identifying those exposed to the educational materials can be developed.

Detailed Budget Plans

The various educational elements are adapted from the successful New York program, which is carried out in partnership with the federal Energy Star Program. The general public education or Awareness-Raising Program will use the Energy Star ratings as a platform for its "buy energy efficient appliances" message. A breakdown of budgetary items for the program elements described is shown in Table 20. The budget item and amounts should be used to generate ideas for implementation. We would expect budget allocation decisions between media channels and specific media buys to be best made by program implementers. It may be desirable, for example, to front load spending in the early years of program implementation. Accordingly, the budget figures in Table 20 are for the full five-year period rather than try to estimate the timing of expenses.

Table 20. Public Education Budget Items and Amounts

Budget Item	**Budget (5-year total)**
Produce Public Service Announcements	$ 100,000
Develop an Energy Star Promotional Program	$ 320,000
Develop and Printing of Literature	$ 100,000
In-House Production of Print Material	$ 60,000
Quarterly Meetings with Trade Allies and Business Leaders	$ 50,000
Purchasing Promotional Items	$ 70,000
Educational Pages on Website	$ 130,000
TV, Radio and Print Advertising	$ 1,200,000
Total 5-Year Budget	**$ 2,030,000**

Performance Tracking

General public awareness questions will be added to ongoing corporate satisfaction surveys (typically conducted by Customer Service staffs at most utilities).

Residential and Commercial Programs

Program 2. Residential and Commercial Direct Load Control Program

The Residential Direct Load Control (DLC) program is a continuation of the Vectren's existing residential load control program, which is of high quality and notable for its participation and program longevity. The program provides remote dispatch control for residential central cooling, electric water heating, and pool pumps through radio controlled load management receivers (LMR). The Vectren Commercial Direct Load Control program is parallel in technology, however participation has declined; also while incentives for residential and small commercial central cooling units are identical, the incentive for larger commercial units is different.

All homes with central air conditioners or heat pumps deemed compatible with the LMR are eligible to participate in the program. Similarly, all commercial customers with central cooling equipment deemed compatible with the LMR are eligible to participate.

The program involves the installation of an LMR on participating customer's central cooling units (central AC and heat pumps). In addition, the LMR can be installed on electric water heaters where compatible.

Table 21. Measure and Incentive - Residential and Commercial DLC

Measure	Incentive Amount
Switch Installation	$ 144
Annual Bill Reduction	$ 24

For each residential central cooling unit, the program provides a $5 bill credit for each month of participation during the four summer months (June, July, August, and September). A maximum of $20 per year for each participating home is allowed. Additionally, participants who allow control of their electric water heater receive a bill credit of $2 per month of participation during the four summer months, up to $8 per year. The incentive for smaller commercial cooling units is identical to the residential program; for larger units it is $4 per month for each kW reduced.

Cycle strategy for direct load control of central cooling units employs either a 33 percent or 50 percent cycling strategy. The 33 percent cycling strategy is most commonly used. Savings are achieved by cycling compressors off for ten minutes out of every half hour during the cycling period. The cycling is random, reducing the possibility of producing a post-control peak.

For water heaters, load is completely shed, shutting off all units during the cycling period. The cycling period is typically from two to six hours, depending on system needs. Equipment is brought back on-line randomly to prevent production of a post-control peak. Pool pumps have not been actively recruited for many years due to a technology incompatibility.

Rationale for Program

The direct load control program provides a method to decrement system load during summer peak events, as needed. Although conservation programs also reduce load, the advantage of direct load control is that it may be dispatched when needed and has an immediate and sizable effect.

Based on load research conducted by Vectren and on engineering estimates, the estimated peak demand reductions for central cooling units are 0.73, 0.92 and 1.10 kW for cycling strategies of 33, 42, and 50 percent, respectively. The load reduction for each water heater is estimated to be 0.32 kW. The program objective is to reduce coincident peak demand by direct, temporary cycling of central cooling units and by direct shedding of connected water heater loads.

In some years, many load shedding events were called. In 2004, cycling occurred five times, the first on May 19th and the last on August 19th. The Summer Cycler Program was used for a one to five and a half hours per cycling period, with an average duration of 4.05 hours. A cycling strategy of 33 percent was used.[14] In 2004, there were 41,323 residential switches and 2,690 commercial switches in the program; the total cost of the combined residential and commercial program was $1,062,074.

Average Annual Expected Savings

Participation shown in Table 22 is incremental to the existing program participation, which is expected to be maintained. Currently, the program is at somewhat above a participation rate of 40 percent of potential participation. The program is designed to push participation to about 50 percent (only incremental participation is shown in Table 22). The pattern of incremental participation has been designed with a goal of 713 for Year 1. This is an ambitious first year goal, but less than the goals set for the following years. The goal is an additional 1,212 in Year 2, and an additional 1,640 in Year 3. For Years 4 and 5, the goal in each year is an additional 1,783. Year 1 will involve a transition from a near steady-state baseline period in which the goal was maintenance of existing numbers. Not shown, but part of the program expectation is that customers who leave the program will be replaced to bring the total participation at the end of Year 5 to 7,131 participants above baseline participation.

Table 22. Estimated Participation and Savings - Residential and Commercial DLC

Potential participants				71,320
Per participant savings (kWh):				0
Per participant savings (kW):				0.7
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	713	1.0%	-	520
Year 2	1,212	1.7%	-	885
Year 3	1,640	2.3%	-	1,197
Year 4	1,783	2.5%	-	1,302
Year 5	1,783	2.5%	-	1,302
Cumulative	7,131	10.0%	-	5,206

[14] Based on Southern Indiana Gas & Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc. Demand-Side Management Annual Report & Evaluation for 2004, May 1, 2005.

Participation shown in Table 22 is incremental to the existing program participation, which is expected to be maintained. Currently, the program is at somewhat above a participation rate of 40 percent of potential participation. The program is designed to push participation to about 50 percent (only incremental participation is shown in Table 22). The pattern of incremental participation has been designed with a goal of 713 for Year 1. This is an ambitious first year goal, but less than the goals set for the following years. The goal is an additional 1,212 in Year 2, and an additional 1,640 in Year 3. For Years 4 and 5, the goal in each year is an additional 1,783. Year 1 will involve a transition from a near steady-state baseline period in which the goal was maintenance of existing numbers. Not shown, but part of the program expectation is that customers who leave the program will be replaced to bring the total participation at the end of Year 5 to 7,131 participants above baseline participation.

Marketing Plans

- The residential program is currently marketed through bill inserts, media coverage of how to manage summer electric bills, customer service representatives, and seasonal promotion on Vectren.com. Proposed marketing efforts are to continue and to include mention of the program in any Vectren communications with customers regarding energy efficiency program options.
- The commercial program has experienced a slight reduction in participation and demand savings, so in 2006 Vectren planned to do a direct mail solicitation and to have key customer account managers interact with current and former participants regarding the benefits of the program.
- While the program has a high and relatively stable participation rate, it is reasonable to set more challenging participation goals over the planning period.
- A standard technology adoption curve is shown below in Figure 20. If we consider this curve to represent all potential participants in this program, note that the base case puts current adoption at around 40 percent of potential, the high and relatively stable participation rate maintained by Vectren for many years. The market goal in this DSM plan (see Table 22) is to move participation forward by an additional 10 percent, while retaining current participants to bring participation slightly above 50 percent of potential.

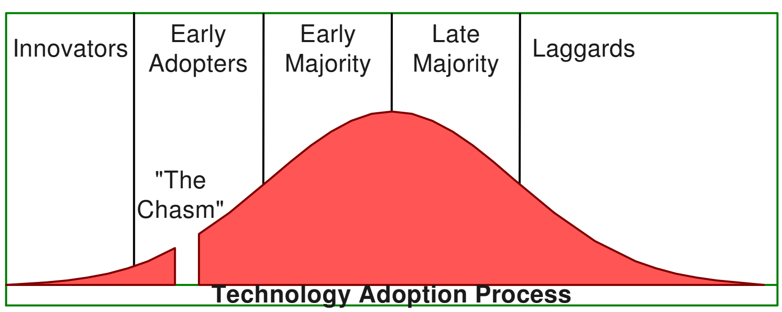

Figure 20. Characteristics Adoption Curve

This process can also be represented by the characteristic "S-Curve" for innovation diffusion shown in Figure 21. In this figure, again cumulative for the base case of slightly over 40 percent participation plus the 10 percent goal for the new effort, participation begins at zero at the left bottom of the curve. It then rises as measured on the vertical axis. The process takes place over time (measured on the horizontal axis). The standard result follows the "S" shape until it reaches the participation ceiling.

However, both standard curves shown are actually members of families of curves, and in these families, the curves sometimes take different shapes depending on how participation takes place in actual practice. In particular, the shape of the curve (Figure 21) may well take a different form following the midpoint of the process of diffusion. In this case, (once 50 to 60 percent participation is achieved) it is likely that further participation can be encouraged more easily should the need arise to reach the actual potential program participation. That is, instead of stretching to form the top section of the "S", it may be almost vertical so that the overall curve would take on an approximate "J" shape. In any case, part of the value of this program is that once it reaches 50 to 60 percent participation it could be moved rapidly to complete participation should the need arise.

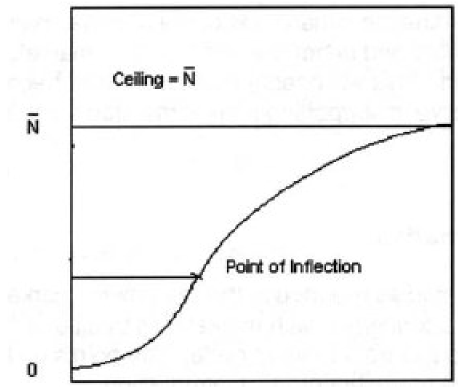

Figure 21. Characteristic Innovation-Diffusion Curve

- This program does not exhibit a gas DSM synergy and is not designed to be directly coordinated with a parallel gas DSM effort.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to advertise, oversee and monitor the program.
- Incentive per connected switch. Incentives for this program have been designed as a continuation of the incentive for the legacy program.

Costs to participating customers:

- Customer's time to learn about the program and sign up.
- Marginal difference in equipment operation of cooling units when a load event is called
- Temporary loss of water heater units for the duration of each load event.

Table 23. Estimated Five-Year Program Budget - Residential and Commercial DLC

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$5,000					$5,000	0.3%
Staffing, Administration and Overhead		$30,800	$30,800	$30,800	$30,800	$30,800	$154,000	9.0%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$0	$0	$0	$0	$0	$0	0.0%
Total		$35,800	$30,800	$30,800	$30,800	$30,800	$159,000	9.2%
Variable Program Costs								
Incentives (*)	$144.00	$119,784	$220,728	$321,720	$385,104	$427,896	$1,475,232	85.8%
Other Program Expenses	$1.31	$934	$1,588	$2,148	$2,336	$2,336	$9,342	0.5%
Monitoring and Evaluation	$10.76	$7,675	$13,046	$17,653	$19,192	$19,192	$76,756	4.5%
Total	$156.07	$128,393	$235,361	$341,521	$406,631	$449,423	$1,561,330	90.8%
Total Budget		$164,193	$266,161	$372,321	$437,431	$480,223	$1,720,330	100.0%

Residential Programs

Program 3. Energy Star Lighting Program

The Vectren Energy Star residential lighting program is a market-based residential DSM program designed to reach residential customers through retail outlets. The program provides direct incentives to consumers to facilitate their purchase of energy-efficient lights. The incentive is in the form of discounted pricing available for lighting products that carry the Energy Star logo.

This program is justified based on direct energy savings targets but also has a significant market transformation dimension. Generally, throughout the US, the Energy Star program has been affecting the types of lighting products available in stores. The relative amount of available lighting shelf space assigned to Energy Star lighting products has been increased. The quality of CFL has dramatically increased. The diversity of applications has greatly increased. There has been as sizable decrease in the cost of energy-efficient lighting. In this program, Vectren Energy South will become an active part of this campaign for its electric service territory. Through this participation, it is expected that Vectren will move more Energy Star lighting into retail stores, help make energy-efficient lighting more affordable to its customers, and provide a continuing and responsible guidance and energy-efficiency education message to customers in the electric service territory.

Incentives will be implemented by coupons, in-store markdowns, or upstream manufacturer buy-downs. A coupon approach is more suitable for a six county area because it gives the program administrator direct control over where coupons are available and for which sales outlets.[15] The following incentives will be offered to Vectren customers.

Table 24. Measures and Incentives - Energy Star Lighting

Measures	Incentive Amounts
Energy Star CFL Instant Coupon	$1 per bulb
Energy Star CFL 4-Pak Coupon	$4 per bulb
CFL 6-Pak Coupon	$6 per bulb

This program is modeled after a set of programs that is implemented by Energy Federation Incorporated. These programs are sponsored by Connecticut Light and Power, United Illuminating Company, the Cape Light Compact, National Grid, NSTAR Electric, and Western Massachusetts Electric (www.myEnergyStar.com).[16]

[15] The coupon approach is available as a "packaged" approach through Energy Federation Incorporated (EFI), which can also provide coupon processing services (www.efi.org). An alternative approach offered by some utilities, the "lighting catalog," is not recommended since it would provide competition to existing lighting outlets. Since the long term goal is to influence a transformation of the market, it also seems reasonable to focus on changing the market share within existing supply channels and retail outlets.

[16] The EFI coupon system may offer better control to Vectren than the MEEA regional chain store system. For a statewide campaign, the MEEA system offers advantages, including the enlistment of chain stores (specifically, Ace Hardware, True-Value Hardware, and Home Depot) and the potential for the same campaign to be run in neighboring states and neighboring service territories. However, the six county service territory of Vectren South may require much more careful individual selection of stores and promotions to prevent substantial "spillage" of program effects outside the service territory. If this kind of spillage is a potential concern, then coupons need to be limited to stores that draw customers almost exclusively from within the six counties, and not be equally available (for example) at a Home Depot on the border of the six counties that draws

The proposed program is also similar to the MEEA lighting promotion, which for 2006 was supported by AmerenUE, Aquila, City Utilities of Springfield, Columbia Water and Light, Kansas City Power and Light, Empire District Electric Company, Independence Power and Light, Commonwealth Edison, Xcel Energy, Minnesota Department of Commerce, Willmar Municipal Utilities, Alexandria Light and Power, Southern Minnesota Municipal Agency, Indianapolis Power and Light, and the Office of Energy Efficiency of the Ohio Department of Development.[17]

Rationale for Program

The program rationale is epitomized by the Energy Star "Change a Light, Change the World" marketing theme because although each light bulb is a small thing, changing a bulb is within individual control and together the cumulative effect is one of the largest of potential DSM measures. Although simple, it is very cost effective.

Average Annual Expected Savings

Potential participants come from the total count of residential and small commercial customers. The participation goals for this program are 6,550 in Year 1, followed by 13,100 in each of years 2, 3, 4, and 5. This is equivalent to a 5 percent of potential target for Year 1, and a 10 percent of potential target for each of the following four years, and a total of 45 percent cumulative over five years. These targets have been set to provide a reasonable start and a manageable program effort throughout this implementation period. Based on experience in Year 1, these goals may be adjusted for the subsequent years. But the beginning of Year 3, it should be possible to revisit goals based on solid experience in actual service territory markets.

Table 25. Estimated Participation and Savings - Energy Star Lighting

Potential Participants				131,000
Per participant Savings (kWh):				246
Per Participant Savings (kW):				0.0
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	6,550	5.0%	1,611,300	272
Year 2	13,100	10.0%	3,222,600	544
Year 3	13,100	10.0%	3,222,600	544
Year 4	13,100	10.0%	3,222,600	544
Year 5	13,100	10.0%	3,222,600	544
Cumulative	58,950	45.0%	14,501,700	2,449

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers, and coordinated advertising with selected retail outlets. It is assumed that the vendor ensure bulb supply as well as coupon processing. Vectren will work with the vendor to tailor the program "package" as much as possible to Vectren's needs.

customers primarily from outside the service territory. A related concern is that chain stores may have coordinated advertising that crosses service territory lines.

[17] The MEEA program vendor for this program is WECC, which can provide details on the strengths and weaknesses of the MEEA regional approach. See the MEEA website for annual program reports (http://www.mwalliance.org/programs/changealight/).

- According to Ecos Consulting, the first approximately twenty years of CFLs did not have much influence in retail markets. "Then, in 2001, the market share gains for CFLs outpaced all of the gains achieve in their first 260 months of existence." National sales reached 2.1 percent of market in the fourth quarter of 2001.[18] Markets have changed since 2001 with CFLs acquiring self space within major chain stores, accompanied by some in-store advertising and promotion. This makes utility support more effective because the utility program can leverage substantial promotional efforts. At the same time, the documentation of baseline market share becomes a dynamic concern and documentation of incremental sales in relation to incremental (utility) cost has to be carefully developed.
- Data collection and documentation for program purposes and annual reporting will be included as features of the vendor program "package." Data estimation of the baseline market and market potential for Energy Star bulbs and fixtures in Vectren's service territory should be refined as a part of the vendor services and developed for each product type (CFL, CFL pack, exterior fixtures, interior fixtures).
- This CFL program is quite cost effective and attractive to customers. It is a good candidate program for bundling with other gas and electric DSM programs.

Big Box Store Initiatives

Since this program was designed, Wal-Mart has announced a major CFL initiative designed to introduce at least one CFL to each of its 100 million US customers over the next few years. In initiating this campaign, they have devoted additional shelf space to CFLs and arranged with GE for an initial 21 percent cut in the price of CFLs. We can expect a number of promotions for 4-packs, 6-packs, 12-packs, an increasing variety of bulb types, and possible additional price reductions. Although this initiative has received major buzz, other stores, such as Home Depot and Lowe's are implementing similar CFL promotions. These big box initiatives are compatible with the program design and can be viewed as additional leverage for program efforts. Utilities with current CFL DSM programs have been working with both local and big box retailers, and see any further contributions on the part of manufacturers and retailers in cutting prices and extending promotions as contributing to their programs.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program
- Vendor services for the program vendor (assuming that Vectren buys into to an existing turnkey lighting program, marketing and promotional package such as MEEA's or the Energy Federation's).
- Incentives for the installation of approved measures as demonstrated through the provision of coupons collected and processed from the retail outlets.
- Incentive levels have been set equal to the 2007 levels adopted by N-Star and National Grid companies (www.myEnergyStar.com). These are good levels, reflecting the realities of ongoing market changes and in the middle of the range of currently offered incentives. The bottom of this range is $1.50 for a single bulb (Efficiency Vermont), and a few utilities go slightly higher than the $2 recommended.

Costs to participating customers:

- Customer's share of the cost (cost of product after the application of the coupon discount).

[18] US DOE Energy Efficiency and Renewable Energy, September-October 2003 Conservation Update Feature Article, "Laying the Foundation for Market Transformation by Chris Calwell and John Zugel, Ecos Consulting (www.eere.energy.gov/state_energy_program/update/printer_friendly.cfm/volume=48).

Table 26. Estimated Five-Year Program Budget - Energy Star Lighting

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$30,000					$30,000	4.7%
Staffing, Administration and Overhead		$57,341	$57,341	$57,341	$57,341	$57,341	$286,705	45.0%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$10,000	$10,000	$10,000	$10,000	$10,000	$50,000	7.9%
Total		$97,341	$67,341	$67,341	$67,341	$67,341	$366,705	57.6%
Variable Program Costs								
Incentives	$4.00	$26,200	$52,400	$52,400	$52,400	$52,400	$235,800	37.0%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$0.58	$3,774	$7,547	$7,547	$7,547	$7,547	$33,963	5.3%
Total	$4.58	$29,974	$59,947	$59,947	$59,947	$59,947	$269,763	42.4%
Total Budget		$127,315	$127,288	$127,288	$127,288	$127,288	$636,468	100.0%

Program 4. Energy Star Appliances and Programmable Thermostats Program

The Vectren Energy Star Appliances Program is a market-based residential DSM program designed to leverage on existing national and collaborative effort in improving appliance energy efficiencies to reach residential customers through retail outlets. The program provides direct incentives to consumers to facilitate their purchase of Energy Star appliances. The incentive is in the form of discounted pricing available for appliances that carry the Energy Star logo.

This program is justified based on direct energy savings targets but also has a significant market transformation dimension. In this program, Vectren South will become an active part of the Energy Star campaign for its electric service territory. Through this participation, it is expected that Vectren will move more Energy Star appliances into retail stores, help make energy-efficient appliances more affordable for its customers, and provide a continuing and responsible guidance and energy-efficiency education message to customers in the electric service territory.

The Vectren Energy Star Appliances Program will provide rebate coupons to its customers toward the purchase of Energy Star appliances. A coupon approach is recommended because it is more suitable for the six-county area. This approach gives the program administrator direct control over where coupons will be made available and for which sales outlets.[19]

Table 27. Measures and Incentives - Energy Star Appliances and Programmable Thermostats

Measures	Incentive Amounts
Energy Star Clothes Washers	$100 per unit
Energy Star Refrigerators	$25 per unit
Energy Star Dishwashers	$25 per unit
Energy Star Room Air Conditioner	$15 per unit
Programmable Thermostats	$20 per unit

The incentives for this program are lower than might be expected. This is due in part to recent changes in the Energy Star program and the gradual increase in energy efficiency of base case (non-Energy Star) equivalent products (clothes washers, refrigerators, dishwashers and room AC). In the case of programmable thermostats, the incentive has been set equal to the incentive in the Vectren natural gas program to better communicate the program to customers. During the development of this report, we had originally considered rebates for programmable thermostats of $50, significantly higher than the $20 per unit in Table 27. Although we lowered the rebate amount to $20 in order to be consistent with the rebate level currently offered to Vectren North gas customers, installation problems should be carefully monitored. If installation problems appear, Vectren should consider increasing the incentive for both gas and electric DSM programmable thermostats to cover professional installations.

For clothes washers, MEEA utilities have been using a $75 to $100 rebate, however this amount includes an arranged manufacturer rebate of $25 to $50. According to a September 2006 Consortium for Energy Efficiency

[19] The coupon approach is available as a "packaged" approach through Energy Federation Incorporated (EFI), which can also provide coupon processing services (www.efi.org). WECC administers several similar programs. Marketing and promotional plans for this program area have been developed collaboratively through the Consortium for Energy Efficiency (CEE), as well as regional coordinating organizations such as MEEA.

(CEE) report, Alliant Energy provided a $50 rebate for vertical axis and a $100 rebate for horizontal axis clothes washers. To communicate a consistent message to gas and electric customers, the rebate for clothes washers is set at $100.

Efficiency Vermont provided a $50 rebate for a CEE Tier 3a clothes washer, $25 for a room AC, and $25 for an Energy Star refrigerator. The Long Island Power Authority clothes washer rebate is $15, $35, or $50 to customers along with a $50 clothes washer rebate for builders who install a clothes washer with a modified energy factor (MEF) of 2.0 or higher.[20] Los Angeles Water and Power (LADWP) provides a $65 refrigerator rebate and a $50 room AC rebate. National Grid provides a $100 clothes washer rebate for washers with MEF of 1.8 or higher. United Illuminating and Connecticut Light & Power both provide a $20 or $50 clothes washer rebate. Sacramento Municipal Utility District (SMUD) has a $50 refrigerator rebate, a $50 room AC rebate, and clothes washer rebates at $75 and $125 depending on CEE tier level. SMUD dishwasher rebates are $30 or $50, depending on CEE tier.[21]

This program was developed after a review of existing utility Energy Star appliance programs had been completed. The effort involved combining elements of the best programs and applying a Vectren focus to develop the proposed approach. However, it is expected that other program features and coordinated promotional plans will be combined with this approach, depending on the program alliance adopted and program vendor selected.

Rationale for Program

Energy Star appliance programs are the current form of one of the earliest DSM program types, originally attempted on a regional level, such as the Bonneville Power Administration "Blue Clue" program and several California programs. But appliance programs are best developed on a national level with participation by utilities and government units. Energy Star has overcome all of the defects of the earlier local or regional programs through a single national program structured to periodically advance program standards and regulate minimum efficiencies. At the same time, it is structured to work with regional marketing initiative and local promotion.[22]

The overall cost effectiveness of this set of measures is carried largely by the programmable thermostats. While five recent evaluations of programmable thermostat programs have shown that a large number of households do not use the program once the thermostat is installed, the technology is sound and many other studies show the technology works well when it is used. This puts a premium on the selection of thermostats, and it is expected that over time and though program experience the range of applicable thermostats will be narrowed to those that are easy to use, read, and install. Also, as noted in Appendix D, cost effectiveness of the programmable thermostat would support a higher rebate that would cover part of the installation cost. It is expected that implementation staff

[20] The higher the MEF, the more efficient the clothes washer.

[21] See "Residential Appliance Programs National Summary, Prepared by the Consortium for Energy Efficiency, September 2006; MEEA 2004 Energy Star Clothes Washer Rewards Rebate Program Final Report to Com Ed, Illinois Department of Commerce and Economic Opportunity, and Southern Minnesota Municipal Power Agency.

[22] For example, for the history of the residential clothes washer initiative, see Shel Feldman Management Consulting, Research into Action incorporated, and Xenergy incorporated, The Residential Clothes Washer Initiative, A Case Study of the Contributions of a Collaborative Effort to Transform the Market, prepared for the Consortium for Energy Efficiency, June 2001 (http://www.cee1.org/eval/RCWI_eval.pdf).

will look at pros and cons of including installation if it is determined that units are not being properly installed or that customers are having difficulty in properly setting the units.

Average Annual Expected Savings

All residential customers are included in the pool of potential participants. The implementation design calls for a program participation rate of 16 percent of potential customers (19,360 out of 121,000) over the five-year program period. As with most other programs, the target for Year 1 (2,420) is lower than for succeeding years and the program ramps to 3,630 for Years 2 and 3, and to 4,840 in Years 4 and 5. Once experience is gained through Years 1 and 2, the implementation team will have sound contextual knowledge needed to adjust the targets for Years 3, 4 and 5.

Table 28. Estimated Participation and Savings - Energy Star Appliances and Programmable Thermostats

Potential Participants				121,000
Per participant Savings (kWh):				316
Per Participant Savings (kW):				0.1
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	2,420	2.0%	764,720	189
Year 2	3,630	3.0%	1,147,080	284
Year 3	3,630	3.0%	1,147,080	284
Year 4	4,840	4.0%	1,529,440	379
Year 5	4,840	4.0%	1,529,440	379
Cumulative	19,360	16.0%	6,117,760	1,516

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers, and coordinated advertising with selected retail outlets. This type of program is best implemented using an implementation vendor. Vectren will work with the chosen program vendor to tailor the package to Vectren's needs.
- A basic assumption in the development of this program is that it is not so much the size of the rebate so much as the existence of a rebate and the skill in developing engaging promotions and long-term relationships with the appliance industry and dealers.[23,24]
- Appliance programs can combine "spiffs," coupon promotions, and consumer rebates,[25] but the reality of this type of program is that for Vectren, immediate access to these well developed and ongoing industry relationships will require an experienced implementation vendor. For this plan, we limit the design to energy efficiency consumer rebates sponsored by Vectren. However the actual implementation may involve other program features as a part of an overall program "package."
- The basic marketing goals for the program come from the Consortium for Energy Efficiency and are provided below:[26]

[23] See the WECC paper on residential appliances at http://www.aceee.org/utility/ngbestprac/wecc.pdf. Note that this paper is for a natural gas clothes washer program, however "lessons learned" regarding relationships and promotion would apply across appliance programs.

[24] A review of rebates offered across the US indicates that most utilities are offering rebates from this kind of marketing and promotional perspective rather than from a direct resource acquisition perspective. See the Database of State Incentives for Renewables & Efficiency, (DSIRE), maintained by the North Carolina Solar Center for the Interstate Renewable Energy Council (IREC) funded by the U.S. Department of Energy (DSIRE) at (http://www.dsireusa.org/library/includes/techno.cfm?EE=1&RE=0).

[25] See Residential Appliances Exemplary Program, "Northeast Residential Energy Star Appliances Initiative," Northeast Energy Efficiency Partnerships, Inc. and participants at http://aceee.org/utility/3aresappNE.pdf.

[26] CEE's National Residential Home Appliance Market Transformation Strategic Plan, December 2000 (http://www.cee1.org/resid/seha/seha-plan.php3).

1. Consumers understand and value the benefits from energy-efficient features.
2. Retail sales force is knowledgeable about Energy Star and considers it a meaningful distinction for making a sale.
3. Manufacturers market and promote energy-efficient products and/or features.
4. Energy efficiency, defined by Energy Star performance levels, becomes a standard feature or is available across all manufacturers' product lines.
5. Energy Star represents the most energy efficient quality products available.

- As with other rebate programs, care will have to be taken to either avoid "spillage" across service territory boundaries or to secure commission acceptance of reasonable spillage as integral to state interests in supporting appliance programs across utilities and for the region and the nation. Either way, spillage must be specifically addressed in the micro design of the program.
- Markets for Energy Star appliances are steadily developing. As a result, this is a good time to introduce an Energy Star campaign, and to provide continuity of support for a number of years because given these conditions the programs have a major opportunity to advance.
- Data collection and documentation for program purposes and annual reporting will be included as features of the vendor program "package." Data estimation of the baseline market and market potential for the specific Energy Star appliances promoted in the program should be refined as a part of the vendor services and developed for each product type (clothes washers, refrigerators, dishwashers, room air conditioners).
- This program is designed as a downstream, customer focused program. However, cooperation with manufacturers to expand the program promotional features should be explored by implementation staff after the first year.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program. Administration will include Vectren membership in CEE, MEEA, or a similar overarching energy efficiency program membership.
- Vendor services for the program vendor (this program type requires "buy-in" to an existing turnkey appliance program, for example through MEEA or CEE).
- Evaluation of incentives will be based on coupons processed and collected from the retail outlets.

Costs to participating customers:

- Customer's share of the cost (cost of product after the application of the program discount).

Table 29. Estimated Five-Year Program Budget - Energy Star Appliances and Programmable Thermostats

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$35,000					$35,000	2.7%
Staffing, Administration and Overhead		$24,190	$24,190	$24,190	$24,190	$24,190	$120,950	9.2%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$15,000	$15,000	$15,000	$15,000	$15,000	$75,000	5.7%
Total		$74,190	$39,190	$39,190	$39,190	$39,190	$230,950	17.6%
Variable Program Costs								
Incentives	$52.00	$125,840	$188,760	$188,760	$251,680	$251,680	$1,006,720	76.8%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$3.79	$9,162	$13,743	$13,743	$18,325	$18,325	$73,299	5.6%
Total	$55.79	$135,002	$202,503	$202,503	$270,005	$270,005	$1,080,019	82.4%
Total Budget		$209,192	$241,693	$241,693	$309,195	$309,195	$1,310,969	100.0%

Program 6. Old Refrigerator Pick-Up and Recycling Program

Old refrigerators present many hazards to life and health, from the problem of children and animals being trapped inside when refrigerators are improperly disposed of, the leaking of PCB toxins, and the problem of mercury in switches. However, when refrigerators and freezers are sent for metal recycling, the refrigerator foam is shredded resulting in the release of CFC-11. According to program literature, the ten pounds of foam and one pound of CFC-11 in an average refrigerator is equivalent to 2.3 tons of carbon dioxide. Proper recycling will dispose of the CFC-11, preventing its release into the atmosphere, and will also deal constructively with mercury and other health and safety hazards. This emphasis on environmental health is an example of the crossover of DSM programs into the areas of health and safety and other "non-energy benefits" (NEBS) integrally associated with DSM.

From a purely energy perspective, the value of this program is in disassembly of hugely inefficient refrigerators and freezers so they do not operate on the power system. It is a tendency of households to retain an old refrigerator for the garage or basement when a new refrigerator takes its place in the kitchen. Generally, the old refrigerator is plugged in but used as a convenience to cool canned beverages or casual meals or snacks. But though it seems a convenience, the actual price both on the household electric bill and to the electric system is very disproportionate to the actual benefits provided.

This program is justified based on direct energy savings targets but also on the significant health and safety benefits of the program; that is, it produces a definite benefit to the household, to the electric system, and to the community as a whole. Through this program, it is expected that Vectren will reduce energy consumption and energy demand on the system, as well as, provide an educational dimension. Vectren South will provide continuing and responsible guidance and energy-efficiency education message to customers in the electric service territory.

The incentive will be an easy pick-up service with responsible disposal, provided by a vendor and overseen and verified by Vectren. Although designed as a standalone program to be run by a national or regional vendor, a program of this type can also be cooperatively developed with appliance vendors in the service territory.[27]

Table 30. Measure and Incentive - Old Refrigerator Pick-Up and Recycling

Measure	Incentive Amount
Refrigerator or Freezer Pick-Up	$30 per unit

This program is modeled after the Old Refrigerator Pick-Up and Recycling Program of the Sacramento Municipal Utility District[28] and several similar programs in the Northeast, West[29] and Northwest (including Snohomish County PUD No. 1[30]).

[27] This is not included in the current design, but is an option to pursue for future development once an experienced vendor is selected.
[28] Residential Appliance Recycling Exemplary Program, Old Refrigerator Pickup & Recycling Program, Sacramento Municipal Utility District (http://aceee.org/utility/4brefrigrecylingsacramentca.pdf).
[29] See: http://www.nevadapower.com/conservation/residential/programs/rebates/refrigrator_recycling.cfm.
[30]See "PUD Offers Incentive for Recycling Old Refrigerators/Freezers" on their website at http://www.snopud.com/energy/home/econpgms/recycle.ashx?p=2543. Also, several similar programs are listed in Residential

The incentive amount of $30 compares with an incentive of $35 in the Snohomish program, $30 at Nevada Power, $30 (Canadian) at BC Hydro, $35 at Los Angeles Department of Water and Power (LADWP), and $35 at Sacramento Municipal Utility District (SMUD).[31]

Rationale for Program

This is another early DSM program that has developed into a stable type of mature program with national and regional vendors. The basic energy rationale for the program is to insure proper destruction of inefficient older refrigerators and freezers, while also providing substantial health and safety benefits to the community.

Average Annual Expected Savings

The potential participants are estimated using 28 percent of residential customers with a second refrigerator (2005 Residential Survey). As with most programs, the target for Year 1 (678) is lower for the start-up year, then it moves to 1,016 in Year 2, and to 1,355 for Years 3, 4 and 5. The total participation over five years is planned at 5,759 or almost 17 percent of potential. It is expected that after Years 1 and 2 implementation staff will have solid contextual knowledge of program dynamics and the effectiveness of program promotional effort, including the size of the rebate. At that time it is reasonable to adjust targets for Years 3, 4, and 5 based on the practical insights and knowledge attained.

Table 31. Estimated Participation and Savings - Old Refrigerator Pick-Up and Recycling

Potential Participants				33,880
Per participant Savings (kWh):				700
Per Participant Savings (kW):				0.1
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	678	2.0%	474,600	83
Year 2	1,016	3.0%	711,200	124
Year 3	1,355	4.0%	948,500	165
Year 4	1,355	4.0%	948,500	165
Year 5	1,355	4.0%	948,500	165
Cumulative	5,759	17.0%	4,031,300	701

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers, and coordinated cooperation with appliance sales outlets. This type of program is best implemented using an implementation vendor. The program vendor will be asked to tailor the program "package" as much as possible to Vectren's needs.
- Appliance programs can combine "spiffs," coupon promotions, and consumer rebates,[32] but the reality of this type of program is that for Vectren, immediate access to these well developed and ongoing industry relationships will require an experienced implementation vendor. For this plan, we limit the design to energy efficiency consumer rebates sponsored by Vectren. However the actual implementation may involve other program features as a part of the program "package."

Appliance Programs National Summary, September 2006, Prepared by Consortium for Energy Efficiency (http://www.cee1.org/resid/seha/06seha-progsum.pdf).

[31] See other references in this section, plus Residential Appliance Programs National Summary, Prepared by Consortium for Energy Efficiency, September 2006.

[32] See Residential Appliances Exemplary Program, "Northeast Residential Energy Star Appliances Initiative," Northeast Energy Efficiency Partnerships, Inc. and participants at http://aceee.org/utility/3aresappNE.pdf.

- Data collection and documentation for program purposes and annual reporting will be included as features of the vendor program "package." Data estimation of the baseline market and market potential should be refined as a part of the vendor services.
- Periodic independent verification of removal of appliances from the secondary market and second or third refrigerators from the home is necessary.
- The refrigerator rebate program does not show synergy with other gas or electricity DSM efforts. It is essentially a standalone program. However, implementation staff may, after Year 1, find ways to coordinate with appliance store trade allies and the Energy Star refrigerator rebate in the Energy Star Appliance and Programmable Thermostat Program.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program. Administration will include a share of Vectren membership in CEE, MEEA, or a similar overarching energy efficiency program membership.
- Vendor services for the program vendor (this program type requires "buy-in" to an existing turnkey appliance recycling program vendor).
- Incentives for the program participation in the form of a rebate.

Costs to participating customers:

- Customer's attention and time to coordinate appliance pick-up.

Table 32. Estimated Five-Year Program Budget - Old Refrigerator Pick-Up and Recycling

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$15,000					$15,000	3.8%
Staffing, Administration and Overhead		$15,940	$15,940	$15,940	$15,940	$15,940	$79,700	20.2%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$22,000	$22,000	$22,000	$22,000	$22,000	$110,000	
Total		$52,940	$37,940	$37,940	$37,940	$37,940	$204,700	52.0%
Variable Program Costs								
Incentives	$30.00	$20,340	$30,480	$40,650	$40,650	$40,650	$172,770	43.9%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$2.85	$1,932	$2,895	$3,861	$3,861	$3,861	$16,411	4.2%
Total	$32.85	$22,272	$33,375	$44,511	$44,511	$44,511	$189,181	48.0%
Total Budget		$75,212	$71,315	$82,451	$82,451	$82,451	$393,881	100.0%

Program 9. Low and Moderate Income Weatherization Enhancement Program

The Vectren Low and Moderate Income Weatherization Enhancement Program is designed as a "piggyback" or "coordinated" program with the federal Weatherization Assistance Program[33] and will be implemented through Indiana's Community Action Agencies (IN-CAA)[34] in coordination with the federal Weatherization Assistance Program (WAP).

The federal low-income program has a payment assistance (LIHEAP) and weatherization component (WAP), both highly under-funded. The total national LIHEAP allocation today is approximately one-half of the original allocations in real dollars, and the Weatherization Assistance Program is able to service only a very small fraction of actual need each year, while need continues to grow. At the same time, the federal poverty metric, used to determine qualification for program participation, is far out of calibration with the reality of income insufficiency as experienced by households and families. Although federal real dollar funding is much less, the US population is larger than it was when the federal program began. In addition, attaining sufficient real income for a normal level of living is much more problematic for low and moderate income families today than it was for low and moderate income families in the middle of the last century, and particularly so with regard to the "good years" of the 1960s when America seemed to be poised, as was said at the time, "at the edge of abundance."

Today, it takes a family about twice the labor hours to secure approximately the same real income as in 1965. A large part of this problem is that job structures are weaker today than in the past, in that many jobs today are not designed to be parts of "career ladders" and job security is greatly decreased. Further, low and moderate income workers today are much less likely than in the past to be able to connect with a job that includes a defined benefit pension, a family wage, or an adequate health plan. Essentially, compared with the 1960's, we have the equivalent of a wartime labor force mobilization (with two or more members of a household at work for about the same wage as one worker received in 1965). During World War II we had wartime mobilization with strong price control and rationing of consumer and production goods. Today we have the equivalent labor engagement as wartime mobilization with strong wage rationing. For all such reasons, helping agencies and volunteer resources are continually stressed because both need and potential program service loads continue to increase.

These general conditions affect many aspects of family life, from ability to secure medical care and obtain prescriptions, to the ability to provide adequate and healthful food, clothing, and child care while paying for housing and necessary utilities. In particular, the long term trends resulting in increasing need and decreasing federal resources make it difficult to meet low and moderate income weatherization needs.

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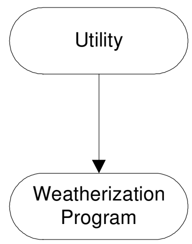
[33] The U.S. Department of Energy's (DOE's) Weatherization Assistance Program was created by Congress in 1976 under Title IV of the Energy Conservation and Production Act. The purpose and scope of the Program as currently stated in the Code of Federal Regulations (CFR) 10CFR 440.1 is "to increase the energy efficiency of dwellings owned or occupied by low-income persons, reduce their total residential expenditures, and improve their health and safety, especially low-income persons who are particularly vulnerable such as the elderly, persons with disabilities, families with children, high residential energy users, and households with high energy burden" (Code of Federal Regulations, 2005).

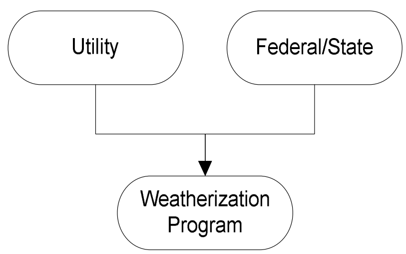
[34] The Community Action Agencies are coordinated by Indiana Community Action Association, IN-CAA (http://www.incap.org/).

This program is designed to accomplish DSM objectives while contributing to meeting the need for low and moderate income weatherization. It is designed to be coordinated with Indiana's current Weatherization Assistance Program effort to augment the services of that program. It will primarily provide "GAP funding" for households that are just above the income eligibility cutoff for the federal program, but have equivalent need. It will also provide increased capability to meet needs of households in need of "health and safety" repairs and furnace replacement.

A standalone utility DSM weatherization program looks like this:



This program, however, is a "coordinated" program, treated as an "add-on" to the existing federal/state low-income Weatherization Assistance Program, and looks like this:[35]



As such, the program will be delivered by the IN-CAA agencies. IN-CAA agencies follow federal and state requirements that require strong emphasis on "health and safety" as well as on weatherization to achieve energy savings. The advantage of connecting delivery through the IN-CAA agencies is that the program, program rules, staffing, and delivery capability are defined and program success has been demonstrated through ongoing operations.

The program is designed to provide two conceptually different services. The primary modality is provision of "GAP funding" for households above 150 percent of the federal poverty level but below 200 percent of the federal poverty level. A secondary program objective is to provide some additional funding for special needs cases from zero to 200 percent of poverty that require furnace replacement and/or health and safety related housing repairs in addition to weatherization. The major focus of the program is on GAP funding, but funding will also be available

[35] Beginning January 1, 2005, eligible customers of Citizens Gas and Vectren, who have applied for the state's LIHEAP through local community action agencies, were automatically enrolled in the new Universal Service Program (USP) and receive bill reductions in addition to LIHEAP. Monthly bill reductions range from 9 percent to 32 percent of the total bill (not including LIHEAP benefits), depending on the consumer's income level and utility provider. The pilot USP also provides additional funding to both utilities' weatherization programs. These are examples of a payment assistance program coordinated with the federal/state LIHEAP program, and of utility weatherization assistance which may be coordinated with the federal/state Weatherization Assistance Program.

for furnace replacement and health and safety repairs in discretionary situations in the course of normal program operation. The balance between these two objectives will be developed through practice as the program is implemented.

(1) "GAP" Funding. Currently, the Indiana Weatherization Assistance Program is operating with a low eligibility limit of up to and including 150 percent of the federal poverty level. As noted above, one of the major problems with low-income programs is that the old federal poverty metric has become miscalibrated in relation to actual income insufficiency in the nearly half-century since it introduced. Although arithmetically adjusted each year, the method of adjustment does not take into account major shifts in society and the economy over the last half century. For example, the standard has not been adjusted to include costs of child care, assumes at least one adult is at home to care for children and the work of homemaking, does not account for actual food budgets required for foods that are actually available, projects need as a simple multiple of the cost of low-quality (but nutritionally adequate) foods that require long hours of preparation and are not generally available, does not account for the doubling of household labor hours required to secure equivalent real income, and fails to take into account the actual costs of households and families. "…[T]he most significant shortcoming of the federal poverty measure is that for most families, in most places, it is simply not high enough."[36]

In contrast, the newer "income insufficiency" methodology takes into account actual family budgets required for a normal level of living, given different family structures and sizes.[37] While there is a shortage of funds and full weatherization services cannot be provided to all households in need, it is important to provide weatherization through "GAP funding" for households above 150 percent of poverty but below the income insufficiency standard.[38] Although eventually, GAP funding would reach to all households below the self-sufficiency standard for Indiana, the current program proposal is more conservative and would reach to and include households at 200 percent of federal poverty level.

(2) Health and Safety Additions in Discretionary Cases. The "comprehensive treatment" provided through the federal/state Weatherization Assistance Program (WAP) provides a strong emphasis on "health and safety" repairs, and furnace replacements, in cases in which they are determined to be necessary. However, the realities of available funding limit the ability to meet "health and safety" requirements while providing energy saving weatherization. A limited amount of funding from this program will be available for that purpose to round out treatment of a home where IN-CAA agencies determine that it is necessary. For example, consider the case of a senior citizen where there is no money to replace a failed furnace and the home also needs weatherization. When a home needs both weatherization and a replacement furnace, the Weatherization Assistance Program (WAP) will typically provide a furnace and note that funds do not permit completing the standard blower-door test or other household diagnostic tests, necessary insulation, and other weatherization measures. A portion of program funding will be available to enable the IN-CAA agencies to make up all or much of the difference in these individual situations. This modality will be exercised on a case-by-case basis.

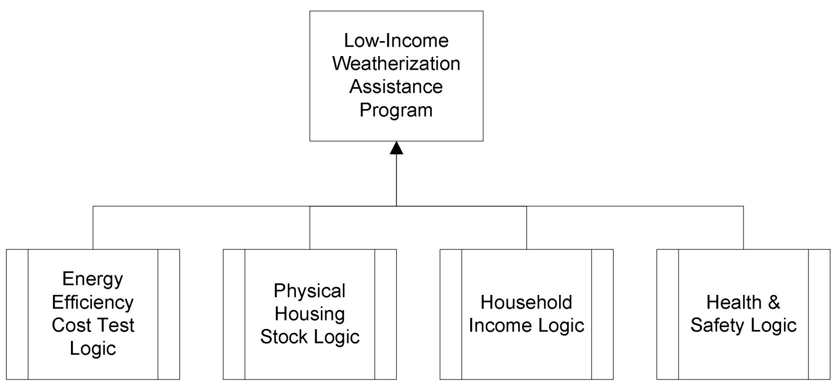
[36] See "Introduction," P. 1, *The Self-Sufficiency Standard for Indiana: Where Economic Independence Begins*, prepared by the Indiana Coalition on Housing and Homeless Issues, September 2005 (http://www.ichhi.org).

[37] Income insufficiency studies, a superior method to the federal poverty metric have been carried out across the states and for many regions, counties, and communities. See *The Self-Sufficiency Standard for Indiana: Where Economic Independence Begins*, prepared by the Indiana Coalition on Housing and Homeless Issues, September 2005 (http://www.ichhi.org). Also see Jill Nielsen-Farrell, "Refining Measures of Economic Stability: The 2005 Self-Sufficiency Standard for Indiana," Pp. 5-9, Indiana Business Review, Spring 2006 (http://www.ibrc.indiana.edu).

[38] The "GAP Funding" portion of the program is modeled on Nevada Power's "GAP Funding" program which provides weatherization services for homes from 151% to 200% of the federal poverty level and is carried out by the state subgrantee agencies the implement the federal Weatherization Assistance Program for households up to 150% of the federal poverty level.

Special Considerations in the Cost Analysis of Low and Moderate Income Program

For most DSM programs, the traditional cost effectiveness criterion granted highest importance has been either the Total Resource Cost (TRC) test or the Societal test. Generally, low-income programs are acknowledged to be different from traditional DSM programs. Although these programs typically employ a cost effectiveness methodology, they have strong justifications in addition to energy cost effectiveness. As shown in the diagram below, for low and moderate income programs the traditional energy cost test logic is one of four equal logics supporting the program concept (Energy Efficiency Cost Test Logic). In addition, there is the physical reality of the condition of the Indiana housing stock and the necessity to maintain housing standards (Physical Housing Stock Logic), the reality of decreasing real incomes and doubling of labor hours required to support roughly a constant level of income since 1965 (Household Income Logic), and the essentials of health and safety to keep families alive, in their homes, and healthy (Health & Safety Logic). Because there is more than one logic (and implied metric) requiring low and moderate income weatherization services, the Community Action Agencies typically adopt a comprehensive approach to homes weatherized (budget permitting), so that often the home repairs necessary to implement weatherization measures and/or a furnace replacement, and/or health and safety measures will accompany the strictly energy-related weatherization measures installed in each home.[39]



For this reason, the national practice in the area is not to focus solely on the TRC measure, one of the old "California tests" traditionally used in DSM program review and usually the most important of the "California Tests" for commission review of DSM program alternatives.[40] Instead, commissions have been adopting different tests for low-income programs, while retaining a form of cost benefit testing.

- For example, the DC Commission uses the "All Ratepayers Test" (comparing avoided costs to customers to energy efficiency program costs) as its general test, and the "Expanded All Ratepayers Test" (incorporating several "non-energy benefits" for low-income programs if the Benefit Cost ratio on the initial test is 0.8 or above.

[39] The physical condition of low and moderate income housing stock makes a comprehensive approach materially necessary.
[40] Program cost-effectiveness is a lesser issue, although still an important objective. Because of their particular focus on the special needs of disadvantaged households, low-income energy efficiency programs are generally not held to the same cost-effectiveness criteria as utility energy-efficiency "resource" programs (i.e., they are not judged with a strict "total resource cost" test, or TRC). More typically, the focus is on the magnitude of utility bill savings to participating customers, rather than the utility system avoided production costs. Also, low-income programs often include broader "non-energy benefits" (NEBs) such as lowered credit and collection costs and avoided bad debt for the utility, and improved health and safety for customers. Kushler, Martin, Dan York & Patti Witte, "Meeting Essential Needs: The Results of a National Search for Exemplary Utility-Funded Low-Income Energy Efficiency Programs." Washington, DC: American Council for an Energy-Efficient Economy, Report Number U053, September 2005.

- The California commission uses a "Modified Participant Test" and Utility Test (including "non-energy benefits") for screening measures for low-income programs and a measure is accepted if it passes either test. Thus, the overall TRC for the Southern California Edison Low-Income Energy Management Assistance Program was 0.63 for 2004 and 0.61 for 2005. Similarly, the TRC for Pacific Gas & Electric's Low-Income Energy Partners Program was 0.41 for 2004.
- As a final example, while relying primarily on the TRC test for DSM programs, the Public Utilities Commission of Nevada (PUCN) approved a Nevada Power whole house AC replacement addition coordinated with the Community Action Agency WAP program with a TRC of 0.55 on a trial basis in 2006. This is similar to a furnace replacement in a cold weather climate, but applies to the southern tip of the state where summer temperatures are very high and AC is essential to health and safety, for example, of senior citizens and families with health conditions or young children. This is a trial program, but it does show that around the country commissions are moving beyond the TRC as the test for low and moderate income DSM programs.

In this connection, the "non-energy benefits" (NEBS) of residential programs have been demonstrated to be quite high. A recent American Council for an Energy-Efficient Economy (ACEEE) study found, in a survey of results of all type of residential home retrofit programs, that non-energy benefits are from 50 percent to 300 percent of the dollar benefit from annual household energy bill savings.[41] Similarly, in a national study of results of the federal/state Weatherization Assistance Program (WAP), Oak Ridge National Laboratory found that for weatherization of gas heated homes the non-energy benefits average to a dollar amount greater than 100 percent of the average net present value of energy savings.[42] The non-energy benefits counted in the Oak Ridge study include enhanced property value and extended life of dwelling, reduced fires, reduced arrearages, federal taxes generated from direct employment, income generated from indirect employment, avoided costs of unemployment benefits, and environmental externalities. The ratepayer benefits include rate subsidies avoided, lower debt write-off, reduced carrying cost on arrearages, fewer notices and customer contacts, fewer shut-offs and reconnections, and reduced collection costs. In this study many of the non-energy benefits are quantified, while others are only noted, resulting in a conservative final number which gives the total benefit of the program at greater than twice the value of the computed energy savings benefit. As these studies suggest, for residential and residential low-income weatherization programs the benefit to society is considerably in addition to the energy savings benefit that is computed for the Total Resource Cost (TRC) test. In general for the Weatherization Assistance Program is reasonably between 50 percent and somewhat over 100 percent more than the value entered into the TRC. This means that there is considerable (quantified) value beyond the energy savings. These programs easily pass the Societal test, which incorporates the value of the more easily quantified non-energy benefits.

For this program, we suggest that the most relevant cost tests are the Societal Test and the Utility Cost Test (Program Administrator's Test) and not the TRC. The grounding for emphasizing the Societal Test has been developed above. From a practical perspective, however, the Utility Cost Test is also relevant. For a coordinated program with utility and federal/state contributions, a methodology has been developed at Oak Ridge National

[41] Jennifer Thorne Amann, *Valuation of Non-Energy Benefits to Determine Cost-Effectiveness of Whole-House Retrofit Programs: A Literature Review*. Washington, DC: American Council for an Energy-Efficient Economy, May 2006, Report Number A061.
[42] Sweitzer, Martin & Bruce Tonn, *NonEnergy Benefits from the Weatherizaton Assistance Program: A Summary of Findings from Recent Literature*. Oak Ridge, Tennessee: Oak Ridge National Laboratory, April 2002, ORNL-CON-484.

Laboratory for allocating cost effectiveness between the utility and the federal/state effort. The methodology applies in situations of coordinated programs with joint federal/state and utility funding.[43] Because the federal/state Weatherization Assistance Program (WAP) has three primary goals, one of which is health and safety, it is structured to provide both health and safety, as well as energy savings results. This provides an opportunity to view a utility DSM program that is coordinated with WAP as receiving substantial leverage from WAP funding. It also permits allocation of costs and allocation of benefits between the utility portion and the federal/state portions of the program at each home, so as to produce substantial leverage for the utility DSM program over a standalone utility DSM weatherization program.

From a government perspective, cost effectiveness criteria apply differently than for a utility. For the Weatherization Assistance Program, the government counts all utility, fuel fund, housing support and other contributions to Weatherization Assistance Program installations in individual homes as leverage. Similarly, from a utility perspective, when a traditional TRC test is required to satisfy commission rules, many of the federal job costs in a particular home installation can be excluded from the calculation. For example, repairs necessary to permit installation of weatherization measures which are mandated by federal/state health and safety requirements and furnace replacements may be excluded. Also all or most of the common costs of getting the weatherization team to each site, as well as other program overheads can be assigned to the federal/state side. There is a natural synergy in coordinated programs in that certain costs can be treated as external to the utility funding, while other costs can be included.

This permits a partitioning of total job costs and total benefits between the utility and the federal/state program that can permit both programs' benefit cost calculations (which have different calculation rules) to be met. For example, the utility can be assigned the high benefit to cost measures while the federal/state program covers transportation, overheads, administration, health and safety measures, and the like. This coordinated calculation is equivalent to converting part of what would go into the Total Resource Cost (TRC) test for a standalone utility DSM program to federal/state costs external to the program. The relevant test for this synergistic opportunity situation is the Utility Cost Test (Program Administrator's Test). The rationale is that by choosing to work through IN-CAA, the utility achieves the leverage of federal/state investment.

The need for developing flexibility in which cost test to emphasize for low and moderate income programs stems from the material reality encountered in this DSM program area. On a material basis, the investment in health and safety, repairs, furnace replacements, and the like is a physical necessity in low-income weatherization work and is a function of the nature of the housing stock and the inability of households to deal with health and safety or furnace replacements and the like. In screening for cost-effectiveness from an inclusive perspective for the utility

[43] Brown, M.A. and L.J. Hill, *Low-Income DSM Programs: The Cost Effectiveness of Coordinated Partnerships.* Oak Ridge, Tennessee: Oak Ridge National Laboratory, ORNL/CON-375, May 1994; Hill, L.H. and M.A. Brown, *Standard Practice: Estimating the Cost-Effectiveness of Coordinated DSM Programs.* Oak Ridge, Tennessee: Oak Ridge National Laboratory, ORNL/CON-390, December 1994; Hill, Lawrence J. & Marilyn A. Brown, "Estimating the Cost-Effectiveness of Coordinated Utility Programs, *Evaluation Review*, Vol. 19, No. 2, April 1995: 181-196.

"add-on" to the existing Weatherization Assistance Program, the question is one of "break-even" analysis or the place at which the curve of total benefits to the utility (that is, energy benefits plus other benefits) produces a benefit-cost ratio of one. This determines an overall limit to utility percentage of joint funding to the program. Within that limit, a Utility Cost Test (Program Administrator's Test) perspective is best applied. In this connection, the government has different requirements and uses a different mathematical calculation than the TRC to satisfy its legislated requirements for accountability.

Table 33. Measure and Incentive - Low and Moderate Income Weatherization Enhancement

Measure	Incentive Amount
Melded Weatherization Addition	$ 1,136

This program is modeled after several coordinated programs, and in particular the program developed by Nevada Power, and approved by the Public Utility Commission of Nevada. The general tendency in the US is now for utilities to coordinate efforts with the state Community Action Agencies rather than to run independent (utility only) low-income weatherization programs.

Rationale for Program

Only state subgrantees, usually Community Action Agencies, have access to federal/state Weatherization Assistance Program dollars. These IN-CAA related Community Action Agencies are generally known for integrity of service, a philosophy of fairness (or even-handed service to all households served), and observance of federal/state requirements for comprehensive service to each household weatherized including extensive health and safety requirements. By coordinating with the Community Action Agencies, Vectren maintains an invaluable business partnership and could not find a better placement for its low-income weatherization efforts. At the same time, to the extent Vectren provides "add-on" incremental measures or dollar contributions to the coordinated effort, the Weatherization Assistance Program can provide (a) services to additional homes (GAP homes) under the existing program structure and procedures, and (b) address more fully the needs of individual homes where furnace replacement and health and safety repairs are required. Providing program delivery through the IN-CAA agencies provides a very strong, defined program, with well developed rules and a history of successful service delivery.

Average Annual Expected Savings

Potential participants were calculated using two-thirds of the 26 percent of residential customers with less than $25,000 annual income (2005 Residential Survey). Reducing the estimate of potential participants by two-thirds of the 26 percent was based on our experience in other jurisdictions. As with most other programs, participation starts somewhat lower in Year 1, and then increases after the start-up year. The cumulative five-year total is 3,593 households or about 16 percent of the potential. Since this program will primarily serve GAP customers, but also customers in specific need of additional health and safety repairs, including furnace repairs, cases will be split between these modalities. This program is a likely precursor to a more aggressive program in terms of numbers served in following DSM program cycles. Evaluation for this program should include a strong component on estimation of need to guide future funding in this area. In the long run, and after a few years of program experience is gathered, the program targets should be raised to the level indicated in the Indiana Income Insufficiency studies (carried out by the Indiana Coalition on Housing and Homeless Issues).

Table 34. Estimated Participation and Savings - Low and Moderate Income Weatherization Enhancement

Potential Participants				21,780
Per participant Savings (kWh):				1,940
Per Participant Savings (kW):				0.3
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	545	2.5%	1,057,300	139
Year 2	653	3.0%	1,266,820	167
Year 3	653	3.0%	1,266,820	167
Year 4	871	4.0%	1,689,740	222
Year 5	871	4.0%	1,689,740	222
Cumulative	3,593	16.5%	6,970,420	917

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers for customer education, and mention of the low-income program in any Vectren communications with customers regarding energy efficiency program options. It is expected that ongoing operations of IN-CAA agencies and referrals to IN-CAA agencies by other helping agencies will be the primary contact for qualified customers. The GAP funding will permit additional customers to be served.
- However, there is no special marketing for this program beyond the current effort to direct customers to IN-CAA weatherization services.
- This program is a clear case of synergy between electric and gas DSM programs, as represented by the holistic focus of the IN-CAA agencies and the federal and state regulations that guide the federal/state Weatherization Assistance Program.

Data collection and documentation for program purposes and annual reporting will require some modification to state weatherization databases to permit more detailed tracking of cost contributions to the Weatherization Assistance Program by source, and to permit separate tracking of GAP customers. Also, the state database will need to incorporate exact measure costs for each job, including all work done on each home (including repairs, replacement furnaces, replacement AC, etc.) to permit complete desegregation of Vectren and other funding and assignment of funding across measures. This will permit a separate analysis for Vectren and a comprehensive analysis for federal reporting purposes, as at present.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Costs for the two program services (GAP funding and coordination where necessary for individual homes on a case-by-case basis.

Costs to participating customers:

- Customer’s time.

Table 35. Estimated 5-Yr Program Budget - Low and Moderate Income Weatherization Enhancement

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	0.5%
Staffing, Administration and Overhead		$27,562	$27,562	$27,562	$27,562	$27,562	$137,810	3.0%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$27,000	$27,000	$27,000	$27,000	$27,000	$135,000	
Total		$79,562	$54,562	$54,562	$54,562	$54,562	$297,810	6.4%
Variable Program Costs								
Incentives	$1,136.00	$619,120	$741,808	$741,808	$989,456	$989,456	$4,081,648	87.7%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$76.33	$41,602	$49,846	$49,846	$66,486	$66,486	$274,265	5.9%
Total	$1,212.33	$660,722	$791,654	$791,654	$1,055,942	$1,055,942	$4,355,913	93.6%
Total Budget		$740,284	$846,216	$846,216	$1,110,504	$1,110,504	$4,653,723	100.0%

Program 10. New Residential Construction – Beyond Energy Star Program

Due to the particular combination of lower rates, building codes, climate and weather, the New Residential Construction program is targeted beyond Energy Star in order to be cost effective. Although Energy Star characteristics are noted in the program description, this is not a generic Energy Star program with an assortment of builder pathways to meet Energy Star criteria. Instead, the requirement for participation is beyond Energy Star, and the selection of energy-saving improvements is limited to higher savings and lower cost DSM measures.

The primary target for this program is builders of Energy Star new homes. However, the program requirement is more strict than Energy Star in the selection of only improvements with lower cost and high energy savings. This is necessary to keep the program cost-effective and requires going beyond Energy Star.

The goal of this program is to build homes that are 30 percent more efficient than those built to standard code. Energy Star homes are homes that are independently certified and are more efficient, comfortable and durable than standard homes constructed according to local building codes.

Energy Star homes feature additional insulation; better windows, doors and bath ventilation; and high efficiency appliances such as furnaces, AC units, heat pumps, and water heaters. These homes typically sell for a factor of three times the actual cost to builders for the energy efficiency improvements, providing excellent leverage in an upstream program model that can provide something like three times the customer value for each dollar of upstream buydown. The incentives cover the incremental cost for the builder to build a beyond Energy Star home.

Table 36. Measures and Incentives - New Residential Construction-Beyond Energy Star

Measures	Incentive Amounts
Energy Star New Home	$1000
Additional Surface Mounted Fixture	$15
Recessed Lighting Fixture	$25
Lighting and Appliance Bonus when 10 energy efficient fixtures and 3 labeled Energy Star appliances are included	$700

The selected measures shown in Table 36 are representative of high-savings and lower cost builder pathways. Some are 'beyond Energy Star' measures. This particular path is indicative of a set of options that will produce a similar cost-effectiveness result. A package such as this is essential to keep the program cost-effective. While Energy Star new construction DSM programs typically allow considerable builder freedom in developing pathways that meet Energy Star energy savings goals for reasonable cost, the Vectren South program is more constrained because Vectren energy costs are lower than for many other utilities, and due to climate. It will be of key importance to develop variation on builder pathways that will provide cost-effective results. This will require attention to a subset of Energy Star builder pathways that make use of the highest energy savings least cost DSM measures, and will require going beyond Energy Star.

The incremental cost of $2,017 per home is what is required for this illustrative measure package. For program purposes, the measure package is to be kept in the neighborhood of $2,000 per home and savings are to be sufficiently beyond Energy Star to provide a successful effectiveness analysis for the home. Incentives for new residential buildings programs vary greatly across utilities. For example, the Eugene Water and Electric Board (EWEB) provides incentives of $250 or $1,000, and other utilities in the Pacific Northwest states provide $1,000, $1,500, or $2,000. NYSERDA and Long Island Power Authority (LIPA) in New York provide incentives from $750 to $3,500 to builders of Energy Star homes. New Hampshire utilities provide up to $3,000. Southern California Edison provides incentives up to $700, depending on climate zone.

This program is modeled after the Efficiency Vermont Energy Star Homes Program, the Texas Energy Star Homes Program, and the Idaho Energy Star Homes Program.

Rationale for Program

The primary target for this program is the homebuilder. Seminars and training sessions are provided for builders. Financial incentives are provided directly to homebuilders to help offset the additional cost to build an Energy Star home. This program provides information, as well as money to overcome the higher incremental cost.

Average Annual Expected Savings

The pool of potential participants is based on our analysis of building permits in the service area presented in the Market Assessment section. The cumulative participation goal is 460 or about 7 percent of the potential market over five years. The reason the target is set low is that these will be high-end homes and beyond Energy Star. The housing market differentiates into segments, and only the top segments are likely to be effectively in the market for very energy efficient new homes. As with other programs, the Year 1 goal is set low for the start-up year, and then increases.

Table 37. Estimated Participation and Savings – New Residential Construction-Beyond Energy Star

Potential Participants (yearly)				1,300
Per participant Savings (kWh):				3,555
Per Participant Savings (kW):				0.5
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	25	1.9%	88,875	12
Year 2	75	5.8%	266,625	36
Year 3	125	9.6%	444,375	60
Year 4	125	9.6%	444,375	60
Year 5	125	9.6%	444,375	60
Cumulative	475	7.3%	1,688,625	227

Marketing Plans

The building community lends itself to a wide variety of marketing activities. The following list of marketing activities is based on what was successful in other programs. The Texas program found that using advertising and promotion was more valuable in attracting the builders than the incentive dollars paid. The key, they found, is to promote the value of the brand to builders.

The marketing methods should include:

- Newspaper and real estate guide ads
- Signage
- Marketing materials
- Builder and subcontractor training and ongoing technical assistance
- An annual conference that brings together building professionals from the area and throughout the country to share expertise and experiences in designing and building high-performance homes and buildings.
- Training in the advantages of Energy Star homes for all the builders, sales staff, realtors, and the lending community.
- Seminars and literature targeted at consumers. This is a valuable addition to a marketing effort because consumers can create a market pull.

Key elements that should be incorporated into this program to make it successful include[44]:

- Establish a single stable multi-year approach. This will give stability to builders and allow the program to grow more readily.
- Establish a single, simple, and high program standard of efficiency. This is important because it lets builders know where they stand and what is expected.
- Establish good relationships with area builders and developers.
- Ensure that staff professionalism, delivery systems, equipment, marketing materials and quality assurance are all of high quality.
- Maintain strict adherence to specifications based on sound building science and economics to maintain program credibility and consistency.
- Establish a process for certifying and documenting homes built to requirements.[45]
- Develop a solid infrastructure of experienced, well-known and respected organizations.
- Develop targeted incentives that are well coordinated with marketing and other service-related materials.
- Coordinate with health and safety standards and codes for residential construction.
- Provide ongoing technical training for builders and subcontractors.
- Promote builders buy-in into the program by getting them financially invested in the program through advertising, building requirements, and training so they will support all aspects of the program.[46]
- New construction is an excellent area to review for strategic combination of gas and electric energy efficiency measures.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- A vendor contract to market and deliver the new home program.
- Incentives to be paid to the builder.

Costs to participating customers include:

- Customer's outlay for any remaining incremental cost of the new residential buildings - beyond Energy Star home, including any additional energy saving features beyond those covered in the program.

[44] Drawn from the Vermont Energy Star Homes program run by Efficiency Vermont and Vermont Gas Systems.
[45] See the Texas program
[46] See the Texas program

The planned ramp up for this program incorporates a one-year planning period following approval of the program. The extra planning period is due to the recent changes in the housing market coupled with the shift in Energy Star residential new construction standards that took place in 2006. Year 1 is to be spent on developing vendor arrangements for the program and on program planning in cooperation with local builders, with the program to go into effect in Year 2, after current market and national Energy Star changes have shaken out.

Table 38. Estimated Five-Year Program Budget – New Residential Construction-Beyond Energy Star

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$10,000					$10,000	1.8%
Staffing, Administration and Overhead		$6,677	$6,677	$6,677	$6,677	$6,677	$33,385	5.9%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$3,000	$3,000	$3,000	$3,000	$3,000	$15,000	
Total		$19,677	$9,677	$9,677	$9,677	$9,677	$58,385	10.3%
Variable Program Costs								
Incentives	$1,000.00	$25,000	$75,000	$125,000	$125,000	$125,000	$475,000	83.9%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$69.57	$1,739	$5,218	$8,696	$8,696	$8,696	$33,045	5.8%
Total	$1,069.57	$26,739	$80,218	$133,696	$133,696	$133,696	$508,045	89.7%
Total Budget		$46,416	$89,895	$143,373	$143,373	$143,373	$566,430	100.0%

Program 12. Flow Efficient Fixtures Program

The primary target for this program is installation of replacement residential showerheads, swivel kitchen aerators, and bathroom faucet aerators. Where possible, this will be accomplished as an "add on" to home visits justified for other reasons.

Rationale for the Program

According to the American Water Works Association, showers are typically the third largest users of water in the home. At the present time, the US national standard for showerheads is 2.5 Gallons per Minute (GPM).[47] However, a glance at any of the airline merchandise catalogs, or a quick web search on "high pressure shower heads" will show strong marketing of high-end comfort fixtures that may have a GPM of 7.62 to 13.[48] Also, many 2.5 GPM showerheads come with detachable flow restrictors.[49]

Flow efficient fixtures have been identified as a cost effective energy saving resource for situations where the hot water is heated electrically. The electricity savings proceed from the savings in the use of electrically heated hot water, but the water and sewer savings are also important, and in some localities these water and sewer savings are more valuable than the energy savings.[50]

For this program, we specify showerheads with 2.0 GPM. This specification will insure savings over the current national standard of 2.5 GPM, which will serve as the measurement baseline. The table below contrasts the program showerhead with showerheads typically installed in customer homes. Generally, customers will not be able to find 2.0 GPM showerheads in stores.

Table 39. Energy Savings and Estimated Energy Use by Showerheads

Vintage	Rated Flow (GPM)	Actual Flow (GPM)	Est. Energy Use per Household (kWh/year)	Estimated Saving per Household with a 2.0 GPM Showerhead (kWh/year)
Program	2.0	1.4	929	0
1994-Present	2.5	1.7	1,128	199
1980-1994	3.0	2.0	1,328	399
1980-1994	4.0	2.7	1,793	864
Pre-1980	5.0 to 8.0	4.3	2,855	1926

Note 1: Assumes 5.3 minutes per person per day; 2.64 persons per household, 0.13 kWh of electricity per gallon of water at 106 degrees Fahrenheit.
Note 2: The first 4 columns (with the exception of the "Program" row) reproduced from *Energy Down the Drain, The Hidden Costs of California's Water Supply*, National Resources Defense Council & Pacific Institute, August 2004. The original source is Peter W. Meyer, et al., *Residential End Uses of Water*. Denver, Colorado: American Water Works Association Research Foundation, 1999.

[47] The established test procedure for showerheads is ASME A112.18-2000. The standard is 2.5 GPM at 80 psi.
[48] *WaterWiser,* "CWCC an Seattle Take on High-Flow Web-Marketed Showerheads," The Water Efficiency Clearinghouse, February 2006 (http://www.awwa.org/waterwiser/watch/index.cfm?ArticleID=547.
[49] It is illegal to sell a fixture with higher than 2.5 GPM, but legal to perform any personal modifications on a showerhead in the home, for example it may be useful to remove the flow restrictor if water pressure is low.
[50] It is also important to recognize that flow efficient fixtures are cost effective for gas water heating, so all customers (gas or electric) could be eligible

As with all data that covers a range of fixtures, the actual results will not be known until the program is implemented and results measured. For planning purposes, we assume a melded energy use of 1,494 kWh, reduced to 929 kWh for a savings per showerhead of 565 kWh. This is rounded down to 500 kWh for use in budgeting and in cost benefit analysis.

Average Annual Expected Savings

Potential participants were estimated at the 40 percent of residential customers with electric water heaters (2005 Residential Survey). The pattern of participation is arbitrary for this program. Since the primary modality for service delivery involves mailings by a turnkey vendor, the mailing could be done in full at any time. We show the mailing broken into segments over the five-year program, with a final participation rate of a little over 20 percent of eligible customers at the end of five years. Some utilities, for example Pacific Power and Northwest Natural Gas, have run similar programs in a single mailing. Each year the option of ramping the mailing may be considered.

Table 40. Participation and Savings - Flow Efficient Fixtures

Potential participants				48,400
Per participant savings (kWh):				500
Per participant savings (kW):				0.1
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	2,000	4.1%	1,000,000	112
Year 2	2,000	4.1%	1,000,000	112
Year 3	2,000	4.1%	1,000,000	112
Year 4	2,000	4.1%	1,000,000	112
Year 5	2,000	4.1%	1,000,000	112
Cumulative	10,000	20.7%	5,000,000	561

Marketing Plans

As noted above, the product is a 2.0 GPM showerhead. In all showerhead programs a significant issue is the longevity of the installation.

- Satisfaction. A satisfying shower is the first requirement. Everyone has a different perspective on showerheads, and a minority (usually less than 15-20%) will want to remove anything they are not familiar with. There is one problem that causes a higher level of rejection: misting. Some showerheads, usually with small holes, create a cooling mist as water evaporates from smaller drops. This is usually perceived as uncomfortable.
- Durability. Among showerheads that are acceptable enough to remain in place, durability is the next issue. Clogging and scaling are the principal deterioration modes. The most durable designs will avoid small holes, and avoid pressure compensating flow restrictors. The more durable products will be fabricated from a more scale resistant plastic such as “Teflon” or “Delrin”. In this application brass is physically durable but more subject to fouling.
- Options. The ideal showerhead will be offered in both a regular and a hand-held option.
- Value. The 2.0 showerhead is advertised in upscale catalogs at about $30. The showerhead will be nicely packaged and include an informative write-up in the package.
- This is an excellent program to review for synergies in the combination of natural gas and electricity DSM.

There are four delivery options for showerhead programs: direct installation, distribution at energy fairs (giveaways), mail-based programs, and distribution through coupons good at retail stores.

- Direct installation: The overall savings from this program is generally not large enough to support site-by-site access costs, so direct installation must be piggybacked on other programs that require visits to homes. Yet, direct installation provides the surest confirmation of installation, while confirmation of installation is a drawback of the other delivery options. There is also the possibility of exploring work with plumbers as trade allies in direct install of low flow fixtures as a optional service when they are in customer homes for other plumbing services.
- Distribution at Energy Fairs: Free distribution is not recommended because partial customer payment is likely to lead to installation.

To keep site costs low, retail rebate-based programs and mail-based programs have been used with success.

- Coupons Redeemable at Retail Stores: Retail rebates would cover three different items: showerheads, swivel kitchen faucet aerators, and small lavatory aerators. It is very important that the showerheads be 2.0 GPM rated to produce optimal energy savings. This specification, however, points to a problem in the retail approach in that most hardware retailers will likely not have a 2.0 GPM showerhead on display in the store (although they may offer it as a catalog order). Basically, the store management thinks it is already selling efficient equipment because it sells Energy Star showerheads (which are rated at 2.5 GPM), and Energy Star showerheads are more efficient that showerheads sold in the past. But in this category the Energy Star standard is identical to the national standard. This is the baseline for new showerheads, and no incremental savings can be associated with showerheads of this class. Even if a flow efficient showerhead were on display, it would have to compete visually with about fifty glittering 2.5 GPM showerheads, all offering showering bliss. In a large home products store, the display will also include high flow showerheads and multiple showerhead fixtures that wink at the national standards but appear to offer enjoyment and comfort. Any retail rebate program will have to recognize that a significant associated marketing effort would be required to get stores to stock 2.0 GPM showerheads and to alter their displays.
- Mail-Based Programs: Mail-based programs are usually administered through a vendor who operates the whole program on a "turnkey" basis. They rely on a single type of showerhead and aerator, so the consumer is not selecting among various brands and features as they might at a retail display at a home products store. However, the selected equipment is chosen for high quality and durability, and usually purchased in bulk as part of the turn key program. Both Pacific Gas & Electric[51] and Pacific Power have run programs using this approach. The mail-based program is typically a turnkey program with the utility providing only a current customer list of addresses. In this option, marketing involves a multi-step process:
    1. A card is sent making the offer, just check the box, and drop in mail postage prepaid.
    2. The new showerhead is sent and received by the customer. The customer self-installs the new showerhead. If they need help there is a number to call for assistance.
    3. The customer returns a card certifying that they have installed the new showerhead. In return, they receive an incentive such as a coupon for a free item or a "dollars off" coupon good at a local home products store.
    4. If they don't return within a reasonable period, they are sent a prompt to install and an offer of help. It is possible to keep track of the status of each customer by sophisticated coding on the labels.

For retrofit showerheads, the 2.5 GPM flow will be about 0.4 GPM lower than the existing flow estimated to be about 2.9 GPM. But a 2.0 GPM showerhead would be about 0.9 GPM lower, leading to at least double savings.

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[51] Results Center, *Pacific Gas and Electric Company, The Energy-Saver Showerhead Program*, Profile No. 14, 1992 (http://www.bpa.gov/Energy/n/reports/Results_Center/pdf/14.pdf).

Evaluations have shown much better savings for programs that use a 2.0 GPM showerhead instead of a 2.5 GPM one.

For purposes of developing a program budget, it is assumed that showerheads, swivel kitchen aerators and bathroom faucet aerators will be installed directly in cases in which another program requires a home visit. Also, it is assumed that the major mode of delivery will be a mailing program rather than a store coupon program. An important consideration in a showerhead program is the value of the water and sewer savings. These savings have tangible value and may be the basis for some degree of cost sharing with water and sewer agencies. For budgeting purposes it is assumed that such arrangements are not in place for this program cycle, however it is expected that they may be developed in the future.

The Flow Efficient Fixtures program will yield a cost offset per electricity customer of approximately $40.00 per year (see Table 41). As shown in the table, there is also cost offset to natural gas customers from the showerheads.[52]

Table 41. Customer Cost Offset - Flow Efficient Fixtures

Yearly Cost Offset to Customers						
Water Heating Fuel	**Percentage of Customers**	**Hot Water Saved (gallons/year)**	**Electricity Savings ($/year)**	**Gas Savings ($/year)**	**Water Savings ($/year)**	**Total Savings ($/year)**
Electricity	40%	4197.5	$35.86	0	$4.20	$40.05
Natural Gas	60%		0	$18.83	$4.20	$23.02
Population Weighted Average Savings:						$29.84

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program. Administration will include a share of Vectren membership in CEE, MEEA, or a similar energy efficiency organization membership.
- The program approach will be to use Vendor services for a turnkey type of program effort using the mail-based program option. The plan is to offer the showerheads (plus kitchen aerator and bathroom sink aerators) free to customers who send in a request card.
- It is assumed that Vectren will also deliver this program directly as a component of other programs that carry the cost of home visits. Vectren will also explore the possibility of a trade ally approach, working with plumbers who may offer the low flow fixtures as an option as they work in customers' homes providing other plumbing services.

Costs to participating customers:

- The cost to the customer is the customer's attention to the offer plus time and effort to self-install.

[52] Table 41 is calculated assuming a daily eleven and a half minute shower, with one GPM saved, an electric rate of seven cents per kWh, a gas rate of seventy cents per therm, and a water rate of one dollar per thousand gallons. With more showers (dependent on household or family size), savings will be higher.

Table 42. Estimated Five-Year Program Budget – Flow Efficient Fixtures

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	3.8%
Staffing, Administration and Overhead		$19,770	$19,770	$19,770	$19,770	$19,770	$98,850	14.9%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$0	$0	$0	$0	$0	$0	0.0%
Total		$44,770	$19,770	$19,770	$19,770	$19,770	$123,850	18.7%
Variable Program Costs								
Incentives	$50.00	$100,000	$100,000	$100,000	$100,000	$100,000	$500,000	75.4%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$3.89	$7,785	$7,785	$7,785	$7,785	$7,785	$38,925	5.9%
Total	$53.89	$107,785	$107,785	$107,785	$107,785	$107,785	$538,925	81.3%
Total Budget		$152,555	$127,555	$127,555	$127,555	$127,555	$662,775	100.0%

The inclusive cost per unit of $25 has been developed by checking with a vendor of this type of program. It is not the first price position of vendors, which may be $30 or $35. There are likely vendors who would go below $25 but that would likely imply a less pleasant showerhead. It is essential that the program showerhead be tested to be sure it looks good and provides a pleasant and comfortable shower experience, since that is the key to the showerhead remaining in place.

Commercial Programs

Program 13. Commercial Incentives Program

This program targets small and medium commercial businesses by providing financial incentives and technical assistance for installing prescriptive measures such as lighting, cooling, motors, refrigeration, and vending machine miser technology. This program is run through a number of delivery contractors who market their services and install the approved measures.[53] The incentives offered are intended to cover the incremental cost of a premium efficiency measure over a standard efficiency measure. They have been preset so the customer knows what incentive they will be getting based on the measures chosen. Technical assistance will be offered by in-house staff or trade allies on engineering issues related to any of the measures.

Table 43. Measures and Incentives - Commercial Incentives

Measures	Incentive Amounts
Lighting	
Replace T12 Magnetic with T5/T8 Electronic (per lamp)	$10
Hardwired CFL (per fixture)	$18
Exit Signs (LED or Electroluminscent)	$10
Traffic Signs (per lamp)	$25
Occupancy Sensors	$20
Bi-Level Switching (per room)	$50
Cooling	
Air Cooled AC and HP (per unit eff. over qual eff., per ton)	$30
Water and Evaporative Cooled A/C (per unit eff. over qual eff., per ton)	$80
Setback Thermostat (per unit)	$12
Motors	$10 to $120
Refrigeration	
Refrigeration Measures (strip curtains - /sq ft)	$0.50
Night Covers (/linear ft)	$ 4
Anti-Sweat Heater Controls (per door)	$35
VendingMisers®	$150
Technical Assistance	varies

The incentive values in Table 43 have been tested for cost effectiveness. They are approximately equivalent to the values used in current programs. By comparison, the National Grid small program has the goal of providing 80 percent of incremental cost as an incentive and financing the remaining 20 percent for the customer (http://www.nationalgridus.com/masselectric/business/energyeff/3_small.asp). Western Massachusetts Electric provides a 50 percent incentive, and finances the remaining 50 percent within the electric bill, without raising the bill, due to the energy savings (http://www.wmeco.com/Business/SaveEnergy/EnergyEfficiencyPrograms/SmallBusEnergyAdvantage.aspx). Pacific Gas & Electric (PG&E) provides a full range of incentives plus a zero interest financing program for the balance of measures (http://www.pge.com/biz/rebates/small_business/index.html). Comparison of actual incentive

[53] National Grid Small Business Services Program

rebates by equipment type is complex and can be done over the Internet. On some sites there are multiple tables and sub-tables.

This program is modeled after National Grid's Small Business Services program, PG&E's Downstream Express Efficiency Program, and Northeast Utilities: Connecticut Light and Power Company, and Western Massachusetts Electric Company's Small Business Energy Advantage programs.

Rationale for Program

The program targets small- to medium-sized commercial building owners, by helping customers overcome the cost barrier associated with installing high efficiency measures. It also provides technical assistance to customers to better understand the high efficiency measures.

Average Annual Expected Savings

The total number of commercial customer sites estimated in the Market Assessment section is the pool of potential participants for this program. As with other programs, the Year 1 participation goal is set low at 375 for the start-up year. In Years 2, 3, 4 and 5 the participation goal is moved up to 625. These targets provide a cumulative five-year program participation of about 23 percent of potential. After two years of direct program experience, the targets should be revisited and reset based on contextual knowledge and actual program experience.

Table 44. Estimated Participation and Savings - Commercial Incentives

Potential Participants				12,500
Per participant Savings (kWh):				13,246
Per Participant Savings (kW):				2.3
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	375	3.0%	4,967,250	875
Year 2	625	5.0%	8,278,750	1,459
Year 3	625	5.0%	8,278,750	1,459
Year 4	625	5.0%	8,278,750	1,459
Year 5	625	5.0%	8,278,750	1,459
Cumulative	2,875	23.0%	38,082,250	6,709

Marketing Plans

Marketing and outreach methods should include door-to-door marketing by a vendor, the use of utility credibility to help vendors sell the program to participants, and mass marketing to small business customers introducing the vendors to the customers. In addition the program should ally itself with cities and community-based organizations.

This program has multiple marketing targets. The lighting vendors and contractors play an integral role in the success of this program so they need to be informed and kept up to date on program rules and changes.

The Commercial Incentives Program is an excellent area to look for leverage of gas and electric DSM.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program
- A vendor contract to market and deliver Targeted Technical Assessments to customers, usually charged on a square footage basis plus a management fee.
- Incentives for the installation of recommended measures as demonstrated through the provision of receipts by the customer.

Costs to participating customers include:

- Customer's share of the costs of covered measures and equipment
- Installation cost

Table 45. Estimated Five-Year Program Budget - Commercial Incentives

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$35,000					$35,000	0.6%
Staffing, Administration and Overhead		$150,580	$150,580	$150,580	$150,580	$150,580	$752,900	13.4%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$65,000	$65,000	$65,000	$65,000	$65,000	$325,000	
Total		$250,580	$215,580	$215,580	$215,580	$215,580	$1,112,900	19.8%
Variable Program Costs								
Incentives	$1,458.40	$546,900	$911,500	$911,500	$911,500	$911,500	$4,192,900	74.5%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$111.82	$41,932	$69,886	$69,886	$69,886	$69,886	$321,477	5.7%
Total	$1,570.22	$588,832	$981,386	$981,386	$981,386	$981,386	$4,514,377	80.2%
Total Budget		$839,412	$1,196,966	$1,196,966	$1,196,966	$1,196,966	$5,627,277	100.0%

Program 14. Commercial New Construction Program

The new construction program offers rebates or design assistance to building owners and design teams for developing projects that are at least 30 percent more efficient than current building code. This program promotes energy efficiency in new buildings by providing incentives to design teams and project owners for projects that exceed current building code by at least 30 percent.

Incentives are offered to both project owners and the design team. These incentives will either cover 60-90 percent of the incremental cost difference between standard and energy efficient equipment, or the amount of the incentive will be enough to decrease the incremental cost to a 1.5 year payback, whichever is less. These incentives are designed to address the cost barrier.[54]

The program can also offer in-house technical assistance to design teams and project owners. This service should be an in-house service because if the service is provided by a consultant the designers may see it as a threat.[55]

Table 46. Measures and Incentive – Commercial New Construction

Measures	Project Incentive
Design Team Incentive	$ 3,320
Project Owner Incentive	

This program is based on National Grid's Design 2000 Plus program. For comparison, Western Mass Electric's (WMECo's) Energy Conscious Construction program covers most costs plus, for larger and complex projects, provides design assistance (described at http://www.wmeco.com/business/saveenergy/energyefficiencyprograms/newconstruction.aspx). National Grid's Design 2000 Plus program covered 60-90 percent of incremental cost plus a comprehensive design approach for larger and complex projects (http://www.aceee.org/utility/9angriddesign2000.pdf). More recently, as a mature program, National Grid Design 2000 Plus now covers 75 percent of incremental cost (http://www.nationalgridus.com/masselectric/business/energyeff/4_new.asp).

Rationale for Program

Project owners and design teams are the intended participants. They should be targeted using seminars on efficient building and by direct customer contact by utility staff. This program is designed to overcome first cost barriers by providing incentives that cover the incremental cost, and to provide information to project developers and design teams.

Average Annual Expected Savings

Potential participants are based on analysis of Vectren South premise data by year built. Participation in this program is estimated to be small, which is appropriate because the program is complex and will require an intensive

[54] Design 2000 Plus by National Grid. Delivered in Massachusetts
[55] Energy Conscious Construction. Delivered by Northeast Utilities: Connecticut Light & Power Company (CL&P) and Western Massachusetts Electric Company (WMECo)

focus with participants in comparison with other programs. Participation in Years 2 and 3 is projected at 15, then the participation goal is ramped to 30 for Years 4 and 5. The total over five years is 105, or about 8.4 percent of the potential market. In general programs of this type start slow and require several years of effort before the design and design/build communities fully accept participation. However, this should be viewed as an investment for the following DSM cycles in which the program can be modified and ramped higher.

Table 47. Estimated Participation and Savings - Commercial New Construction

Potential Participants				250
Per participant Savings (kWh):				28,000
Per Participant Savings (kW):				5.4
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	15	6.0%	420,000	82
Year 2	15	6.0%	420,000	82
Year 3	15	6.0%	420,000	82
Year 4	30	12.0%	840,000	163
Year 5	30	12.0%	840,000	163
Cumulative	105	8.4%	2,940,000	571

Marketing Plans

The marketing effort requires a multi-faceted approach that includes trade allies, trade association training, direct personal communication from utility staff, training sessions, direct marketing approaches, and annual meetings. The goal is to promote the quantifiable customer benefits first and to focus on the energy efficiency benefits second. The target of the marketing effort will be the project owners and the design teams. The Commerical New Construction program is an excellent area to develop DSM synergies across both natural gas and electric end uses.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Incentives for the installation of recommended measures as demonstrated through the provision of receipts by the customer.

Costs to participating customers include:

- Customer’s share of the costs of covered measures and equipment.
- Installation costs.

Table 48. Estimated Five-Year Program Budget - Commercial New Construction

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$30,000					$30,000	6.1%
Staffing, Administration and Overhead		$11,625	$11,625	$11,625	$11,625	$11,625	$58,125	11.9%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$5,000	$5,000	$5,000	$5,000	$5,000	$25,000	
Total		$46,625	$16,625	$16,625	$16,625	$16,625	$113,125	23.2%
Variable Program Costs								
Incentives	$3,320.10	$49,802	$49,802	$49,802	$99,603	$99,603	$348,611	71.4%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$251.79	$3,777	$3,777	$3,777	$7,554	$7,554	$26,438	5.4%
Total	$3,571.89	$53,578	$53,578	$53,578	$107,157	$107,157	$375,048	76.8%
Total Budget		$100,203	$70,203	$70,203	$123,782	$123,782	$488,173	100.0%

Program 15. Controls, Lights and Signs Program

The target participants include lodging and restaurants. The program installs AC controllers, occupancy sensors, in-room programmable thermostats, energy saving lighting, VendingMiser®, and LED exit signs. Incentives will cover the incremental cost of the measures above the cost of a standard efficiency measure. This is designed as a rebate program with no technical assistance component.

Table 49. Measures and Incentive - Controls, Lights and Signs

Measures	Melded Incentive Amount
AC controller	$ 3,342
Occupancy Sensor	
In-room programmable thermostats	
Energy saving lighting	
VendingMiser®	
LED Exit Signs	

This program is modeled after the "Nevada Power Cool Controls Plus" program. In the Nevada Power program, systems controllers and occupancy sensors are fully rebated. Also, for vending misers, lighting, and LED exit signs, the rebate is 90 percent and the customer pays 10 percent of the cost of the measure and installation.[56]

Rationale for Program

Motel and small hotel owners will be targeted for this program. In these markets, there is typically no energy efficiency manager, but simply a business manager or owner/manager who focuses on the business. There is generally a recognition of the value of energy efficiency, but a lack of resources to make the interest effective. Often, but not always, the building stock is older and contains few, if any, energy efficiency measures. This program helps customers overcome the first cost barrier by providing incentives for the incremental cost over the cost of standard efficiency equipment.

Average Annual Expected Savings

Potential participants come from the number of restaurants and lodging sites from the Market Assessment section.

Table 50. Estimated Participation and Savings - Controls, Lights and Signs

Potential Participants				600
Per participant Savings (kWh):				18,893
Per Participant Savings (kW):				4.8
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	30	5.0%	566,790	144
Year 2	42	7.0%	793,506	202
Year 3	48	8.0%	906,864	231
Year 4	54	9.0%	1,020,222	260
Year 5	60	10.0%	1,133,580	289
Cumulative	234	39.0%	4,420,962	1,126

[56] See Cool Controls Plus June 2006, Pp. A-121 to A-123 in Nevada Power Company 2006 Integrated Resource Plan (2007-2026), Volume 5, Demand Side Plan.

Participation is projected at 30 in Year 1, ramping gradually to 60 during Year 5. Total participation over the five years is targeted at 234. After two years experience, it is reasonable to plan to readjust subsequent year targets based on the actual program experience.

Marketing Plans

Proposed marketing efforts include direct mail and company website presence that is targeted towards motels and small hotels. The marketing materials should include informational pieces which describe the measures, their savings, their costs, and focus on the features and benefits of each measure to the motel or hotel owner. This program is specialized and probably not a good candidate for synergies with gas DSM efforts.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Incentives for the installation of approved measures as demonstrated through the provision of receipts by the customer.

Costs to participating customers include:

- Customer's share of the costs of covered measures and equipment.
- Installation costs.

Table 51. Estimated Five-Year Program Budget - Controls, Lights and Signs

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$30,000					$30,000	3.6%
Staffing, Administration and Overhead		$17,481	$17,481	$17,481	$17,481	$17,481	$87,405	10.4%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$10,000	$10,000	$10,000	$10,000	$10,000	$50,000	
Total		$57,481	$27,481	$27,481	$27,481	$27,481	$167,405	20.0%
Variable Program Costs								
Incentives	$2,663.59	$79,908	$111,871	$127,852	$143,834	$159,815	$623,279	74.5%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$197.41	$5,922	$8,291	$9,476	$10,660	$11,845	$46,194	5.5%
Total	$2,861.00	$85,830	$120,162	$137,328	$154,494	$171,660	$669,474	80.0%
Total Budget		$143,311	$147,643	$164,809	$181,975	$199,141	$836,879	100.0%

PROGRAM COST EFFECTIVENESS

Program cost effectiveness analysis answers the question of would we be better off with the DSM program compared to not having the program. The answer almost always depends on who is asking the question. In other words, better off from whose perspective? Standard DSM cost effectiveness analysis includes four perspectives that will be addressed in this report:

- Total Resource Cost (TRC)
- Participant
- Ratepayer Impact (RIM)
- Administrators Cost (formerly named Utility Cost)

A detailed discussion of cost effectiveness methodology, including the four standard tests listed above, is included in Appendix B. In this section we present the results of the cost effectiveness analysis beginning with a summary of total budget and energy savings across all programs followed by a discussion of avoided electric costs. Cost effectiveness results are then presented for each perspective and DSM program.

Expected Program Costs

The total program budget over the first five years of program activity is shown in Table 53 on page 77. We recommend a minimum of five years for program implementation and tuning for maximum effectiveness. Program budgets include the cost of incentives and other program specific expenses. They also include costs for fully loaded program staffing, administration and overhead. General public education spending for energy efficiency awareness is discussed in the Program Plans section and is not allocated to individual program budgets.

Staffing assumptions to administer the collective bundle of programs are listed in the table below. Except for the DLC program, staffing expenditures have been allocated back to each program based on the distribution of cumulative savings across all programs, regardless of cost effectiveness. Staffing expenses for the DLC program were assumed to be 7 percent of the total education budget, approximately equal to the average cost per program. This allocation strategy results in a staffing budget that scales lower with lower levels of program implementation. If all programs were implemented the entire staffing budget in Table 52 would be necessary. Summing the "Staffing, Administration and Overhead" line item of each program implemented will show the total staffing budget for implemented programs.

Table 52. Program Staffing, Administration and Overhead Assumptions

Staffing	FTE	Fully Loaded Salary	Cost
Analyst and Support Staff	4.0	$80,000	$320,000
Managerial Staff	1.0	$120,000	$120,000
Total Staffing	**5.0**		**$440,000**

Program monitoring and evaluation cost are assumed to be 6.5 percent of all other program expenses. Monitoring and evaluation expenses typically range from 5 to 10 percent of program cost.

The program budgets presented in this report include all program-specific fixed and variable expenses paid by the program administrator. It is important to understand that actual expenditures will vary from planned expenditures in their timing and distribution between specific DSM programs. For this reason it is important for the program administrator to have flexibility in the administration of DSM program funding without having to obtain approval from the Public Utility Commission. We recommend that flexibility include the following, with each action subject to review and approval by the Advisory Board:

1. Roll over unspent funds within program budgets at end of year to categories within the same program in the next year.
2. Reallocate program funds across line items within a program.
3. Shift up to 25 percent of total budget among approved programs at any time within a program year.

Having some flexibility in the administration of program funding will assist in the management of programs and enable staff to fine tune efforts for maximum resource effectiveness.

Expected Program Savings

Energy savings expected from the program are based on the designs and assumptions presented earlier in this report. Key assumptions affecting the annual savings and program cost effectiveness are shown in Table 54 below.

Most of the items listed in Table 54 were addressed in the Program Plans section. The savings life is calculated from the life of individual measures weighted by program savings and represents the duration of energy savings flowing from a participant in the program. The net-to-gross ratio captures the effect of free riders, participants in the program who would have installed the energy efficient measures without the program. Higher ratios imply a lower rate of free riders in the program.

Annual energy savings across all programs are shown in the table below. Cumulative program activity is expected to result in annual savings of 103 million kWh by the end year five. This represents approximately 3.9 percent of total kWh.

Table 53. Total Program Budget

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Res Com PV	**Res Com DLC**	**Res ES Lighting**	**Res ES Apps**	**Res Pool Pump**	**Res Refrig Removal**	**Res Cool Attics**	**Res AC Tuneup**	**Res Low Inc Wea'ize**	**Res ES New Const**	**Res ES Mnf Home**	**Res Eff Flow**	**Com Incentives**	**Com New Const**	**Com Controls & Lighting**
Year 1	399,263	164,193	127,315	209,192	95,328	75,212	291,586	482,838	740,284	46,416	55,782	152,555	839,412	100,203	143,311
Year 2	683,505	266,161	127,288	241,693	85,328	71,315	524,583	860,392	846,216	89,895	49,999	127,555	1,196,966	70,203	147,643
Year 3	683,505	372,321	127,288	241,693	97,083	82,451	524,583	860,392	846,216	143,373	49,999	127,555	1,196,966	70,203	164,809
Year 4	683,505	437,431	127,288	309,195	97,083	82,451	524,583	860,392	1,110,504	143,373	69,215	127,555	1,196,966	123,782	181,975
Year 5	683,505	480,223	127,288	309,195	108,646	82,451	524,583	860,392	1,110,504	143,373	69,215	127,555	1,196,966	123,782	199,141
Total	3,133,284	1,720,330	636,468	1,310,969	483,468	393,881	2,389,916	3,924,407	4,653,723	566,430	294,209	662,775	5,627,277	488,173	836,879

Table 54. Summary of Program Assumptions

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Per Participant:	**Res Com PV**	**Res Com DLC**	**Res ES Lighting**	**Res ES Apps**	**Res Pool Pump**	**Res Refrig Removal**	**Res Cool Attics**	**Res AC Tuneup**	**Res Low Inc Wea'ize**	**Res ES New Const**	**Res ES Mnf Home**	**Res Eff Flow**	**Com Incentives**	**Com New Const**	**Com Controls & Lighting**
Electric Savings (kWh)	2,671	0	246	316	790	700	429	1,300	1,940	3,555	3,000	500	13,246	28,000	18,893
Summer On-Peak	1,675	0	118	151	790	339	201	544	527	800	535	169	5,660	12,351	8,129
Summer Off-Peak	0	0	43	49	0	120	62	169	178	254	167	56	1,815	3,772	2,479
Winter On-Peak	996	0	71	93	0	201	97	344	796	1,568	1,420	206	4,314	8,998	6,300
Winter Off-Peak	0	0	15	24	0	41	68	243	438	933	878	68	1,457	2,880	1,984
Electric Savings (kW)															
Summer On-Peak	1.70	0.73	0.04	0.08	0.41	0.12	0.15	0.29	0.26	0.48	0.27	0.06	2.33	5.44	4.81
Winter On-Peak	0.47	0.00	0.03	0.04	0.00	0.07	0.05	0.15	0.39	0.96	0.78	0.78	1.46	3.18	3.14
Gas Savings (therms)				18					86						300
Installed Cost ($)	15000	144	12	272	180	100	500	324	1136	2017	1500	50	4166	9486	7610
Incentive ($)	2000	144	4	52	180	30	500	324	1136	1000	1500	50	1458	3320	2664
Program Costs (excl. incentives$)	325	12	1	4	13	3	33	23	76	70	101	4	112	252	197
Tax Rebate ($)	4500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Incentive Payments ($)		24													
Savings Life (years)	25.0	20.0	5.0	14.2	10.0	5.0	12.0	5.4	10.6	25.0	25.0	10.0	14.6	25.0	10.7
Net to Gross Ratio	0.95	1.00	0.90	0.90	0.90	0.95	0.90	0.90	1.00	0.95	0.95	0.80	0.95	0.95	0.95

Table 55. Total Program Savings

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Res Com PV	**Res Com DLC**	**Res ES Lighting**	**Res ES Apps**	**Res Pool Pump**	**Res Refrig Removal**	**Res Cool Attics**	**Res AC Tuneup**	**Res Low Inc Wea'ize**	**Res ES New Const**	**Res ES Mnf Home**	**Res Eff Flow**	**Com Incentives**	**Com New Const**	**Com Controls & Lighting**
Year 1	357,914		1,611,300	764,720	95,590	474,600	207,636	1,510,600	1,057,300	88,875	36,000	1,000,000	4,967,250	420,000	566,790
Year 2	1,071,071		4,833,900	1,911,800	191,180	1,185,800	622,908	4,530,500	2,324,120	355,500	108,000	2,000,000	13,246,000	840,000	1,360,296
Year 3	1,784,228		8,056,500	3,058,880	334,960	2,134,300	1,038,180	7,550,400	3,590,940	799,875	180,000	3,000,000	21,524,750	1,260,000	2,267,160
Year 4	2,497,385		11,279,100	4,588,320	478,740	3,082,800	1,453,452	10,570,300	5,280,680	1,244,250	288,000	4,000,000	29,803,500	2,100,000	3,287,382
Year 5	3,210,542		14,501,700	6,117,760	669,920	4,031,300	1,868,724	13,590,200	6,970,420	1,688,625	396,000	5,000,000	38,082,250	2,940,000	4,420,962

Avoided Costs

The avoided or marginal cost associated with a reduction in energy and demand is of primary importance when evaluating the cost effectiveness of DSM programs. These costs represent the value of avoided electric loads. Vectren's avoided costs are the reduction in the cost of supplying kWh and kW compared to what they would have been without the reduction in loads and include all incremental energy, transmission and distribution costs as well as the cost of avoided capacity. These costs vary by time of day and month. In order to capture this variance, we constructed avoided cost numbers by "costing period". A costing period is defined as a distinct time of day and season characterized by differences in supply cost compared with other periods. After reviewing supply cost data by hour and month, we defined four periods based on two seasonal and two time-of-day distinctions as follows:

- Seasonal, Summer (April-September) and Winter (October-March)
- Time of Day, On-Peak (8AM-10PM weekdays) and Off-Peak (all other times)

We used two sources of information to construct Vectren South specific avoided costs: 1) the 2005 Integrated Resource Plan (IRP) and 2) power supply costs modeled as part of the analytical work supporting the Cogeneration and Small Power Production (CSP) rate schedule. The preferred supply development plan in the 2005 IRP includes capital investments for supply in 2011 (Coal), 2015 (Large CT) and 2021 (Large CT). The dollars, MW capacity and timing of these investments were used to construct a base case avoided cost scenario that reflects these investments in power supply. Energy costs by hour and month from the CSP analysis were the basis for our estimation of energy costs. Real levelized avoided costs are shown by cost period and life of energy savings in Table 56.

Avoided costs are expressed in real levelized terms for the purposes of calculating the cost effectiveness of DSM programs. Real levelized costs reflect the annualized value over a specific period which corresponds to the expected life of the savings from program participation. The fuel cost forecast from the 2005 IRP was used to forecast energy costs through the forecast horizon, 2025. We assume that fuel costs increase at the same rate as general price inflation from 2026 through 2035. Some programs involve therm load impacts in addition to electric savings. Avoided cost for gas loads are also shown in Table 56 and were derived from the Vectren North DSM Action Plan. Demand costs per therm are dependent on the nature of the load served. System coincident peaking loads, such as space heating, have greater demand costs per therm served than non-seasonal loads, such as water heating. This relationship is reflected in the table below.

Table 56. Real Levelized Marginal Cost (2005 Dollars)

Savings Life	Energy ($/kWh)				Capacity ($/kW)		Natural Gas ($/therm)	
	Winter On-Peak	Winter Off-Peak	Summer On-Peak	Summer Off-Peak	Summer	Winter	Space Heat	Non Space Heat
1	$0.0391	$0.0239	$0.0558	$0.0253	$24.00	0	$ 1.2758	$ 1.2044
2	$0.0396	$0.0243	$0.0566	$0.0257	$28.36	0	$ 1.1687	$ 1.0973
3	$0.0407	$0.0249	$0.0581	$0.0264	$32.62	0	$ 1.0935	$ 1.0221
4	$0.0399	$0.0245	$0.0570	$0.0259	$36.78	0	$ 1.0387	$ 0.9673
5	$0.0395	$0.0242	$0.0564	$0.0256	$40.85	0	$ 0.9962	$ 0.9248
6	$0.0394	$0.0241	$0.0562	$0.0255	$52.25	0	$ 0.9647	$ 0.8933
7	$0.0393	$0.0241	$0.0560	$0.0254	$60.57	0	$ 0.9411	$ 0.8697
8	$0.0391	$0.0240	$0.0559	$0.0254	$66.03	0	$ 0.9243	$ 0.8529
9	$0.0390	$0.0239	$0.0556	$0.0252	$70.55	0	$ 0.9123	$ 0.8409
10	$0.0388	$0.0238	$0.0554	$0.0251	$71.41	0	$ 0.9040	$ 0.8326
11	$0.0387	$0.0237	$0.0552	$0.0251	$72.11	0	$ 0.8982	$ 0.8268
12	$0.0386	$0.0237	$0.0551	$0.0250	$72.69	0	$ 0.8933	$ 0.8219
13	$0.0385	$0.0236	$0.0550	$0.0250	$73.18	0	$ 0.8893	$ 0.8179
14	$0.0385	$0.0236	$0.0549	$0.0249	$73.59	0	$ 0.8866	$ 0.8152
15	$0.0384	$0.0235	$0.0548	$0.0249	$73.95	0	$ 0.8850	$ 0.8136
16	$0.0384	$0.0235	$0.0548	$0.0249	$73.79	0	$ 0.8841	$ 0.8127
17	$0.0383	$0.0235	$0.0547	$0.0248	$73.65	0	$ 0.8839	$ 0.8125
18	$0.0383	$0.0235	$0.0547	$0.0248	$73.53	0	$ 0.8838	$ 0.8124
19	$0.0383	$0.0234	$0.0546	$0.0248	$73.43	0	$ 0.8838	$ 0.8124
20	$0.0382	$0.0234	$0.0546	$0.0248	$73.33	0	$ 0.8839	$ 0.8125
21	$0.0382	$0.0234	$0.0546	$0.0248	$73.25	0	$ 0.8843	$ 0.8129
22	$0.0382	$0.0234	$0.0545	$0.0247	$73.17	0	$ 0.8846	$ 0.8132
23	$0.0382	$0.0234	$0.0545	$0.0247	$73.11	0	$ 0.8849	$ 0.8135
24	$0.0382	$0.0234	$0.0545	$0.0247	$73.05	0	$ 0.8851	$ 0.8137
25	$0.0382	$0.0234	$0.0545	$0.0247	$72.99	0	$ 0.8854	$ 0.8140
26	$0.0381	$0.0234	$0.0545	$0.0247	$72.94	0	$ 0.8856	$ 0.8142
27	$0.0381	$0.0234	$0.0544	$0.0247	$72.89	0	$ 0.8858	$ 0.8144
28	$0.0381	$0.0234	$0.0544	$0.0247	$72.85	0	$ 0.8860	$ 0.8146
29	$0.0381	$0.0234	$0.0544	$0.0247	$72.81	0	$ 0.8861	$ 0.8147
30	$0.0381	$0.0233	$0.0544	$0.0247	$72.78	0	$ 0.8863	$ 0.8149

Cost Effectiveness Results

In this section, we present the findings of the cost effectiveness analysis which provides a systematic comparison of the program benefits and costs discussed in previous sections. Results are shown from the four perspectives mentioned at the beginning of this section. Net present value (NPV) and benefit-costs ratios are shown for all perspectives. Other measures used to assess cost effectiveness differ by perspective.

The TRC perspective is the broadest of the tests represented in Table 59. As the name implies, TRC shows the total cost of the resource relative to supply side resources. The Participant Test shows the economics of program participation from the participant's perspective and reflects benefits from lower bills and incentive payments. Elements of program design, such as incentive payments, can greatly impact participant economics. Since rates are higher than avoided costs the lost revenue calculation in the RIM test exceeds the avoided cost of supply causing the programs to fail the RIM test. The one exception is the Direct Load Control program which passes the RIM test because the avoided cost of peak supply is larger than lost revenue. Lost revenues are zero for residential customers who are not assessed a demand charge. The Administrator's Cost Test reveals that when only costs paid by the program administrator are considered, the cost of the acquired resource is generally lower than the TRC unless the utility pays for the full cost of installation.

From a TRC perspective, ten of the programs are cost effective and five are presently not cost effective. If only the cost effective programs are implemented, the energy savings from the programs would generate $12 million in NPV benefits. Even after spending $2 million for the public education and awareness campaign described in the Recommended Programs section, there is still $10 million of TRC surplus generated by the recommended DSM programs.

These results are obtained using avoided supply costs calculated from assumptions and fuel price forecasts in the Vectren South 2005 IRP. As with any point forecast, the volatility and uncertainty that characterizes long term energy supply is not represented. It is our belief that most forecasts of energy prices contain more upside risk than downside. If so, this means that our forecast of DSM program cost effectiveness is a conservative view of the economic viability of alternatives to supply side resources.

Other Assumptions

Free-riders, program participants who would have installed the measure without the program, are measured through the net-to-gross ratio. A ratio of 1.0 assumes no free-riders. Most programs assume 5 to 10 percent free-riders, net-to-gross ratios of 0.95 to 0.90, respectively. The DLC program uses a net-to-gross ratio of 1.0 (no free-riders) while the Flow Efficient Fixtures program assumes 0.8 (20% free-riders). All of these assumptions are based on subjective professional opinion. Accurate estimates are beyond the scope of this study and involve specialized research that can cost several hundred-thousand dollars. There is debate over the appropriateness of including free-riders without also including free-drivers, an opposite and offsetting impact. Our approach is conservative since free-riders may be offset by program spillover effects.[57]

Certain global assumptions are required to calculate program cost effectiveness beyond those assumptions already discussed. All tests except the Participant Test use a nominal discount rate of 8.5 percent, Vectren's weighted cost of capital (2005 IRP). This translates to a real discount rate of 6.58 percent, assuming an inflation rate of 1.8 percent (2005 IRP). The participant discount rate is set higher (16% nominal) reflecting the cost of consumer capital. Externalities are set to zero percent meaning that no preferential treatment is given DSM resources over supply side options due to avoidance of environmental impact of energy supply. The Societal Test, a variant of the TRC Test, is not used in this report.

[57] Although conservative, our approach did not impact the slate of recommended programs since the non-cost-effective programs are still not cost effective at a net-to-gross ratio of 1.0.

Currently Recommended Programs

We initially formulated our slate of DSM programs from the results of our market assessment, a review of best practices and our own experience. Some of these programs have not proved to be cost effective. Conditions may change in the future which cause some of these to become cost effective. For now, however, we feel that the emphasis should be placed on implementing those programs have been shown to be currently cost effective.

Our recommendation is to implement all currently cost effective programs. Our recommended programs include:

- Residential and Commercial Direct Load Control – page 34
- Energy Star Lighting – page 38
- Energy Star Appliances and Programmable Thermostats– page 42
- Old Refrigerator Pick-Up and Recycling – page 46
- Low and Moderate Income Weatherization Enhancement – page 49
- New Residential Construction – Beyond Energy Star – page 58
- Flow Efficient Fixtures – page 62
- Commercial Incentives – page 67
- Commercial New Construction – page 70
- Controls, Lights and Signs – page 73

The low income weatherization program is barely cost effective and is also included because of the unique needs of this segment. The budget and savings impacts of recommended programs are provided in Table 57.

Table 57. Energy Savings and Annual Budget for Recommended Programs

	All Programs	Recommended Programs	Percent
Annual kWh Savings (millions - Year 5)	103.5	83.8	81%
Average Annual Program Budget (millions)	$ 5.8	$ 3.8	65%
Percent of Revenue ($207.5 million)	2.8%	1.8%	
Program Dollars per Customer	$ 41.95	$ 27.23	

Recommended programs are expected to achieve 83.8 million kWh in annual savings after five years of operation. This amounts to 81 percent of the savings from all of the programs considered. Over the five-year period, the average annual budget for recommended programs is $3.8 million, about two-thirds of the budget for all programs. Spending, on recommended programs, amounts to 1.8 percent of total annual revenue for residential and commercial customers.

Demand side management spending and savings information reported to the Energy Information Administration (EIA) is shown in Table 58 for utilities with 100,000 to 200,000 residential and commercial customers. Spending levels reported for 2005 have been adjusted to 2006 dollars. The results show a wide range of spending and savings. Spending per customer ranges from less than fifty cents to over $46. When expressed as a percent of revenue DSM spending ranges from less than one tenth of a percent to nearly three percent. Energy savings ranges from one-tenth of a percent of kWh sales to over 12 percent.

Table 58. Comparison of DSM Program Spending and Savings

Name of Utility	Ownership	DSM Spending per Customer	kWh Saved as % kWh Sales	DSM Spending as % Revenue
Southern Maryland Elec Coop Inc.	Cooperative	0.45	1.3	0.0
Kentucky Power Co.	Investor Owned	3.58	1.3	0.3
City of Tallahassee	Municipal	6.99	8.2	0.3
Sawnee Electric Membership Corp.	Cooperative	7.06	0.2	0.4
Union Light Heat & Power Co	Investor Owned	9.93	0.6	0.6
Lee County Electric Coop, Inc.	Cooperative	17.69	1.8	1.0
Tacoma City of	Municipal	22.70	12.0	2.6
Otter Tail Power Co.	Investor Owned	23.38	0.8	1.3
City of Anaheim	Municipal	25.84	8.0	2.2
Minnesota Power Inc	Investor Owned	26.89	12.4	2.4
Modesto Irrigation District	Political Subdivision	29.29	1.2	1.7
Madison Gas & Electric Co.	Investor Owned	34.49	1.2	1.7
City of Riverside	Municipal	40.36	0.1	2.8
South Carolina Pub Serv Auth	State	46.19	2.0	2.5
Average		**21.06**	**3.7**	**1.4**
Vectren South Recommended Programs		27.23	3.2	1.8
Note: Values are for total residential and commercial customers at utilities with 100,000 to 200,000 customers.				

Source: US DOE Energy Information Administration Form 861 (except Vectren South)

The spending levels recommended in this action plan are higher than the averages reported in Table 58 but well within the range of spending, a reasonable result for a utility beginning to ramp up its DSM effort. Vectren South's recommend programs achieve slightly less than average percentage savings but are higher than 10 of the 14 utilities reported. Large savings percentages from utilities with long running DSM programs tend to distort the average.

Table 59. Cost Effectiveness Results by Program

Program #	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Recommendation (Yes / No)	No	**Yes**	**Yes**	**Yes**	No	**Yes**	No	No	**Yes**	**Yes**	No	**Yes**	**Yes**	**Yes**	**Yes**
Total Resource Cost Test	**Res Com PV**	**Res Com DLC**	**Res ES Lighting**	**Res ES Apps**	**Res Pool Pump**	**Res Refrig Removal**	**Res Cool Attics**	**Res AC Tuneup**	**Res Low Inc Wea'ize**	**Res ES New Const**	**Res ES Mnf Home**	**Res Eff Flow**	**Com Incentives**	**Com New Const**	**Com Controls & Lighting**
Net Present Value (thousands of $)	(7,742)	2,740	1,488	627	(112)	34	(1,083)	(846)	130	35	(50)	852	4,884	740	383
Benefit-Cost Ratio	0.5	2.0	2.6	1.1	0.7	1.1	0.4	0.7	1.0	1.0	0.8	2.7	1.4	1.8	1.2
Real Levelized Cost ($/kWh)	0.3165	NA	0.0181	0.0958	0.1036	0.0457	0.1495	0.0665	0.0876	0.0486	0.0598	0.0185	0.0371	0.0303	0.0597
Breakeven Levelized Cost ($/kWh) *	0.0907	NA	0.0478	0.0582	0.0754	0.0481	0.0641	0.0485	0.0505	0.0506	0.0478	0.0501	0.0533	0.0542	0.0592
Participant Test															
Net Present Value (thousands of $)	(6,212)	963	3,124	972	241	656	741	3,264	3,801	428	185	1,884	6,586	624	801
Average NPV per Participant	(5,168)	135	53	50	284	114	170	312	1,058	901	1,402	188	2,291	5,945	3,423
Benefit-Cost Ratio	0.5	2.3	6.8	1.2	3.1	2.5	1.4	2.3	2.2	1.6	2.3	5.8	1.7	1.8	1.6
Simple Payback (years)	Never	1	1	8	1	2	1	1	1	7	1	1	6	6	6
Electric Rate Payer Impact (RIM) Test															
Net Present Value (thousands of $)	(1,486)	1,450	(2,130)	(1,857)	(411)	(766)	(1,469)	(3,657)	(4,641)	(725)	(304)	(1,416)	(6,571)	(665)	(849)
Benefit-Cost Ratio	0.7	1.6	0.5	0.6	0.4	0.5	0.4	0.4	0.3	0.6	0.4	0.5	0.7	0.7	0.7
Lifecycle Revenue Impact ($/kWh)	0.0001	(0.0001)	0.0002	0.0001	0.0000	0.0001	0.0001	0.0003	0.0003	0.0000	0.0000	0.0001	0.0003	0.0000	0.0000
Administrator's Cost Test (Electric)															
Net Present Value (thousands of $)	373	1,018	1,837	1,512	(125)	359	(1,272)	(1,141)	(1,718)	407	(58)	764	11,163	1,254	913
Benefit-Cost Ratio	1.1	1.4	4.3	2.3	0.7	2.0	0.4	0.7	0.6	1.8	0.8	2.3	3.3	3.9	2.2
Real Levelized Cost ($/kWh)	0.0798	NA	0.0112	0.0251	0.1070	0.0236	0.1644	0.0727	0.0876	0.0275	0.0618	0.0218	0.0163	0.0137	0.0263

[a] Based on real levelized cost figures in Table 56 and program load impacts. If real levelized costs of the program are less than the breakeven levelized costs then the program passes the TRC test.

PROGRAM EVALUATION

The table below provides a summary of the recommended DSM Monitoring and Verification (M&V) plans for each DSM Program. These are not complete plans, but they outline the type of M&V commitment that will be required to conservatively demonstrate results with high confidence, following general practice standards.

Table 60. Recommended Evaluation Approaches

Program	Evaluation (M&V) Approach
Residential and Commercial	
1. Residential and Small Commercial PV	Evaluation will combine engineering calculations with limited site monitoring of selected sites and utility metered data on all sites. Solar orientation will be recorded for each site, and direct monitoring will be conducted on selected sites. The monitoring protocol, including specification of instrumentation, and the data analytic protocol will be developed prior to implementation.
2. Residential and Commercial Direct Load Control	Evaluation will follow the existing Vectren Annual DSM Evaluation reporting format for prior years. In addition, selected sites will be monitored using thermostats and 2-way communications to quantify indoor comfort impacts. The evaluation will also produce load shape impacts for each curtailment event, and curtailment events will be interpreted with reference to Vectren's load duration curve. The evaluation will include recommendations for ramping up the participation for both residential and commercial DLC to increase the load controlled.
Residential	
3. Energy Star Lighting	The evaluation approach will be to verify the CFL wattage and to check the reasonableness of CLF life of all rebated units according to vendor/brand specifications. Also to verify the typical wattage of incandescent bulbs replaced by CFLs (the basic assumption is that all CFLs will replace an incandescent bulb of equivalent luminosity; other assumptions will be taken from the national Energy Star program, as listed on their website). Results will be quantified according to standard M&V protocols to estimate the annual and lifetime energy savings. The evaluation report will present these results and report the distribution of CFLs by brand, model, and wattage.
4. Energy Star Appliances	The evaluation approach will be to gather complete technical descriptive information to identify each Energy Star appliance rebated (brand, model, characteristics). Results will be quantified using industry standard M&V calculations for each appliance type. The evaluation report will summarize this information and present the calculation results to document energy savings.
5. Energy Efficient Pool Pumps	The M&V approach will validate energy savings by contrasting a sample with equal numbers of participant (two-speed) and non-participant (single speed) units, stratified based on motor capacity (rated horse power, for example 1.0-1.5, 2.0-2.5, 3.0). There will be an on-site mini-survey to capture technical information and customer and contractor feedback. Short-term sub-metering will be conducted to establish 15-minute demand load profiles. Electrical load and pool pump run times will be monitored. Energy savings and demand reduction calculations will follow the International Performance Measurement and Verification Protocols (IPMVP) under Option A (Partially Measured Retrofit Isolation). Under this option, the energy savings are calculated using short term measurements and using reasonable assumptions the savings are projected for the year.
6. Old Refrigerator Pick Up & Recycling	The evaluation will first verify via sample telephone survey that participating customers received the pick-up service and the rebate. For each pick-up the program vendor will be required to gather technical information on each refrigerator or freezer (manufacturer/brand, model number, defrost auto or manual, ice maker included, location (such as kitchen or garage), pick up date, and refrigerant type (cf11, cf12, cf22, hfc134, hfc141b). Calculation of energy savings and demand reductions will be carried out using industry standard M&V protocols. Environmental effects will also be estimated using standard calculations. All calculations will make use of unit specific data maintained on the DOE website to insure standard results. The evaluation report will summarize and present the results of this analysis.
7. Cool Attics	M&V will be based on short-term temperature logging before and after installation, and a comparison of utility metered data by season using a non-equivalent control group design.
8. AC Tune-Up	M&V will follow methods recommended by Proctor Engineering for this type of program or equivalent methods.

9. Low and Moderate Income Weatherization Enhancement	For GAP homes, M&V will follow a traditional non-equivalent control group design using either PRISM or regression modeling, with an equal number of treated and similar untreated homes. For augmented homes, the evaluation will use Oak Ridges methods of partitioning cost and benefit according to a coordinated design to apportion energy savings primarily to the utility (and utility funded measures) and health and safety, furnace replacement, and repairs essential to permit weatherization to government funding under a health and safety calculus. For the addition of homes, the state will be requested to modify its federal reporting database to add variables that will permit breaking out Vectren funded homes for standard evaluation using a traditional non-equivalent control group design.
10. Energy Efficient Residential New Construction	Savings calculations will follow the International Performance Measurement and Verification Protocol (IPMVP) Option D (Calibrated Computer Simulations), assisted by information from the DOE website, onsite survey and verification of a few selected homes, and limited data logger monitoring. An evaluation plan will provide the specifics of the instrumentation for the data logger, calculation methods, and assumptions.
11. Energy Efficient Manufactured Homes	Savings calculations will follow the International Performance Measurement and Verification Protocols (IPMVP), Option A (Partially Measured Retrofit Isolation). Energy savings will be calculated using engineering calculations, short-term measurements, and specified assumptions. The basic approach will be to attach data loggers to an equal number of Energy Star and non-Energy Star manufactured homes and measure the home's energy usage during the same weather conditions. The particular focus will be on indoor temperature, and electrical usage characteristics of the home under summer, winter, and shoulder seasonally conditions. Homes will be selected in pairs to be of the same class.
12. Flow Efficient Fixtures	Evaluation will be based on different levels of analysis. First, customer cards certifying installation will be tabulated giving an overall install rate. Second, 60 homes in which direct install is carried out will be measured (before and after) for flow rate for showerhead, kitchen aerator, and bathroom sink aerators (to measure at least 60 of each fixture) using a Microwier or similar device. Results will be used to adjust the planning equations based on American Water Works Research Foundation data and to compute kWh, therms, water, and sewage savings.
Commercial	
13. Commercial Incentives	For each project selected for verification, a verification plan will be developed for the site, depending in part on the measures (ECM complexity, technologies, anticipated interactive effects), the project estimated value of energy conserved, and site review. For each project selected, there will be a pre-installation site review, as site-specific plan detailing how measurements will be taken (with assumptions), any pre-installation M&V effort as required by the plan (to establish the baseline), post-installation M&V (with post-installation metering), and development of a post-installation M&V report. A final Evaluation report will summarize results over the sites and characterize the yearly savings due to the program. Spot or short-term metering is expected to determine baseline and post-installation energy use. Analysis will follow the International Performance Measurement and Verification Protocols (IPMVP) under Options A (Partially Measured Retrofit Isolation, B (Retrofit Isolation), C (Whole Facility), and D (Calibrated Simulation) as suitable under IPMVP to the specific measures installed at specific sites.
14. Commercial New Construction	Savings calculations will follow the International Performance Measurement and Verification Protocol (IPMVP) Option D (Calibrated Computer Simulations), assisted by information from the DOE website, onsite survey and verification of selected buildings, and limited data logger monitoring. An evaluation plan will provide the specifics of the instrumentation for the data logger, calculation methods, and assumptions.
15. Controls, Lights, and Signs	A M&V sample will be developed to validate energy savings based on technologies installed. Analysis will be primarily by short-term metering of energy consumption and run-times. Spot and short-term metering will be used to establish baseline conditions. Analysis will combine metered results with engineering calculations and specific assumptions, following the International Performance Monitoring and Verification Protocol (IPMVP) Option A (Partially Measured Retrofit Calculation) and Option B (Retrofit Isolation). The final evaluation plan will specify how savings are calculated for each specific technology (VendingMisers®, LED Exit Signs, etc.)

APPENDIX A. METHODOLOGY

At the root of most DSM analysis there is some form of energy usage model. The model often used in larger multi-utility DSM planning, synthesizes estimates from demographics applied to engineering prototypes. This approach is easy to apply to individual measures and to small groups of measures where the result of all the measures is small relative to the total energy sales. But the simple synthesis approach becomes unstable where a large or comprehensive technical potential is contemplated because the simple sum may not include measure interactions, and can result in inflated savings estimates. Also demographic information and market penetration information are more accurate applied to large regions, but lack precision when applied to smaller regions. Under this circumstance, the cumulative errors due to lack of precision can compound into large errors.

Therefore, in this case, where a technical potential will be derived from a maximum application of a wide variety of interacting measures and applied to a relatively small region, we have opted to approach the estimate with a "calibrated engineering model". With this approach we will true the models to the current actual energy sales by fitting a relatively simple algebraic model to the recorded energy use (and demand) and the associated average monthly temperatures. This approach has the strong advantage of starting the analysis from a verifiable energy use situation. Another significant advantage of this approach is that it is somewhat empirical, and the data fitting process will reveal large unusual energy use situations, if they exist. Finally, it is particularly important to be able to establish a reasonably bounded estimate of the aggregate energy under conditions representing the full technical potential, which requires the explicit treatment of measure interactions afforded by the engineering modeling approach.

Within conditioned spaces, heating and cooling energy will be influenced by lighting and other internal gains and by large scale refrigeration. This results in an interaction of energy savings measures. Another form of measure interaction is related to changes in thermal conversion efficiency. Whenever there is a load reduction measure, the net realized energy savings will also be dependent on an assumed thermal conversion efficiency. Where a thermal conversion efficiency is changed at the same time as a load reduction, the result is interactive, and it is important to consider the effect of both measures simultaneously. In this case, where a wide range of efficiency and load reduction measures will be applied, it is particularly important to be able to deal with measure interactions in an orderly way.

The model has been devised and structured with explicit variables to express in physical or engineering terms, the measures and treatments involved in attaining the full technical potential. This includes variables for conversion efficiency, load reductions and thermal and electrical solar energy measures. The model will also estimate the changes in peak demand associated with the applied efficiency measures. The following discussion will be in two parts: the first part for the energy model, and the second part for the demand model.

The Nature of the Data

A brief review of the energy sales and the associated average temperature, as illustrated in Figure 22 and Figure 23, shows that the daily average energy use has a close relationship to temperature.

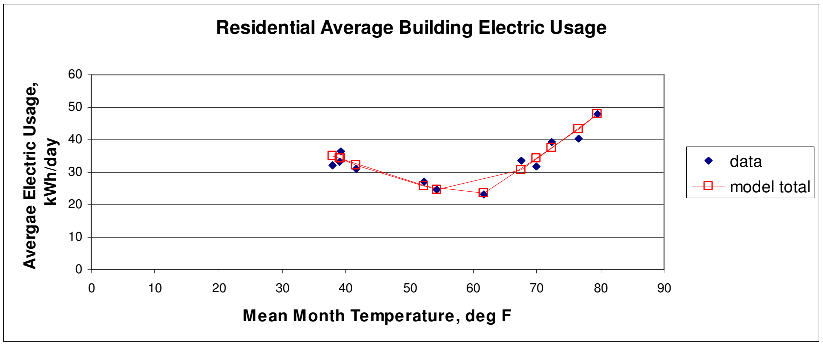

Figure 22. Existing Single Family, Average of 1,000 Cases

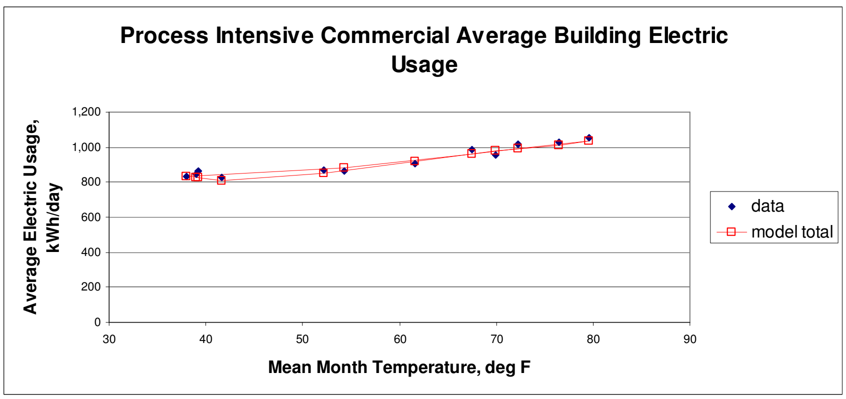

Figure 23. Grocery, Average of About 200 Cases

Figure 22 was derived from a random sample of 1,000 cases drawn from a pool of about 99,000 residential single family units older than five years. This model is intended to characterize the energy use in the largest portion of the residential sector. There are other similar models for the three other smaller portions of the sector. In general, these models of average performance fit quite closely with an R square usually in excess of 95 percent. This figure shows clearly the increased energy use at higher temperatures for air conditioning. And it also shows increased average energy use at low temperatures for heating, mostly by about 20,000 customers with electric furnaces. Note that at average temperatures in the range of 55-65 deg F, there appears to be no heating or cooling. Energy use at these temperatures is mostly the residential base load: lights, plugs, hot water.

Figure 23 was derived from all the available billing histories of customers classified as Grocery in the Vectren service territory, about 200 cases. The model and the data fit quite closely here. The average grocery store shows an increased energy use with temperature associated with air conditioning and mostly with refrigeration. There appears to be little electric heating. In Figure 23 most of the energy use appears to be grocery base load, typically interior refrigeration, lights, and ventilation.

Analysis Categories

Customers in the Vectren commercial and residential sectors were subdivided into 16 categories such as the two discussed in Figure 22 and Figure 23, and a simple engineering model was fitted to the usage and temperature data. The first four of these categories apply to the residential sector subdivided as in Table 61.

Table 61. Residential Sector Analysis Categories

Age of Structure	Single Family	Multifamily
Older than 5 Years	99,241	12,317
Less than 5 Years	7,683	1,817

And the next twelve are the commercial categories listed in Table 62.

Table 62. Commercial Sector Analysis Categories

Commercial Type	CIS Premises	Physical Structures
Grocery Stores	216	191
Hospital	76	69
Lodging	103	82
Office	4,547	3,275
Other	3,457	2,453
Other Health	577	508
Restaurant	494	462
Retail	1,201	1,008
Schools	302	253
Wholesale, Warehouse	1,095	798
Agric, Mining, Util, Constr	5,221	2,903
Manufacturing	644	518

Note in Table 62 that there are more CIS premises than physical structures. This is because some of the commercial accounts are for non-structures, such as, lighted signs etc. When accounts, with usage less than 3,500 kWh per year, are excluded, the number of physical structures is estimated. The analysis in the energy model is carried out on the basis of the number of CIS premises, but other analysis, such as program planning, is based on the number of physical structures.

The Structure of the Energy Model

The models applied in each of the sixteen analysis categories, including Figure 22 and Figure 23, are all similar and represent six very fundamental end-uses:

- Heating
- Cooling
- Hot Water
- Lighting
- Internal Uses, Plugs, Cooking, Dishwasher
- External Uses, Outdoor Lights, Washer, Dryer

Note that the fundamental end-uses distinguish between internal and external electric energy use. This is for the purpose of estimating measure interactions between the heating and cooling end-uses and the electrical energy use within the conditioned space. Lighting and internal uses are assumed to occur within the conditioned envelope.

Model Inputs

Some of these end-uses are dependent on weather variables. The heating and cooling end-uses depend on average monthly temperature; the hot water end-use depends on the average monthly inlet water temperature, and lighting depends slightly on calendar month and day length. The thermal and electrical solar energy benefits depend on the average monthly solar. The other end-uses are assumed constant from month to month. For weather dependent inputs the models use the inputs shown in Table 63.

Table 63. Weather Inputs to Modeling

End-use	Inputs
Heating	Monthly average temperatures, and long-term average month temperatures
Cooling	Monthly average temperatures, and long-term average month temperatures
Hot Water	Monthly long-term average Inlet water temperatures
Lighting	Seasonal lighting usage factors

Beyond the weather inputs are the inputs pertaining to the distribution and operation of the energy using systems. These are the variables that are changed in the process of fitting a model to the data. It is noteworthy that the relatively few systems inputs shown in Table 64 are sufficient to fit a model so closely to the data, but that lies in the nature of fitting the averages of hundreds or thousands of sites.

This model is very simple in an attempt to be reasonably transparent and reviewable. It admittedly does not include many well known second order effects, such as variation of heating COP with temperature. However, the simple treatment of energy use in terms of first order effects is sufficient to the principal purposes here, which are: 1) to be able to true-up the model to the current energy use, and 2) to be able to estimate a physically reasonable energy use assuming conditions of full technical potential.

Table 64. Energy Systems Performance Inputs

DHW saturation
DHW gal/day
Tank loss btu/deghr
DHW set temp
DHW efficiency
Space Saturation
Space efficiency
Space set temp
Space slope btu/deghr
Lights kWh/day
Lights saturation
Internal loads kWh/day
Internal penetration
External Loads
External penetration
Cool saturation
Cool set temp
Cool slope BTU/deg hr
Cool efficiency
Cooling fraction

Separation into End-Uses

The total energy use is partitioned into the six fundamental end-uses by a combination of empirical discovery and engineering calculation, however simple.

The heating and cooling end-uses are empirically derived through the fitting of the model to the energy versus temperature slope in the usage and temperature data. The hot water end-use is explicitly calculated from water usage, inlet water temperature, and storage loss assumptions.

During weather neutral months such as April and May, these models empirically show the total building base load. But the models cannot go further and separate that total base load into its constituent end-uses: hot water, lighting, internal loads, and external loads.

The further separation of end-uses is done by removing the explicitly calculated hot water end-use and partitioning the remaining base load (lighting, internal loads, and external loads) on the basis of US national electric energy end-use splits. For the residential sector as a whole and for most of the commercial analysis categories there are published end-use splits on the average energy use for a full range of end-uses.

For this analysis appropriate items from the full range of end-uses are aggregated into the three fundamental end-uses used in this analysis: lighting, internal uses, and external uses. From these aggregated end-uses two ratios are developed, *internal usage/lighting*, and *external usage/lighting*. These two ratios are then used in the models to maintain the appropriate relationships between lighting, internal uses, and external uses.

Usage Normalization

For planning purposes, usage data is normalized to the average 30-year temperatures for the region, in this case Evansville Airport. Figure 24 shows the actual temperatures in the test year and the long term average temperatures.

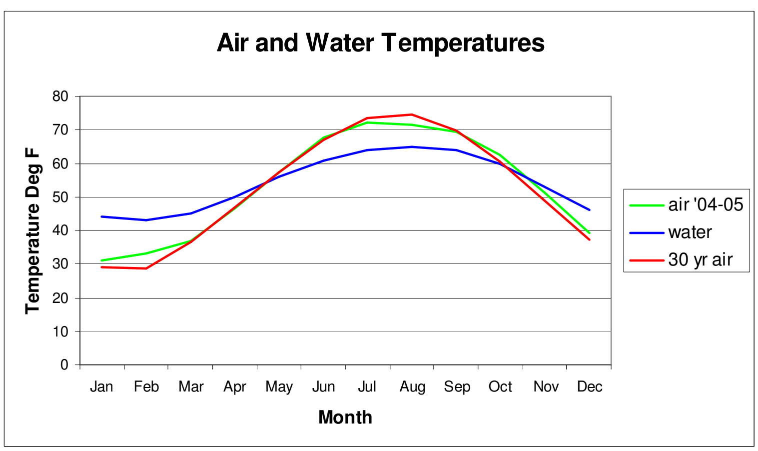

Figure 24. Air and Water Temperatures

In Figure 24, it is evident that the test year, green, is close to the 30-year average, red. The water temperature in Figure 24 refers to the ground water temperature which is used in the end-use models for hot water heating energy. In this case, the 30-year estimate of the groundwater temperature is assumed the same for the test year.

Perspectives on Energy

For perspective and review, the average daily energy use by end-use category and by month for each of the sixteen analysis categories is shown graphically at the end of this appendix.

Part 2. The Demand Model

The Available Data

Vectren made available a System Peak Day Load Analysis. This analysis proceeded from a load metered sample worked to an estimate of the total system load, and to the load of the principal customer sectors, i.e., residential, commercial etc. The portion of the load under study in this analysis is only the residential and commercial loads, which comprise only about half the total system load. The loads excluded from this analysis are the direct sales to municipalities, industrial transport, and some primary service commercial customers.

This load analysis provided separately the total residential and total commercial coincident peak load for each hour of the peak day for each month for the analysis period, September 2004 through August 2005. This analysis is the benchmark to which this demand model is trued up.

But first it is important to note that the energy model developed here estimates the average demand for a particular hour for each month. The average hourly demand from this model is quite different than the peak day hourly load for the same hour and month in the Vectren System Peak Day Load Analysis. They are almost as different as apples and oranges because the hourly demand is born of the monthly average and the peak hourly load comes from the monthly extreme and includes transmission and distribution losses. Initially, it appeared that they were not strictly comparable because the peak day energy use was greater than the average daily energy use for the month. But initial analysis using the real monthly temperatures for the load study months, was done. This showed that if the peak day loads were de-rated to 74 percent of their value, the daily energy was the same as the average day demand. More importantly, the initial analysis showed that the shape of the de-rated peak day load curves provided an opportunity to empirically modify and tune the timing of the predicted demand.

The Demand Model

The demand model is driven by the energy model. For each end-use and for each month, the energy model estimates the average daily energy use, kWh/day. The demand model then takes the estimated daily energy use and distributes it among the twenty four hours of the day.

The objective of this demand model is to estimate the average distributed hourly demand for a large number of customers. The concept of distributed demand assumes that thousands of the same device, (stove water heater, computer, etc) will be turning on and off according to use at random times within the hour of interest. The contribution of any one of these devices is the full load power*duty cycle for the hour. For example, if a 1400 watt toaster is on for one-tenth of the hour, the distributed demand is 1400 watts times 0.1 hours, or 140 watts. In essence, the distributed demand is the energy used in the hour.

The distribution from daily energy use to hourly is done by means of "demand distribution functions". The demand distribution function consists of twenty-four hourly demand factors that specify the fraction of the daily energy use that occurs in each hour. Figure 25 and Figure 26 show the hourly demand factors empirically derived from this analysis and applicable to the residential customers.

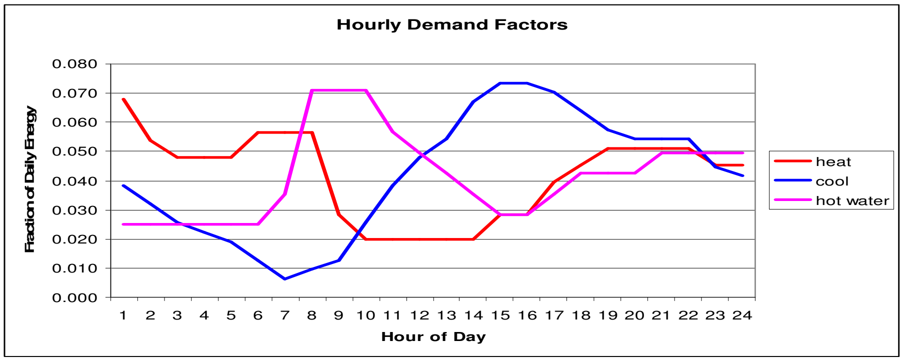

Figure 25. Residential Hourly Demand Factors for Heat Cool, Hot Water

Notice in Figure 25 that the cooling demand factor is greatest at about 4-5 PM when the cooling energy for each hour reaches about .073*daily average cooling energy. Similarly, the hourly demand factor for heating appear to be maximum at 1 AM when the hourly demand factor is .068 and the hourly heating energy is .068*daily average heating energy. Hot water demand is known to be bi-modal occurring in the morning and late evening.

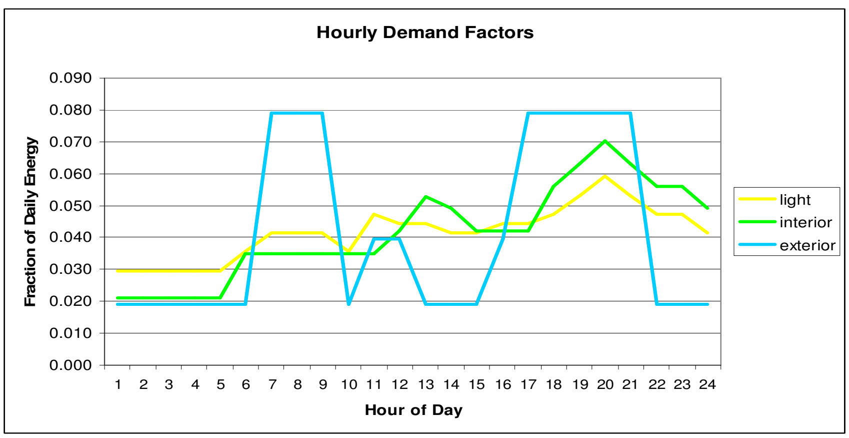

Figure 26. Residential Hourly Demand Factors for Lighting, Interior, and Exterior Loads

Notice in Figure 26 that the interior loads and lighting work toward a daily peak at about 8PM. The exterior load here consists of washer and dryer activity and some exterior lighting. Washers and dryers are considered here to be external loads because most of the energy is discharged outside as in the case of dryers. Or because the load may occur in an attached space such as a basement or wash porch that is not directly part of the conditioned space, as in the case of washers.

In the model there is a set of hourly demand factors for each of the six end-uses for each of the 16 analysis categories. In principal quite a lot of unique demand specifics. But in practice the comparison of the modeled demand and the de-rated peak day load curves was done at a much aggregated level. For example the de-rated commercial peak day load was compared hour by hour to the sum of the demand estimated in the twelve commercial analysis categories. In this comparison, the data is not detailed enough to distinguish one commercial load from another. Therefore, there is a set of hourly demand factors for each of the six end-uses, and these are used in all twelve of the commercial analysis categories. The commercial hourly demand factors are shown in Figure 27 and Figure 28.

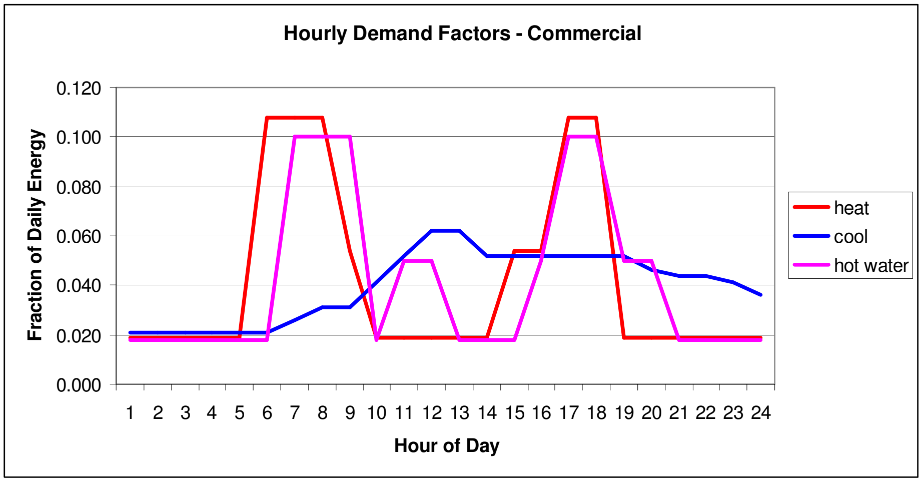

Figure 27. Commercial Hourly Demand Factors for Heating, Cooling, and Hot Water

There is very little electric heating or water heating in the commercial sector, and the demand factors for these end-uses find minimal use. In Figure 27 the demand factors for cooling are the most important.

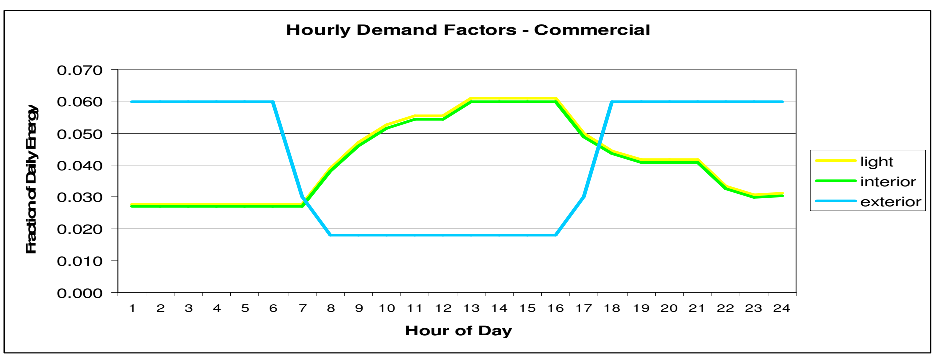

Figure 28. Commercial Hourly Demand Factors for Lighting, Internal and External Loads

In Figure 28, the hourly demand factors for the exterior loads express the fact that these loads are principally exterior lighting which is on at night. The hourly load factors her of principal importance are those for the lighting and interior loads

Truing the Demand Model

The demand model is ultimately trued against the coincident peak day. But the truing process first requires an adjustment from peak load to average demand. The residential peak load is de-rated by the factor 0.73, and the commercial peak load is de-rated by the factor 0.76. The de-rating from peak load to average demand is intended to adjust for transmission and distribution losses, and it is intended to adjust for the increased energy use on a peak day relative to an average day. These peak de-rating factors are empirically derived by comparing the total energy use for the peak day to the total energy use on the average day. In principle, the peak de-rating factors will vary from month to month, but in this model the constant peak de-rating factors noted above are used for all months. After this adjustment, the peak load is comparable to the average demand.

The first step in the demand true-up is to adjust the base load end-uses, lighting, internal loads, external loads, and hot water. The adjustment consists of modifying the hourly demand factors for these end-uses until the model is close to the demand derived from the load study. This comparison is best done when heating and cooling are at a minimum. Once the hourly demand factors are so adjusted they are then used to represent the base load in heating and cooling situations. Figure 29 shows a close comparison between the demand estimated by the model and the demand from the load study after this first true up step.

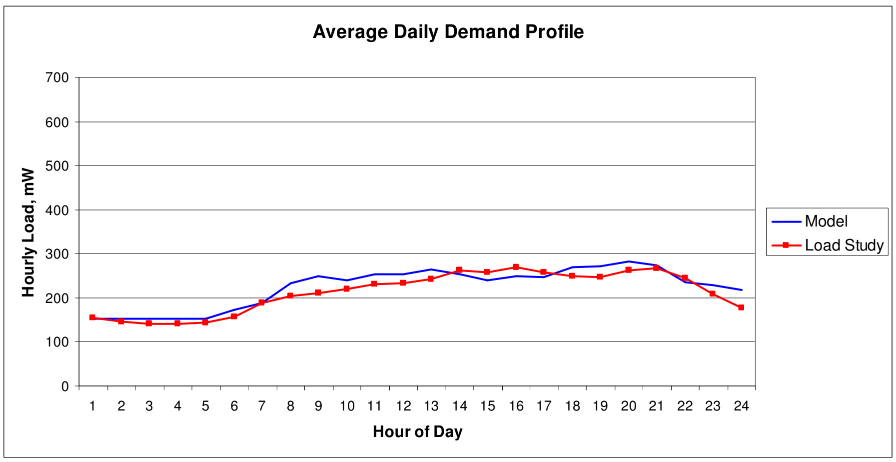

Figure 29. The Base Load True-Up - Commercial and Residential, April

The next step in the true-up is for cooling. In this case the model is compared to the load study for a maximum cooling month and the hourly load factors for the cooling end-use are adjusted for best fit between the model and load study. This true-up step is best done for the months of July or August.

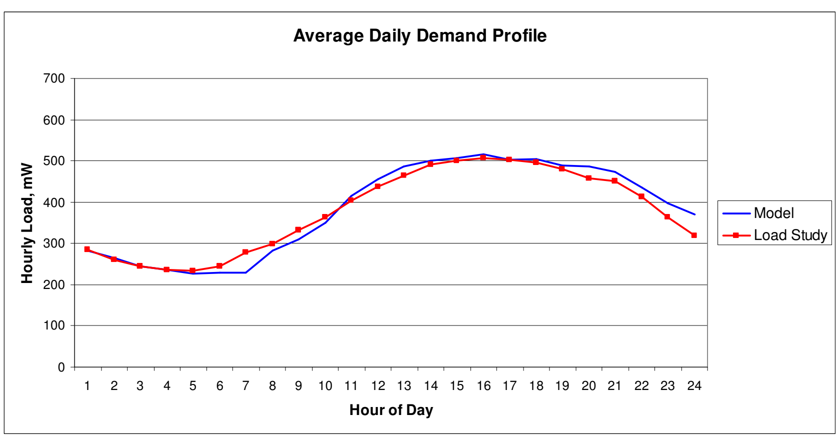

Figure 30. The Cooling True-Up - Commercial and Residential, August

Figure 30 shows a close comparison between the demand estimated by the model and the demand from the load study after this cooling true-up step.

The final demand true-up step is for heating. In this case the model is compared to the load study for a maximum heating month and the hourly load factors for the heating end-use are adjusted for best fit between the model and load study. This true-up step is best done for the months of December or January.

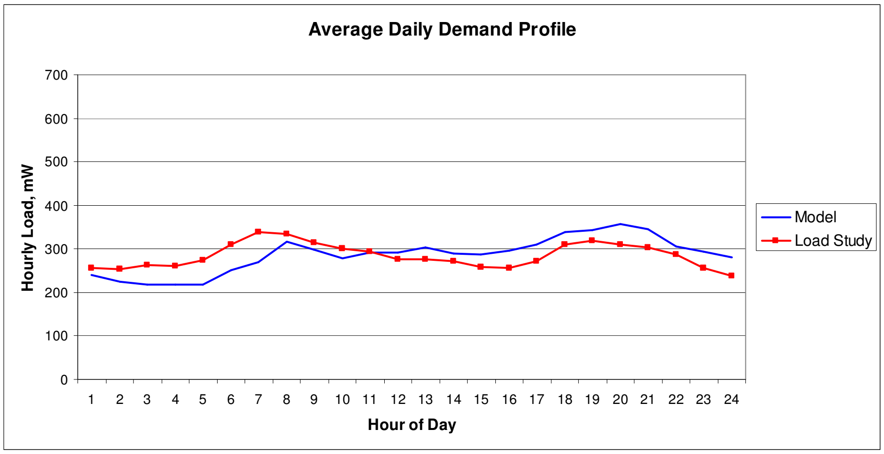

Figure 31. The Heating True-Up - Commercial and Residential, January

Figure 31 shows a close comparison between the demand estimated by the model and the demand from the load study after this heating true up step. Through these true-up steps, the most significant hourly demand factors are derived and the demand model can now estimate the average daily demand versus hour for each month.

Estimating the Coincident Peak Day Load

There is a relationship between the coincident peak day load versus hour and the average day demand versus hour produced by this model. It is the peak de-rating factors. To estimate the coincident peak load, the average demand is divided by the peak de-rating factor, just the opposite as was done to derive average demand from peak load above.

Estimating the Technical Potential for Demand Savings

This model will estimate the change in average hourly demand for each month corresponding to any group of efficiency measures or all the measures used to express full technical potential. This month by month change in hourly demand will be reported as the demand impact. As such, this demand impact does not include effects of transmission and distribution losses that will be in the financial analysis to both energy and demand.

Measure Savings

The screening relies on measure savings that are observable in real world billing histories. Thus the measure savings used in this screening are the net observable savings after and including the effects of take back, measure interactions, and background energy usage changes. Competent impact evaluations often report savings at the measure level as in Table 65.

Table 65 is based on an impact evaluation and mini load study by Proctor Engineering done on SIGECO's 1994-96 set of DSM programs. These programs were operated in the current Vectren electric service territory. This comprehensive evaluation has useful information on electric and gas savings observed, and electric demand savings observed. The results of this evaluation are consistent with our modeling of this building stock and with evaluations at other utilities.

Table 65. Net Energy Savings by Measure - Proctor, 1997

Measures	**Electric Savings from Measures applied to Gas Heated Buildings**	**Electric Savings from Measures applied to Electrically Heated Buildings**	**Gas Savings from Measures applied to Electrically Heated Buildings**
	(kWh/year)	**(kWh/year)**	**(therms/year)**
Average per Site	1,040	1,497	Not estimated but present
Attic Insulation		1,891	
Water Heater Insulation		240	
Duct Sealing		1,104	

The measure specific estimates in Table 65 were derived by regression from a billing and temperature data for each site and they have been normalized for weather.[58] The table does show evidence of "crossover savings," that is, electric savings resulting from measures intended to produce gas savings. There is no regression of gas savings resulting from measures intended to produce electric savings the fundamental relations of building physics tell us they will be there. These crossover savings result from measures such as duct sealing, attic insulation, wall insulation, or house sealing which produce both gas heat and electric cooling savings. The table highlights a cost effectiveness issue for this analysis: the true cost effectiveness of some measures will need to include the value of both the electric and gas savings.

[58] The work, on which Table 65 is based, has much more detail on gas energy savings at the measure level which is not shown.

APPENDIX B. COST EFFECTIVENESS METHODOLOGY

Cost effectiveness analysis refers to the systematic comparison of program benefits and costs using standardized measures of economic performance. In this report, cost effectiveness is discussed at both the technology level and the program level. The assumptions and approach used to calculate technology and program cost effectiveness are presented in this appendix. Much of the material in this section is taken from the *California Standard Practice Manual: Economic Analysis of Demand Side Management Programs and Projects, October 2001* (SPM 2001),[59] which has broad industry acceptance.

Technology Cost Effectiveness

It is desirable to consider some measure of a technology's cost effectiveness in the preliminary stages of program design. This allows program planners to subjectively tradeoff cost and other attributes of energy conservation measures (ECM) when considering possible program designs. Cost effectiveness analysis is less precise at the technology screening stage because estimates of energy savings and costs at the measure level are subject to a great deal of variance due to interaction with other measures and actual program implementation. Still, measure cost effectiveness provides a useful metric for consideration along with the many other factors outlined in the Program Plans section of this report.

What is needed at the technology or measure level is a simple measure of cost effectiveness that does not require assumptions of avoided resource cost, rebates, program delivery cost and other program level details. Levelized Cost (LC) provides such a measure by expressing the cost of a measure in annual terms per unit of energy saved. This allows an easy way to compare and rank order the cost effectiveness of measures. The formula used for the LC calculations in this report is presented below:

LC=DCosts / DSavings

$$DCost = \sum_{t=1}^{N} \frac{IC_t + OM_t}{(1+d)^{t-1}} \qquad DSavings = \sum_{t=1}^{n} [(\Delta EN_t) \div (1+d)^{t-1}]$$

where:

LC	=	Levelized cost per unit of the total cost of the resource (dollars per kWh)
IC	=	Incremental cost of the measure or technology
OM	=	Annual operation and maintenance cost
DCost	=	Total discounted costs
DSavings	=	Total discounted load impacts
ΔENit	=	Reduction in net energy use in year t
N	=	Life of measure
d	=	Discount rate

[59] Prepared by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). All formulas and discussion are based on the SPM 2001. Formulas have been modified to remove peak savings, multiple costing periods, and otherwise adapted to be relevant for use with this project.

Although not suited for fuel substitution and load building programs, LC provides an easily calculated way of comparing measures. Measure cost, savings, useful life, and discount rate are the only assumptions required for calculating LC. Real levelized cost refers to LC expressed in constant dollars (i.e., without inflation).

The formula used in Microsoft Excel to approximate LC is as follows:

LC = (OM-PMT(d,N,IC))/EN

where PMT is the payment function in Excel and the other terms are defined as above.

For example, using a real discount rate of 6.6%, a measure life of 18, an incremental cost of $200, and annual savings of 100 kWh with no annual O&M, results in real levelized costs of $0.1931.

Program Cost Effectiveness

Many additional assumptions over and above those required for calculating ECM cost effectiveness must be made when calculating program cost effectiveness. Cost effectiveness of energy efficiency programs involves describing the economic impact of the program from the perspective of various groups. This analysis required detailed program budgets and design elements such as rebate levels and other program features. Perspectives, also called tests, presented in this report are listed in the table below along with the primary benefits and costs used to compute cost effectiveness.

Table 66. Benefits and Costs by Cost Effectiveness Test

Cost Effectiveness Test	Benefits	Costs
Participant	Reduced gas bill Incentive payments Tax credits Decreased O&M costs	ECM installation Increased O&M costs
Ratepayer Impact	Avoided gas costs (net)	Lost gas revenue (net) Program expenses
Total Resource Cost	Avoided gas costs (net) Tax credits Decreased O&M costs	ECM installation Program expenses Increased O&M costs
Program Administrator Cost (formerly named Utility Cost)	Avoided gas costs (net)	Program expenses paid by program administrator

Reference to “net” indicates that the load used to measure the benefit or cost is net of free riders. ECM installation includes all incremental costs to acquire and install an ECM. Program expenses include all costs related to delivery of the program and include staffing and overhead, advertising, incentive payments, administration fees, and monitoring and evaluation expenses.

Various measures of the economic impact are available for each perspective. The two primary measures we will use in this report are listed below:

- Net Present Value
- Benefit-Cost Ratio

In addition to the economic criteria listed above, other criteria may be unique to a given perspective. For example, simple payback of investment is often cited as an important criterion from the participant perspective. Each of the perspectives is discussed in detail below including the assumptions and formulas required to calculate the measures of economic impact. Each of the cost effectiveness tests are discussed below.

Participant Test

This test compares the reduction in energy bills resulting from the program with any costs that might have been incurred by participants. Other benefits included in this test include incentive payments and tax credits. When calculating benefits, gross energy savings are used rather than reducing savings for free-riders.

The main value of the Participant Test is that it provides insight into how the program might be received by energy consumers. The incentive level required to achieve some minimum level of cost effectiveness, for example, can be useful in program design efforts. It should be noted, however, that consumer decision making is far more complex than reflected by the Participant Test. For this reason, the test should be used as one consideration of likely program acceptance and not an absolute indicator.

Ratepayer Impact Measure Test

The Ratepayer Impact Measure (RIM) Test measures the impacts to customer bills and rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates will go up if revenues collected after program implementation is less than the total costs incurred by the utility for implementing the program. This test indicates the direction and relative magnitude of the expected change in customer rate levels.

The benefits calculated in the RIM Test are the savings from avoided supply costs. These avoided costs include the reduction in commodity and distribution costs over the life of the program.

The costs for this test are the lost revenues from gas sales and all program costs incurred by the utility, including incentives paid to the participant. The program costs include initial and annual costs, such as the cost of equipment (either total cost for a new installation or net cost if done as a replacement), operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in supply costs and lost revenues should be calculated using net savings.

Total Resource Cost Test

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. Of all the tests, the TRC is the broadest measure of program cost effectiveness. This makes the TRC Test useful for comparing supply and demand side resources.

The primary benefit in the TRC Test is the avoided cost of gas. Loads used in the avoided cost calculation are net of free riders. Tax credits and reductions in annual O&M costs, if applicable, are also treated as a program benefit (or a reduction in costs). Costs used in the TRC calculations include all ECM installation costs, program related costs and any increased O&M costs no matter who pays them. Incentive payments are viewed as transfers between participants and ratepayers and are excluded from the TRC Test.

Program Administrator Cost Test

The Program Administrator Cost Test measures the cost of acquired energy savings considering only the costs paid by the program administrator. Benefits are similar to the TRC Test but costs are more narrowly defined. Its primary purpose is for assessing resource acquisition from the perspective of the program administrator. In this sense, it is similar to the Participant Test in that the test provides a measure of cost effectiveness from a single perspective that does not include all costs.

Benefits included in the calculation are the avoided cost of gas. Net loads are used for the purpose of calculating avoided cost of gas benefits. The costs include all administrator program expenses including incentive payments for ECM installation.

APPENDIX C. NON-RECOMMENDED DSM PROGRAM PLANS

Programs that are not recommended are presented in this appendix and summarized below.

Residential and Commercial Programs

- Program 1. Residential and Small Commercial Photovoltaic

Residential Programs

- Program 5. Energy Efficient Pool Pumps
- Program 7. Cool Attics
- Program 8. AC Tune-Up
- Program 11. Energy Star Residential Manufactured Home

Residential and Commercial Programs

Program 1. Residential and Small Commercial Photovoltaic Program

The Vectren Residential and Small Commercial Photovoltaic (PV) program is designed to provide incentives for the installation of residential and small commercial building PV systems (small PV or solar electric systems). A secondary objective is to provide customer education on the benefits and drawbacks of PV systems, grid connected and non grid-connected, and the realities of net metering.[60]

The program will offer a $3 per watt incentive up to $7,500 per system or up to 50 percent of the cost of installing renewable generation, whichever is less. It is expected that a 2 kW system suitable for a single-family home may cost in the neighborhood of $20,000 or more. However, there is a federal tax credit of 30 percent through December 31, 2007 which may be extended or renewed.[61]

Vectren will provide an on-line cost and benefits estimator on its website to indicate likely utility bill savings and percentage of bill savings, as well as, estimated cost of system, taking the federal tax credit into account. Customers will be required to sign the incentive application form and a customer purchase agreement prepared by the installer. The customer purchase agreement will outline total installed costs, provide detailed costs of all major components, identify the expected cash incentive(s), and provide an installation schedule. Customers will be required to sign off on the packing slip indicating all system components have been delivered to the installation site. Eligible installers will be required to complete all paperwork required by Vectren for administration of the program.

Table 67. Measure and Incentive - Residential and Small Commercial PV

Measures	Incentive Amount
PV Systems	$ 2,000

Rationale for Program

The number of utilities promoting a PV option continues to grow, in part because PV systems remove load from the electric system on summer peak days. The program is modeled on the NYSERDA New York Energy $mart[SM] Photovoltaic (PV) and Solar-Electric System Incentive Program.

[60] Under "net metering" the PV system is connected to the electric utility system (the "grid"). This requires signing an interconnection agreement with the utility company. The interconnection agreement sets the terms and conditions under which a PV system can be safely connected to the utility grid and outlines metering arrangements (net metering) for the PV system. Net-metering allows the PV system to send excess electricity back through the electric meter to the utility.

[61] The Energy Policy Act of 2005 (EPACT) tax credit reduces tax on a dollar per dollar basis. It provides a credit equal to 30% of qualifying expenditures for purchase for qualified photovoltaic property and for solar water heating property used exclusively for purposes other than heating swimming pools and hot tubs. The ceiling for the credit is $2000 (http://www.energy.gov/taxbreaks.htm). The possibility of state tax credits or incentives should be researched.

Average Annual Expected Savings

Table 68. Estimated Participation and Savings - Residential and Small Commercial PV

Potential participants				133,500
Per participant savings (kWh):				2,671
Per participant savings (kW):				1.7
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	134	0.1%	357,914	228
Year 2	267	0.2%	713,157	454
Year 3	267	0.2%	713,157	454
Year 4	267	0.2%	713,157	454
Year 5	267	0.2%	713,157	454
Cumulative	1,202	0.9%	3,210,542	2,043

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers for customer education, and mention of the program in any Vectren communications with customers regarding energy efficiency program options.
- The program will also be marketed through trade allies.
- The incentive will be paid to eligible PV installers that have been approved by Vectren. Vectren will maintain a list of qualified installers, inspect the work, and require that the full initiative be passed through as a cost reduction to the customer.

Data collection and documentation for program purposes and annual reporting will require tracking of jobs, job costs, and materials, as well as results of inspections. At the beginning of the program it will be necessary to estimate the number, type, size, and reliability of operating PV systems within Vectren's electric service territory (grid and non-grid) to establish the baseline for the program.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Incentive per job.

Costs to participating customers:

- Customer's time.
- The balance of cost, beyond the customer incentive.

Table 69. Estimated Five-Year Program Budget - Residential and Small Commercial PV

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	0.8%
Staffing, Administration and Overhead		$12,695	$12,695	$12,695	$12,695	$12,695	$63,475	2.0%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$50,000	$50,000	$50,000	$50,000	$50,000	$250,000	8.0%
Total		$87,695	$62,695	$62,695	$62,695	$62,695	$338,475	10.8%
Variable Program Costs								
Incentives	$2,000.00	$268,000	$534,000	$534,000	$534,000	$534,000	$2,404,000	76.7%
Other Program Expenses	$180.00	$24,120	$48,060	$48,060	$48,060	$48,060	$216,360	6.9%
Monitoring and Evaluation	$145.13	$19,448	$38,750	$38,750	$38,750	$38,750	$174,449	5.6%
Total	$2,325.13	$311,568	$620,810	$620,810	$620,810	$620,810	$2,794,809	89.2%
Total Budget		$399,263	$683,505	$683,505	$683,505	$683,505	$3,133,284	100.0%

Program 5. Energy Efficient Pool Pump Program

The Vectren Energy-Efficient Pool Pump program will provide incentives to residential customers who retrofit their pools with energy-efficient two-speed pool pumps. These pumps are expected to reduce contribution to summer peak demand by about 0.54 kW per pump. They will also reduce annual kWh consumption.

The proposed incentive of $180 is the incremental cost of the efficient versus standard pool pump.[62] In this approach, by covering full incremental cost, it will be possible for Vectren to work directly with pool pump dealers and contractors. Rather than working directly with customers, the dealers and contractors will work with customers. The incentive will go to the dealers and contractors with the requirement that the full benefit be passed to the customer in the form of a cost reduction.

Table 70. Measure and Incentive - Energy Efficient Pool Pump

Measure	Incentive Amount
Two-Stage Pool Pump	$180 per unit

This program is modeled after the June 2006 Nevada Power Company Energy-Efficient Pool Pump Project.

Rationale for Program

Utilities have long run pool pump programs. Current in-market technology permits both a meaningful contribution to demand reduction and kWh energy savings by moving the market to the two-stage pump from the current standard single-stage pump.

Average Annual Expected Savings

Table 71. Estimated Participation and Savings - Energy Efficient Pool Pump

Potential Participants				6,050
Per participant Savings (kWh):				790
Per Participant Savings (kW):				0.4
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	121	2.0%	95,590	49
Year 2	121	2.0%	95,590	49
Year 3	182	3.0%	143,780	74
Year 4	182	3.0%	143,780	74
Year 5	242	4.0%	191,180	98
Cumulative	848	14.0%	669,920	343

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers for customer education, and mention of the pool pump program in any Vectren communications with customers regarding energy efficiency program options.

[62] The difference in cost between an efficient two-speed pool pump and the standard one-speed pool pump in the California Energy Commission DEER database. Pool pumps have an average life of ten years.

- However, the marketing strategy for this program is directed "midstream" at the target market of pool pump dealers and contractors. The focus in enlisting and working with trade allies in this program will be promotion of energy-efficiency as a desirable product attribute in interactions with their customers. This program may be developed by Vectren customer representatives or may be administered by a third party program contractor.[63]
- By paying the full incremental price, the goal is to directly replace the sale of standard pool pumps with the energy-efficient option, essentially through price administration and arrangement for direct technical substitution, such that within two years the product and stocking stream moves to the high end product. After two years, the incentive can be reduced if there has been a very strong market effect.
- If a program vendor is used, the program vendor will be asked to tailor the program "package" as much as possible to Vectren's needs.
- Data collection and documentation for program purposes and annual reporting will be included as features of the vendor program "package," or the responsibility of the Vectren program manager with the cooperation of trade allies, who will be asked to provide Vectren with data on sales and stocking practices. Data estimation of the baseline market and market potential should be refined as the program is developed.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program. Administration will include a share of Vectren membership in CEE, MEEA, or a similar overarching energy efficiency program membership.
- Vendor services for the program vendor if the program vendor route is selected (development of promotional materials, rebate forms, and incentive processing; meetings with dealers and contractors or consultation on Vectren customer representative meetings with dealers and contractors).
- Incentives for the program participation in the form of a rebate of full incremental cost.

Costs to participating customers:

- Customer's attention to literature. The customer's time in interacting with dealers and contractors is a sunk cost, only the content of the interactions is changed by the program.
- The installation cost of the new energy efficient pool pump.

Table 72. Estimated Five-Year Program Budget - Energy Efficient Pool Pump

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$10,000					$10,000	2.1%
Staffing, Administration and Overhead		$2,649	$2,649	$2,649	$2,649	$2,649	$13,245	2.7%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$59,360	$59,360	$59,360	$59,360	$59,360	$296,800	61.4%
Total		$72,009	$62,009	$62,009	$62,009	$62,009	$320,045	66.2%
Variable Program Costs								
Incentives	$180.00	$21,780	$21,780	$32,760	$32,760	$43,560	$152,640	31.6%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$12.72	$1,539	$1,539	$2,314	$2,314	$3,077	$10,783	2.2%
Total	$192.72	$23,319	$23,319	$35,074	$35,074	$46,637	$163,423	33.8%
Total Budget		$95,328	$85,328	$97,083	$97,083	$108,646	$483,468	100.0%

[63] For example, WECC or ECOs Consulting (which is administering the Nevada Power pool pump project on which the Vectren program is modeled).

Program 7. Cool Attics Program

The Vectren Cool Attics program is designed to provide a working heat barrier in attics, and focused in particular on attics that contain parts of the home heating and cooling systems. The Cool Attics program is designed to decrease cooling energy use, lower energy bills, and to increase indoor comfort. It will also have a small effect in reducing energy demand on summer peak days.

Residential roofs are usually dark colored and have low-reflectance surfaces which reach temperatures from 50 to 190°F on hot summer days. Attic space is similarly superheated compared with the conditioned space in the home and when a hot attic contains part of the cooling system it can lead to inefficient cooling.

One solution is "cool roofs," that is, replacing the traditional dark roofing materials with white cool roof replacements that have high solar reflectance and high thermal emittance. Solar reflectance is the percentage of solar energy that is reflected by a surface. Thermal emittance is defined as the percentage of energy a material can radiate away after the energy is absorbed. However, roof replacement is infrequent and quite expensive. Also, the introduction of white roofs will change the look of residential neighborhoods. For these reasons, cool roofs are not a good program alternative, although for homes in which the roof is being replaced, a "cool roof" is an excellent replacement. An alternative, low cost approach that homes with hot attics can employ is the attic radiant barrier.

The attic radiant barrier is an aluminum foil blanket installed on the interior of the attic. Along with the barrier, the attic is ventilated with ridge and soffit vents. Vents are louvers, grills, or screen materials which allow passage of air through them. They are typically installed along the top peak (ridge) of the roof, at the top of the side wall (gable), and on the underside of the roof overhang (soffit). Ventilation moves air through the attic by the natural force of wind or by the natural force of heat rising through natural convection. Ventilation also has the ability to remove humidity and improve the effectiveness of attic floor insulation. Attic ventilation is very important because hot air needs to escape from the attic. Attic floors will be insulated to R-30. The radiant barrier is placed between the roof and the attic floor insulation. If properly installed, it will prevent 95 percent of the heat that radiates from the roof into the attic from affecting the attic space. By reducing the amount of heat in the attic, less heat is absorbed by leaks in ducts and through the duct insulation. This system is expected to save on summer cooling bills.[64]

[64]According to the US DOE Fact Sheet, "Since the ceiling heat gains represent about 15 to 25 percent of the total cooling load on the house, a radiant barrier would be expected to reduce the space cooling portion of summer utility bills by less than 15 to 25 percent. Multiplying this percentage (15 to 25 percent) by the percentage reduction in ceiling heat flow (16 to 42 percent) would result in a 2 to 10 percent reduction in the cooling portion of summer utility bills. However, under some conditions, the percentage reduction of the cooling portion of summer utility bills may be larger, perhaps as large as 17 percent. The percentage reduction in total summer utility bills, which also include costs for operating appliances, water heaters, etc., would be smaller." US DOE, "Radiant Barrier Attic Fact Sheet," DOE/CE-35P, June 1991, updated June 27, 2001 (http://www.ornl.gov/sci/roofs+walls/radiant/rb_02.html). Up to 90% of summer heat gain and up to 75% of winter heat loss comes from radiant heat. Insulation is relatively ineffective at blocking radiant heat.

Table 73. Measures and Incentives - Cool Attics Program

Measures	Melded Incentive Amounts
Attic Radiant Barrier	$ 500
Attic Floor Insulation	
Installation of Attic Vents	

Radiant barriers are included as a measure in several utility programs. The radiant barrier is particularly suited for climates with hot summers.

Rationale for Program

The Vectren Cool Attics program will substantially lower interior attic temperature during hot summers, reducing cooling load. The radiant barrier will also have a smaller effect in reducing loss of radiant heat through the attic. By focusing on homes in which the heating/cooling ducts and/or parts of the cooling system are in the attic the effect of the program will be intensified.

Average Annual Expected Savings

Table 74. Estimated Participation and Savings - Cool Attics Program

Potential Participants				48,400
Per participant Savings (kWh):				429
Per Participant Savings (kW):				0.2
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	484	1.0%	207,636	75
Year 2	968	2.0%	415,272	149
Year 3	968	2.0%	415,272	149
Year 4	968	2.0%	415,272	149
Year 5	968	2.0%	415,272	149
Cumulative	4,356	9.0%	1,868,724	671

Marketing Plans

- Proposed marketing efforts include the use of utility bill stuffers for customer education, and mention of the program in any Vectren communications with customers regarding energy efficiency program options.
- The program will also be marketed through trade allies in the crafts that install radiant barriers, and, if possible, through IN-CAA.

Data collection and documentation for program purposes and annual reporting will require tracking of jobs, job costs, and materials, as well as results of inspections.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Measures and installation costs.

Costs to participating customers:

- Customer's time.
- The balance of cost, beyond the customer incentive.

Table 75. Estimated Five-Year Program Budget - Cool Attics Program

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	1.0%
Staffing, Administration and Overhead		$7,389	$7,389	$7,389	$7,389	$7,389	$36,945	1.5%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$1,200	$1,200	$1,200	$1,200	$1,200	$6,000	
Total		$33,589	$8,589	$8,589	$8,589	$8,589	$67,945	2.8%
Variable Program Costs								
Incentives	$500.00	$242,000	$484,000	$484,000	$484,000	$484,000	$2,178,000	91.1%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$33.05	$15,997	$31,994	$31,994	$31,994	$31,994	$143,971	6.0%
Total	$533.05	$257,997	$515,994	$515,994	$515,994	$515,994	$2,321,971	97.2%
Total Budget		$291,586	$524,583	$524,583	$524,583	$524,583	$2,389,916	100.0%

Program 8. AC Tune-Up Program

This program targets both residential and small commercial customers, and technicians who tune existing AC systems to make them operate at their stated efficiency. The technician can receive an incentive for diagnosing the system, an additional incentive for refrigerant and airflow adjustment, and the customer can also receive an incentive for completing a systematic tune-up of the system.

The program uses trained HVAC technicians who repair or service AC and heat pump systems and verify the diagnosis through a computerized expert system which analyzes and recommends proper settings for refrigerant and airflow which the technician then adjusts. The computerized expert system ensures accurate test results and proper repairs of the HVAC system because certified technicians verify their diagnosis through the system. The technicians test the system and send their test readings to the system call center while still on the client site. The call center immediately analyzes the reading and makes recommendations on refrigerant charge and airflow, which the technician then implements on the spot. The system also has the capability to pay incentives to the technician immediately.

The incentives are included to induce technicians to use the expert system program so that they accurately tune the HVAC systems. The incentives are also designed so that customers request certified technicians and get a proper tune-up and to offset the increased cost for use of the expert system. Thermostats will also play an important role.

Table 76. Measures and Incentives - AC Tune-Up

Measures	Incentive Amounts
Bundled Tune-Up	$300
Thermostat	$120

Rationale for Program

The targets for this program are HVAC technicians who tune-up systems for residential and small commercial customers. The program addresses the fact that efficient HVAC systems rarely operate at their rated efficiencies. The expert system and protocol insure that before the technician leaves, the parameters are correctly set.

This program pays the incremental cost for the technician to complete the expert system protocol and to precisely adjust the unit so that it operates at stated efficiencies. The technicians must undergo training and work with expert system vendor staff thereby incurring some cost. This program offsets those costs. The incentive to the customer creates a market pull which will induce more technicians to become certified for the program.

Average Annual Expected Savings

Table 77. Estimated Participation and Savings - AC Tune-Up

Potential Participants				116,160
Per participant Savings (kWh):				1,300
Per Participant Savings (kW):				0.3
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	1,162	1.0%	1,510,600	336
Year 2	2,323	2.0%	3,019,900	671
Year 3	2,323	2.0%	3,019,900	671
Year 4	2,323	2.0%	3,019,900	671
Year 5	2,323	2.0%	3,019,900	671
Cumulative	10,454	9.0%	13,590,200	3,022

Marketing Plans

This program is targeted to both technicians and customers. The expert system vendor recruits, trains, certifies and verifies technician's work. They also promote the program to Vectren customers. Vectren could additionally target residential and small commercial customers via bill stuffers and with a strong page on the company website. This page must comprehensively describe the program parameters and clearly delineate for the customer why they should request expert system vendor certified technicians for their tune-ups. Customers need to know that, unless a system has been checked and adjusted, it is exceedingly likely that their "efficient" unit is operating far below its rated efficiency.

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program
- Program fees to the expert system vendor for establishing the program. They will recruit and train contractors, gather and report data, develop a customer packet and document the service provided to the customer. Program details will be negotiated with the expert system vendor.[65]
- Technician incentives
- Customer incentives

Costs to participating customers include:

- Participating customers pay the cost of the service call. The value of the incentive is the additional amount it would cost to hire a certified technician.

[65] This design is based on the Proctor Engineering CheckMe!® program.

Table 78. Estimated 5-Yr Program Budget - AC Tune-Up

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	0.6%
Staffing, Administration and Overhead		$53,737	$53,737	$53,737	$53,737	$53,737	$268,685	6.8%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$1,200	$1,200	$1,200	$1,200	$1,200	$6,000	
Total		$79,937	$54,937	$54,937	$54,937	$54,937	$299,685	7.6%
Variable Program Costs								
Incentives	$324.00	$376,488	$752,652	$752,652	$752,652	$752,652	$3,387,096	86.3%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$22.73	$26,413	$52,803	$52,803	$52,803	$52,803	$237,626	6.1%
Total	$346.73	$402,901	$805,455	$805,455	$805,455	$805,455	$3,624,722	92.4%
Total Budget		$482,838	$860,392	$860,392	$860,392	$860,392	$3,924,407	100.0%

Program 11. Energy Star Residential Manufactured Home Program

The primary target for the national program to which this Vectren program will be tied is housing manufacturers who manufacture Energy Star manufactured homes. An Energy Star qualified manufactured home is a home that has been designed, produced, and installed in accordance with Energy Star guidelines by an Energy Star certified plant and is up to 30 percent more efficient than HUD code.[66] Both the plants and the homes are inspected. This program will require a vendor arrangement which will supply the Energy Star manufactured home program as a package arrangement. There are thirteen Indiana participating builders of Energy Star manufactured homes listed as partners on the US DOE Energy Star website (www.energystar.gov), including a new partner builder listed in Evansville in 2006.

Energy Star homes feature properly installed insulation, duct sealing and testing to ensure proper performance (typically an upgrade), ventilation that moves fresh air through the home, energy efficient windows , dishwashers, water heating and heat pumps, and compact fluorescent lighting.

These homes typically sell for an additional $4,500 and cost manufacturers about $1,500 more per home. The incentives encourage the manufacturers to make Energy Star homes available and encourage the agent to promote the homes. In this program, there is a buy-down of the cost of the home representing the energy value of the home to Vectren. The local sales agent and dealership is viewed as the key because if they sell the homes the manufacturers are more likely to make them available. A program vendor is expected to handle the manufacturer end of the package.

Table 79. Measures and Incentives - Energy Star Residential Manufactured Home

Measures	Incentive Amounts
Energy Star Partial Buy-down	$ 1,500

This program is developed from the Energy Star Manufactured Home, and The Energy Trust of Oregon Energy Star Manufactured Home Program, and the EarthAdvantage Manufactured Home Program.

Rationale for Program

Vectren's target for this program is the manufactured home sales agent. The program aims to encourage manufacturers to have Energy Star homes on the lots for sale and the sales agents need to be educated about the value of an Energy Star manufactured home so they can better sell them. This program aims to make efficient homes easily available and more affordable for Vectren customers, by insuring that at least some Energy Star homes are available on sales lots in Vectren's service territory.

The basis of this program is not volume, but education and taking practical steps to open energy efficiency housing options for customers. Relationships with manufacturers and plants are expected to be a part of a vendorized

[66] See Energy Star website (www.energystar.gov/index.cfm?c=bldrs_lenders_raters.pt_builder_manufactured).

program package, while Vectren will focus on dealer relationships and customer relationships within its electric service territory.

Average Annual Expected Savings

Table 80. Estimated Participation and Savings - Energy Star Residential Manufactured Home

Potential Participants				110
Per participant Savings (kWh):				3,000
Per Participant Savings (kW):				0.3
Program Year	**Number of Participants**	**Percent Participation**	**kWh Saved**	**kW Saved**
Year 1	12	10.9%	36,000	3
Year 2	24	21.8%	72,000	7
Year 3	24	21.8%	72,000	7
Year 4	36	32.7%	108,000	10
Year 5	36	32.7%	108,000	10
Cumulative	132	24.0%	396,000	36

Marketing Plans

Vectren Energy Delivery currently provides assistance in home energy assistance, marketing support, and consumer education for the new home market, though not targeted to the manufactured home market segments. It is difficult to focus an energy efficiency program on the manufactured home market. Manufacturers build the homes, but typically independent agents sell the home. At the same time a pattern in the industry over the last fifteen years has been the integration of firms from financing through manufacturing and sales, and the industry is becoming vertically integrated. For the independent dealers there is typically a high turnover of sales agents. For vertically integrated firms the turnover is less, but one of the challenges of this program is to insure the presence of sales personnel who understand and believe in the value of energy efficiency as a product attribute.

A primary goal of the program is to ensure Energy Star manufactured homes are available on sales lots in Vectren service territory, and are replenished as stock is sold so that Vectren customers will also have an energy-efficient manufactured housing option available for inspection and delivery. Second, the Vectren program will provide a partial buy-down of the energy value of the home. Third, Vectren will work with dealers to insure sales personnel understand the advantages of energy efficient homes and use this knowledge in showing options to customers. Fourth, Vectren will include information on energy-efficient choices in manufactured housing on its website and provide promotional literature on Energy Star manufactured homes to customers and through dealers.

The marketing methods should include:

- Newspaper and real estate guide ads
- Signage
- Marketing materials
- Builder and subcontractor training and ongoing technical assistance.
- An annual conference that brings together building professionals from the area and throughout the country to share expertise and experiences in designing and building high-performance homes and buildings.

- Training in the advantages of Energy Star homes for all the builders, sales staff, realtors, and the lending community.
- Seminars and literature targeted at consumers are a valuable addition to a marketing effort because consumers can create a market pull.

Key elements that should be incorporated into this program to make it successful include[67]:

1. Establish a single stable multi-year approach because this will give stability to builders and allow the program to grow more readily.
2. A single, simple and high program standard of efficiency is important because it lets builders know where they stand and what is expected.
3. Establish good relationships with area builders and developers
4. Ensure that staff professionalism, delivery systems, equipment, marketing materials and quality assurance are all of high quality.
5. Strict adherence to specifications based on sound building science and economics to maintain program credibility and consistency.
6. The program must be developed such that it establishes a process for certifying and documenting homes built to Energy Star requirements.[68]
7. Develop a solid infrastructure of experienced, well-known and respected organizations.
8. Develop targeted incentives that are well coordinated with marketing and other service-related materials
9. Coordinate with health and safety standards and codes for residential construction.
10. Provide ongoing technical training for builders and subcontractors.
11. Promote builders buy-in into the program by getting them financially invested in the program through advertising, building requirements, and training so they will support all aspects of the program.[69]

Detailed Budget Plans

An estimated five-year budget for this program is provided below. The anticipated cost to Vectren for offering this program to customers involves budgets for:

- Vectren administrative costs to develop, advertise, oversee and monitor the program.
- Spiff to be paid to the agent or dealership.
- Partial buy-down of cost of the home.

Costs to participating customers include:

- Customer's outlay for any remaining incremental cost of an Energy Star manufactured home.

Table 81. Estimated Five-Year Program Budget - Energy Star Residential Manufactured Home

	Cost per Participant	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr Total	Percent of Total
Fixed Program Costs								
Start Up Costs (First Year Only)		$25,000					$25,000	8.5%
Staffing, Administration and Overhead		$1,566	$1,566	$1,566	$1,566	$1,566	$7,830	2.7%
General Public Education		$0	$0	$0	$0	$0	$0	0.0%
Program Specific Implementation		$10,000	$10,000	$10,000	$10,000	$10,000	$50,000	
Total		$36,566	$11,566	$11,566	$11,566	$11,566	$82,830	28.2%
Variable Program Costs								
Incentives	$1,500.00	$18,000	$36,000	$36,000	$54,000	$54,000	$198,000	67.3%
Other Program Expenses	$0.00	$0	$0	$0	$0	$0	$0	0.0%
Monitoring and Evaluation	$101.36	$1,216	$2,433	$2,433	$3,649	$3,649	$13,379	4.5%
Total	$1,601.36	$19,216	$38,433	$38,433	$57,649	$57,649	$211,379	71.8%
Total Budget		$55,782	$49,999	$49,999	$69,215	$69,215	$294,209	100.0%

[67] Drawn from the Vermont ENERGY STAR Homes program run by Efficiency Vermont and Vermont Gas Systems.
[68] See the Texas program
[69] See the Texas program

APPENDIX D. RESIDENTIAL ECM DOCUMENTATION

The purpose of this appendix is to provide documentation of the assumptions used to screen the residential Energy Conservation Measures (ECM) identified for consideration in this report. Our assumptions are based on references cited throughout this section as well as the direct experience of our team with technologies in the field and actual DSM program evaluations. While not all of the field and DSM program experience can be cited in published works, published references are used to establish a reasonable range of assumptions. The point estimate used within that range is based on our professional opinion.

Solar Photovoltaic (R-1)

This technology consists of a roof or ground mounted solar electric array with a full sun output of 2 kW. Such an array has an area of 200-300 square feet. Electricity from the array is converted to AC by an inverter and the power is immediately used on site with excess fed into the grid. This technology needs full solar exposure and shadows can significantly restrict output. This technology is fully mature, but local builders and building officials are still unfamiliar with it.

Measure Applicability

No local studies have estimated the percentage of housing stock with suitable exposure; for this analysis it is assumed that 35% of residential buildings are suitable sites.

Incremental Cost

A system installation usually requires an electrical inspection to verify appropriate wire sizing, disconnects, and grounding. Costs are quite site specific, with most of the costs associated with solar electric panels. In the current supply-constrained 2007 market, costs are $5.00-$7.00/watt peak for the solar cells alone. Installation and balance of system can be expected to add $3.00/watt. For the 2 kW array considered here the total cost will be taken as $16,000[70] or $8.00/watt.

Average Annual Expected Savings

The electrical output for this technology is directly related to the solar intensity. Monitoring studies in this region of the US have shown that 1 kW of installed capacity can yield in excess of 1,100 kWh/yr. For the 2 kW array considered here the annual savings will be taken as 2,200 kWh/yr.

Expected Useful Life

This equipment demonstrated long trouble free service in severe applications such as remote communications, navigation lighting, and road signage. The long term output of the cells is assumed to decrease with time, but the rate of decrease for current technology is not known. The crystalline and semi-crystalline forms of the technology have already demonstrated degradation of less than 20% in 20 years. But earlier thin film forms of the technology

[70] The C&RD Database lists the incremental capital cost as $6,000 per kW, which would be comparable for an installed 2 kW system.

have showed shorter lifetimes. The lifetime of new thin film technologies is expected to be of the order of 25 years but it is not known. For these purposes the lifetime is taken as 25 years.[71]

Resistance Electric Furnace to SEER 13 Heat Pump (R-2, R-3)

This measure is designed save heating energy and cooling energy by replacing an existing central air conditioner/electric furnace by a modern heat pump. Most of the savings proceed from replacing resistance heating by a heat pump at more than twice the thermal efficiency. This measure has significant savings, but also significant costs because it involves replacing the whole heating and cooling system, not including ducts.

Measure Applicability

This measure is applicable to about 17% of the residential sector that heats with and electric (resistance) furnace.

Incremental Cost

This measure requires replacing the whole heating/cooling system not including ducts. The cost of such a replacement is quite site specific, but can be expected to be a first cost of $10,000 or more. There are two contexts for such a replacement: 1) early retirement in-order to achieve large heating savings, and 2) where the central AC needs to be replaced anyway, the most prudent thing would be to replace with a heat pump because of its significant heating savings. The upgrade to a heat pump can be expected to cost about $5,500-$6,500 more than the AC replacement alone. For this analysis we assume $10,000 as the incremental cost.

Average Annual Expected Savings

The average annual expected savings from this measure depends on the size of the residence. Based on Vectren specific simulations we find savings in the range of 6,000 kWh/yr for a single family residence and 4,800 kWh/yr in the multifamily application.

Expected Useful Life

The physical life of this measure is about 20 years, but for the purposes of this analysis we will take 10 years as the useful life of this measure to reflect the application of this measure in an early retirement context.

SEER 8 to SEER 13 Central Air Conditioner (R-4, R-5)

This measure is designed to save cooling energy by preemptively replacing an inefficient old central air conditioner by a modern efficient one. This measure is applied to a gas heated residence.

Measure Applicability

This measure is applicable to existing residential air conditioners, about 79% of the residential stock.

Incremental Cost

This measure physically involves replacing the entire air conditioning unit but not the ducts. The cost would be $3,500 at a minimum.

[71] The Conservation and Renewables Database lists a measure life of 20 years for standard technology solar PV.

Average Annual Expected Savings

The average annual expected savings from this measure depends on the size of the residence. Based on Vectren specific simulations we find average cooling of 1,400 kWh for single family residence and 1,200 for a multifamily residence.

Expected Useful Life

The physical life of this measure is about 20 years, but for the purposes of this analysis we will take 10 years as the useful life of this measure to reflect the application of this measure in an early retirement context.

Refrigeration Charge and Duct Tune Up (R-6, R-7)

This measure is designed to save electric energy by increasing the operating efficiency of the refrigerant system by insuring that it is properly charged. It is common in residential cooling or heat pump systems to have an incorrect amount of refrigerant charge because these systems are usually charged on site during installation. This measure also leads to savings from finding and sealing duct leaks which increases the system distribution efficiency.

Measure Applicability

This measure is applicable to most of the residential stock. Notably even new installations can benefit from this measure.

Incremental Cost

The incremental cost of this measure pays for a visit by a specially trained HVAC technician. For this analysis this cost is taken as $300.

Average Annual Expected Savings

The average annual expected savings from this measure depends on the size of the residence. Based on Vectren specific simulations we find savings of 1,200 kWh/yr for a heat pump (electrically heated residence) and 300 kWh/yr on a gas heated residence with AC only.

Expected Useful Life

This is essentially a tune-up measure and is considered here to have a useful life of 5 years.

Upgrade the Heat Pump Efficiency from a SEER 13 to a SEER 15 (R-8, R-9)

This measure is designed to encourage the installation of more efficient heat pump equipment. Rather than installing a heat pump with a SEER of 13, the homeowner is encouraged to install a more efficient heat pump with a SEER of 15.

Measure Applicability

This measure is applicable to new or replacement heat pump installations. In recent years the rate of heat pump installations has increased. For this study we will take this measure as applicable to 25% of the new electrically heated residential stock.

Incremental Cost

The incremental cost of $1,000 used in this analysis is very similar to the value of $1,062 given in DEER for this measure.

Average Annual Expected Savings

The average annual expected savings from this measure depends on the size of the residence. Based on Vectren specific simulations we find savings in the range of 600-900 kWh/yr. For this study we will take savings of 800 kWh/yr for single family sites and 700 kWh/yr for multifamily.

Expected Useful Life

The DEER uses an expected useful life (EUL) of 15 years; however, for other heat pump measures the DEER uses 18 years which is similar to the 20 years used in this analysis.

Upgrade the Central Air Conditioner from a SEER 13 to a SEER 15 (R-10, R-11)

This measure is designed to encourage the installation of more efficient central air conditioning equipment. Rather than installing a central air conditioner with a SEER of 13 the homeowner is encouraged to install a more efficient central air conditioner which has a SEER of 15.

Measure Applicability

This measure is applicable to new or replacement central air conditioner installations. Central air conditioners (and not heat pumps) are used by about 74% of Vectren residential customers. In this study we assume that the replacements in the next ten years are applicable to about 20% of residential customers and that efficient central air conditioners are applicable to about 60% of new residential construction.

Incremental Cost

The incremental cost of $800 used in this analysis is comparable to DEER's $970 for this measure.

Average Annual Expected Savings

The average annual expected savings from this measure depend significantly on the size of the residence and the thermal integrity of the shell. Simulations of savings using Vectren specific information show savings in the range of 250-500 kWh/yr. For this study we will use 400 kWh/yr for single family residences and 350 kWh/yr for multifamily.

Expected Useful Life

The DEER uses an EUL of 18 years, which is similar to the 20 years used in this analysis.

Efficient Window AC (R-12)

An efficient window or room air conditioner saves energy by slightly more efficient operation, and often by use of an internal timer to restrict operation to occupied periods. An equally important consideration in the selection of a room air conditioner is to avoid over-sizing the unit, in which case additional spaces may be unintentionally cooled.

Measure Applicability

This measure is applicable in the residential and small commercial sector where central air conditioning is not used. The Vectren market survey finds 16% of residences with window AC units. For this analysis, the applicability is taken as 15% of the residential sector and 15% of the commercial sector.

Incremental Cost

The incremental cost of the more efficient unit will vary with the size of the unit. For this study we will take the average incremental cost to be $150.

Average Annual Expected Savings

The energy savings from this measure will vary considerably with the size of the unit and the particular application. In this study we assume an application where the room air conditioner is used as the primary means of cooling a space that is used through out the cooling season. In the Vectren service area the average cooling energy for a small residence is about 2,000 kWh/yr. A properly sized efficient window air conditioner can be expected to save 10% of this cooling energy or 200 kWh/yr.

Expected Useful Life

In this study we assume the expected useful life to be 13 years.

Cool Attics (R-13)

This measure is intended to save cooling energy by reducing the temperature in the attic through attic ventilation and through the use of a "radiant barrier" that thermally isolates the interior of the attic from the very hot roof surface. Attic cooling lowers the thermal gain to the residence below, and it also improves the distribution efficiency of any attic duct work. At least half the cooling savings attributable to this measure proceed from the improved distribution efficiency, and therefore this measure is intended for application where there are attic ducts or distribution fans. This is essentially a site built measure including the installation of roof vents and the installation of several hundred square feet of reflective material to the inside of the roof rafters.

Measure Applicability

This measure is considered applicable to all central air conditioning applications with distribution ductwork in the attic. According to the appliance survey 92% of residences have central AC, and of these 15% are assumed to have attic ductwork. Overall the applicability is taken as 14% of the residential sector.

Incremental Cost

The incremental cost of this measure is considered to be $500/treated residence

Average Annual Expected Savings

The savings from this measure proceed from lowered cooling energy by reducing ceiling heat gain. According to DOE, ceiling heat gain accounts for 15-25 percent of the residential cooling load. The radiant barrier has been observed to reduce ceiling heat gain by 16-42%. The cool attic strategy also improves cooling distribution efficiency if the cooling ducts or fan unit is in the attic. For this study we will take the annual energy savings to be 400 kWh/yr, about 17% of cooling.

Expected Useful Life

This measure consists of reasonably durable material installed in an attic. The useful life is assumed to be 12 years.

EE Windows (R-14)

This measure involves increasing window insulation from a U value of 1.1 BTU/sqft/hr deg F to a U value of .45. This measure saves both heating and cooling energy. In the case of gas heated residences, the electric savings are for cooling only and are much less than the heating savings. So the cost effective application of this measure is to electric heated residences only.

Measure Applicability

This measure is considered applicable to a portion of the 23% of residential customers that heat with electricity. Of these customers about 5% have heat pumps and live in more recent stock that is probably insulated. Of the remaining 17% we will assume that half are poorly insulated enough to benefit from this measure. Overall the applicability is taken as 8% of the residential sector.

Incremental Cost

We assume a cost of $25 per square foot of window area. DEER uses a value of $28.00 per square foot of window area, and C&RD uses a value of $16 per square foot. For the average residence considered here with 100 square feet of window upgraded, the cost would be $2,500.

Average Annual Expected Savings

Savings from this measure are strongly dependent on the efficiency of the electric heat source and the square feet of windows replaced. The stock to which this measure is applied consists primarily of electric furnaces. Therefore the simulations assume the displacement of resistance heat. Building simulations from Vectren specific weather data show savings of 900 kWh to 1,300 kWh/yr for electric heated residences and less than 400 kWh/yr for gas heated residences. For this analysis the annual savings will be taken as 1,334 kWh/yr for electric heated residences.

Expected Useful Life

This analysis uses an effective useful life of 25 years, the DEER uses 20 years.

Programmable Thermostats (R-15)

Programmable thermostats save energy by lowering the average daily temperature of the inside of a building. Most of the energy savings is heating energy because that heating thermal load is much larger than the cooling load, but some energy savings in cooling energy will also be realized. Programmable thermostats are commonly sold for self installation. But the installation has the following four important issues that need to be considered.

1. Some thermostats are line voltage thermostats, and there is some shock hazard to the unaware.

2. The first step in programming a thermostat is the system specification. Here the installer tells the thermostat what kind of a system it is controlling. The system type is selected from a list of about 30-50 different system types. This is a non-obvious choice.
3. For system controls there are standard colored wires, but often hookups use non-standard wire. For the mechanically inclined this process is OK but for others it is daunting.
4. Then, after it is installed successfully there is the issue of controlling it to get satisfactory results. Sometimes this needs a guiding hand.

It came to light during the preparation of the final Vectren South Action Plan that the US DOE is planning to phase out programmable thermostats from the Energy Star program over the next year. The planned phase out is apparently related to recent evaluation studies that found insufficient savings to warrant the Energy Star designation. Proper installation and operation appear to be at the root of the lack of energy savings. We have chosen to leave these devices in our mix of recommended ECMs and feel that with proper installation and setup the technology is sound. Our incremental cost includes the cost of installation over and above the off-the-shelf cost of programmable thermostats. Even with proper installation, there is an ongoing need for a design that is more user-friendly and easier to operate.

Measure Applicability

The Vectren Appliance study shows 23% of the respondents reported the use of a programmable thermostat. Also the Appliance Study reports 23% have electric heating in the form of resistance heat or heat pumps. It is not clear if the reported programmable thermostats were all on electric heating situations. For this analysis one half the electric heating situations, 11.5%, are taken as good candidates for a new programmable thermostat.

Incremental Cost

Programmable thermostats cost retail in the range of $50-$100. A utility program may be able to purchase in bulk. It may be necessary to have a range of options which include at least line voltage and low voltage. For these purposes we take $70 as the melded cost of the thermostats.[72] It is assumed here that thermostats will be installed as part of a site visit in a broader program with $25 allocated for installation labor. In total the installed cost will be taken as $120 per thermostat.[73] Some sites with line voltage thermostats may require more than one thermostat.

Average Annual Expected Savings

Thermostat savings are best realized when the set back interval is of the order of 8 hours or longer, and the amount of savings depends on the number of degrees the thermostat is set back. The rule of thumb is 1% heating savings for every degree the thermostat is set back for at least 8 hours. For this estimate a five degree thermostat set back is assumed, leading to heating savings in the average electrically heated home of 500 kWh/yr.

[72] DEER lists the incremental cost as $56.3, and the installed cost as $73.33 per unit.

[73] DEER lists the incremental cost as $73.33 of which $56.37 is equipment cost and $16.96 in labor. This analysis uses $50 for the labor cost which accounts for some of the difference in the costs.

Expected Useful Life

In principal, these thermostats can last for in excess of 20 years, but the backup batteries have a finite life and the programming can be changed or confused. In this case, the effective lifetime will be taken as 10 years.[74]

Ceiling Insulation R6-R30 (R-16, R-17)

This measure involves increasing ceiling insulation from R-6 to the R-30 level. This measure saves both heating and cooling energy. In the case of gas heated residences, the electric savings are for cooling only and are much less than the heating savings. So the cost effective application of this measure is to electric heated residences only.

Measure Applicability

This measure is considered applicable to a portion of the 23% of residential customers that heat with electricity. Of these customers about 5% have heat pumps and live in more recent stock that is probably insulated. Of the remaining 17% we will assume that half are poorly insulated enough to benefit from this measure. Overall the applicability is taken as 8% of the residential sector.

Incremental Cost

We assume a cost of $0.75/sqft of wall area and 1000 square feet of wall space for a total cost of $750. DEER uses a value of $0.757 per square foot of wall area. This job includes the cost of providing for adequate attic venting.

Average Annual Expected Savings

Savings from this measure are strongly dependent on the efficiency of the electric heat source. The stock to which this measure is applied consists primarily of electric furnaces. Therefore the simulations assume the displacement of resistance heat. Building simulations from Vectren specific weather data show savings of 1,500 kWh to 2,700 kWh/yr for electric heated residences and less than 400 kWh/yr for gas-heated residences. For this analysis, the annual savings is assumed to be 1,800 kWh/yr for electric-heated residences and 300 kWh/yr for gas-heated residences.

Expected Useful Life

This analysis uses an effective useful life of 25 years. The DEER uses 20 years.

House Sealing Using Blower Door (R-18, R-19)

This measure applies to residential electrically heated properties. It involves using blower door technology to pressurize the home. Once the house is pressurized, the air leaks are identified and sealed with appropriate materials to decrease heat loss from the building envelope.

Measure Applicability

This measure is applicable to most of the residential stock.

[74] DEER list the EUL as 12 years.

Incremental Cost

The incremental cost of sending a technician to a home and performing a Blower Door test and sealing the identified leaks is assumed here to be $300 per 1,000 square foot home. By comparison, the C&RD database lists $0.16 per 0.1 air change per square foot which translates to $320 per house with 0.2 air changes per square foot.

Average Annual Expected Savings

An electrically heated home will achieve 1,000 kWh in annual savings according to our modeling, and a gas home will save 200 kWh annually.

Expected Useful Life

The life of the savings for this measure depends on the quality of the materials used especially for the gaskets for the windows and doors. An expected useful life of 15 years is being used. DEER lists 13 years and C&RD 20. We feel 20 years is too optimistic and have chosen a conservative value of 10 years.

Ground Source Heat Pump (R-20)

The ground source heat pump uses the ground as the energy source/sink in a heat pump cycle. This allows the ground source heat pump to operate with about twice the efficiency of a conventional air source heat pump. Because the ground is at a much more stable temperature than the air, resistance backup heat can be avoided. And it also simplifies the operation of the heat pump because defrost is not an issue.

Measure Applicability

This measure is applicable to new electrically heated residential construction and to existing Vectren heat pump customers that have suitable sites. The total pool of candidate customers will be taken as 10% of residential customers, and we will assume that only 30% of these have suitable sites. Overall measure applicability is taken as 3% of residential sector.

Incremental Cost

The ground source heat pump is essentially a standard heat pump except that the outdoor unit is replaced by a trenched pipe as a ground heat exchanger a few hundred feet long. The burying of the pipe is highly site specific. In this study the incremental cost will be taken as the cost of the ground heat exchanger only and the remainder of the system will be considered similar in cost to a conventional heat pump. Although the site costs are highly site specific we will take $7,000 as incremental cost.

Average Annual Expected Savings

This measure saves on both heating and cooling relative to the basecase which is a standard heat pump. Using Vectren specific weather conditions, the savings relative to a heat pump are 3,300 kWh/yr.

Expected Useful Life

This measure is considered to have a useful life of 25 years.

Wall Insulation (R-21, R-22)

This measure involves increasing wall insulation from R-3 and adding insulation to the R-11 level. This measure saves both heating and cooling energy. In the case of gas heated residences, the electric savings are for cooling only and are much less than the heating savings. Therefore the cost effective application of this measure is for electrically heated residences only.

Measure Applicability

This measure is considered applicable to a portion of the 23% of residential customers that heat with electricity. Of these customers, about 5% have heat pumps and live in more recent stock that is probably insulated. Of the remaining 17%, we will assume that half are poorly insulated and could benefit from this measure. Overall the applicability is taken as 8% of the residential sector.

Incremental Cost

This measure contemplates adding wall insulation to a 2x4 stud wall where there is none. We assume a cost of $1.25 per square foot of wall area. DEER uses a value of $1.32 per square foot of wall area, the DEER values are based on going from an R-0 to an R-13, the equipment costs are given as $0.15 for equipment and $1.17 for labor resulting in the overall cost of $1.32. Our estimate is more conservative. The total installed cost for the home modeled is $1,400.

Average Annual Expected Savings

Savings from this measure are strongly dependent on the efficiency of the electric heat source. The stock to which this measure is applied consists primarily of electric furnaces. Therefore the simulations assume the displacement of resistance heat. Building simulations from Vectren specific weather data show savings of 1885 kWh to 2600 kWh/yr for electric-heated residences and less than 400 kWh/yr for gas-heated residences. For this analysis the annual savings will be taken as 2,100 kWh/yr for electric-heated residences and 400 kWh/yr for gas-heated residences.

Expected Useful Life

This analysis uses an effective useful life of 25 years, the DEER uses 20 years.

Solar Siting Passive Design (R-23)

This measure applies to new construction that can be designed and sited to capture solar gain through windows in-order to displace space heating. In a new building, the cost of proper orientation and of solar design is small to non existent if the orientation and design decisions are made before construction starts.

It is well known that if a new residence is tightly designed thermally, and oriented so that about 75-100 feet of glazing is near south facing, then its heating requirements can be reduced by about 30%. Much larger heating reductions have been demonstrated, but then the designs need to become more extreme with respect to south glass and with respect to protection from unwanted summer sun. This measure is intended to represent a "minimum graceful design", yielding the maximum savings with the least departure from a normal residential appearance. Physically, this measure consists of re-orienting and re-distributing glazing that would have been used anyway, and in using proper overhang to provide some summer shade. In passive solar design, the south glazing should usually have a high solar heat gain factor. This is an unusual glazing specification for current residential applications because most residential glazing is intended to reject solar gain for cooling purposes. Passive solar design also includes increasing the thermal mass, such as floor tile, adjacent to south facing glazing. The thermal mass of the existing sheetrock and furniture etc in a building also plays a role in thermal storage. Building codes generally try to discourage excessive glazing and solar gain, but they allow for exceptions where thermal design has been explicitly considered and documented.

Measure Applicability

This measure is applicable to new electrically heated construction with suitable solar exposure. In this study the measure will be applied to the 40% of new residential construction that will potentially use heat pumps, and of these 50% are assumed to have a suitable solar exposure. The overall applicability of this measure is taken as 20% of the residential sector.

Incremental Cost

This measure is considered a minimum passive design, and it essentially consists of a redistribution or reorientation of materials that would have been used anyway. The cost of this measure is taken as the cost for the information or advice necessary to "tune the design to the sun". The cost for this measure is taken here as $500 per building. Not very much needs to be done to capture these minimal passive solar heating savings, especially if it is done at the outset. The context for this incremental cost is assumed to be to a developer for some extra consideration in overall site planning.

In many reported cases of solar design, the cost is many times this and the building is usually much more expensive as well, but these costs are the common costs associated with personalized new construction, not particularly related to solar design.

Average Annual Expected Savings

The annual savings for this measure are considered only for electrically heated residences, though this measure is well suited to gas heated sites as well. For this analysis, the savings are taken as one-third of the electric energy used in typical heat pump-heated residences in Vectren territory, 1,500 kWh/yr. These savings have been referenced to a heat pump as base case because it is unlikely that a new electrically heated residence would be built with electric resistance heat. However, relative to the rare case of a new resistance heated building, the savings would be much larger, about 3,000 kWh/yr.

Expected Useful Life

This measure will last the life of the building which can easily be 50 years or more. However for this analysis the measure life is taken as the maximum life used in this analysis, 25 years.

Energy Star Manufactured Home (R-24)

An Energy Star qualified new manufactured home is required to be 15% more efficient than a similar home that meets the 2004 International Energy Conservation Code, IECC. The mechanism for estimating Energy Star compliance is through the use of a HERS (Home Energy Rating System) score calculated from a brief estimate of annual energy use. The savings proceed principally from heating, cooling, lighting and water heating savings.

Measure Applicability

This measure is applicable to all new manufactured home construction. But for the purposes of this study the measure is restricted to new residential manufactured all electric construction. In the Vectren service area manufactured homes are not a major component of new construction and are estimated here to be 10% of new construction.

Incremental Cost

The incremental cost for this measure consists of the increased cost of building components such as insulation, windows, lighting and appliances. This cost is site specific, but for this study it is taken as $1,500. This incremental cost is less than noted for Energy Star construction because it is derived from the manufacturing environment where the costs increment is at the OEM level.

Average Annual Expected Savings

The savings from this measure are specifically site modeled, estimates for this region are in the range of 2,500-3,500 kWh/yr. For this study, the savings is assumed to be 3,000 kWh/yr.

Expected Useful Life

This measure has a useful life comparable to that of new construction and for this study the life will be taken as 25 years.

Energy Star Construction (R-25)

An Energy Star qualified new home is required to be 15% more efficient than a similar home that meets the 2004 International Energy Conservation Code, IECC. The mechanism for estimating Energy Star compliance is through the use of a HERS (Home Energy Rating System) score calculated from a brief estimate of annual energy use. The savings proceed principally from heating, cooling, lighting and water heating savings.

Measure Applicability

This measure is applicable to all new residential construction. But for the purposes of this study the measure is restricted to new residential all electric construction, estimated here to be 40% of new construction.

Incremental Cost

The incremental cost for this measure consists of the increased cost of building components such as insulation, windows, lighting and appliances. This cost is site specific, and there is some choice in selecting the package of measures. An initial cost effectiveness screening of this measure showed that the maximum cost effective cost is

$2,000. This requires composing a package of only the most cost effective measures. Therefore this package includes the strongly cost effective measures of a flow efficient showerheads and inspection and checkout of heat pump that are not commonly part of the Energy Star package (but should be). Based on the choice of the most cost effective measures, the cost used for this study is $2,017.

Average Annual Expected Savings

The savings from this measure are specifically site modeled, estimates for this region are in the range of 3,000-4,000 kWh/yr. For this study, the savings is assumed to be 3,555 kWh/yr.

Expected Useful Life

This measure has a useful life comparable to that of new construction and for this study the life will be taken as 25 years.

Eliminate Old Refrigerators (R-26)

This measure involves creating electric energy savings by collecting and dismantling underused older refrigerators. Ideally only operating or operable refrigerators would be eligible for removal.

Measure Applicability

This measure is applicable to the 28% of the residential sector that have more than one refrigerator. Of these only 50% are assumed to have an interest in removing a refrigerator. For this study the applicability will be taken as 14% of the residential sector.

Incremental Cost

The incremental cost of this measure will be taken as the cost of acquiring and recycling the unit. For this study that cost will be assumed to be $100.

Average Annual Expected Savings

Savings from this measure are dependent on the age of the refrigerator and the location where it is used. Savings estimates for this measure also need to include the zero effects of including operable but not operating refrigerators. Reported savings estimates vary widely from an astonishing 1,900 kWh/yr for C&RD to 413 kWh/yr observed in the Connecticut Appliance Turn-In program. For this program, the savings will be assumed to take the middle road, 700 kWh/yr.

Expected Useful Life

The useful life of this measure is the length of time the removed refrigerator would have continued to be used absent the program. There is no reliable research on this and for this program the useful life will be taken as 5 years.

HVAC Set Back (R-27)

This measure is a voluntary set back of both the heating and cooling set points by 3 deg F. This is the average set back for the whole day not just the night set back. This type of set back could lead to slight behavior changes such as different clothing when lounging around or sedentary. The heating and cooling savings from such a simple change can be large, of the order of 2000 kWh/yr. The savings will be greatest in houses heated by resistance heat, but they will be significant in heat pump houses as well.

Measure Applicability

This measure is applicable throughout the residential sector. But the greatest savings will be where the measure is applied to electrically heated homes which are 23% of the residential sector.

Incremental Cost

This measure has essentially no cost. As a token cost here we assume $5.

Average Annual Expected Savings

The savings for this measure depend strongly on the amount of set back and the heating type. Based on Vectren specific weather, low savings would be about 500 kWh/yr for a mild set back to a good heat pump, and high savings would be about 2,000 kWh/yr for a five degree set back to an electric furnace. For this study we will take 1,000 kWh/yr as the savings.

Expected Useful Life

This is a temporary measure. The set back strategy may only work for one or two seasons. Accordingly the useful life is taken as 2 years.

Energy Star Clothes Washers (R-28)

This measure involves obtaining an Energy Star clothes washer which is a more efficient clothes washer than a standard clothes washer. This measure has significant water and detergent savings in addition to the electric savings.

Measure Applicability

This program applies only to customers who have electric water heaters, electric dryers, and who have no high efficiency clothes washer. This applies to 40% of Vectren customers.

Incremental Cost

The incremental cost for clothes washers vary significantly depending on the features. The value used in this analysis is $400, DEER uses a value of $565.82 and the C&RD lists a value of $245.26. Due to the wide variety of costs for Energy Star clothes washers $400 is a good mid-range value for the purposes of this analysis.

Average Annual Expected Savings

The kWh savings from a clothes washer depend to a significant extent on the source of the water heating and dryer's energy source. If the water heater is a gas water heater the kWh savings are insignificant but if the source is an electric water heater the savings can be substantial. Savings also depend on whether the clothes washer has a built in heat source which some do have. This analysis used 400 kWh. DEER lists 199 kWh and C&RD lists a range from 54 kWh to 509 kWh depending on the model chosen. Savings will be assumed to be 400 kWh because the program will be limited to customers with electric water heat and electric dryers.

Expected Useful Life

The expected useful life used in the analysis is 18 years; however, both DEER and C&RD use 14 years.

Energy Star Dishwashers (R-29)

This measure is defined as the purchase of a new Energy Star dishwasher. By definition Energy Star dishwashers are more efficient than a comparable standard new dishwasher. This measure applies strictly to the improved level of performance, Energy Star versus Standard. An Energy Star qualified dishwashers uses at least 41 percent less energy than the federal minimum standard for energy consumption, which was set in 1994. In this measure the dishwasher being replaced has an EF of 0.46 and is being replaced by a 0.58 EF dishwasher, and has an average usage of 215 washes.

Measure Applicability

The Vectren market survey does not address Energy Star dishwashers. For this study, we will take the applicability of these units to be 60% of the existing residential sector and all of the new residential sector. In fact, Energy Star dishwashers are a required item in Energy Star new construction.

Incremental Cost

The incremental retail cost for dishwashers, varies depending on the features present in the model chosen. The value used in this analysis is $50, DEER uses a value of $133 and the C&RD lists $6 as the incremental cost, this analysis has incorporated an intermediate value.

Average Annual Expected Savings

The savings from this measure are primarily due to decreased hot water usage. The C&RD lists 119 kWh/yr and DEER lists 72 kWh/yr. This analysis uses 75 kWh per year.

Expected Useful Life

The expected useful life used in the analysis is 10 years. However DEER lists 13 years and C&RD lists 9 years.

Energy Star Refrigerators (R-30)

This measure is defined as the purchase of a new Energy Star refrigerator which is slightly more efficient than a comparable standard new refrigerator. This measure applies strictly to the improved level of performance, Energy Star versus Standard.

It should be noted here that this measure definition will under-count the real savings because the current stock of new refrigerators is much more efficient than the older stock more than 10 years old, and significant savings will result when an old refrigerator is replaced by a new one, even a non-Energy Star one. These savings are a natural part of the background residential usage changes in response to the current standard market and are considered savings that would have happened absent any particular measure. For this particular measure, the measure savings used in program cost effectiveness are only for the Energy Star increment, but the technical potential estimate inherently captures the full replacement savings.

Measure Applicability

This measure is assumed to apply to 90% of the residential sector, essentially all of the residential sector for which an Energy Star model is available.

Incremental Cost

The incremental retail cost for refrigerators, vary significantly depending on the features present in the model chosen. The value used in this analysis is $200, DEER uses a value of $135.75 and the C&RD does not list a value due to the variability in the possible costs. Due to the wide variety of costs for Energy Star refrigerator, $200 is a good mid-range value for the purposes of this analysis.

Average Annual Expected Savings

Savings vary by type of refrigerator/freezer configuration and by size. The range is 80-100 kWh/yr. Savings for this analysis will be taken as 100 kWh/yr. These savings are relative to the energy use of a new but non-Energy Star refrigerator. In fact a significant portion of the new refrigerator purchases are to replace old refrigerators, and even a non-Energy Star refrigerator will save about 300 kWh/yr relative to the old refrigerator it replaces.

Expected Useful Life

The expected useful life used in the analysis is 18 years and both DEER and C&RD also use 18 years.

Pool Pumps (R-31)

This measure saves energy by employing a two speed pool pump motor. At the lower speed the pump is still doing a good job of filtering, but it uses about 75% less energy. This is typical of the savings from slowing down pumps or fans. While these savings are significant it should be noted that the slower pumping rate can adversely affect pool accessories such as a solar pool heater.

Measure Applicability

This measure is applicable to in ground pools only and is expected to be applicable in less than 5% of the residential sector.

Incremental Cost

The incremental cost for this measure consists of the increased cost of a 2 speed pump, ($180) and the increased labor to install it. In a retrofit case the labor is of the order of $300, but in a new installation there is no increased labor. For this study we will take $180 as the incremental cost.

Average Annual Expected Savings

The savings from this measure depend on the degree of flow reduction and the number of hours of reduced flow. A typical power reduction to be expected is 500 watts, and in a full season the duration of reduced flow is 1,000-1,500 hours. For this study we will take the annual savings as 648 kWh/yr.

Expected Useful Life

The expected useful life of this measure is assumed to be 10 years.

Compact Fluorescent (R-32)

This measure consists of substituting compact fluorescent lighting for incandescent lighting. At each socket treated, such a substitution will reduce lighting power by about 80%. A full application of this measure consists of converting all the most used lighting fixtures from incandescent to compact fluorescent. Housing audits taken over the last 10 years show that an average house has about 25-45 lighting sockets with an aggregate connected incandescent lighting load of about 2,700 watts. But of this load, only about 10-15 sockets are used for about an average of 5 hours/day, the rest are infrequently used. So it is the ten-fifteen most frequently used sockets that are the primary targets for a whole house lighting conversion. A satisfactory conversion of these most important sockets may require recourse to a variety of bulb styles, powers, and even adapters (such as lamp harps) to facilitate accommodating the CFL to these ten best locations.

Measure Applicability

This measure is applicable in 100% of residential sector, but to allow for some existing use of compact fluorescents this study will use 95% as the applicability factor for this measure.

Incremental Cost

The cost for this technology continues to decrease, and there are various sales or promotions where the cost may be as low as $2.00/bulb. But for the purpose of this program planning we will assume $5.00/average bulb to cover the costs of larger or outdoor rated bulbs, and another $5.00/bulb for installation or adaptation labor. Full application of this measure, assuming treatment of the 15 most important fixtures in a residence is taken here as costing $150. The C&RD lists $5.73 for the incremental cost and the DEER lists $8.03 for the incremental installed cost.

Average Annual Expected Savings

It is assumed here that the fifteen treated sockets reduce the connected load by 750 watts, and that the average on time for these sockets is 3 hours/day, leading to energy savings of 2.25 kWh/day. This equates to 55 kWh/yr/bulb. The savings listed in DEER range from 20 to 59 kWh/yr/bulb depending on which CFL is replacing which incandescent bulb. For these purposes the full application of this measure is assumed to save a total of 800 kWh/yr for replacing 15 bulbs.

Expected Useful Life

Compact fluorescent bulbs have a life time of 10,000 hours, about 7-10 times as long as the incandescent bulbs they replace. Assuming the average compact fluorescent bulb is used 2,000 hours/yr (5-plus hours/day) gives a conservative estimate of useful life of 5 years.

Daylighting Design (R-33)

This measure is intended to reduce the lighting energy in new residential construction. Daylight has the highest lumens/watt of any light source. A little bit of daylight can go a long way toward lighting a space without introducing as much heat as other light sources. Physically daylighting takes the form of small skylights or clearstories, and high small windows coordinated with light colored interior wall and ceiling surfaces. In practice, good daylighting design involves the avoidance of glare and over lighting as well.

Measure Applicability

This measure is applicable to 100% of the residential new construction.

Incremental Cost

This measure is being applied in new residential construction where lighting is a natural consequence of window placement. In this context daylighting design is considered in the distribution of the windows and skylights to make light distribution more uniform and to avoid glare. These design impacts will have minimal cost if they are brought in at the planning stage. For this study the incremental cost is assumed to be $500.

Average Annual Expected Savings

Properly designed daylighting can save almost all the lighting energy used during daylight hours, but not all residences are used during the day. The Vectren market assessment shows about 2,300 kWh/yr for lighting in the average residence. The savings will wary widely from site to site, but for this study we will take 30% lighting savings, 750 kWh/yr.

Expected Useful Life

Daylighting features integrated into a house during construction will last the life of the house. For these purposes the lifetime will be taken as 25 years.

Occupancy Controlled Outdoor Lighting (R-34)

This measure is designed to save lighting energy by turning on selected outdoor lighting only when occupancy or movement is detected. This measure has a strong security context, but it also is very convenient at entrances, garages, etc, where light switches can only be accessed from inside and lighting is left on for long periods of time in order to provide light for the short time it is actually needed.

Measure Applicability

This measure is applicable through out the existing residential stock.

Incremental Cost

This measure physically involves replacing three frequently used outdoor lights by occupancy controlled lights. It is assumed that a single occupancy controller and light costs $50, and that a full installation consisting of two lights would cost $100.

Average Annual Expected Savings

The average annual expected savings from this measure depends on the type of light that is being controlled. The preferred type of light to control is a compact fluorescent spot light because of its lower power use and long life. But in colder outdoor applications these lights can take from 30 seconds to a minute to come to full brightness which may be unacceptable in some cases. For this analysis, we will assume that 150 watts is being controlled, and that a savings of 5 hours/day is achieved. Annual savings for these purposes is taken as 250 kWh/yr.

Expected Useful Life

For the purposes of this analysis, we will take 10 years as the useful life of this measure.

Tank Wrap, Pipe Wrap, and Water Temperature Setpoint (R-35)

This technology consists of adding insulation around the water heater, a checking and resetting the tank thermostat, and replacing leaky shower flow diverters. These measures are principally tank-centric, and can be self installed or by a site visit if the package is part of a broader program. Resetting the tank thermostat is also a safety issue because it can reduce scaling and burns due to too high a set temperature.

Measure Applicability

The applicability for measures of this type is discussed under low flow fixtures. In Vectren service territory electric water heat accounts for 40% of water heating, 2/3 of that 40 percent would be eligible for this measure because in some cases the tank cannot be accessed to install a blanket or one has already been installed. As a result the applicability is taken as 25%.

Incremental Cost

The cost of this treatment breaks down as $30 for materials and $20 for installation labor. For these purposes the measure cost is taken as $50 because these measures will typically be part of a larger program.

Average Annual Expected Savings

The dwelling savings for these measures is discussed under low flow fixtures. Based on prior experience and evaluation work on other programs it is estimated that the savings would be about 1 kWh per day.[75] For this program we have used the conservative value of 200 kWh/yr savings.

Expected Useful Life

The lifetime of these measures is potentially quite long. For practical purposes the lifetime will be considered limited by the expected lifetime of the hot water tank, 10 years.[76]

Low Flow Fixtures (R-36)

This technology consists of a new showerhead rated at 2.0 gallons per minute (gpm) at 80 pounds per square inch (psi) and a swivel aerator for the kitchen faucet and fixed aerators for the lavatory faucets. The current US standard for showerheads is 2.5 gpm. Measurements of the existing shower flows in building stock show a range of 2.75 gpm to 3.75 gpm with frequent individual cases in excess of 5 gpm. Evaluations have shown that programs that replace with 2.0 gpm heads have greater savings than programs that replace with the standard 2.5 gpm shower

[75] Khawaja S. PhD, and Reichmuth, H. PE., 1997. *Impact Evaluation of PacifiCorp's Ebcons Multifamily Program.* Pacificorp.

[76] DEER says 15 years for pipe insulation, 9 years for faucet aerators, and 15 years for an efficient water heater so 10 years is conservative. The C&RD lists 10 years for a water heater with a minimum warranty of 10 years.

heads. Program shower heads should be 2.0 gpm at 80 psi and with a lifetime scaling and clogging warranty. It is important also to be cautions about the use of "pressure compensating" showerheads. These are more prone to clogging and can lead to unintentional increases in flow rate in low pressure situations such as well water systems or older systems with occluded piping. Customer acceptability is an important component in a showerhead program. Customers will remove new low flow showerheads if the quality of the showering experience declines with the new showerhead. Therefore it is important to research and test the showerhead chosen for the program carefully. In addition, the old showerhead must be removed from the premises to decrease the likelihood of having it reinstalled.

Measure Applicability

This measure is applicable to the 40% of the residential sector that heat water with electricity.

Incremental Cost

Low flow fixture costs vary widely, and depend on whether the fixtures are purchased retail or in bulk. The costs for a bulk purchase for a showerhead and three aerators also have a wide range, about $8.00-$15.00/set. The most important feature of these fixtures is the long term acceptability and durability because these factors have a direct impact on the lifetime savings. With a long enough lifetime, this is such a cost effective measure that all prices in the range are quite cost effective. Because the cost of the showerhead varies significantly and quality is so important for this program, it is essential to test, choose and pay the price for a high quality showerhead. This measure is so cost effective that even with a more expensive showerhead the program will still remain cost effective and a quality showerhead will ensure measure persistence. The per-unit-installed cost will be taken as $25/residence.[77]

Average Annual Expected Savings

Field monitoring studies can demonstrate the flow savings, but ultimately the overall savings will be a combination of flow savings and the duration of use. The flow of the showerhead used has a significant impact on savings. This program is designed around a 2.0 gpm showerhead as compared to a 2.5 gpm showerhead. Therefore the savings will be more than the 120–133 kWh per unit listed in DEER. In addition the climate is different and the inlet water temperature is lower so the savings in this Vectren program will be greater. Several studies have measured final savings in terms of electric input to the tank, but usually these studies have included savings from comprehensive treatments including other measures including tank and pipe insulation, kitchen and bath lavatory aerators, tank thermostat set back, and leaky diverter replacement. Savings can very from program to program depending strongly on the choice of showerhead. Savings can also diminish with "takeback" in the event that the new showering experience is longer than the original. Actual savings observed in the comprehensive cases include these takeback effects, and are in the range of 650 kWh/yr to 950 kWh/yr. The savings from a showerhead and aerator change alone are taken as 500 kWh/yr.

[77] The DEER Database lists measure costs as $22.946 per unit and $37.946 installed cost

Expected Useful Life

The life time of this equipment is the key to its cost effectiveness. If an adequate, even pleasant, shower can be provided through lifetime warranted equipment, then the practical lifetime of the equipment is the length of time until the equipment is replaced in the course of renovation. For these purposes that lifetime is taken as 10 years.[78] Normally showerheads will last longer but with renovations and changes in ownership a 10 year EUL is a good planning number.

Heat Pump Water Heaters (R-37)

Water heating is one of the largest energy uses in the home. In the case of electrically heated water, the annual water heating energy is about 4800 kWh/yr. The heat pump water heater is essentially a small heat pump drawing heat from the air by cooling and de-humidifying it and injecting this heat into a storage tank. Physically, this measure consists of a small self contained heat pump and a water storage tank and associated pumps and controls.

Measure Applicability

This measure is applicable to the 40% of the residential sector with electric water heat. Of these, 50% are assumed to have a suitable location for the unit. Overall measure applicability is assumed to be 20% of the residential sector.

Incremental Cost

The incremental cost of this measure consists of the cost of the heat pump water heater, water storage tank and installation plumbing and general construction labor. The siting of such a unit is important; it should never be sited in an attic and freezing situations should also be avoided. Therefore, some special site adaptation and plumbing may be necessary. For this study we will take $2,500 as the cost; others report lower costs but we do not think these take adequate account of special site costs.

Average Annual Expected Savings

For this study it is assumed that the heat pump water heater will perform with a coefficient of performance of 2, leading to annual savings of 2,000 kWh/yr.

Expected Useful Life

The useful life of this measure is assumed to be that of a similar appliance, a window air conditioner, 18 years.

Tankless Water Heaters (R-38)

Water heating is one of the largest energy uses in the home. In the case of electrically heated water, the annual water heating energy is about 4,800 kWh/yr. This measure saves energy by eliminating the standby energy losses attributable to a hot water storage tank. However these relatively small energy savings are at the cost of a significant demand increase. In the case of gas water heating, this type of measure has greater energy savings and

[78] DEER Database, 2005

no troublesome demand savings, and the measure makes sense. In the context of a switch from an electric tank to an electric tankless heater, this measure makes no sense.

Measure Applicability

This measure is applicable in the residential sector only where space is a premium.

Incremental Cost

The incremental installed cost for this measure is $1,500.

Average Annual Expected Savings

The expected savings are 400 kWh per year. But it should be recognized that this type of appliance has a negative demand impact.

Expected Useful Life

This measure's expected useful life is 18 years.

Solar Water Heaters (R-39)

Water heating is one of the largest energy uses in the home. In the case of electrically heated water, the annual water heating energy is about 4,800 kWh/yr. Countless demonstration cases have shown that solar energy can supply all or a portion of this heating. The portion of the water heating load assumed by a solar water heater depends on the size of the solar water heater in relation to the size of the load. Field experience has shown that the best combination of system size to load favors the more moderately sized systems that can fully meet the summer water heat load, but that only meet about 40-50% of the non summer load. In physical terms, this is a system consisting of about 40-65 square feet of solar collector and an additional 80 gallon heated water storage tank and appropriate pumps and controls.

Measure Applicability

This measure is intended to apply to the 40% of residential customers with electrically heated hot water. Of these electric hot water customers, only 50% are assumed to have an adequate solar exposure and an adequate roof mounting site. Overall measure applicability is assumed to be 20% of the residential sector.

Incremental Cost

The installation of a solar water heating system involves a mix of building skills including plumbing, electrical, roofing and general carpentry. In the general market, a turn key installation for one of these systems is in the range of $5,000 to $7,000. For this study we will take the cost to be $6,000.

Average Annual Expected Savings

The savings from solar water heaters depend on site specifics, principally solar insulation, air temperature, incoming water temperature, and hot water usage rate. Considering these dependencies for the Vectren service area, leads to average annual savings for a system sized and designed to be in the cost effective range to be 2,500 kWh/yr.

Expected Useful Life

Solar water heating systems are essentially plumbing fixtures that are certified products (SRCC) and are often inspected by local building officials. A well designed system will have a lifetime in excess of 25 years, even though the system will take some intermediate maintenance such as inspecting the pump and fluid level. This study will take 25 years as the useful life.

Efficient Plumbing (R-40)

This measure saves hot water heating energy by leaving less hot water in the pipes to cool during periods of non-use. Conspicuously, the primary motive for this measure is the amenity benefit of limiting the waiting time for usable hot water at the tap or showerhead; waiting times can be reduced from a significant fraction of a minute to only a few seconds. Physically this measure involves the use of smaller diameter continuous PEX water pipes with no elbows or Tees and the use of carefully sized pipe manifolds. While this measure is tested and viable it involves the use of small diameter piping in a context that is not familiar to the plumbing trade or to building officials. It is therefore considered an emerging technology and will not be included in program recommendations.

Average Annual Expected Savings

The savings from this measure have not been widely measured but savings of 10% of the hot water end use are reasonable. For this analysis, savings is assumed to be 500 kWh/yr.

Incremental Cost

In large scale use, this measure offers the possibility of actually lowering the cost of hot water plumbing because smaller diameter less expensive pipe is used. But specialized manifolds and system planning are required. Therefore for this study an incremental cost of $500 is assumed.

Expected Useful Life

This is a very long-lived measure and an expected useful life of 25 years can be assumed.

Sources

DEER: 2004-05 Database for Energy Efficient Resources (DEER) Version 2.01 October 26, 2005 developed by the California Public Utility Commission and the California Energy Commission.

C&RD: Northwest Power and Conservation Council's Conservation Resource Comments Database, which is continually updated as new information becomes available.

APPENDIX E. COMMERCIAL ECM DOCUMENTATION

The purpose of this appendix is to provide documentation of the assumptions used to screen the Commercial Energy Conservation Measures identified for consideration in this report. Our assumptions are based on references cited throughout this section as well as the direct experience of our team with technologies in the field and actual DSM program evaluations. While not all of the field and DSM program experience can be cited in published works, published references are used to establish a reasonable range of assumptions. The point estimate used within that range is based on our professional opinion.

Solar Photovoltaic (C-1)

This technology consists of a roof or ground mounted solar electric array with a full sun output of 40 kW. Such an array has an area of 4,000-6,000 square feet. Electricity from the array is converted to AC by an inverter and the power is immediately used on site with excess fed into the grid. This technology needs full solar exposure and shadows can significantly restrict output. In the commercial context, this technology can be an architectural enhancement.

Measure Applicability

This measure is applicable wherever there is sufficient space and solar exposure. For this study we assume applicability to 25% of large buildings.

Incremental Cost

A system installation usually requires an electrical inspection to verify appropriate wire sizing, disconnects, and grounding. Costs are quite site-specific, with most of the costs associated with the solar electric panels. In the current supply constrained 2007 market, costs are \$5.00-\$7.00/watt peak for the solar cells alone. Installation and balance of system can be expected to add \$3.00/watt. For the 40 kW array considered here the total cost will be taken as \$320,000[79], or \$8.00/watt.

Average Annual Expected Savings

The electrical output for this technology is directly related to the solar intensity. Monitoring studies in this region of the US have shown that 1 kW of installed capacity can yield in excess of 1,100 kWh/yr. For the 40 kW array considered here the annual savings will be taken as 44,000 kWh/yr.

Expected Useful Life

This equipment demonstrated long trouble free service in severe applications such as remote communications, navigation lighting, and road signage. The long term output of the cells is assumed to decrease with time, but the rate of decrease for current technology is not known. The crystalline and semi-crystalline forms of the technology have already demonstrated degradation of less than 20% in 20 years. But earlier thin film forms of the technology

[79] The C&RD Database lists the incremental capital cost as \$6,000 per kW, which would be comparable for an installed 2 kW system.

have shown shorter lifetimes. The lifetime of new thin film technologies is expected to be of the order of 25 years but it is not known. For these purposes the lifetime is taken as 25 years.[80]

Small HVAC Optimization and Repair (C-2)

This measure applies to packaged rooftop units. These units are the predominant means of conditioning for small to medium scale commercial buildings. The savings proceed from improved compressor performance, better run time control, and fresh air cooling. These rooftop units are a homogenous pool of equipment that has been identified as underperforming. Typically, the refrigerant charge is out of specification, the economizers perform poorly if at all, and the airflow is too low for proper operation. Many utilities are offering programs employing a structured diagnosis and repair protocol, SCE, PG&E, National Grid. Often these programs use trade named processes such as Proctor Engineering "check me", or PECI "aircare plus" etc. Candidates for this measure are roof top units found in a wide range of sizes with output capacities of from 4 tons to 50 tons with the most predominant capacity being 5 tons.

Measure Applicability
This measure is applicable in 70% of the large building commercial sector.

Incremental Cost
The cost for this technology includes site visits and diagnostics with simple repairs performed immediately without need for a second site visit. The costs will naturally vary with the specifics of the repair. Planning estimates for this diverse mix of treatments, made by the Northwest Power and Conservation Council (NWPCC), use $0.20/first year kWh savings. In the average large commercial building considered here, the cost will be $1,417/site treated.

Average Annual Expected Savings
Savings vary from unit to unit, but in the cases where there have been significant corrections to the refrigerant charge or to economizer operation savings on the order of 2,500 kWh/unit have been observed. In the average commercial large building considered here, we will assume 7,000 kWh/yr as the whole building savings where 2-3 units have been improved.

Expected Useful Life
There are inherent limitations to the lifetime of the treatment provided by this measure. The improvements may be superseded by operational changes, and the remaining lifetime of the treated unit may be limited. The effective life of this measure is taken as 5 years.

Commissioning New and Re/Retro (C-3, C-4)

Commissioning is a systematic step by step process of identifying and correcting problems and ensuring system functionality. Commissioning seeks first to verify that the system design intent is properly executed, and it goes further by comparing actual building energy performance to appropriate bench marks to validate building

[80] The Conservation and Renewables Database lists a measure life of 20 years for standard technology solar PV.

performance as a whole. The best candidates for this measure are buildings larger than about 100,000 square feet. While commissioning in general can become quite complex, often the greatest savings proceed from a simple review of building operations to assure that the building is not being unnecessarily used during non-occupied times.

Measure Applicability

This measure is applicable in 75% of commercial sector, and to all of the new commercial buildings.

Incremental Cost

The cost for this technology is quite site specific, based on NWPCC estimates commissioning costs about $0.37/ kWh/yr. For the average building considered here that cost would be $5,191/site.

Average Annual Expected Savings

Savings from this measure can vary widely. It is assumed here that the building electric energy use can be reduced by on average 10%, leading to energy savings of 14,000 kWh/yr for the average large building.

Expected Useful Life

There are inherent limitations to the lifetime of the treatment provided by this measure. The improvements may be superseded by operational changes, and the remaining lifetime of the treated unit may be limited. The effective life of this measure is taken as 5 years.

Low E Windows New and Replace (C-5, C-6)

This measure saves energy by reducing the thermal losses and gains through windows. This measure assumes that the efficient window has a heat loss rate of 0.45 BTU/deg F hr, representing the performance of a quality, double glazed argon filled low E window. The original window is assumed to have a heat loss rate of 0.75 BTU/deg F hr, representing the average losses from a mix of single and double glazed windows.

Measure Applicability

This measure is applicable in 100% of new commercial buildings and 30% of existing commercial stock.

Incremental Cost

The incremental cost for this technology depends strongly on the context of use. If the efficient windows are used in a replacement context, then the full cost of $20/sqft is applicable which leads to a total cost of $30,000 for the average building considered here. But if the efficient windows are used as an upgrade in new construction then an incremental cost of only $3.00/sqft is used, leading to a total cost of $4,500 for the average building in this study.

Average Annual Expected Savings

It is assumed here based on Vectren specific simulations that 1500 square feet of high efficiency window replacement will have savings of 11,200 kWh/yr for an electrically heated building.

Expected Useful Life

This is a very long lived measure with an assumed life of 25 years.

Premium New HVAC Equipment (C-7)

Premium new HVAC equipment employs more efficient motors/pumps and larger heat exchangers and pipes to lower operating energy requirements. Designated premium equipment may not have an Energy Star rating, but it does deliver slightly improved performance and is sold as such.

Measure Applicability

This measure is applicable in 100% of new commercial construction.

Incremental Cost

The incremental cost for this technology will be very diverse and quite site specific. Based on NWPCC estimates, the premium upgrade costs about $0.46/ kWh/yr. For the average building considered here that cost would be $1,947/site.

Average Annual Expected Savings

Savings attributable to this measure are generally fairly small because they represent only an incremental improvement in performance on equipment that is already required to be reasonably efficient. It is assumed here that the savings in new construction will be 3% of total energy use, in the average building considered here that is 4,200 kWh/yr.

Expected Useful Life

The premium upgrades can be expected to last the life of the equipment, taken here as 15 years.

Large HVAC Optimization and Repair (C-8)

This measure refers to restoring large HVAC equipment to its nominal operating performance. This measure needs to be distinguished from commissioning which is used to refine the controls of large HVAC which generally leads to large savings. By contrast this measure applies to the operation of the equipment and includes chiller and condensing tower cleaning, filter maintenance etc.

Measure Applicability

This measure is applicable in 20% of the commercial sector with large HVAC systems.

Incremental Cost

The incremental cost for this technology will be very diverse and quite site specific. Based on NWPCC estimates, the premium upgrade costs about $0.34/ kWh/yr. For the average building considered here that cost would be $1,436/site.

Average Annual Expected Savings

Savings attributable to this measure are generally fairly small because they claim only the savings due to restoring equipment to its original operation. For this study these savings are assumed to be 3% of building energy use. On the average building, this will be 4,200 kWh/yr.

Expected Useful Life

There are inherent limitations to the lifetime of the treatment provided by this measure. The improvements may be superseded by operational changes, and the remaining lifetime of the treated unit may be limited. The effective life of this measure is taken as 5 years.

Integrated Building Design (C-9)

This measure applies to new construction where careful design and specific engineering can get beyond the rules of thumb to the use of smaller equipment more carefully matched to load. Efficient new construction with lower lighting loads, variable speed control of fans, anticipatory controls, daylighting, enhanced duct design, and other energy efficient details all taken together in a design can result in significant energy and demand savings.

Measure Applicability

This measure is applicable in 100% of new commercial construction, but in national chain or franchise designs, the integrated design may already have been done at the corporate level, or getting to a level of integrated design may require interaction at the corporate design level that may not be possible at the local level.

Incremental Cost

The incremental cost for this technology will be very diverse and quite site specific. Based on NWPCC estimates, the premium upgrade costs about $0.34/ kWh/yr. For the average building considered here that cost would be $9,486/site.

Average Annual Expected Savings

The savings due to integrated design will include the savings due to efficient lighting, efficient HVAC equipment, and controls. Taken as a package these savings can easily be on the order of 20-40% of the standard code compliant design. The current US tax code allows preferred treatment for new buildings that are 50% better than code or lighting systems that are 30% better than code. For this analysis we consider 20% better than code to be an achievable and significant goal. For the average building considered here the savings are taken to be 28,000 kWh/yr.

Expected Useful Life

Integrated design can be expected to last the life of the building, taken here as 25 years.

Electrically Commutated Motors (C-10)

An electronically commutated motor is a more efficient motor with variable speed control capability. In fan and pump applications it can save energy by operating at a more efficient speed. Refrigeration applications are especially favored because the power reduction leads to a lower refrigeration load.

Measure Applicability

This measure is broadly applicable throughout the commercial sector. For this study we assume the measure is applicable in 60% of the commercial sector.

Incremental Cost

The incremental cost for this technology will be very diverse and quite site specific. Based on NWPCC estimates, the premium upgrade costs about $0.33/ kWh/yr. For the average building considered here that cost would be $935/site.

Average Annual Expected Savings

It is assumed here that this measure can reduce a building energy use by 3%. The average commercial building considered here is assumed to save 2,800 kWh/yr.

Expected Useful Life

Electrically commutated motors are assumed to have a useful life of 15 years.

Efficient AC/DC Power (C-11)

A modern office environment has a multitude of electronic appliances, most of which are powered by a small transformer AC/DC converter. Standard transformer based converters are about 30-40% efficient. More efficient designs called switching power supplies operate with an efficiency of about 90%. The energy savings for this measure proceed from switching to the more efficient power supplies.

Measure Applicability

This measure is applicable in 100% of the commercial sector.

Incremental Cost

The incremental cost for this technology will be very diverse. Based on NWPCC estimates, the premium upgrade costs about $0.074/ kWh/yr. For the average building considered here, that cost would be $156/site.

Average Annual Expected Savings

Electronics and computers use 12% of commercial energy on a US average basis. This equipment is often on 24 hours a day. It is assumed here that doubling the power supply efficiency from 45% to 90% would save at least 1.5% of the total building energy or 2,100 kWh/yr for the average commercial building considered here.

Expected Useful Life

This measure is assumed to have a useful life of 5 years

Efficient Network Management (C-12)

This measure involves powering down unused network functions during unoccupied hours.

Measure Applicability

This measure is technically applicable in 100% of the commercial sector, but it is assumed that only 10% of the commercial sector will have the networks large enough and staff conversant enough to execute the measure.

Incremental Cost

The incremental cost for this technology will be very diverse. Based on NWPCC estimates, the premium upgrade costs about $0.115/ kWh/yr. For the average building considered here, that cost would be $322/site.

Average Annual Expected Savings

Approximately 12% of commercial energy is for electronics and computers. It is assumed here that, at an applicable site, 2% of energy can be saved by efficient network power management or 2,800 kWh/yr in the average building considered here.

Expected Useful Life

This is a transient measure dependent on the current system configuration. It is assumed to have a useful life of only 2 years.

New and Retrofit Efficient Lighting (C-13, C-14)

Lighting efficiency is the major commercial efficiency measure. Lighting accounts for 35% of commercial energy, and lighting also accounts for significant cooling energy that is saved when lighting is more efficient. There are literally hundreds of combinations of more efficient lighting elements that can replace less efficient elements. This efficient lighting measure goes beyond the light sources only and includes lighting controls, bi-level switching and occupancy sensors. Taken together it is common to find efficient lighting that can reduce lighting energy by 30% from the minimum code required levels (ASHRAE 90.1, 2001). In fact, the 2006 energy legislation offers preferred tax treatment to lighting configurations that can reduce lighting energy by 30%.

Measure Applicability

This measure is applicable in 100% of the new commercial buildings and in 85% of the existing commercial sector.

Incremental Cost

The incremental cost for this technology is essentially the cost of the efficient lighting components. These costs will be will be very diverse and site specific. Based on NWPCC estimates, and averaging the full range of conditions, efficient lighting costs about $.26/ kWh/yr. For the average building considered here that cost would be $3,682/site. For a retrofit application the cost is increased by 25% to $4,603/site in-order to allow for installation constraints.

Average Annual Expected Savings

A comprehensive lighting retrofit or new building lighting can save about 30% of the 35% lighting end use, in all 10% of building energy. In the commercial building considered here, the average annual expected savings is 14,000 kWh/yr.

Expected Useful Life

The useful life of the wide variety of lighting equipment varies widely from one light source or ballast to another. However, these elements are the replaceable elements in an overall system that is assumed to have a useful life of 18 years.

LED Exit Signs (C-15)

Typical existing exit signs are incandescent exit signs. This measure is designed to replace these typical exit signs with an Energy Star Light Emitting Diode (LED) Exit Sign which is more efficient than the incandescent versions.

Measure Applicability

In principal, measure is applicable in the entire commercial sector, and there are no physical constraints to replacing existing exit signs, but to account for already installed LED exit signs the applicability is assumed to be 85% of the commercial sector.

Incremental Cost

The incremental cost of an Energy Star LED Exit Sign over an incandescent exit sign is $45. For the average building considered in this analysis, six exit signs are assumed, for a full site cost of $270.

Average Annual Expected Savings

The average annual expected saving for this replacement is 245 kWh/year.[81] In the average building considered in this analysis, there are assumed to be 6 exit signs, for a full site savings of 1,470 kWh/yr.

Expected Useful Life

LED exit signs are very long-lived light sources. Accordingly, the useful life is taken as 10 years.[82]

LED Traffic Lights[83] (C-16)

LED traffic lights save energy because LED light sources are a much more efficient and long lived light source than the incandescent bulbs they replace. They save energy but they also save in terms of bulb replacement costs. LED traffic lights have a variety of configurations. Each color (red, Green, or yellow), each size (8 inch, or 12 inch) and each type (thru lane, left turn bay, right turn bay, and don't walk large or small) has different incremental cost, savings and effective useful life values.

Measure Applicability

Measure applicability was not estimated due to lack of data on the traffic lights in Vectren service territory. But for this analysis, it is assumed that there are 0.2 retrofittable intersections for every commercial building.

Incremental Cost

Depending on the color, size and type, the incremental cost ranges from $110 to $225. For this analysis we consider LED traffic light replacements in groups of 10, approximately the number of lamp replacements necessary to refit an intersection. For this analysis we will assume the average replaced light costs $200 and that the full intersection with 10 replacement lights costs $2,000. This cost compares favorably with the $1,850 cost derived from NWPCC data. These incremental costs do not assume an installation cost. It is assumed that the installation is done by the agency controlling the lights, and that it is more than paid for by the ongoing maintenance savings.

[81] C&RD Database
[82] C&RD Database
[83] All values for LED Traffic Lights is available in the C&RD Database

Average Annual Expected Savings

Depending on the color, size and type, the savings range from 111 kWh/year to 808 kWh/year. For this analysis we consider LED traffic light replacements in groups of 10, approximately the number of lamp replacements necessary to refit an intersection. For this analysis we will assume the average replaced light saves 500 kWh/yr and that the full intersection with 10 replacement lights saves 5,000 kWh/yr.

Expected Useful Life

Depending on the color, size and type, the expected useful life ranges from 3 – 16 years. For this analysis we will use 10 years.

Perimeter Daylighting (C-17)

This measure saves energy by reducing energy to lighting that is in or adjacent to day lit spaces. This measure controls lighting based on a well placed day light sensor. This measure also includes design and details to control glare or over lighting.

Measure Applicability

This measure is applicable in the new commercial sector, and in suitable retrofit situations. In all this measure is taken as applicable to 30% of the commercial sector.

Incremental Cost

The incremental cost for this technology will be very diverse. Based on NWPCC estimates, perimeter daylighting costs about $0.85/ kWh/yr. For the average building considered here that cost would be $3,568/site.

Average Annual Expected Savings

It is assumed here that a full application of perimeter daylighting can save about 3% of the total building energy. In the average building considered here this measure can save 4,200 kWh/yr.

Expected Useful Life

This measure is essentially a built in measures and is assumed to have a useful life of 18 years.

Low Flow Fixtures (C-18)

This technology consists of a new showerhead rated at 2.0 gpm at 80 psi and a swivel aerator for any kitchen faucets, and fixed aerators for the lavatory faucets. The current US standard for showerheads is 2.5 gpm. And measurements of the existing shower flows in building stock show a range of 2.75 to 3.75 gpm with frequent individual cases showing in excess of 5 gpm. Evaluations have shown that programs that replace with 2.0 gpm heads have greater savings than programs that replace with the standard 2.5 gpm shower heads. Program shower heads should be 2.0 gpm at 80 psi and with a lifetime scaling and clogging warranty. It is important also to be cautions about the use of “pressure compensating” showerheads. These are more prone to clogging, and can lead to unintentional increases in flow rate in low pressure situations such as well water systems or older systems with occluded piping. Customer acceptability is an important component in a showerhead program. Customers will remove new low flow showerheads if the quality of the showering experience declines with the new showerhead. Therefore it is important to research and test the showerhead chosen for the program carefully. In addition the old showerhead must be removed from the premises to decrease the likelihood of having it reinstalled.

Measure Applicability

This measure is applicable to circumstances where there is showering such as schools, hospitality, health clubs etc. The best application will be a site where the water is heated electrically. For this analysis the applicability is taken as 10% of the commercial sector.

Incremental Cost

The incremental cost for this measure is taken as $1,000 reflecting the installation of 10-20 showerheads by appropriately licensed professionals. Because the cost of the showerhead varies significantly and quality is so important for this program, it is essential to test, choose and pay for a high quality showerhead. This measure is so cost effective that even with a more expensive showerhead the program will still remain cost effective and a quality showerhead will ensure measure persistence.

Average Annual Expected Savings

The average annual savings for this measure are directly related to the daily number of showers taken. For this study the showering load is assumed similar to a residential one and the overall savings are taken as 6,000 kWh/yr, representing the savings from 10-20 showerheads. The flow of the showerhead used has a significant impact on savings. Programs should be designed around a 2.0 gpm showerhead as compared to a 2.5 gpm showerhead. Therefore the savings will be more than the 120–133 kWh per unit listed in DEER. In addition the climate is different and the inlet water temperature is lower so the savings in this Vectren program will be greater. Several studies have measured final savings in terms of electric input to the tank, but usually these studies have included savings from comprehensive treatments including other measures including tank and pipe insulation, kitchen and bath lavatory aerators, tank thermostat set back, and leaky diverter replacement. Savings can very from program to program depending strongly on the choice of showerhead. Savings can also diminish with “take back” in the event that the new showering experience is longer than the original. Actual savings observed in the comprehensive cases include these take back effects, and are in the range of 650 kWh/yr to 950 kWh/yr. The savings from a showerhead and aerator change alone are assumed to be 500 kWh/yr.

Expected Useful Life

The life time of this equipment is the key to its cost effectiveness. If an adequate, even pleasant, shower can be provided through lifetime warranted equipment, then the practical lifetime of the equipment is the length of time until the equipment is replaced in the course of renovation. For these purposes that lifetime is taken as 10 years.[84] Normally showerheads will last longer but with renovations and changes in ownership a 10 year EUL is a good planning number.

[84] DEER Database, 2005

Solar Water Heaters (C-19)

The water heating end use in commercial buildings is a smaller end use than in residences. In the Vectren service area large commercial water heating will be done by gas and it will not be a very good candidate for this measure. But the smaller commercial water heating applications will be residential scale in usage and often these smaller applications will be electrically heated. These are the candidate applications for this measure. In the case of electrically heated water, the annual water heating energy is about 4,800 kWh/yr. Countless demonstration cases have shown that solar energy can supply all or a portion of this heating. The portion of the water heating load assumed by a solar water heater depends on the size of the solar water heater in relation to the size of the load. Field experience has shown that the best combination of system size to load favors the more moderately sized systems that can fully meet the summer water heat load, but that only meet about 40-50% of the non summer load. In physical terms, this is a system consisting of about 40-65 square feet of solar collector and an additional 80 gallon heated water storage tank and appropriate pumps and controls.

Measure Applicability

This measure is applicable to large commercial buildings with reasonably low hot water use, and the system is sized as if it were residential. This measure is taken as applicable to 25% of the commercial sector.

Incremental Cost

The installation of a solar water heating system involves a mix of building skills including plumbing, electrical, roofing and general carpentry. In the general market, a turn key installation for one of these systems is in the range of $5,000-$7,000. For this study the incremental cost will be $6,000.

Average Annual Expected Savings

The savings from solar water heaters depend on site specifics, principally solar insulation, air temperature, incoming water temperature, and hot water usage rate. Considering these dependencies for the Vectren service area, leads to average annual savings for a system sized and designed to be in the cost effective range to be 2,500 kWh/yr.

Expected Useful Life

Solar water heating systems are essentially plumbing fixtures that are certified products (SRCC) and are often inspected by local building officials. A well designed system will have lifetime in excess of 25 years, even though the system will take some intermediate maintenance such as inspecting the pump and fluid level. This study will take 25 years as the useful life.

Heat Pump Water Heaters (C-20)

The water heating end use in commercial buildings is a smaller end use than in residences. In the Vectren service area large commercial water heating will be done by gas, and it will not be a very good candidate for this measure. But the smaller commercial water heating applications will be residential scale in usage, and often these smaller applications will be electrically heated. These are the candidate applications for this measure. In the case of electrically heated water, the annual water heating energy is about 4,800 kWh/yr. The heat pump water heater is essentially a small heat pump drawing heat from the air by cooling and de-humidifying it and injecting this heat into a storage tank. Physically, this measure consists of a small self contained heat pump and a water storage tank and associated pumps and controls.

Measure Applicability

This measure is applicable to large commercial buildings with reasonably low hot water use, and the system is sized as if it were residential. This measure is taken as applicable 25% of the commercial sector.

Incremental Cost

The incremental cost of this measure consists of the cost of the heat pump water heater, water storage tank and installation plumbing and general construction labor. The siting of such a unit is important; it should never be sited in an attic, and freezing situations should also be avoided. Therefore, some special site adaptation and plumbing may be necessary. For this study we will take $2,500 as the cost; others report lower costs, but we do not think these take adequate account of special site costs.

Average Annual Expected Savings

For this study it is assumed that the heat pump water heater will perform with a coefficient of performance of 2, leading to annual savings of 2,000 kWh/yr.

Expected Useful Life

The useful life of this measure is assumed to be that of a similar appliance, a window air conditioner, which has an EUL of 18 years.

Energy Star Hot Food Holding Cabinet (C-21)

This measure saves energy by keeping prepared food warm more efficiently; they are 60% more efficient than standard models. These models have better insulation, and may have magnetic door gaskets, auto-door closers, or Dutch doors.

Measure Applicability

This measure is applicable in portions of the restaurant hospitality and education sectors, and the applicability is estimated here to be 7% of the commercial sector.

Incremental Cost

For the average building considered here that cost would be $1,100/site.

Average Annual Expected Savings

It is assumed here that this measure will save 3% at a suitable site or 4,100 kWh/yr[85] in terms of the average building considered here. The DEER Database confirms this value with a value of 4,029.

[85] Energy Star Website: http://www.energystar.gov/index.cfm?c=hfhc.pr_hfhc

Expected Useful Life

This measure is assumed to have a useful life of 15 years.

Energy Star Electric Steam Cooker (C-22)

This measure saves energy by cooking food more efficiently. It also saves water and cooling energy.

Measure Applicability

This measure is applicable in portions of the restaurant hospitality and education sectors. The applicability is estimated here to be 7% of the commercial sector.

Incremental Cost

For the average steam cooker considered here, the incremental cost would be $5,000/site.

Average Annual Expected Savings

It is assumed here that this measure will save1.5% at a suitable site or 2,200 kWh/yr in terms of the average building considered here.

Expected Useful Life

This measure is assumed to have a useful life of 15 years. DEER lists a slightly more conservative value of 12 years.

Pre-Rinse Spray Wash (C-23)

This measure applies to the commercial sector and provides a low pressure nozzle for pre-washing dishes. Using a low pressure nozzle saves water and heating energy in commercial kitchen settings.

Measure Applicability

This measure is applicable in portions of the restaurant hospitality and education sectors. The applicability is estimated here to be 7% of the commercial sector.

Incremental Cost

Based on NWPCC estimates, the pre-rinse spray wash costs about $0.03/ kWh/yr. For the average building considered here that cost would be $177/site.

Average Annual Expected Savings

It is assumed here that this measure will save 5% at a suitable site or 7,000 kWh/yr in terms of the average building considered here.

Expected Useful Life

This measure is assumed to have a useful life of 15 years.

Restaurant Commissioning Audit (C-24)

This measure consists of an audit conducted by a restaurant energy professional to identify the potential for efficiency in a commercial kitchen. Savings proceed from small things such as leaky faucets and unnecessary equipment operation to larger things such as major process changes. Since kitchen equipment is energy intensive the audit includes identification of cost effective equipment changes.

Measure Applicability

This measure is applicable to commercial kitchens in the restaurant, hospitality, and education sectors. In this analysis this measure is taken as applicable in 30% of the commercial sector.

Incremental Cost

The incremental cost for this measure is limited to the cost of the audit only. The cost of any major equipment changes is associated with other measures. The cost for the audit is here assumed to be $1,300.

Average Annual Expected Savings

It is assumed here this measure can reduce the energy use in an applicable facility by 10%, or 14,000 kWh/yr for the average building considered in this analysis.

Expected Useful Life

This measure will have a relatively short life; here it is assumed to be 5 years.

Grocery Refrigeration Tune-Up (C-25)

This measure consists of cleaning heat exchangers and assuring proper airflow at the freezer cases and condenser coil. It also involves appropriate belt adjustment and refrigeration charge correction if necessary.

Measure Applicability

This measure is applicable in portions of the grocery sector and in some restaurants. The applicability is estimated here to be 4% of the commercial sector.

Incremental Cost

Based on NWPCC estimates, the grocery refrigeration tune up costs about $0.19/ kWh/yr. For the average building considered here that cost would be $2,654/site.

Average Annual Expected Savings

It is assumed here that this measure will save 10% at a suitable site or 14,000 kWh/yr in terms of the average building considered here.

Expected Useful Life

This measure is assumed to have a useful life of 5 years.

VendingMiser® (C-26)

The VendingMiser® is a controller placed on vending machines which powers down a vending machine during low use times while maintaining product quality. It cycles the machine to maintain temperature and uses occupancy sensors to control the lighting on the vending machine.

Measure Applicability

This measure is assumed to be applicable in 25% of the commercial sector.

Incremental Cost

The incremental cost for a VendingMiser® unit is $179 and installation costs are expected to be $35.50 in labor for a total incremental cost of $215.[86]

Average Annual Expected Savings

Measure savings range from a low value of 800–1,200 kWh/yr, depending on the vending machine. Large machines with an illuminated front save 1,200 kWh/yr, and small machines or machines without an illuminated front save 800 kWh/yr. For planning purposes, we will assume 1,000 kWh/yr.

Expected Useful Life

The expected useful life for this measure is 10 years.[87]

Sources

DEER: 2004-05 Database for Energy Efficient Resources (DEER) Version 2.01 October 26, 2005 developed by the California Public Utility Commission and the California Energy Commission.

C&RD: Northwest Power and Conservation Council's Conservation Resource Comments Database, which is continually updated as new information becomes available.

[86] DEER
[87] DEER