PUBLIC VERSION
*"**[redacted]**" Designates Confidential Information Has Been Removed.*
Certain Schedules Attached to this Testimony Designated
"Confidential" Also Contain Confidential Information
And Have Been Removed.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

JOSEPH M. O'DONNELL

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
FOR APPROVAL TO IMPLEMENT A PORTFOLIO OF DEMAND SIDE
MANAGEMENT PROGRAMS INCLUDING
AFFORDABILITY, ENERGY EFFICIENCY, DEMAND RESPONSE AND
EDUCATIONAL PROGRAMS, AND TO IMPLEMENT A RIDER FOR RECOVERY OF
PROGRAM COSTS AND INCENTIVES ASSOCIATED WITH THIS PORTFOLIO

DOCKET NO. 10-KCPE-___-TAR

Q: Please state your name and business address.

A: My name is Joseph M. O'Donnell. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or the "Company") as Manager, Market Intelligence.

Q: Please describe your education, experience and employment history.

A: I graduated from the Polytechnic University of New York with a Bachelor of Science in Electrical Engineering (B.S.E.E.) that was awarded Cum Laude. I graduated from the Columbia Business School with a Masters of Business Administration with a dual major in Finance and Operations Management.

I worked for Consolidated Edison of New York from 1974 to 1989 in the System Operation division and held various technical, engineering and management positions. From 1994 through 1996, I was an Assistant Professor on the adjunct faculty of the Columbia Business School where I taught graduate level classes in Production and Operations Management.

I worked for Dow Jones Telerate in the Energy Services group from 1996 to 1999 as the marketing manager of energy pricing and information services. We developed trading systems technology, and information services for the international oil, natural gas and electric power markets. We developed the first market price indexes for the emerging U.S. wholesale power markets, including the California-Oregon Border ("COB") electric power price index, and the PJM power price index.

Thereafter, I worked for Aquila Energy from 1999 to 2002 as a manager in the financial group responsible for energy deal structuring, the fundamental analysis of the U.S. electric power and natural gas markets, and the analysis of commodity pricing. I continued to work for Aquila Energy from 2003 to 2005 as a Director in the financial risk group. In that capacity, I was responsible for the assessment of electric and natural gas price risk for seven U.S. natural gas utilities, three electric power utilities and developed financial volumetric hedging strategies for the firm.

I began working for KCP&L in December of 2005 as a Technical Consultant supporting KCP&L's account executives. In this role, I was responsible for customer load research and customer technical support. In 2007, I accepted a Manager position in the Energy Solutions group where I am responsible for demand side research and planning, the economic analysis and development of demand-side programs, and customer technical support.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe the cost-effectiveness modeling that was used for analyzing demand side management ("DSM") programs and the results of the cost-effectiveness modeling for the DSM plan.

Q: Do you sponsor any schedules with your direct testimony?

A: Yes, I sponsor the following schedules:

- Schedule JMO-1: "*2007 Kansas City Power & Light Single-Family Residential Potential Analysis*" published by RLW Analytics, March 13, 2007
- Schedule JMO-2: "*Kansas City Power & Light C&I Final Report, Energy Efficiency Measures Potential Study*" published by Summit Blue Consulting, September 17, 2007
- Schedule JMO-3: "*Kansas City Power & Light C&I Energy Efficiency Programs Findings and Documentation*" published by Morgan Marketing Partners, January 4, 2008
- Schedule JMO-4: "*A Renewable Energy System Performance Analysis Report for Kansas City Power and Light*" published by The Energy Savings Store, June 1, 2009

- Schedule JMO-5: *"California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects"*, July 2002
- Schedule JMO-6: DSMore^{TM} User Manual Version 7.1
- Schedule JMO-7: *"An Independent Review of DSMore, An Examination of the Structure, Function and Operations of the DSMore Software"*, January 24, 2007
- Schedule JMO-8: Avoided Transmission and Distribution Cost Table

Q: Do you adopt any definitions for the purpose of your testimony?

A: Yes, I adopt the following definitions:

Demand side management (or "DSM"): "...measures that change the amount or timing of electricity consumption in order to utilize scarce electric supply resources most efficiently. These DSM measures, or "conservation programs, increase energy efficiency by focusing on reducing utility customers~ overall energy requirements, during all or significant portions of the year, not only customers ~ peak demands. These programs replace inefficient lighting, heating, cooling, drive power, or building equipment or materials with energy efficient substitutions, while maintaining a comparable level of service or utility, and should result in lower customer bills.[1]

Energy efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours ("MWh")), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating,

[1] Source: The State Corporation Commission Of The State Of Kansas, Order Initiating Investigation And Assessing Costs, Filed 11/6/2007, paragraph 8, Docket No. 08-GIMX-441-GIV ("441 Docket").

motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning ("HVAC") systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.[2]

Demand Response (or "DR"): "...measures that reduce or shift demand for power during system emergencies, energy or capacity shortages, and periods of high wholesale market prices so as to make the best use of generation, transmission and distribution assets. This definition includes "load management" or "peak-load management," which involve reduction of demand during peak generation periods or shifting demand from peak to non-peak periods."

"DR programs may be categorized into two groups: (1) rate structures that provide a price signal to customers reflecting the marginal costs of electricity production; and (2) payments to customers for reducing their energy load when requested. DR programs may include interruptible load tariffs, time-of-use rates, real-time pricing, and direct load control. These programs may target peak periods for load reduction or shape and control load during non-peak periods to respond to variations in power availability or cost. Other types of DR programs include interruptible and curtailable rates that provide discounts to customers willing to decrease load, and energy management computer-based systems that control a customer's lighting, heating, cooling and ventilation systems to manage peak loads. These systems may be controlled by the customer or from a central location.[3]

---

[2] Source: Energy Information Administration – U.S. Department of Energy, Glossary http://www.eia.doe.gov/glossary/glossary_e.htm

[3] Source: The State Corporation Commission Of The State Of Kansas, Order Initiating Investigation And Assessing Costs, Filed 11/6/2007, paragraph 9, 441 Docket.

BACKGROUND

Q: Please explain the process that was used to develop and evaluate KCP&L's DSM programs.

A: KCP&L developed a menu of DSM measures that covered its major customer classes, including residential, commercial, industrial and interruptible and also covered the major end-use classes including, lighting, refrigeration, space cooling, space heating, water heating, motive power and small scale renewable energy such as small wind turbines, solar photovoltaic systems, solar air heat and solar hot water. KCP&L engaged several reputable consulting firms to assist in the analysis and to provide recommendations.

Q: Please discuss the analysis conducted for the residential class.

A: KCP&L engaged the consulting firm, RLW Analytics, Inc., ("RLW")[4] to assist in estimating the residential end-use energy savings potential within the KCP&L service territory and assist KCP&L with development of a menu of residential end-use measures. RLW is a recognized industry leader providing innovative analytical, engineering and market research consulting for energy companies and end users. RLW's final report, "*2007 Kansas City Power & Light Single-Family residential Potential Analysis,*" (the "RLW Report") was published on March 13, 2007, and is attached as Schedule JMO-1.

The categories of residential end-use measures considered were:

- Lighting;
- Space cooling;
- Space heating;
- Residential refrigeration;

[4] In 2009, RLW was acquired by KEMA, an energy consulting firm.

- ENERGY STAR® residential appliances, including dishwashers and clothes washers;
- Water heating; and
- Residential building structure improvements.

Q: Did KCP&L conduct any analysis for the commercial and industrial classes?

A: Yes, KCP&L engaged Summit Blue Consulting ("Summit Blue" or "SBC") to conduct an energy efficiency potential study for KCP&L's commercial and industrial ("C&I") market segments. Summit Blue was formed by experienced utility industry professionals, whose careers have been focused on assessing markets for demand side management, designing and implementing effective delivery mechanisms, and evaluating programs for their energy savings impacts and efficiency of administration. Summit Blue's qualifications include all of the necessary elements to successfully complete the tasks required. Its final report entitled "*Kansas City Power & Light C&I Final Report, Energy Efficiency Measures Potential Study*" (the "SBC C&I Report") was completed by SBC and was published on September 17, 2007. A copy of this report is attached as Schedule JMO-2.

Q: Was any other analysis conducted for the C&I classes?

A: Yes. Morgan Marketing Partners ("MMP") and its subcontractors Architectural Energy Corporation ("AEC") and Franklin Energy Services ("FES") were also retained by KCP&L to further review and validate the SBC C&I Report and to assist in the development of a portfolio of cost-effective C&I DSM programs. MMP is actively involved in the tactical implementation of energy efficiency programs throughout the United States. MMP published its report and recommendations entitled "*Kansas City*

Power & Light C&I Energy Efficiency Programs Findings and Documentation" (the "MMP Report") on January 4, 2008. A copy of the report is attached as Schedule JMO-3. MMP also identified additional residential end-use measures that were not included in the RLW Report.

Q: Please discuss the C&I end-use measures that were considered.

A: The categories of C&I end-use measures considered were:

<u>Commercial</u>

- Lighting systems – indoor, outdoor and traffic control;
- Refrigeration and food service equipment;
- HVAC;
- Motors, pumps and variable frequency drives;
- Commercial ENERGY STAR® washing machines;
- Office equipment, both personal computer and non-personal computer; and
- Thermal storage.

<u>Industrial</u>

- Lighting systems – indoor, outdoor and traffic control;
- Refrigeration and food service equipment;
- HVAC;
- Motors, pumps and variable frequency drives; and
- Industrial process equipment.

Q: Were interruptible customers considered in the analysis?

A: Yes. Interruptible customers were identified as either belonging to the residential or C&I customer classes and having the capability to reduce or shift load. KCP&L conducted internal research, conducted customer-oriented focus groups and identified features and benefits that would facilitate participation in residential, commercial and industrial demand side management programs that induce load shifting or load reduction during peak summer hours.

Q: Were renewable energy sources considered in your DSM analysis?

A: Yes. KCP&L investigated several small scale renewable energy sources and associated energy technologies for incorporation into an energy efficiency program. KCP&L commissioned The Energy Savings Store ("TESS"), a renewable energy services company that designs, provides, installs and maintains renewable energy systems, to model the performance of twelve small scale renewable energy systems and to estimate project costs. The results of TESS analysis can be found in its report, "*A Renewable Energy System Performance Analysis Report for Kansas City Power and Light,*" (the "TESS Report") which was published on June 1, 2009, and is attached as Schedule JMO-4.

BENEFIT/COST TESTING

Q: What is cost-effectiveness modeling?

A: Cost-effectiveness modeling is the manner in which the benefits and costs of demand side management measures and programs are assessed. The standard tests for measuring program cost-effectiveness are described in the "*California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*" (July 2002), which is attached as Schedule JMO-5. Although the cost-effectiveness results can be expressed differently, the industry has largely adopted the cost-benefit ratio as the primary means of expressing cost-effectiveness.

Q: Please discuss the standard practice tests.

A: The standard practice tests calculate the cost and benefit components and cost-effectiveness calculation procedures from different perspectives. The five primary tests are: Participant Test, Utility or Program Administrator Cost ("PAC") Test, Ratepayer Impact Measurement ("RIM") Test, Total Resource Cost ("TRC") Test, and Societal Test.

Q: Please describe the cost and benefit components of the Participant Test.

A: The Participant Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. These quantifiable benefits would include reduction in utility bills, incentives, and tax credits. Costs include out-of-pocket expenses and any increases in the utility bill. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

The benefits of participation in a DSM program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings.[5]

[5] As stated on Page 8 of the "*California Standard Practice Manual: Economic Evaluation of Demand-Side Programs and Projects*" (October 2001), gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

Q: Please describe the cost and benefit components of the Utility or Program Administrator Test.

A: The Utility or PAC Test measures the net costs of a demand side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC Test benefits. Costs are defined more narrowly.

The benefits for the Utility or PAC Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program.

The costs for the PAC Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).

Q: Please describe the cost and benefit components of the Ratepayer Impact Measurement Test.

A: The RIM Test measures the effect to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

The benefits calculated in the RIM Test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or administering the program, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).

Q: Please describe the cost and benefit components of the Total Resource Cost Test.

A: The TRC Test measures the net costs of a demand side management measure or program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The benefits calculated in the TRC Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

Q: Please describe the Societal Test.

A: The Societal Test is structurally similar to the TRC Test; however, it goes beyond the TRC Test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. The benefit of avoided environmental damage is one example of an avoided cost that could be included in the Societal Test. The California Standard Practice Manual identifies additional societal benefits defined as "externalities" that could be included in the Societal Test. KCP&L evaluated three levels of CO_2 emissions costs; $10 per ton, $25 per ton and $40 per ton in the calculation of the Societal Test.

BENEFIT/COSTS ANALYSIS OF KCP&L PROGRAMS

Q: What tools or software did you use for cost-effectiveness evaluation?

A: The Demand Side Management Option Risk Evaluator software ("DSMore^{TM}"), which is available from Integral Analytics, Inc., was used to model the cost-effectiveness of all DSM end-use measures and programs. DSMore^{TM} is an MS-Excel based financial analysis tool designed to evaluate the costs, benefits, and risks of DSM programs. DSMore^{TM} provides all of the familiar cost-effectiveness test results, including Participant Test, Utility or PAC Test, TRC Test, RIM Test, and the Societal Test. The DSMore^{TM} model also provides annual summary tables of utility avoided costs, the DSM energy savings impact in kilowatt ("kW") and kilowatt-hour ("kWh") participation rates, participant costs, program administrator costs and utility lost revenue. This data was used to calculate the test results according to KCC Docket No. 08-GIMX-442-GIE ("442 Docket") methodology which requires the Societal Test to be evaluated under three different CO_2 avoided cost assumptions, $10 per ton, $25 per ton and $40 per ton, and two discount rates, three percent and seven percent.

The DSMore^{TM} User Manual provides more detail about the model's functionality and is attached as Schedule JMO-6. An independent review of the software was conducted by TechMarket Works and Summit Blue Consulting for Duke Energy – Ohio. A copy of this report is attached as Schedule JMO-7.

Q: Please discuss the avoided cost assumptions and inputs used in the DSMore^{TM} model.

A: KCP&L developed estimates of avoided costs which included the avoided hourly cost of energy production both cost-based and market-based, a levelized cost of avoided generation capacity, a levelized cost of transmission and distribution capacity, and avoided Open Access Transmission Tariff ("OATT") fees.

Q: How did you calculate the avoided capacity cost?

A: KCP&L used the levelized cost of a combustion turbine ("CT") as the value for annual avoided generation capacity. The avoided generation capacity cost was **[redacted]** per kilowatt-year ("kW-Yr"). Calculation of this value is shown in Table 1: Avoided Capacity Cost.

<u>Table 1: Avoided Capacity Cost</u>

CT Value Utilized for Avoided Cost Calculations	
Net Capacity (MW)	**[redacted]**
Capacity Factor	**[redacted]**
Fixed O&M ($/kW-Yr)	**[redacted]**
Var O&M ($/MWh)	**[redacted]**
Technology Cost ($/kW)	**[redacted]**
Technology Capital	**[redacted]**
Levelized FCR for construction projects	**[redacted]**
Annual Technology Carrying Cost	**[redacted]**
Transmission Cost ($/kW)	**[redacted]**
Transmission Capital	**[redacted]**
Transmission FCR	**[redacted]**
Annual Transmission Carrying Cost	**[redacted]**
Total Annual Cost	**[redacted]**
Total Fixed O&M	**[redacted]**
Total Variable O&M	**[redacted]**
Total Levelized Fixed Cost Per Year	**[redacted]**
Installed Cost $/kW	**[redacted]**

Q: How did you calculate the avoided transmission and distribution cost?

A: KCP&L's transmission and distribution ("T&D") engineering department developed estimates of T&D system expansion that could be avoided with implementation of a portfolio of DSM programs. The net present value of avoided T&D capital expenditure was **[redacted]** per kW-Yr. The calculation of this value is shown in Schedule JMO-8.

Q: How did you calculate the avoided energy cost?

A: DSMore™ will calculate both the market-based avoided cost of energy and a cost-based avoided cost of energy based upon inputs to the DSMore™ model. A forecast of hourly energy market clearing prices was developed using the MIDAS™ market model. Integral Analytics then calibrated the DSMore™ model to replicate this market-based price forecast. Historical running costs, often referred to as System Lambda, were analyzed and used as the cost-based input into the DSMore™ model.

Q: Please discuss the cost-based methodology.

A: The cost-based methodology has deep roots in utility planning and economic analysis. The marginal cost of electricity required, or "System Lambda", determines the avoided energy cost in the cost-based method.

Q: Has the Commission endorsed a methodology?

A: Yes, but there was some confusion in this regard. In its June 1, 2009 Order in Docket 08-GIMX-442-GIV, the Commission acknowledged that the parties had agreed at the collaborative to use the tests or formulas set forth in the *California Standard Practice Manual: Economic Analysis of Demand-side Programs and Projects* (July 2002) *(California Manual)*, and the Commission endorsed the use of those tests and formulas in its Order (page 7-8.) However, the Commission indicates that the *California Manual* uses a definition of avoided costs that is based on generation costs, not wholesale marketing prices.

Q: Is it your understanding that the *California Manual* uses a definition of avoided costs that is based on generation costs, not wholesale marketing prices?

A: No. The *California Manual* addresses avoided costs by reference to wholesale marketing prices. It should be noted that the California Standard Practice manual, "*Economic Analysis of Demand-Side Programs and Projects,*" published in October 2001 specifies:

> The following 'rules' should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:
>
> 1. In the past, [m]arginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. ***With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices***, ...[6] [emphasis added]

Q: Is the cost-based methodology apparently endorsed by the Commission the preferred methodology?

A: No. The long run production cost method is useful for least cost planning and rate setting but tends to undervalue the short-run consequences of a supply shortage, localized transmission congestion or an unplanned outage. Cost-based methods do not reflect prices observed during these scarcity events. It is during these events that demand side programs provide the most value to the utility. This effect is even more pronounced for demand response programs that reduce load during peak hours when power prices are at their highest of the year.

Q: Please discuss the market-based methodology.

A: Wholesale market traders do not charge System Lambda marginal cost for their transactions in the open market and purchasers do not pay a System Lambda price. The market-based methodology brings the full value of energy supply into the observed price. This can include transmission fees, balancing fees, reserve margin costs and other transaction fees. With the introduction of wholesale competitive markets, supply costs became unbundled and more transparent in these cost categories. Full requirements purchases and sales are also subject to additional charges to cover risk management, and ancillary services costs such as load-following and reserve margins costs. Additional transaction fees also include the bid/ask spread, which is the difference between the offering price to sell energy in the wholesale market versus the price to buy energy in the market. This bid/ask spread is a proxy for the amount of margin wholesale market traders or brokers are extracting from the market. In addition, during periods when supply is scarce, the upper limit on the price charged to purchasers can be much greater than a System Lambda production cost. This represents additional risk to the purchaser.

Q: Please discuss the advantages of the market-based methodology.

A: The market-based avoided energy cost methodology provides another option for calculating avoided energy costs. In today's electricity markets, both regulated and non-regulated electricity producers and suppliers routinely transact using market price bilateral contracts which can be traded electronically through systems such as the Intercontinental Exchange ("ICE"). These market-based prices are greatly affected by short run supply and demand conditions and are a better indicator of the value in the marketplace. During times of supply scarcity, market-based avoided costs would be

---

[6] California Standard Practice Manual, Appendix A, p. 26.

expected to be higher relative to the cost-based method. Conversely, market-based prices can be lower relative to the cost-based method during times of excess supply or lower demand due to an economic downturn.

Q: Please discuss the cost-effectiveness test(s) used by KCP&L for determination of end use measure inclusion.

A: KCP&L utilized the TRC Test to screen the cost-effectiveness of the end-use measures that are included in the DSM programs proposed in the testimony of KCP&L witness Allen Dennis.

Q: Are there exceptions to the rule that all DSM programs should pass the TRC Test with a ratio greater than one?

Yes. As discussed in KCP&L witness Allen Dennis' testimony, KCP&L intends to offer a low income weatherization program and three educational programs.

Q: Should low income programs be required to pass the TRC Test?

A: No. Low income programs produce energy savings and provide benefits. However, the costs to achieve these savings and benefits are generally higher than the cost of other programs. As such, low income programs generally exhibit a benefit-cost ratio less than one and are not considered cost-effective. However, KCP&L recognizes the overall benefits to society from these programs and requests that the Commission not require these programs to have a TRC Test ratio greater than one.

Q: Are there any other exceptions?

A: Yes. KCP&L proposes that all indirect program activities not be required to meet cost-effectiveness evaluation. Indirect activities are those that do not directly produce energy or demand savings but contribute to the effectiveness of a portfolio of DSM programs. An example of an indirect activity is DSM market or customer behavior research.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company for Approval To Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio	)	Docket No. 10-KCPE-____-TAR

AFFIDAVIT OF JOSEPH M. O'DONNELL

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Joseph M. O'Donnell, being first duly sworn on his oath states:

1. My name is Joseph M. O'Donnell. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Manager of Marketing Intelligence.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of twenty (20) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Joseph M. O'Donnell
Joseph M. O'Donnell

Subscribed and sworn before me this 11th day of June, 2010.

Nicole A. Wehry
Notary Public

" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

My commission expires: Feb. 4, 2011

2007 KANSAS CITY POWER & LIGHT SINGLE-FAMILY RESIDENTIAL POTENTIAL ANALYSIS

FINAL REPORT

MARCH 13, 2007

Prepared for Kansas City Power & Light

PREPARED BY:

RLW ANALYTICS

48 4TH STREET

TROY, NY 12180

Table of Contents

Table of Figures

Executive Summary

This is the final draft report of the 2007 Single-Family Residential Potential Study for Kansas City Power and Light (KCP&L). This study was aimed at providing technical, market, and economic analyses specific to the KCP&L service area, with the goal of identifying key characteristics for energy efficiency opportunities.

Approach

A nested sampling methodology was employed in the study to effectively reach time and analysis demands. In line with this approach RLW utilized a dual sampling strategy, using onsite surveys to strengthen phone survey data that was collected. The statistical paradigm required that at least 254 phone surveys be conducted and at least 70 onsite surveys carried out. In accord with KCP&L, RLW made use of onsite data from the recent 2006 Missouri Statewide Assessment (in which KCP&L was one of seven collaborating utilities). RLW successfully completed all phone surveys and on-site visits for this study between January 9th and February 15th.

Key Findings

RLW initially analyzed 32 potential home improvement options. The 20 most promising measures, as ranked by annual electrical energy savings in MWh, offer nearly the same (about 97%) potential savings as all 32 measures combined. This is largely due to the presence of one measure (ID 15) that yielded significant natural gas savings but negative electrical energy savings.

There were three generalized types of energy efficiency measures that were identified as most promising:

1. Appliances and lighting – specifically refrigerators and compact fluorescent lamps;
2. HVAC – Improvements in practices during new construction and prescriptive measures for existing systems; and
3. Weatherization – These would be both new construction and prescriptive measures for reduced air infiltration, insulation, and energy efficient windows.

Introduction

This is the final draft report for the 2007 Single-Family Residential Potential Analysis Study for Kansas City Power & Light (KCP&L). RLW Analytics, Inc. conducted the study on behalf of KCP&L.

The study was designed to provide KCP&L with technical, economic, and market potential for building measures, appliances, and lighting of single-family residential homes. The overarching goals of this assessment were to calculate and present technical, economic, and market potential analyses for energy efficiency opportunities to help target future programs that will have the largest and/or most cost effective impact on peak demand and energy consumption in the single-family residential sector.

Approach

Per KCP&L's request, RLW was requested to meet a March 1' 2007 deadline. To meet this timeline, RLW utilized a nested sampling methodology which would equally accommodate time and project analysis demands. An evenly distributed sample of single-family residential accounts was selected from KCP&L. The nested sampling methodology utilized a dual approach. The majority of the data was collected over the phone which allowed for timely data collection. RLW then randomly selected a subset of customers within this phone survey sample to carry out onsite visits. These visits acquired specific household data, such as building envelope characteristics, appliance model numbers, manufacture dates, efficiency data, and related. This data was used to strengthen the accuracy of the phone survey data.

For statistical purposes, RLW needed phone survey data for at least 254 customers and onsite data for at least 70 customers. KCP&L customers were first recruited to participate in the study by phone. Each participant was offered $20 for agreeing to participate in the phone survey. At the end of each survey, customers were asked if they would be amenable to participating in an onsite survey for an additional incentive of $30. At the end of the phone survey task, a sample of onsite customers was next randomly selected from the list of those who agreed to participate in an on-site visit.

Because of the time constraint to deliver this study, KCP&L and RLW agreed to make use of the KCP&L onsite data that was collected from the recent 2006 Missouri Statewide Assessment. RLW made use of all 28 previously collected KCP&L single-family customer onsite data, and combined it with this newest set of on-site data. A total of 232 successful phone surveys were completed from January 15-26, 2007, and a total of 42 onsite surveys completed from January 29 – February 9' 2007. Overall, RLW collected and used data from a total of 260 phone surveys and 70 on-site visits.

For both the phone and on-site surveys, the surveyors collected data on the major appliances and lighting systems in the home. The onsite surveyors collected nameplate data for the following appliances:

- Refrigerator-Freezer
- Self-standing Freezers

- Dishwashers
- Clothes Washers
- Clothes Dryers
- Water Heaters
- Heating Equipment
- Cooling Equipment

For lighting, the phone and onsite surveyors collected lamp, fixture and wattage data for each lighting fixture within the home, as well as any front porch fixtures. The on-site surveyors also collected data on attic, floor and wall insulation R-values, wall construction, and window type.

Once compiled, the data underwent quality control measures. Model numbers were matched to databases of appliance efficiencies through a number of manufacturer databases, including CEC, ARI, AHAM, and Carrier's 2003 Electronic Blue Book. Once the model numbers were linked, the corresponding efficiency was assigned to the matched appliance. Matching rates varied greatly by appliance type and age. In most cases this is due to the comprehensiveness of the efficiency databases that are available for each appliance type. RLW is confident that the great majority of model numbers found on-site were matched if they appeared in any of the efficiency databases. Matching model numbers to appliance databases is typically a long process. For example, wildcard symbols (*, /, #, etc.) are often included in the model number. The wildcards add to the complexity of the query designs and decrease match rates.

Data Collection Sample Design

Using a nested sampling approach, the statistical paradigm required a minimum of 254 phone surveys and 70 onsite surveys be completed. The targeted single-family phone survey sample of 254 homes was proportionally allocated across the utility to the total number of single-family accounts. The sample for the 70 onsite surveys was randomly selected from the phone survey data. The sample was designed at the regional level in order to achieve an error bound of +/-10% at the 90% level of confidence.

The critical element in using this particular approach is that the onsite data collected was later used to strengthen and validate the data collected over the phone. RLW utilized this approach to test and/or improve customer reported data. In this regard, a broad phone survey tool was used to collect any easily obtainable data (such as window types, basic appliance information, etc.), while the onsite data collected detail-specific data that was necessary for efficiency assessment.

To verify the relative precision of the study, we examined five key characteristics: SEER, wall R-Value, attic R-Value, home square footage, and age of the home. To effectively make use of DOE2 modeling, the data was formed into “bins”, i.e. groups of sites. Hence, the analysis combined specific variables to complete the potential analyses. Using this methodology, the relative precision of the study can be computed by examining each of these five characteristics individually and then as a whole. The calculated resulting relative precision was determined to be 10%.

Potential Analyses and Results

Methodology for Estimating Impacts

The analysis for the technical impacts began with an examination of typical weather patterns for two locations within the KCP&L service area. This examination indicated that there is no significant difference between the two locations. One location was the Kansas City International Airport and the other was downtown Kansas City, Missouri. The downtown weather site appeared to be a little closer to the center of the service area, so RLW elected to use the weather data from that site.

The relative numbers of non-electric heated homes (about 77.4%, and almost exclusively natural gas), proved to be significant. The split between the electric strip heated homes and the electric heat pump heated homes was even, at 11.3% each. Therefore, RLW chose to create three DOE2 physical models to represent the entire KCP&L single family housing stock, but to utilize one central weather file. The three models were created in conjunction with three corresponding sets of field audit data and calibrated monthly to their corresponding electric utility billing data.

These three models were applied to calculate unique measure level savings for the average gas heated home, average electric strip heated home and average heat pump heated home. Any homes that are heated primarily with propane, oil and other miscellaneous fuels were included in this study among the gas heated homes. Of all the phone and on-site data used, about 3% of homeowners reported that they used propane, and one reported using wood for their primary heating fuel. However, none of the homes specifically visited for this study was heated with these alternate fuels.

All three types of homes have customer sites that utilize wood fireplaces to some degree. Heating contributions from these were accounted for in the models, hence impacting the dependence on gas and electricity, but savings on wood consumption are not considered as part of this study. RLW, therefore, assumed that wood consumption remained unchanged by the retrofits. All of the homes in the field audits and in the telephone surveys were also reported to be air-conditioned.

RLW utilized Kansas City, Missouri TMY2 weather data[1] to represent the entire service area. Monthly billing data furnished by KCP&L were first “cleaned” and “calendarized”[2], and then aggregated into the three groups by heating system type as defined by the field audits, telephone surveys and annual usage patterns by month. Finally, the monthly kWh was averaged by month to create the average monthly usage for each

---

[1] TMY2 weather data, used throughout the world, have been derived from actual NOAA (National Oceanic and Atmospheric Administration) hourly measured data through an elaborate statistical and analytical procedure aimed at identifying the most typical of each of 12 months of weather from 50 years of historical data, and combining these 12 months from different years to create a “Typical Meteorological Year”.

[2] That is, meter readings and billing data were converted in calendar months to allow for proper calibration to the models.

group to calibrate each DOE2 model. The models were calibrated to match their actual average monthly kWh within 2% for each month.

Due to some obvious erroneous descriptions of heating system types in the phone survey data, RLW reviewed each set of billing histories to confirm or correct the customer responses. About 25 to 30 percent of the customer descriptions were found to be wrong (which RLW finds as typical of customer telephone surveys throughout the country) and corrected to reflect the obvious heating system types. Whenever the billing history profiles were not conclusive, RLW gave the benefit of the doubt to the customer.

The DOE2 formatted version of the TMY2 weather file contains hourly dry bulb and wet bulb temperatures, humidity ratios, direct and diffuse solar radiation, wind speed and direction, precipitation, ground temperatures and other variables utilized by DOE2 to calculate hourly cooling and heating loads.

The impacts for each measure for each group were derived by first altering the calibrated "as-is" model to create a baseline condition that exceeded a reasonable threshold value. For example, the average house may have had R-23 attic insulation, but the baseline attic insulation R-value would be much lower, say R-7 or R-11. Using this approach, RLW created a specific baseline model for each measure, recognizing that the measure would be applicable only to homes that were below a reasonable threshold value (For example R-10 or lower, so that the average for all these homes would be about R-7). These baseline models, therefore, represent homes that might be expected to participate in a conservation program offering that measure. Next, a retrofit model was created for those homes by upgrading the measure of interest to a significantly higher but reasonably attainable standard, say R-30 for attic insulation.

Savings were obtained by running the baseline and retrofit models to obtain the hourly building demands for a typical year and subtracting the results for every hour. The sum of the hourly differences in cooling system demand represents hourly cooling savings for a typical weather year. Coincident summer electric demand savings were calculated as the average savings over the two hour window of 3-5 PM on the hottest weekday of the typical year. Coincident winter demand savings were calculated for the window of 6-8 AM (the heating peak period) on the coldest weekday. Annual energy savings are the sum of the hourly demand savings for the whole year. Natural gas savings estimates in terms of peak BTU's per hour and Therms per year were derived the same way.

For each measure RLW exercised all three models to calculate unique savings for an average gas heated home (with a gas furnace), average electric strip heated home (with an electric furnace), and average electric heat pump heated home (with a 15kW supplemental electric strip heating element). In the potential analysis the individual results for each measure were combined by weight-averaging them with the fraction of the population represented by each house/model type (0.774 gas heat, 0.113 strip heat, 0.113 heat pump), respectively.

Technical Assessment of Energy and Demand Impacts

Potential Energy Conservation Measures

As listed in Table 1, RLW analyzed 32 potential home improvement options. Average annual savings were calculated for each in terms of kWh and kW electrical energy and demand, and Therms (100,000 BTU) and peak BTUh (British Thermal Units per hour) of natural gas. Shaded IDs represent 20 measures and options that have been identified as priority measures based on their potential savings, and are more fully developed in the market assessment section of this report.

ID	Potential Situation	Improvement	Quantity
1	AC Refrigerant under charged	Add refrigerant	2 hr & 2 Lb R-22
2	AC Refrigerant over charged	Remove refrigerant	2 hours
3	Low evaporator airflow A	Increase duct sizes or add new ducts	75 SF
4	Low evaporator airflow B	Increase blower speed	2 hours
5	High duct leakage (25%)	Reduce duct leakage to 5%	3.41 tons
6	Oversized AC units A	Size AC units to 100% of Manual J	3.09 tons
7	Oversized AC units B	Size AC units to 100% of Manual J	3.09 tons
8	One inch insul. on ducts in attic	Add two more inches of insulation	3.41 tons
9	Gas heat and 13 SEER AC	Install AC SEER = 16	3.41 tons
10	Home has 13 SEER heat pump	Install Heat Pump SEER = 16	3.78 tons
11	Home has electric strip heat	Install Heat Pump SEER = 16	2.65 tons
12	Attic insulation = R-7	Add another R-23 attic insulation	1344 SF
13	Attic insulation = R-11	Add another R-19 attic insulation	1344 SF
14	Exposed walls not insulated	Add R-11 wall insulation	1355 SF
15	Floor over basement not insulated	Add R-19 Insulation to floor	614 SF
16	House infiltration = 0.8 ACH	Reduce infiltration to 0.35 ACH	2077 SF
17	Single pane windows A	Add storm windows	240 SF
18	Single pane windows B	Install Low E double pane window 2904	240 SF
19	Standard double pane windows	Install Low E double pane window 2904	240 SF
20	No E & W window shading A	Add solar screens to E & W glass	86 SF
21	No E & W window shading B	Plant deciduous trees on E & W sides	6 each
22	No Compact Fluorescent Lamps	Use 10 more CFLs throughout house	10 CFLs
23	Refrigerator needs to be replaced	Purchase Energy Star refrigerator	1 each
24	Refrigerator early retirement	Removed unit uses no energy	1 each
25	Dishwasher to be replaced	Purchase Energy Star dishwasher	1 each
26	Clothes washer to be replaced	Purchase Energy Star clothes washer	1 each
27	No prgrammable thermostat	Install programmable thermostat	1 each
28	No faucet aerators	Install faucet aerators	1 each
29	No low flow shower heads	Install low fow shower heads	2 each
30	Hot water pipes not insulated	Insulate hot water pipes	1 each
31	Electric water heater not wrapped	Wrap electric water heater	1 each
32	Gas water heater not wrapped	Wrap gas water heater	1 each

Table 1: Potential Situations and Improvements Evaluated in this Study

Several of the listed improvement options represent multiple ways of dealing with a single potential situation. For example, low evaporator airflow (ID 3 and 4) may be rectified by increasing duct capacities or increasing the speed of the blower. The potential situation in this case is denoted as “A” or “B”, respectively. The cost of implementation of each improvement option is based on the “Quantity” defined in the last column of the table, where labor costs are assumed at $50/hour.

Interpretation of Field Data and Creation of DOE2 Models

As previously described, information gathered for this project included detailed house construction features and demographic information from on-site audits and telephone surveys. Monthly electric billing data obtained from the utility companies were utilized for 259 of these homes (data for the other homes were either not available or not used due to inconsistencies in the billing records).

RLW employed specially created DOE2 models based on the average shell and demographic characteristics of all the sampled homes to estimate potential savings. These models were designed to exhibit weekday, weekend and monthly variations in energy consumption derived from over 100 hourly schedules, which in turn were created from previously metered hourly end-use data. Each model is capable of producing valid seasonal energy savings and peak demand savings. Savings are actually based on differences in hourly demand over a full 8,760 hours. Demand savings can be observed for any hour or demand window of interest, but those reported for this study are coincident summer and coincident winter peak demand savings. As such, they are additive.

First, an “as-is” model for each house type was created to represent the average characteristics of all homes in the sample for that type. Individually calenderized, averaged and weather-normalized monthly billing data were used to calibrate the models. Each group was averaged monthly to establish actual monthly electric energy kWh to be used as calibration targets. Independent adjustments of uncertain variables (within their ranges of uncertainty) for monthly lighting, miscellaneous appliance loads, and monthly temperature setpoints for cooling and heating were made. These adjustments allowed for proper calibration of these models to within 1% annually of their weather-normalized kWh usage.

Many of the descriptive components of the “as-is” home that were used in the DOE2 models are listed in Table 2 below. These are two-story houses (the areas of the second stories vary with house type) with partial (i.e. about 75%) basements, portions of which are heated and cooled. The total heated floor area of each house model is the average of those measured during the site visits. The total conditioned areas of these houses were 2000 square feet (gas heated), 2120 sq. ft. (electric strip heated) and 2496 sq. ft. (heat pump heated).

The models contain three conditioned zones, consisting of a first floor, a second floor and a conditioned portion of the basement. They also contain six unconditioned zones to capture the effects of the heat transfer through ceilings, garage walls and floors over the garage and unconditioned portions of the basements. These buffer zones also provide a means for modeling duct supply and return air leakage to and from these spaces, as well as duct conduction heat transfer to and from the attic.

Exterior shading is modeled by two-foot eaves on the north and south sides and varying amounts of 40-foot high non-deciduous "trees" on the east, south and west faces of the house. The solar transmissivities[3] of these "trees" are varied by height and from model to model to aid in calibration. Interior shading of the glass is modeled by light drapes that are fully open at times and partially closed at other times, which would follow a realistic schedule of occupant behavior. These input parameters are varied as required to model the baseline and retrofit conditions of the two window shading options, IDs 20 and 21.

[3] That is, the amount of sunlight that still passes through the tree's summer foliage.

	DOE2 Calibrated Model Value		
Model Characteristic	Gas Heat	Strip Heat	Heat Pump
Number of audits in sample	205	30	30
First floor conditioned area, sq. ft.	1,064	1,064	1,064
Second floor conditioned area, sq. ft.	750	756	1092
Conditioned basement area, sq. ft.	186	300	340
Unconditioned basement area, sq. ft.	614	500	460
Garage area, sq. ft.	280	280	280
% glass to heated floor area	13.7%	14.5%	13.5%
Window glass type	Double-pane clear	Double-pane clear	Double-pane clear
Solar screens?	No	No	No
Infiltration ACH	0.50	0.50	0.44
Wall insulation R-value	11.0	14.0	14.0
Attic insulation R-value	21.0	25.6	23.4
Number of occupants	2.9	2.8	2.8
Lighting connected load kW	4.08	5.3	4.0
Lighting peak usage kW	1.9	2.5	1.9
Misc connected load kW	5.9	8.5	7.6
Misc peak usage kW	4.2	6.3	5.4
Base elec. usage, kWh/year	8,686	12,616	10,135
Base gas usage, Therms/year	322.9	84.4	217.7
Cooling system type	DX Split	DX Split	DX Split
A/C rated SEER	11.20	11.20	12.00
A/C rated tons	3.41	4.07	4.03
Metering device (TXV, Capillary)	Capillary	Capillary	Capillary
AC Air flow factor	0.85	0.85	0.85
AC Refrigerant charge factor	0.94	0.85	0.95
AC Field Operating SEER	9.87	8.92	10.68
AC Field Operating tons	3.06	3.27	3.66
AC Supply air cfm/ton	340	340	340
AC Supply duct air loss	15%	17%	15%
Duct heat gain factor U*A	29.0	34.6	24.2
Portion of ductwork in attic	50%	60%	50%
Alternate fueled fireplaces (wood)	4%	19%	8%
Heating sytem type	Gas Furnace	Elec. Furnace	Heat Pump
Heating system rated efficiency	81%	100%	3.58 COP
Heating system operating efficiency	75%	100%	3.19 COP
Heating rated capacity, Btu/hour	85,500	51,180	53,000

Table 2: DOE2 Calibrated Model Characteristics

Internal and external energy (both electricity and gas) used for lighting, appliances, and hot water vary hourly according to end-use metered data from other studies. These also vary monthly to follow a typical pattern and allow calibration of the model to match actual utility billing data. Cooling and heating temperature set points were also allowed to vary both hourly and monthly to represent measured data from other studies, as well as to provide fine tuning of the model for calibration.

Cooling and heating system characteristics are shown in Table 2. These values are typical of those observed in this study or borrowed from other similar studies. The airflow factor and AC refrigerant charge factors, for example, are from other studies in which air conditioner performance data were measured. These are used in the models to adjust rated capacity and efficiency to typical operating values.

Calculation of Individual Measure Impacts

The savings for each measure were calculated separately for each DOE2 model. The average savings per house were then calculated as the population-weighted averages of the model savings. For purposes of this study, the KCP&L population of single family detached homes was set at 333,207. The related weighting fractions, based on the sample populations, are 0.774, 0.113 and 0.113, for gas, strip and heat pump homes, respectively.

Weighted average savings estimates for each measure and optional retrofit improvement are summarized in Table 3. Although electric savings for all three house types and all thirty-two measures were calculated, they are not explicitly represented by these averages due to the weighting. Instead, they represent average savings per measure for the mixed population.

The shaded ID numbers represent the measures and options that have been identified by RLW as priority measures. These are the top 20 measures ranked by annual energy savings potential for KCP&L. The blank shaded cells represent housing types where the respective measure does not apply. For example, ID 10 is a heat pump replacement measure that applies only to homes with heat pump heating systems, and ID 11 is a heat pump replacement of an existing electric strip heating system.

Savings for ID numbers 28 through 32 in Table 3 are not directly calculated by DOE2, and the savings for these were taken from the results of previous studies. Direct impacts for lights and appliances located within the conditioned space were programmed into the DOE2 models, however, to capture their secondary impacts on cooling and heating loads.

ID	Therms	Total kW	Cool kWh	Heat kWh	Other kWh	Total kWh	Payback, kWh Only	Payback, all Fuels	Diff. Costs Before Rebate	Diff. Costs After Rebate
1	0	0.18	640	49	0	689	2.6	2.6	$250	$125
2	0	0.12	167	9	0	176	4.1	4.1	$100	$50
3	56	0.82	938	43	0	981	7.0	3.4	$950	$475
4	67	0.67	758	49	0	807	0.9	0.4	$100	$50
5	64	0.45	494	112	0	606	7.2	2.5	$600	$300
6	0	0.27	286	47	0	333	6.9	6.9	$314	$157
7	0	0.83	947	99	0	1046	1.5	1.5	$210	$105
8	45	0.24	184	58	0	242	18.1	4.1	$600	$300
9	0	-0.11	921	0	0	921	6.6	6.6	$840	$420
10	0	-0.52	693	565	0	1258	4.3	4.3	$750	$375
11	0	-0.48	952	3109	0	4061	8.6	8.6	$4,800	$2,400
12	83	0.54	523	357	0	879	8.8	3.2	$1,058	$529
13	50	0.35	326	215	0	541	10.9	4.0	$809	$405
14	360	0.69	1006	1627	0	2634	9.7	2.8	$3,500	$1,750
15	33	-0.12	-408	185	0	-223	-12.8	7.5	$393	$197
16	195	0.43	140	906	0	1046	2.8	0.6	$400	$200
17	143	0.28	196	712	0	908	8.2	2.1	$1,020	$510
18	124	0.54	801	627	0	1428	1.8	0.7	$350	$175
19	-19	0.26	644	-124	0	520	5.0	15.5	$357	$179
20	0	0.22	172	0	0	172	10.9	10.9	$258	$129
21	0	0.18	627	0	0	627	10.4	10.4	$900	$450
22	-9	0.05	129	-89	504	543	1.1	1.5	$80	$40
23	-2	0.02	65	-47	134	152	9.6	11.8	$200	$100
24	-13	0.12	179	-90	865	954	0.4	0.5	$50	$25
25	6	0.01	14	0	93	107	10.2	4.8	$150	$75
26	9	0.02	18	0	93	110	26.4	11.0	$400	$200
27	27	-0.22	566	100	0	666	2.2	1.3	$200	$100
28	7	0.00	4	0	27	31	1.9	0.4	$8	$4
29	22	0.00	9	0	165	174	0.8	0.3	$20	$10
30	11	0.00	0	0	80	80	8.6	2.5	$95	$48
31	0	0.00	0	0	58	58	3.1	3.1	$25	$13
32	11	0.04	118	0	0	118	N/A	1.4	$60	$30

Table 3: Electric/Natural Gas Savings by Measure and Heating System Type

Differential costs shown in the last two columns for each measure are the average costs to install the measure, or, the difference in cost between a standard retrofit and the high efficiency option. These costs are homeowner perspectives, so they are reduced to half when a 50% rebate is applied. Payback for all fuels is the simple payback in years, or the ratio of annual fuel dollars saved - including natural gas therms and electric total kWh - and differential installed cost. Paybacks based on kWh savings alone (excluding therms) are also shown in the table.

Dollars saved are based on annual electric and gas savings and their respective marginal residential customer rates. Differential costs for ID numbers 6 and 7 had to be defined based on their net effects on contractor sales (assumed here to be 20% of the differential installed costs) because they cost less to install than their standard retrofit choices. Otherwise their differential costs would be negative, and their payback values would also be negative, and therefore cannot not be defined.

For this one exception we will assume that the homeowner pays the contractor for the loss of sales revenue to put this net cost differential onto the homeowner. Contractors who participate could add these costs to their bids so that they break even financially, and the homeowners would still realize the 80% remaining savings in differential costs. In this case, both the perceived costs (20% of the differential cost savings) and energy savings apply to the homeowner, and a payback period becomes (loosely) meaningful. This is all hypothetical, and incentives for this measure would have to be directed to the AC installation contractors, and not the homeowners. This situation imposes a formidable market barrier.

Situation and Measure Improvement Descriptions

The following are descriptions of each listed measure and improvement option, explanations of the assumptions made, and the technical approach to estimating impacts.

Undercharged AC Systems – ID 1

Published accounts from several other studies, including a New England HVAC study conducted by RLW in 2002, were used to estimate the technical potential percentages for AC systems. From these studies, about 36% of the measured systems are probably undercharged with refrigerant, which would be enough to exhibit recognizable symptoms. The average undercharged condition was modeled as a 20% reduction in both cooling capacity and efficiency. This 20% reduction represents a general consensus of the other studies.

In the baseline DOE2 models, the refrigerant charge factor was adjusted to 0.8 to reflect this 20% loss. In the retrofit models this factor was set to 1.00 to reflect a properly charged system. At this point the operating capacities and efficiencies were still slightly below rated values due to the fact that evaporator airflow is still a little low. This refrigerant charge correction resulted in an estimated annual savings of 689 kWh, and a peak demand reduction of 0.18 kW per application.

Overcharged AC Systems - ID 2

About 31% of the measured AC systems found in other studies were found to be overcharged with refrigerant. The average effect of this situation, however, is not nearly as dramatic, with only a 5% reduction in both cooling capacity and efficiency. This was represented in the models by a refrigerant charge factor of 0.95, which is in fact the average operating condition. The frequency, degree, and impact of overcharging are not as great as undercharging.

In the retrofit models the refrigerant charge factor was set to 1.00. This resulted in an estimated annual savings of 176 kWh, and a peak demand reduction of 0.12 kW.

AC Systems with Low Evaporator Air Flow – IDs 3 and 4

According to recent studies, about 70% of residential AC systems have a problem of significantly low evaporator airflow. The threshold for this performance characteristic is considered 350 CFM per ton, which is generally used as the lowest acceptable flow rate before capacity and efficiency are appreciably reduced. The average airflow for all those below the threshold was about 300 CFM per ton.

In the baseline DOE2 models the system airflow rate was set at 300 CFM per ton. In the retrofit models this was increased to 400 CFM per ton.

Two different approaches to the correction of a low airflow problem were examined because the associated costs and impacts of each are significantly different. The easiest, and least expensive, solution is to increase the blower speed whenever practical. In many cases, however, this will not be practical due to the presence of single speed blowers or a limited remaining blower capacity.

The other approach is to reduce airside system operating pressures by locating and removing restrictions or by increasing duct capacities. In an existing system the only practical ways to increase supply duct capacity are to replace existing ductwork with larger runouts to several rooms, or add more runouts at or near the supply plenum to new supply grilles.

In past studies, it was found that many return duct systems are simple but undersized. Return duct undersizing often occurs with systems in the attic that have one central return air filter grille in the ceiling of a corridor with one large flexible duct to a return plenum. In most, if not all, cases these can be replaced with larger ducts and return grilles, or new ducts and grilles can be added in parallel.

Any reliable and practical correction to the problem of low airflow would have to be determined by a careful on-site analysis of each problematic system. Often it may be necessary to combine fan speed corrections with increased supply and return duct capacities to obtain proper airflow at a reasonable cost.

The retrofit DOE2 model for increased duct capacity, ID 3, assumed that the total static pressure of the air distribution system could be reduced enough to allow the existing blower to deliver the required air flow without increasing the blower speed. The blower power was increased linearly with the increased airflow rate, and the system capacities and efficiencies were increased to rated conditions. This resulted in an estimated annual savings of 981 kWh, and a peak demand reduction of 0.82 kW.

The retrofit model for increasing blower speed, ID 4, required an increase in motor power equal to the square of the ratio of the flow rates. The increased fan power offset some of the energy savings due to increases in system capacity and efficiency. This resulted in an estimated annual savings of 807 kWh, and a peak demand reduction of 0.67 kW.

AC Systems with High Duct Leakage – ID 5

In the recent New England study that RLW conducted, it was found that about 73% of the AC systems had a problem of significantly high supply duct leakage to the outside. The threshold for supply air leakage was 15% of actual system airflow. The average leakage for all those above the threshold was 25 percent. The systems with high duct leakage do not seem to correlate at all with duct location or plenum static pressure. Based on field observation, however, these systems were characterized by poor installation workmanship, and they tended to be older than others.

The DOE2 model treats duct leakage as primary air delivered to and returning from unconditioned spaces such as attics and basements. About one third of the leakage was assigned to the unconditioned portion of the basement, and the remainder went to the first and second floor attic spaces. This leakage air actually tends to cool these spaces slightly, and they are modeled as buffer zones so that return leakage from them approximates the actual zone conditions. In this way, the primary effects of both supply and return air leakage to these spaces are captured in the model.

The baseline model used 25% duct leakage, and this was reduced to 5% in the retrofit case. This resulted in an estimated annual savings of 606 kWh, and a peak demand reduction of 0.45 kW.

In this analysis the inherent but small reduction in evaporator airflow was not modeled because an average value was not known.[4] Many systems with leaky ductwork also suffer from insufficient airflow. In the New England study RLW found that about 79% of those with high duct leakage also had low airflow below 350 CFM per ton. Additionally, it was observed that 29% had a high blower motor power over 150 Watts per ton. The sealing of leaky ducts will tend to reduce air flow through the evaporator coil. In practice, therefore, it is necessary to measure the existing system airflow and blower motor power to determine if these other two potential problems need to be corrected before duct sealing is attempted.

Proper Sizing of AC Systems – IDs 6 and 7

An oversized system in this study is defined as having a rated cooling capacity greater than 100% of a valid Manual J cooling load estimate[5]. Based on an average Manual J estimate of capacity in terms of square feet per ton and the individually observed home sizes and installed capacities, about 80% of the AC systems of this study are oversized relative to this criterion. It was found in the 2002 study by RLW that those that qualified as oversized averaged about 50% above the Manual J estimate.

---

[4] The effect on energy usage is even smaller due to offsetting effects of fan power and system efficiency.

[5] The Air Conditioner Contractors of America (www.acca.org) maintains a Manual J Residential Load Calculation Procedure. This is the accepted industry standard, approved by ANSI, for the proper sizing and selection of HVAC equipment in residential homes.

The DOE2 models estimate the cooling system efficiency each hour as a function of a part load ratio. This is the ratio of system load and cooling capacity, and the function is empirically designed to approximate the efficiency penalty due to system cycling.

In the baseline model for ID 6 the systems were oversized by about 1.6 tons, and the retrofit was sized to 100% of Manual J, while the airflow and duct sizing was maintained at 360 CFM per ton. The rationale for maintaining this airflow rate is the probability that the same duct sizing practice will be applied by the contractor based on system size. This would be applicable to new AC systems that are installed where there is no existing ductwork. The estimated annual savings is 333 kWh, with a peak demand reduction of 0.27 kW.

On the other hand, if a new system is to be installed to replace an old system or with an existing forced air furnace that already has supply and return ductwork, the contractor may not install new ductwork. In this scenario, ID 7, there is even more to gain by keeping the system size to a minimum. This is due to the fact that the existing ductwork would be able to deliver the same airflow in CFM as before with the same fan power (which would become a higher CFM per ton as the tons are reduced), thus reducing the system losses due to low airflow and excessive system cycling.

The retrofit DOE2 models for this case assume that the duct sizes, airflow rates, and fan static pressures remain unchanged. Even though the fan power is not increased, the annual fan energy consumption increases due to the fact that the system operates for longer periods of time, and this is accounted for in the models. The estimated annual savings for this scenario is 1046 kWh, with a peak demand reduction of 0.83 kW.

The advantages of reducing system size are all positive as long as the system capacity is sufficient to maintain acceptable comfort conditions about 97.5% of the time (which are all but a few hours of the typical cooling season). The smaller system will typically maintain better humidity control, last longer, make less noise, use less energy and cost less to install.

Most of the problems of low evaporator airflow in houses with evaporator coils added to existing forced air furnaces could be greatly reduced or avoided if the AC system is properly sized for the application. In recent studies, about 70% of the systems that are oversized also have evaporator airflow below 350 CFM per ton.

Unfortunately, downsizing is not a viable option after the system has been installed. Therefore, as an effective conservation program component, information and incentives will need to be presented to prospective homeowner participants before they even contact a contractor. Information and incentives should also be directed toward the contractors.

Addition of Duct Insulation – ID 8

It was observed that most ducts in the basements were not insulated, whereas nearly all ducts in the attics had at least one inch of insulation. The only appreciable savings available would be due to the addition of another inch or two of insulation to exposed ducts in the attic. Exact modeling of this was not within the scope of this project, but some assumptions were made regarding the duct heat gains due to conduction from a hot attic.

In the baseline DOE2 models it was assumed that 90% of the ducts were located in the attic and the product of U*A (i.e. thermal conduction coefficient times duct surface area) would be about 49.7, yielding an approximate peak air temperature rise of 1.0 degree Fahrenheit during the cooling cycle. In the retrofit case this U*A value was reduced to about 20.5. The estimated annual savings for this measure is 242 kWh, with a peak demand reduction of 0.24 kW.

High Efficiency SEER 16 AC in Gas Heated Homes – ID 9

Significant savings are potentially available for the installation of high efficiency AC systems instead of standard efficiency SEER 13 units. In the existing home retrofit market this might be applied to homes with old existing systems that are at the end of their useful operating lifetimes and need to be replaced. This might also apply to an existing home in which air conditioning was never before installed and the homeowner wants to install a new central AC system. Modeling the unit savings for this measure was straightforward. The baseline DOE2 model was assigned a rated efficiency of SEER 13, and the retrofit model used SEER 16. Additionally, the expansion device for both was changed from a capillary tube to a thermal expansion valve (TXV). All other conditions remained unchanged. The estimated annual savings for this measure is 921 kWh, with a peak demand reduction of -0.11 kW. The peak demand reduction is negative because a practical SEER 16 AC unit is achieved by applying a dual-speed compressor to an otherwise lower efficiency system. RLW found that a combination of an SEER 11 system and a dual speed compressor would yield a system that would be ARI rated at about SEER 16. The retrofit peak efficiency, however, is actually lower than the baseline peak efficiency.

High Efficiency SEER 16 Heat Pump – IDs 10 and 11

The installation of a high efficiency heat pump might be an option as a retrofit measure for existing homes with old heat pumps or with electric resistance heat.

The base case model for an old heat pump replacement, ID 10, assumed the baseline replacement heat pump would have been an SEER 13 heat pump. The retrofit model was similar to the SEER 16 AC, except it was equipped for reverse cycle operation. Potential savings for this option are about 1258 kWh and -0.52 kW for the average home.

The base case models for an electric resistance heat system replacement, ID 11, assumed the replacement equipment would be same as above. Potential savings calculated for this option were 3109 kWh and -0.48 kW. Average savings for electric strip heated homes is a little lower than anticipated due to the fact that the average electric strip heated home is slightly better insulated, and the occupants are more frugal in their energy usage practices (due to naturally reoccurring high heating costs). Additionally, there may be some significant “takeback” behavior involved. After upgrades are done, a homeowner would perceive heating bills are lower, and take some of the potential savings back in terms of increased comfort

Add Attic Insulation – IDs 12 and 13

Savings achievable for increasing attic insulation vary greatly with the amount of insulation already in place, as well as the amount of extra insulation added. Whether this is cost effective depends more on the amount of existing insulation. Two different baseline insulation values of R-7 and R-11 were assumed. In both retrofit scenarios the final R-value was R-30. Addition of any more than this is typically not cost-effective.

In the first scenario, ID 12, the baseline models were given an attic insulation value of R-7 with a retrofit to R-30. The calculated savings are 879 kWh and 0.54 kW. In the second scenario, ID 13, the base case was R-11 and the retrofit was R-30. Savings were estimated to be 541 kWh and 0.35 kW.

Add Wall Insulation – ID 14

Similar to attic insulation, achievable savings by increasing wall insulation vary greatly with the amount of insulation already in place, as well as the amount of extra insulation added. Whether this is cost effective depends more on the amount of existing insulation. RLW evaluated this measure with a baseline of no wall insulation, and added R-11 insulation to represent a realistic best-case scenario.

The calculated savings are 2634 kWh and 0.69 kW. Due to the high cost of adding insulation to existing walls, however, the simple payback for this measure based on kWh savings alone is relatively long at about 9.7 years. But this measure achieves some significant gas savings on average of about 360 Therms, and the simple payback to the average homeowner is only 2.8 years after rebate.

Although the potential savings are high, the long payback suggests that it would not be cost-effective to insulate existing walls with some insulation already in place. In fact, the existence of any batt insulation in existing walls renders it impractical to add more insulation by the normal method of blowing it through holes drilled into the stud cavities, because the batts would tend to block the flow of new insulation in many places.

Add Insulation to Floor over Unheated Basement – ID 15

Most basements are enclosed by thick masonry foundation walls and have direct contact with the earth. As such, they are naturally cooled by relatively low ground temperatures typical of Kansas City, where the averages are about 67 degrees Fahrenheit during the summer and about 43 during the winter.

As a result of the low ground temperatures, the savings are negative for most of the cooling season. The base case for this measure assumed no insulation and the retrofit provided for the addition of R-19 to the floors over the unconditioned basement areas. Calculated savings are -223 kWh and -0.12 kW. Due to differences in the costs of electricity and gas, the monetary savings from gas offset the increase in electricity usage, and the simple payback is about 7.5 years.

Reduce Infiltration by Caulking and Weatherstripping – ID 16

For this measure RLW assumed a baseline infiltration value of 0.8 ACH (Air Changes per Hour) and a retrofit of 0.35 ACH. RLW learned from several studies in different parts of the country that the average home infiltration rate is about 0.5 ACH. Calculated savings for weatherization measures are 1046 kWh, most of which (about 90%) is due to reduced heating requirements in electric heated homes, and 0.43 kW.

Add Storm Windows to Standard Single Pane Windows – ID 17

The average house in this study has about 240 square feet of window area. Less than 6% of the windows in this study were single pane, about 68% were double pane and 26%, were triple pane, counting those with storm windows. The overall average number of glass panes is 2.2, based on the study sample.

RLW used a typical single pane window with a U0 (thermal transmission coefficient) value of 1.09 and a SHGC (Solar Heat Gain Coefficient) of 0.81 for the base case, and applied storm windows in the retrofit case. The retrofit window structure had a U0 of 0.46 and a SHGC of 0.76, and the estimated savings were 908 kWh and 0.28 kW.

Replace Standard Single Pane Windows – ID 18

RLW used a typical single pane window with a U_0 value of 1.09 and a SHGC of 0.81 for the base case, and applied a typical high performance double pane window in the retrofit case. The retrofit window had a U_0 of 0.40 and a SHGC of 0.55, and the estimated savings were 1428 kWh and 0.54 kW.

Replace Standard Double Pane Windows – ID 19

RLW used a typical double pane window with a U_0 (thermal transmission coefficient) value of 0.46 and a SHGC (Solar Heat Gain Coefficient) of 0.76 for the base case, and applied a typical high performance double pane window in the retrofit case. The retrofit window had a U_0 of 0.40 and a SHGC of 0.55, and the estimated savings were 520 kWh and 0.26 kW.

Add Shading to East and West Facing Windows – IDs 20 and 21

Although external window shading might be added to all four faces of a house, the east and west faces offer the greatest potential savings. Also, to obtain maximum energy savings, the shade would have to be applied during the cooling season and removed during the heating season to avoid increasing the heating loads during the winter.

RLW considered and analyzed two different ways of shading east and west facing windows for this study, because one method will apply to some, while the other method is better for others. Neither alternative will be applicable to homes with significant east

and west shading from existing trees or other things. To model these measures RLW removed all but about 5% of the external shading from the calibration models.
One practical method, ID 20, of shading windows from the exterior is the addition of solar screens that can be removed during the heating season. To model this retrofit, RLW increased the calibrated model east and west building shade transmissivities from about 0.7 to about 0.95 for the base case and the U_0 value from 0.8 to 0.7 for the period of June 1 to October 31. To simulate the addition of solar screens, RLW reduced the SC of the east and west windows by half and the U_0 value from 0.9 to 0.8 for July 1 through August 31. Estimated savings for this scenario are 172 kWh and 0.22 kW.

The other (and more desirable from both an aesthetic and practical perspective) method is the planting of deciduous trees in strategic locations to the east and west of the house. In this scenario, (ID 21) RLW assumed that three deciduous trees had been planted at about 20 feet from each side of the house (a total of six trees) to shade the windows as much as possible, and that they had grown to an effective height of 20 feet. Their solar transmissivities were changed from 0.1 during the summer (June 1 through October 31) to 0.9 during the winter. Resultant savings are 627 kWh, 0.18 kW. As these trees continue to grow, the savings will increase.

Install Compact Fluorescent Lamps – ID 22

Field data from the site visits indicated that the average home had about 9.7% CFL's (Compact Fluorescent Lamps) by bulb count. Hence, there is a high technical market potential for this measure. In the impact analysis RLW assumed that each program participant would install and use an average of ten 15-watt CFL's to replace ten 60-watt incandescent lamps, for a connected load reduction of about 450 Watts.

Lighting hourly usage patterns utilized in the models are based on actual measured hourly residential lighting usage patterns from a large number of long-term and short-term end-use studies RLW has performed or examined. Calculated savings amounted to 504 kWh and 0.05 kW. The peak heating load was not measurably affected because it occurred during the night when the lights are not being used.

One may note that the peak kW savings was 0.05 kW, or 50 Watts, whereas the reduction in connected load was 450 Watts. This is due to natural diversity in the lighting usage patterns so that all ten of these lamps are never on at the same time. These electric savings include both direct and indirect savings due to the reduction in internal heat gains that reduce the need for cooling.

Purchase Energy Star Labeled Refrigerator – IDs 23 and 24

Two options for replacing an existing refrigerator with an Energy Star certified unit were examined in this study. The first option assumes that an existing refrigerator is at the end of its functional life and the homeowner has already decided to replace it. The other option examines the potential of enticing a homeowner to retire an existing refrigerator before the end of its functional life.

For the firs option, ID 23, it was assumed that a standard new refrigerator on the market today uses about 564 kWh per year, and an Energy Star refrigerator will use about 432 kWh per year (10% below the 2001 federal standard average of about 480). The difference is 132 kWh per year. This direct energy reduction was modeled into the retrofit DOE2 models, and the resultant total interactive net savings are 152 kWh and 0.02 kW. Some secondary impacts are seen due to the fact that the refrigerator is in the conditioned spaces. Gas heated homes realize the full operating reduction of 132 kWh, but electrically heated homes pay a heating penalty due to the fact that savings inside the house increase the need for heat in the winter.

The baseline for the second option, ID 24, was 850 kWh per year. The resultant total interactive savings due to removal of this unit are 954 kWh and 0.12 kW. In addition to interactive effects, it was assumed that the primary refrigerator will be used more, thus adding slightly to its annual kWh usage.

Purchase Energy Star Labeled Dishwasher – ID 25

An average new dishwasher uses about 121 kWh per year directly, and an equivalent Energy Star dishwasher will use about only about 78 kWh per year. Estimated savings for a house with a weighted combination of electric and gas water heaters are 107 kWh and 0.01 kW, most of which is due to savings in weighted average electric hot water usage.

On the other hand, more substantial electric savings are possible if the water heater is electric. In this scenario, the savings would be about 240 kWh per year and 0.02 kW peak demand.

Purchase Energy Star Labeled Clothes Washer – ID 26

Maximum electric savings for high efficiency clothes washers can be achieved if both the water heater and dryer are electric, although by far most of the savings is due to the dryer. The most common KCP&L home, however, uses natural gas for hot water. A significant number of homes had electric dryers (76%) and about 19% had electric water heaters.

For the typical home, RLW estimated annual savings to be about 110 kWh and 0.02 kW. The Energy Star clothes washer actually uses slightly more electric energy during the spin cycle to wring more water out, consequently reducing the time required for drying.

For the all-electric scenario, RLW estimated annual savings to be about 400 kWh and 0.04 kW.

Install Programmable Thermostat – ID 27

More than half of the homes visited already had programmable thermostats. RLW modeled the potential impacts of programmable thermostats by increasing the cooling setpoints 3.75 degrees F and decreasing the heating setpoints by 3.75 degrees F daily from 8AM to 3PM.

For this scenario RLW estimated annual savings to be about 666 kWh and -0.22 kW. Demand savings may actually be negative, as they are in this case, depending upon the setback schedule, the building mass and a thermal flywheel effect that causes the system to run longer to "make up" for the hours during which it was set back.

Install Faucet Aerators – ID 28

It was assumed, based on RLW's previous study for Missouri, that about 63% of all single family detached homes in Kansas City do not have a faucet aerator. RLW estimated the impacts of these by assuming that one faucet aerator would be installed on the kitchen sink, and that the energy savings would occur through a reduction in the use of hot water. The homes with gas water heaters will see no electric savings, but many of the homes in this study had electric water heaters.

The estimated savings for the typical home are 31 kWh and no measurable demand savings. For the 19% of homes with electric water heaters, the annual electric savings would be about 120 kWh and no peak demand. Actual demand savings may exist in some homes, but the schedule of kitchen faucet usage is small during the peak demand window.

Some homeowners may be willing to install and keep a faucet aerator in the bathroom. Although savings for these are not well defined, RLW has previously estimated that they might achieve about one tenth to one third the savings of the kitchen aerator. The reduced savings are, of course, due to the fact that the average bathroom sink utilizes significantly less hot water.

Install Low Flow Showerheads – ID 29

Field results of the previous study for Missouri indicate that about 40% of all single-family detached homes in Kansas City already use a low flow showerhead. RLW estimated the impacts of these by assuming that two low flow showerheads would be installed, and that the energy savings would occur through a reduction in the use of hot water. Again, the most common water heater is gas fired.

The estimated savings for the typical home are 174 kWh per year, and demand savings are negligible. For the 19% with electric water heaters the annual savings would be about 725 kWh and negligible coincident peak demand.

If there are more than two showers in a home, the low flow showerheads should be installed on the two most frequently used showers. If more than two devices are installed in a single home, the savings for the third one will probably be significantly less than those of the first two, but it will depend on how much the showers are actually used. On the other hand, if only one showerhead is installed because there is only one shower present, the savings for the one will probably be more than half the savings for two.

Insulate Hot Water Pipes – ID 30

All the audited homes of this study have hot water piping, but only portions of the pipes are easily accessible. RLW estimated conservation impacts by assuming that the exposed pipes could be insulated, and that the energy savings would occur through a reduction in the hot water standby losses. Again, the typical water heater is gas fired.

The estimated savings for the typical home are 80 kWh per year and negligible coincident peak demand. For the 19% with electric water heaters the annual electric savings would be about 355 kWh and negligible kW peak demand. Actual savings will vary significantly, depending on the amount and locations of exposed piping and the hot water usage patterns.

Insulate Electric Water Heater Storage Tanks – ID 31

RLW found that about 90% of the homes had electric water heaters that were not externally wrapped. The estimated savings for the typical home are 58 kWh per year and negligible kW. Savings for this measure will vary with the ambient temperatures surrounding the hot water tank.

Insulate Gas Water Heater Storage Tanks – ID 32

RLW found that about 91% of the homes had gas water heaters that were not externally wrapped. The estimated savings for the typical home are 11 Therms per year. Savings for this measure will vary with the ambient temperatures surrounding the hot water tank. Also, since some of the hot water tanks are located adjacent to or within conditioned spaces, RLW found that there were potential indirect electrical savings of about 118 kWh due to reductions in the cooling loads.

Technical Assessment of Program Market Potentials by Measure

Preferred Energy Conservation Measures

RLW initially analyzed 32 potential home improvement options. The 20 most promising measures, as ranked by annual electrical energy savings in MWh, offer nearly the same (about 97%) potential savings as all 32 measures combined. This is largely due to the presence of one measure (ID 15) that yielded significant natural gas savings but negative electrical energy savings.

Market potentials for all measures are shown in Table 4, with the top 20 highlighted. These measures are ranked by their estimated “Electric Savings Potential, MWh”. The base case situation is described in the third column, followed by seven columns of marketing metrics, all of which are defined in their respective column headings.

The market potentials of this study were calculated under the assumption that the program sponsors would identify appropriate measures for each home and would offer rebates of 50% of the differential costs for all measures. Appropriate measures would include all existing situations that fall below the minimum thresholds of performance.

The last three rows of the table show sums for the first six columns and averages for the last column. They are also self-explanatory. Notice that the top 20 measures capture 97.3% of the electric savings and 95.9% of the demand savings available through all 32 measures, while capturing 92.4% of the total potential gas savings and 94.9% of the customer annual fuel bill savings. On the other hand, the rebate costs necessary to capture these are reduced significantly, to 87.7%, and the average program rebate costs are reduced from $0.50 to $0.47 dollars per kWh saved. The gray cell in the last column has no meaning because the electric energy savings are either zero or negative for that measure.

Pri	ID	KCP&L Energy Savings Measure Potential Situation	Potential Installs Per Year Count	Multiple Options Fraction	Demand Technical Potential MW-S	Demand Economic Potential MW-S	Demand Market Potential MW-S	Electric Technical Potential MWh	Electric Economic Potential MWh	Electric Market Potential MWh	Gas Market Potential kTherms	Annual Fuel Savings k$	Utility Rebate Costs k$	Electric Rebate Costs $/kWh
1	27	No prgrammable thermostat	17121	1.00	-43.7	-43.7	-3.7	133,143	133,143	11,402	464	$1,363	$1,712	$0.15
2	22	No Compact Fluorescent Lamps	18948	1.00	10.3	10.3	1.0	108,624	108,624	10,295	-161	$506	$758	$0.07
3	24	Refrigerator early retirement	5326	1.00	18.3	7.3	0.6	149,329	59,732	5,080	-70	$261	$133	$0.03
4	16	House infiltration = 0.8 ACH	3567	1.00	35.5	35.5	1.5	87,143	87,143	3,732	695	$1,126	$713	$0.19
5	29	No low flow shower heads	19992	1.00	0.0	0.0	0.0	34,775	34,775	3,478	439	$788	$200	$0.06
6	4	Low evaporator airflow B	3387	1.00	29.9	29.9	2.3	36,141	36,141	2,733	228	$473	$169	$0.06
7	1	AC Refrigerant under charged	3698	1.00	22.0	22.0	0.7	82,630	82,630	2,547	0	$175	$462	$0.18
8	32	Gas water heater not wrapped	17247	1.00	0.0	0.0	0.0	31,848	28,663	2,035	190	$377	$517	$0.25
9	3	Low evaporator airflow A	2039	1.00	190.8	190.8	1.7	228,775	228,775	2,000	115	$281	$969	$0.48
10	30	Hot water pipes not insulated	22684	1.00	0.0	0.0	0.0	22,677	22,677	1,816	247	$434	$1,077	$0.59
11	5	High duct leakage (25%)	2543	1.00	87.7	87.7	1.2	117,198	117,198	1,542	163	$310	$763	$0.49
12	19	Standard double pane windows	1801	1.00	66.3	19.0	0.5	132,033	37,907	937	-35	$21	$322	$0.34
13	2	AC Refrigerant over charged	4373	1.00	11.8	11.8	0.5	17,919	17,919	771	0	$53	$219	$0.28
14	21	No E & W window shading B	2363	0.50	26.8	19.6	0.2	94,081	68,679	741	0	$51	$1,063	$1.43
15	28	No faucet aerators	20992	1.00	0.0	0.0	0.0	6,573	6,573	657	146	$228	$84	$0.13
16	25	Dishwasher to be replaced	4874	1.00	1.8	0.6	0.1	16,472	5,238	524	32	$76	$366	$0.70
17	12	Attic insulation = R-7	479	1.00	180.8	14.6	0.3	293,038	23,736	421	40	$78	$253	$0.60
18	7	Oversized AC units B	382	1.00	221.8	15.5	0.3	278,891	19,522	399	0	$27	$40	$0.10
19	20	No E & W window shading A	4362	0.50	36.0	26.3	0.5	28,577	20,918	374	0	$26	$563	$1.50
20	26	Clothes washer to be replaced	3115	1.00	2.6	1.1	0.1	17,333	7,141	344	27	$57	$623	$1.81
21	14	Exposed walls not insulated	130	1.00	32.4	32.4	0.1	122,851	122,851	343	47	$82	$228	$0.66
22	31	Electric water heater not wrapped	5698	1.00	0.3	0.3	0.0	3,306	3,306	331	0	$23	$71	$0.22
23	23	Refrigerator needs to be replaced	1767	1.00	3.3	0.4	0.0	26,984	2,941	268	-3	$15	$177	$0.66
24	13	Attic insulation = R-11	485	1.00	7.3	7.3	0.2	11,363	11,363	262	24	$49	$196	$0.75
25	18	Single pane windows B	125	1.00	10.7	3.1	0.1	28,549	8,222	179	15	$32	$22	$0.12
26	9	Gas heat and 13 SEER AC	189	1.00	-28.2	-2.0	0.0	236,300	16,541	174	0	$12	$79	$0.46
27	8	One inch insul. on ducts in attic	670	1.00	40.0	12.0	0.2	39,902	11,970	162	30	$49	$201	$1.24
28	17	Single pane windows A	112	1.00	5.6	4.0	0.0	18,154	12,890	102	16	$27	$57	$0.56
29	6	Oversized AC units A	192	1.00	71.7	3.6	0.1	88,799	4,440	64	0	$4	$30	$0.47
30	11	Home has electric strip heat	9	1.00	-18.0	-1.3	0.0	152,910	10,704	38	0	$3	$22	$0.59
31	10	Home has 13 SEER heat pump	23	1.00	-15.6	-1.1	0.0	37,908	2,654	29	0	$2	$9	$0.30
32	15	Floor over basement not insulated	2316	1.00	-26.0	-13.0	-0.3	(49,351)	(24,675)	-516	77	$61	$455	
		Sums and Average, All Measures	171,008	**All 32**	982	494	7.8	2,634,874	1,330,339	53,265	2,727	$7,068	$12,555	$0.50
		Sums and Average, Top 20	159,292	**Top 20**	899	448	7.5	1,917,198	1,147,133	51,829	2,520	$6,710	$11,006	$0.47
		Top 20 Percent of All	93.1%	**% Top 20**			95.9%			97.3%	92.4%	94.9%	87.7%	94.7%

Table 4: Market Potential Metrics for All 32 Measures

Schedule JMO-1

Calculation of Market Potentials

The realizable market potential of a measure may be defined to represent the extent to which a measure might actually be applied annually throughout the service area over a reasonable period of time, which can be 5 to 15 years of full implementation of a well-designed conservation program.

KCP&L market potentials for each measure were calculated by multiplying together the individual savings per measure, the realizable market potentials in terms of percentages, and the total current number of single-family detached homes throughout the service area. These realizable potential savings are presented in terms of a) total electric demand in megawatts, b) electric energy savings in megawatt-hours, c) natural gas in kilotherms and d) thousands of dollars. Effects of possible population growth over the projected time period were not considered in this study.

Figure 1 below shows a general market potential schematic. Moving from left to right, the “Technical Potential” for the intended program or measure can be defined as the percentage of all targeted customers that a measure may be applied to, regardless of cost. The “Raw Economic Potential” reflects the percentage of eligible homes in which the measure can be economically applied.

The expected actual penetration rates under different program scenarios, or the “Market Potential”, involves the estimation of how many customers might participate in a specific program over a given time period. That is, the “Market Potential” indicates the percentage of targeted homes that would install the measures delivered by well-defined and aggressively executed programs. The values, of course, depend on the measures, the length of time the program is offered, the specific markets, numbers of customers targeted, and finally the level of subsidy (if any).

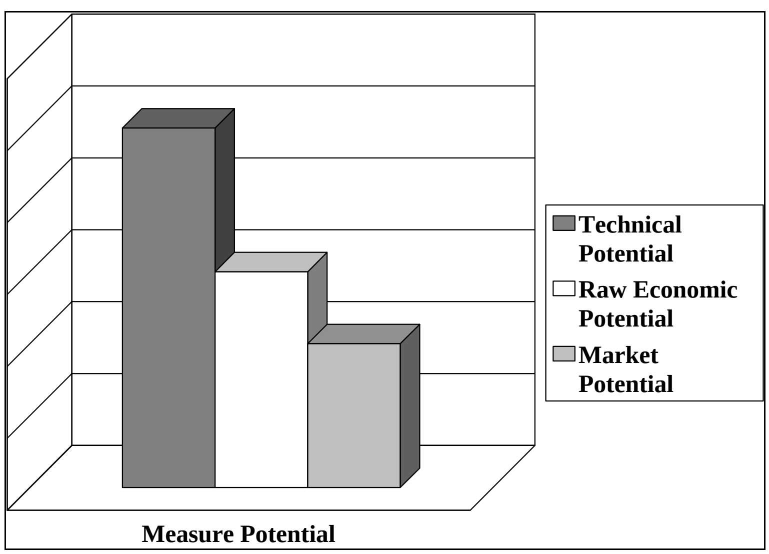


Figure 1: Market Potential Schematic

This measure potential schematic can be applied to the residential population of KCP&L as follows:

(1) The "Technical Potential" is the total number of single-family detached homes that a measure might actually be applied to without regard to cost. Using deciduous shade trees as an example, the "Technical Potential" for this study is the percentage of all single-family detached residential customers who have air-conditioned homes and have space in their yards to plant trees on the east and west sides of their houses. Homes that are not air-conditioned will not be eligible for this measure because there would be no technical basis for obtaining energy savings.

(2) The "Raw Economic Potential" was determined through analysis of the in-home audits and telephone surveys to assess what percent of qualified customers could achieve savings through installation of the measure, within the realm of economic feasibility. For example, it would not be economically feasible for a homeowner to replace existing double pane windows with higher performance windows solely for the purpose of saving energy, even though the home is technically eligible. The total cost of replacing windows is far too great to incur on these terms alone. If, however, the windows need to be replaced for other reasons (such as excessive age and unacceptably poor condition) the much smaller differential cost of choosing high performance windows over standard windows is economically feasible from an energy savings perspective.

(3) The final "Market Potential" was estimated through existing utility research and past participation rates in other programs. The primary factors that influence marketing potential at the customer level are first cost, annual savings, payback and intangible market barriers. Necessary driving factors include the existence of energy and demand conservation programs with aggressive marketing strategies, meaningful rebates or other incentives to offer and effective delivery mechanisms and strategies.

Table 5 below lists the 32 measures that were analyzed in this study. This table shows ID numbers, their potential situations, improvement options, and three columns of market potential estimates. The "Technical Potential (% of Homes that Qualify)" is the "Technical Potential" previously described. The last column, "Raw Economic Potential (% of Population)" is the previously defined "Raw Economic Potential". It is simply the product of the "Technical Potential (% of Homes that Qualify)" and the "Economically Feasible (% of Technical Potential)".

ID	KCP&L Energy Savings Measure: Potential Situation	Improvement	Technical Potential (% of Homes that Qualify)	Economically Feasible (% of Technical Potential)	Raw Economic Potential (% of Population)
1	AC Refrigerant under charged	Add refrigerant	36%	100%	36%
2	AC Refrigerant over charged	Remove refrigerant	31%	100%	31%
3	Low evaporator airflow A	Increase duct sizes or add new ducts	70%	100%	70%
4	Low evaporator airflow B	Increase blower speed	13%	100%	13%
5	High duct leakage (25%)	Reduce duct leakage to 5%	58%	100%	58%
6	Oversized AC units A	Size AC units to 100% of Manual J	80%	5.0%	4.00%
7	Oversized AC units B	Size AC units to 100% of Manual J	80%	7.0%	5.6%
8	One inch insul. on ducts in attic	Add two more inches of insulation	49.5%	30%	14.9%
9	Gas heat and 13 SEER AC	Install AC SEER = 16	77.0%	7.0%	5.4%
10	Home has 13 SEER heat pump	Install Heat Pump SEER = 16	9.0%	7.0%	0.63%
11	Home has electric strip heat	Install Heat Pump SEER = 16	11.3%	7.0%	0.79%
12	Attic insulation = R-7	Add another R-23 attic insulation	100.0%	8.1%	8.1%
13	Attic insulation = R-11	Add another R-19 attic insulation	6%	100%	6%
14	Exposed walls not insulated	Add R-11 wall insulation	14%	100%	14%
15	Floor over basement not insulated	Add R-19 Insulation to floor	66%	50%	33%
16	House infiltration = 0.8 ACH	Reduce infiltration to 0.35 ACH	25%	100%	25%
17	Single pane windows A	Add storm windows	6.0%	71%	4%
18	Single pane windows B	Install Low E double pane window 2904	6.0%	29%	2%
19	Standard double pane windows	Install Low E double pane window 2904	76%	29%	22%
20	No E & W window shading A	Add solar screens to E & W glass	100%	73%	73%
21	No E & W window shading B	Plant deciduous trees on E & W sides	90%	73%	66%
22	No Compact Fluorescent Lamps	Use 10 more CFLs throughout house	60%	100%	60%
23	Refrigerator needs to be replaced	Purchase Energy Star refrigerator	53%	11%	6%
24	Refrigerator early retirement	Purchase Energy Star refrigerator	47%	40%	19%
25	Dishwasher to be replaced	Purchase Energy Star dishwasher	46%	32%	15%
26	Clothes washer to be replaced	Purchase Energy Star clothes washer	47%	41%	19%
27	No prgrammable thermostat	Install programmable thermostat	60%	100%	60%
28	No faucet aerators	Install faucet aerators	63%	100%	63%
29	No low flow shower heads	Install low fow shower heads	60%	100%	60%
30	Hot water pipes not insulated	Insulate hot water pipes	85%	100%	85%
31	Electric water heater not wrapped	Wrap electric water heater	17%	100%	17%
32	Gas water heater not wrapped	Wrap gas water heater	81%	90%	73%

Table 5: Technical and Raw Economic Market Potentials for Preferred Measures

The final "Market Potential" estimates of this study are based partly on historical penetrations of existing programs in other states and partly on an analytical model designed to utilize the differential costs and simple payback periods calculated, and a market barrier factor for each measure.

Table 6 shows the results of the market analyses for the program measures included in this study. The "Quantity" column shows the quantity of each item that was modeled in the impact analysis and used as a basis for estimating the associated differential installed cost of each measure. For example, if the homeowner has to choose between installing a measure or not installing it, the cost is total installed cost. On the other hand, if the choice is between a standard efficiency unit and a high efficiency unit, the applicable cost is the incremental cost between the two options. Utility program rebates are designed to render the first cost and payback of a measure beneficial and desirable to a qualifying homeowner.

"Raw Economic Potential %" is the same as that shown in Table 5 under "Raw Economic Potential (% of Population)". The qualitative "Market Barrier Factor" is shown in the next column of Table 6. The column labeled "Annual Market Capture %" shows the results of the analytical model previously mentioned. It represents the probability that a given measure will be adopted based solely on its installed cost, simple payback, and market barrier factor. In the model this probability is inversely proportional to the installed cost, the simple payback and the market barrier factor. First cost was assigned an importance equal to three times that of the payback period.[6]

The market barrier factor captures the effects of known non-economic market barriers by using a discreet value of 1, 2 or 3. A 1 indicates that little or no known barriers exist, a 2 indicates average barriers and a 3 indicates the existence of formidable barriers. For example, ID 21 represents the option of adding solar screens to the east and west facing windows for shading. This option was assigned a market barrier factor of 3 because major non-economic market barriers here are the diminished appearance of the home perceived by most homeowners, and the fact that they have to be removed and replaced each year to achieve their potential savings.

The analytical model also includes a scaling constant to permit calibration of the model to known conservation program results. Annual market penetrations expressed as percentages were found for recent programs throughout the country for several of the measures, including high performance windows, compact fluorescent light bulbs, and Energy Star appliances (refrigerators, dishwashers and clothes washers). The analytical model was calibrated by iteratively adjusting the scaling factor until the model agreed with the overall average of the percentages of these existing programs.

The "Yearly Realizable Potential %" column shows the actual estimated "Market Potential" for each measure. It is the product of the "Raw Economic Potential %" and the "Annual Market Capture %".

The last column of Table 6 shows the actual counts of potential applications per year for each measure. This is the product of the yearly realizable potential and the target population (333,207 single family detached homes).

[6] In previous market assessment and market potential studies done by RLW, we have found that after other barriers are diminished or eliminated, first cost continues to remain as the primary barrier by about a 3 to 1 margin.

KCP&L Energy Savings Measure				Raw Economic Potential	Market Barrier	Annual Market Capture	Yearly Realizable Potential	Potential Installs Per Year
Pri	**ID**	**Potential Situation**	**Quantity**	**%**	**Factor**	**%**	**%**	**Count**
7	1	AC Refrigerant under charged	2 hr & 2 Lb R-22	36.0%	2	3.08%	1.11%	3698
13	2	AC Refrigerant over charged	2 hours	30.5%	3	4.30%	1.31%	4373
9	3	Low evaporator airflow A	75 SF	70.0%	2	0.87%	0.61%	2039
6	4	Low evaporator airflow B	2 hours	13.4%	2	7.56%	1.02%	3387
11	5	High duct leakage (25%)	3.41 tons	58.0%	2	1.32%	0.76%	2543
29	6	Oversized AC units A	3.09 tons	4.0%	3	1.44%	0.06%	192
18	7	Oversized AC units B	3.09 tons	5.6%	3	2.05%	0.11%	382
27	8	One inch insul. on ducts in attic	3.41 tons	14.9%	2	1.35%	0.20%	670
26	9	Gas heat and 13 SEER AC	3.41 tons	5.4%	2	1.05%	0.06%	189
31	10	Home has 13 SEER heat pump	3.78 tons	0.6%	2	1.11%	0.01%	23
30	11	Home has electric strip heat	2.65 tons	0.8%	2	0.36%	0.00%	9
17	12	Attic insulation = R-7	1344 SF	8.1%	1	1.77%	0.14%	479
24	13	Attic insulation = R-11	1344 SF	6.3%	1	2.31%	0.15%	485
21	14	Exposed walls not insulated	1355 SF	14.0%	2	0.28%	0.04%	130
32	15	Floor over basement not insulated	614 SF	33.2%	2	2.09%	0.69%	2316
4	16	House infiltration = 0.8 ACH	2077 SF	25.0%	1	4.28%	1.07%	3567
28	17	Single pane windows A	240 SF	4.3%	2	0.79%	0.03%	112
25	18	Single pane windows B	240 SF	1.7%	2	2.17%	0.04%	125
12	19	Standard double pane windows	240 SF	21.9%	2	2.47%	0.54%	1801
19	20	No E & W window shading A	86 SF	73.2%	3	1.79%	1.31%	4362
14	21	No E & W window shading B	6 each	65.7%	2	1.08%	0.71%	2363
2	22	No Compact Fluorescent Lamps	10 CFLs	60.0%	2	9.48%	5.69%	18948
23	23	Refrigerator needs to be replaced	1 each	5.8%	1	9.11%	0.53%	1767
3	24	Refrigerator early retirement	1 each	18.8%	3	8.51%	1.60%	5326
16	25	Dishwasher to be replaced	1 each	14.6%	1	10.00%	1.46%	4874
20	26	Clothes washer to be replaced	1 each	19.4%	1	4.82%	0.93%	3115
1	27	No prgrammable thermostat	1 each	60.0%	1	8.56%	5.14%	17121
15	28	No faucet aerators	1 each	63.0%	3	10.00%	6.30%	20992
5	29	No low flow shower heads	2 each	60.0%	3	10.00%	6.00%	19992
10	30	Hot water pipes not insulated	1 each	85.0%	2	8.01%	6.81%	22684
22	31	Electric water heater not wrapped	1 each	17.1%	1	10.00%	1.71%	5698
8	32	Gas water heater not wrapped	1 each	72.9%	3	7.10%	5.18%	17247

Table 6: Market Potential Summary for the Preferred Measures

One measure was analyzed with multiple retrofit options that represent different improvement choices. Two window shading options, ID numbers 20 and 21, were analyzed to represent different possible homeowner choices. For a single house, however, only one option can be applied. Each option was assigned a special market fraction of 0.5 in the model. This was necessary to avoid double counting of the annual savings when they are summed across all the measures and options.

The preferred measures highlighted in the previous tables were based on the 20 measures that yielded the most electrical energy savings. These were all estimated assuming a 50% rebate to encourage adoption. The next table, Table 7, shows how the metrics for the top 20 electric energy savings measures might vary with rebate percentage, where the rebates are used to “buy down” the costs of installing these measures. Savings are expressed in summer coincident demand (MW-S), GigaWatt-hours per year (GWh) and millions of Therms of gas savings per year (MTherms).

KCP&L customer savings in millions of dollars are shown, followed by total rebate expenses for each rebate level. Then the normalized savings in terms of rebate costs per customer dollar saved for the first year and for ten years levelized.

Ranked by GWh Saved

	Program Savings Potentials			Millions of Dollars		Rebate $/kWh	
Rebate	**MW-S**	**GWh**	**MTherms**	**Savings**	**Rebate**	**Yr 1**	**10 Yrs**
0%	4.3	29.4	1.6	$4.0	$0.0	$0.00	$0.000
25%	5.3	36.7	1.9	$4.9	$4.0	$0.24	$0.024
50%	7.5	51.8	2.5	$6.7	$11.0	$0.47	$0.047
75%	14.4	70.1	3.8	$9.5	$25.6	$0.71	$0.071

Table 7: Top 20 Measures Ranked by GWh vs. Rebate %

For comparison purposes RLW also ranked these 32 measures from a utility cost perspective based on increasing rebate dollars per kWh saved. The results for the new top 20 measures are shown in the next table. The interesting result of this table is the last three rows, which show that this ranking method optimizes the market capture achievable with rebate money. With rebates set at 50%, it will take only $7.3 million to obtain nearly the same savings as before, which required $11.0 million, and the levelized rebate costs per kWh saved is reduced from $0.047 to $0.025. Put another way, the savings in GWh is reduced by only 6.4% ((51.8-48.5)/51.8), while the corresponding rebate costs are reduced by 33.6% (($11.0-$7.3)/$11.0).

Ranked by Rebate $/kWh

	Program Savings Potentials			Millions of Dollars		Rebate $/kWh	
Rebate	**MW-S**	**GWh**	**MTherms**	**Savings**	**Rebate**	**Yr 1**	**10 Yrs**
0%	3.7	27.4	1.4	$3.7	$0.0	$0.00	$0.000
25%	4.6	34.4	1.7	$4.5	$2.6	$0.12	$0.012
50%	6.6	48.5	2.2	$6.1	$7.3	$0.25	$0.025
75%	12.8	65.3	3.4	$8.7	$17.0	$0.37	$0.037

Table 8: New Top 20 Measures Ranked by $/kWh vs. Rebate %

The next table, Table 9**,** shows the measures ranked by rebate dollars per kWh saved ($/kWh), with the new top 20 measures highlighted, and summary statistics in the last three rows. This shows that 91% of the total electric energy savings may be achieved at a rebate cost of only $7.3 million, and at a levelized cost of only $0.25 dollars per kWh saved.

KCP&L Energy Savings Measure		Potential Installs Per Year	Demand Market Potential	Electric Market Potential	Gas Market Potential	Annual Fuel Savings	Utility Rebate Costs	Electric Rebate Costs
ID	**Potential Situation**	**Count**	**MW-S**	**MWh**	**kTherms**	**k$**	**k$**	**$/kWh**
24	Refrigerator early retirement	5326	0.6	5,080	-70	$261	$133	$0.03
29	No low flow shower heads	19992	0.0	3,478	439	$788	$200	$0.06
4	Low evaporator airflow B	3387	2.3	2,733	228	$473	$169	$0.06
22	No Compact Fluorescent Lamps	18948	1.0	10,295	-161	$506	$758	$0.07
7	Oversized AC units B	382	0.3	399	0	$27	$40	$0.10
18	Single pane windows B	125	0.1	179	15	$32	$22	$0.12
28	No faucet aerators	20992	0.0	657	146	$228	$84	$0.13
27	No prgrammable thermostat	17121	-3.7	11,402	464	$1,363	$1,712	$0.15
1	AC Refrigerant under charged	3698	0.7	2,547	0	$175	$462	$0.18
16	House infiltration = 0.8 ACH	3567	1.5	3,732	695	$1,126	$713	$0.19
31	Electric water heater not wrapped	5698	0.0	331	0	$23	$71	$0.22
32	Gas water heater not wrapped	17247	0.0	2,035	190	$377	$517	$0.25
2	AC Refrigerant over charged	4373	0.5	771	0	$53	$219	$0.28
10	Home has 13 SEER heat pump	23	0.0	29	0	$2	$9	$0.30
19	Standard double pane windows	1801	0.5	937	-35	$21	$322	$0.34
9	Gas heat and 13 SEER AC	189	0.0	174	0	$12	$79	$0.46
6	Oversized AC units A	192	0.1	64	0	$4	$30	$0.47
3	Low evaporator airflow A	2039	1.7	2,000	115	$281	$969	$0.48
5	High duct leakage (25%)	2543	1.2	1,542	163	$310	$763	$0.49
17	Single pane windows A	112	0.0	102	16	$27	$57	$0.56
11	Home has electric strip heat	9	0.0	38	0	$3	$22	$0.59
30	Hot water pipes not insulated	22684	0.0	1,816	247	$434	$1,077	$0.59
12	Attic insulation = R-7	479	0.3	421	40	$78	$253	$0.60
23	Refrigerator needs to be replaced	1767	0.0	268	-3	$15	$177	$0.66
14	Exposed walls not insulated	130	0.1	343	47	$82	$228	$0.66
25	Dishwasher to be replaced	4874	0.1	524	32	$76	$366	$0.70
13	Attic insulation = R-11	485	0.2	262	24	$49	$196	$0.75
8	One inch insul. on ducts in attic	670	0.2	162	30	$49	$201	$1.24
21	No E & W window shading B	2363	0.2	741	0	$51	$1,063	$1.43
20	No E & W window shading A	4362	0.5	374	0	$26	$563	$1.50
26	Clothes washer to be replaced	3115	0.1	344	27	$57	$623	$1.81
15	Floor over basement not insulated	2316	-0.3	-516	77	$61	$455	
	Sums and Average, All Measures	171,008	7.8	53,265	2,727	$7,068	$12,555	$0.50
	Sums and Average, Top 20	127,755	6.6	48,487	2,206	$6,088	$7,330	$0.25
	Top 20 Percent of All	74.7%	84.3%	91.0%	80.9%	86.1%	58.4%	49.6%

Table 9: Measures Ranked By Rebate $/kWh, Highlighting Top 20

Conclusions

This section provided a comparative overview of recent programs that have been implemented towards raising share and consumer acceptance of high efficiency home products and measures. The strategies and program designs, to be sure, are driven in large part by the existing markets for the "standard" product the promoted item is meant to replace. Given that, there are common threads that can be incorporated into the program designs for any of these measures that were analyzed at length here.

Utilize a wide variety of marketing tools and elements. As discussed earlier, the best programs for sustainable market share growth utilized a comprehensive set of marketing and promotional tools to build and sustain knowledge, interest, and product desirability. Successful strategies have not just used the traditional means – bill inserts, advertising – but also used creative and highly visible promotional campaigns and events to build "top of mind" awareness and recognition. Conversely, program managers that RLW interviewed in a recent study felt that a marketing campaign built on only one or two elements made only limited impact and will not generally move consumers to any notable degree.

Engage the market actors at all levels of the product sales cycle. Successful programs have outreach tasks that identify and engage key players on each step of the product sales cycle – manufacturer, distributor, retailer, contractor, and consumer. The complementary "push" and "pull" strategy creates buy-in from the market actors on each level, and helps reinforce the message between them (ex. in a balanced approach, the distributor knows and understands the energy efficient product as well as the contractor, who in turn can reinforce or corroborate the information known by the consumer).

Position the energy efficient product as a desirable "high quality, high value" item. Appliance manufacturers in particular have added a variety of special features and functions to their ENERGY STAR models. Although no literature explicitly explains why, it appears these features, many of which are "high tech" in design and function, creates a "high value" perception. This high value perception is likely geared toward those consumers who can afford, and less likely to balk at, the higher price premium comparable to "standard" models that lack these specialized designs and functions. This kind of product positioning is typically built towards consumers who are comfortable paying a premium for products that are perceived to be of a high quality, reliability, or safety, whether it's cars, appliances, or organically grown foods.

Kansas City Power and Light

Final Report

C&I Energy Efficiency Measures Potential Study

Prepared for:

Joe O'Donnell

Technical Consultant, Energy Solutions

Kansas City Power and Light
P.O. Box 418679
Kansas City, MO 64141

September 17, 2007

Prepared by:

Summit Blue Consulting, LLC
1720 14th Street, Suite 230
Boulder, Colorado 80302
Phone: 720-564-1130

Contact:

Randy Gunn, Principal
312-938-4242
rgunn@summitblue.com

TABLE OF CONTENTS

ACKNOWLEDGEMENTS

This study was a collaborative effort between Summit Blue and KCPL, and the following KCP&L personnel were key contributors:

Joseph O'Donnell, Technical Consultant, Energy Solutions

Randy Hughes, Manager, Resource Planning

Roger Powell, Manager, Fundamental Analysis

E. EXECUTIVE SUMMARY

This section of the report provides a high-level overview of the project methodology and results.

E.1 Introduction and Overall Methodology

Kansas City Power and Light (KCP&L) hired Summit Blue Consulting (Summit Blue) and Energy Insights in January 2007 to conduct a commercial and industrial (C&I) energy efficiency potential study. This study was requested to help fulfill the goals of the DSM aspects of KCP&L's Comprehensive Energy Plan.

Study Strategy and Tactics

This project was conducted in two phases. Phase I was completed in March 2007 and included the following elements:

1. An avoided cost study, for both residential customers and C&I customers.
2. Baseline market profiles for large and small office buildings, education, and manufacturing.
3. A market potential study for energy efficiency for the C&I sector, based on the results of Summit Blue's DSM benchmarking analysis.

Phase II of the study was completed in July 2007 and included:

1. Baseline market profiles for communications, health care, retail, grocery, entertainment, printing, data centers, petroleum, utilities, warehouses, lodging, churches, restaurants, apartments, and transportation.
2. Characterization of C&I energy efficiency measures, including energy and peak demand savings, lifetimes, and costs.
3. DSMore benefit-cost analysis for the C&I energy efficiency measures.
4. Technical, economic, and market energy efficiency potential estimates.

E.2 DSM Benchmarking and Best Practices Assessment

Data and information were collected for 2005 DSM program results for twenty-five utilities and energy agencies in five regions—the US Midwest, Northeast, Southeast, West, as well as Canada. This analysis of DSM program results normalized the reported total program results for utility or agency size, sales to major customer class, and currency, where necessary.

The achievement of significant DSM savings is influenced by several factors, including the regulatory environment under which utilities and agencies operate, whether DSM funds are provided through systems benefits charges, how the issue of lost revenues is addressed, the provision of financial incentives for DSM performance, etc. British Columbia, California, Iowa, Minnesota, New York, and Vermont all achieved about 1% or more reduction in annual energy sales due to DSM programs in 2005.

All states achieving high DSM savings either set significant mandated goals for utilities' DSM programs or use public benefits funds to implement DSM programs. Other success factors include financial incentives for cost-effective DSM (Minnesota, Vermont), adjustments for lost revenues caused by DSM programs (California), and use of the TRC test or societal test for cost-effectiveness rather than the RIM test (British Columbia, California, Iowa, Minnesota, New York, Vermont).

Table E-1 shows the median results for DSM spending, savings, and costs overall for the C&I customer sector for all organizations.

Table E-1. Medians for Overall Results

Spending as % of Revenue	Energy Savings as % of Sales	Demand Savings as % of Peak Demand	Cost of Savings	
			$/kWh	$/kW
1.0%	0.5%	0.5%	0.16	803

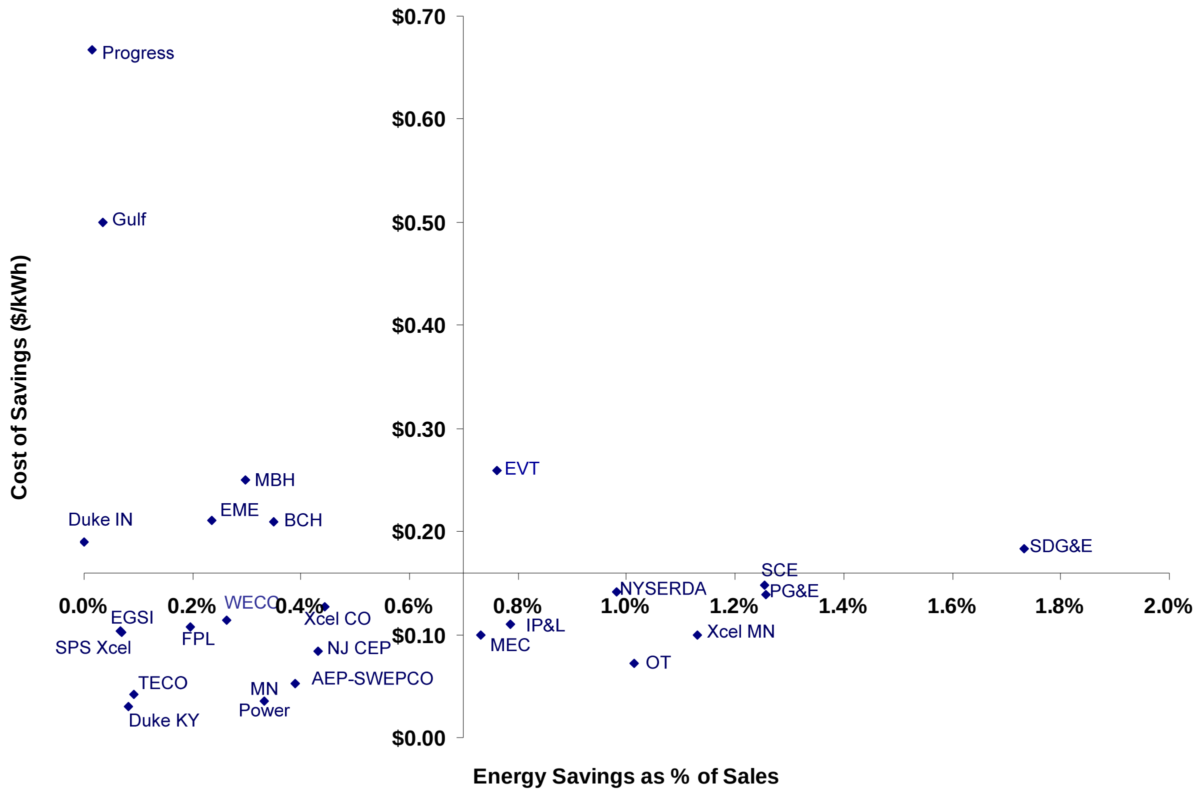
Utilities with the highest spending rates are San Diego Gas & Electric (SDG&E) and Manitoba Hydro at 2.2% - 3.1% of revenues. In the Midwest, Xcel Energy (MN), Interstate Power and Light, and Otter Tail Power have the highest DSM spending as a percentage of revenue at 1.3% - 2.0% of revenues.

SDG&E has the highest energy savings as a percentage of sales at about 1.7%. In the Midwest, Xcel Energy (MN), Interstate Power and Light, and Otter Tail have the highest percentage of savings rates at 0.8% -1.1% of sales. Duke Energy Kentucky, Minnesota Power, and Tampa Electric achieved the lowest cost of energy savings at $0.03 to $0.04 per first year kWh saved.

SDG&E, Interstate Power & Light, Xcel Energy (MN), and NYSERDA have the highest demand savings as a percent of peak demand at 1.2% - 1.5% of baseline C&I peak demands. Duke Energy Kentucky and Minnesota Power have the lowest costs of conserved demand at $97/kW and $333/kW respectively.

The scatter plot below portrays the utility energy savings and costs of conserved energy graphically.

Figure E-1. Scatter Plot of C&I Energy Savings and First Year Costs ($/kWh)



E.3 Avoided Cost Analysis

Summaries of the approaches taken to produce avoided costs and some of the results are presented here:

Avoided capacity costs are calculated with a capacity spreadsheet model. There are three cases in the model – low, base, and high peak demand – and each case has a "with EE" and "without EE" scenario. The difference in NPV of capital costs between the two scenarios for each case gives the avoided costs, presented as levelized $/kW-yr. A weighted average of the three cases is calculated to give a final single value, as shown in Table E-2.

Table E-2. Summary of Capacity Model Results

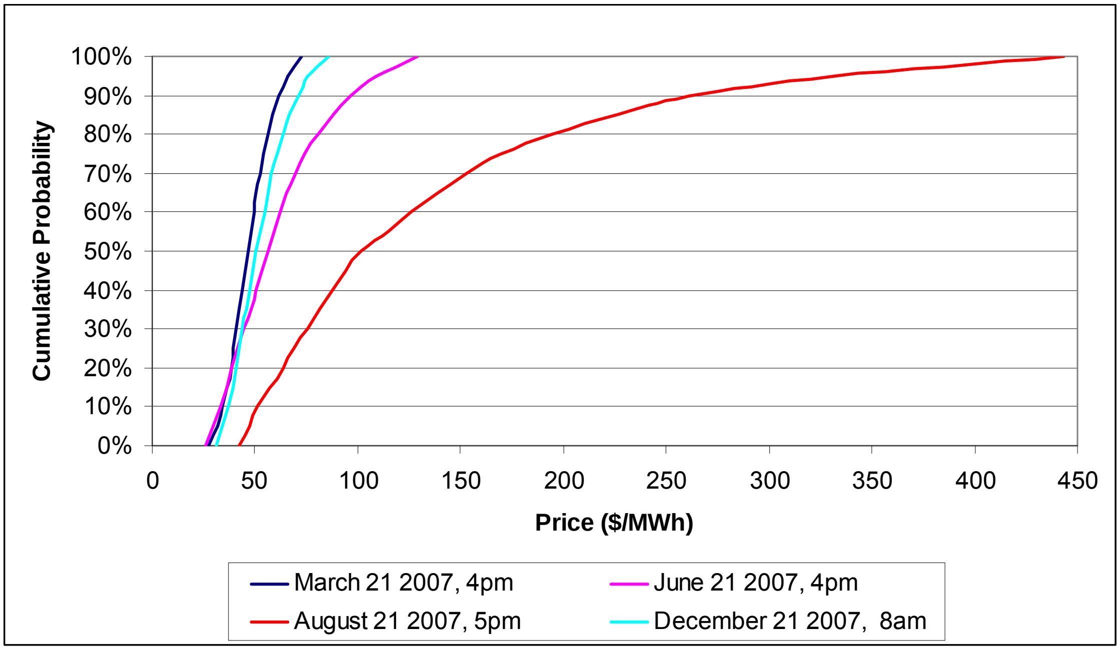
Case	Probability	Annualized NPV Savings	Annualized MW from EE	Mean	5%	95%	Std. Dev.
Low Demand	15%	$6,092,293	85.1	$71.57	64.59	78.69	4.29
Base Demand	55%	$9,624,582	88.0	$109.32	89.59	129.74	12.13
High Demand	30%	$11,930,391	89.9	$132.75	113.95	151.80	11.46
Weighted Average				110.69	93.15	128.70	10.75

Source: Final KCP&L Avoided Capacity Model.xls

Avoided energy costs are derived from the MIDAS market prices, in $/MWh. These prices are adjusted to reflect the fact that a proportion of energy is sold by the system, and then formatted into unique probability distributions for each hour of the year. These distributions represent the 35 cases of price drivers run through the model. Three sets of these distributions will be produced. The values in the 2^{nd} and 3^{rd} sets will be adjusted to reflect the mid CO_2 and high CO_2 cases from the CO_2 MIDAS runs.

As the final data set of avoided energy costs is large (distributions for 8760 hours times 20 years), it is not possible to show the data in this report. Instead, four sample hours are shown here to give an idea of the spread of prices in the 35 values for one hour (Note: these prices have not yet been adjusted to reflect energy sales). Figure E-2 below shows cumulative probability for four different hours and the range of possible prices for those hours.

Figure E-2. Cumulative Probability for Ranges of Prices, for Four Different Hours



E.4 Baseline Energy Consumption Profiles

KCP&L supplied considerable input data for this task including customer counts and billing data by market segment and sales forecasts for the Company's overall commercial and industrial customer sectors. Other data sources included Energy Insights' proprietary Energy Market Profiles data, available to KCP&L through their Load Analysis Strategies subscription. Table E-3 below shows end use consumption estimates for small office buildings, an example of the results from a Phase I market segment.

Table E-3. Small Office Energy Consumption Profile

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	24.6%	4.07	1.00	31.5
Space Cooling	90.1%	2.50	2.26	70.8
Water Heating	54.5%	0.59	0.32	10.1
Ventilation	100.0%	0.36	0.36	11.4
Cooking	1.5%	0.19	0.00	0.1
Lighting	100.0%	2.81	2.81	88.2
Refrigeration	5.1%	0.09	0.00	0.1
Office Equipment (PC)	89.4%	1.30	1.16	36.5
Office Equipment (non-PC)	100.0%	3.13	3.13	98.0
Other Uses	100.0%	5.87	5.87	184.1
Total			16.92	530.7

E.5 DSM Measure Characterization and DSMore Benefit-Cost Analysis Results

Summit Blue evaluated 33 C&I DSM measures for possible inclusion in KCP&L's DSM portfolio. Representative and common examples of each technology type, such as compact fluorescent lamps, were analyzed. The majority of measures evaluated were cost effective from each of the four main California stakeholder perspectives considered. All analyses were done using the DSMore benefit-cost analysis model, and the analyses were conducted on a net present value basis over the lifetime of the measures.

1. The utility test (UT): measures are cost effective from this perspective if the avoided costs caused by the measures' energy and demand savings is greater than the utility DSM program costs to promote the measure, including customer rebates.

2. The total resource cost (TRC) test: measures are cost effective from this perspective if their avoided costs are greater than the sum of the measure costs and the DSM program administrative costs.

3. The rate impact (RIM) test: measures are cost effective from this perspective if their avoided costs are greater than the sum of the DSM program costs and the "lost revenues" caused by the measure.

4. The participant test: measures are cost effective from this perspective if the reduced electric costs to the participating customer from the measure exceed the after-rebate cost of the measure to the customer.

KCP&L decided to treat the TRC test as the main cost effectiveness test for this project. The RIM test is a more restrictive test that is only used as the main DSM benefit-cost test in very few states.[1] Only one to three measures analyzed did not pass the TRC test for one or more market segments.

The number of C&I measures by end use were:

- Thirteen lighting energy efficiency measures.
- Nine HVAC and controls energy efficiency measures.
- Five efficient refrigeration measures.
- Three custom and efficient motors measures.
- Three hot water energy efficiency measures.

Almost all of the C&I measures analyzed passed each of the utility, TRC, and RIM tests, so they were almost all considered to be cost effective, and applicable to KCP&L's C&I DSM program portfolio. Additional DSM measures beyond the 30 or so analyzed are expected to be covered by a KCP&L's Custom Rebate program.

E.6 DSM Potential Results

The total estimated commercial and industrial energy efficiency potential over the 20 year forecast period is about 2,300 GWh and 510 peak MW. Slightly more than half of this energy efficiency potential is projected to come from energy efficient lighting products, about 20% is projected to come from energy efficient HVAC equipment and controls, and about 25% of the total potential is expected to come from custom and motors measures. The total C&I energy efficiency potential amounts to approximately 17% of KCP&L's forecast 2028 C&I energy consumption of about 13,700 GWh. This is equal to an annual average energy savings of about 115 GWh, or 1.2% of KCP&L's forecast 2007 C&I sales. The peak demand reduction potential is about 19% of KCP&L's forecast 2028 C&I peak demand of 2,700 MW. The total C&I energy efficiency program costs over the 20-year forecast period are estimated at about $220 million, or about $11 million per year on average.

[1] Florida and Georgia, for example, require DSM programs to pass the RIM test.

Table E-4. Summary and Five Year DSM Potential

Commercial	20 Year Total	2008	2009	2010	2011	2012
Lighting						
Achievable Potential Demand Savings (kW)	307,746	3,077	6,155	12,310	15,387	16,926
Achievable Potential Energy Savings (kWh)	1,267,173,588	12,671,736	25,343,472	50,686,944	63,358,679	69,694,547
Measure Costs	$228,317,854	$2,283,179	$4,566,357	$9,132,714	$11,415,893	$12,557,482
Program Costs	$123,098,333	$1,230,983	$2,461,967	$4,923,933	$6,154,917	$6,770,408
HVAC						
Achievable Potential Demand Savings (kW)	145,384	1,454	2,908	5,815	7,269	7,996
Achievable Potential Energy Savings (kWh)	433,712,894	4,337,129	8,674,258	17,348,516	21,685,645	23,854,209
Measure Costs	$67,918,370	$679,184	$1,358,367	$2,716,735	$3,395,919	$3,735,510
Program Costs	$51,742,915	$517,429	$1,034,858	$2,069,717	$2,587,146	$2,845,860
Refrigeration						
Achievable Potential Demand Savings (kW)	220	2	4	9	11	12
Achievable Potential Energy Savings (kWh)	22,881,940	228,819	457,639	915,278	1,144,097	1,258,507
Measure Costs	$2,088,118	$20,881	$41,762	$83,525	$104,406	$114,847
Program Costs	$867,032	$8,670	$17,341	$34,681	$43,352	$47,687
Water Heating						
Achievable Potential Demand Savings (kW)	100	1	2	4	5	6
Achievable Potential Energy Savings (kWh)	1,295,571	12,956	25,911	51,823	64,779	71,256
Measure Costs	$150,991	$1,510	$3,020	$6,040	$7,550	$8,305
Program Costs	$30,081	$301	$602	$1,203	$1,504	$1,654
Custom						
Achievable Potential Demand Savings (kW)	58,163	582	1,163	2,327	2,908	3,199
Achievable Potential Energy Savings (kWh)	538,912,472	5,389,125	10,778,249	21,556,499	26,945,624	29,640,186
Measure Costs	$107,541,101	$1,075,411	$2,150,822	$4,301,644	$5,377,055	$5,914,761
Program Costs	$42,957,364	$429,574	$859,147	$1,718,295	$2,147,868	$2,362,655
Total						
Achievable Potential Demand Savings (kW)	511,613	5,116	10,232	20,465	25,581	28,139
Achievable Potential Energy Savings (kWh)	2,263,976,465	22,639,765	45,279,529	90,559,059	113,198,823	124,518,706
Measure Costs	$406,016,436	$4,060,164	$8,120,329	$16,240,657	$20,300,822	$22,330,904
Program Costs	$218,695,725	$2,186,957	$4,373,914	$8,747,829	$10,934,786	$12,028,265

E.7 Conclusions and Recommendations

The DSM benchmarking analysis results presented in this report should give KCP&L management confidence that a variety of utilities across North America are achieving large- scale results from their C&I DSM programs. Peak demand and energy reductions of 1% of utilities' baseline C&I peak demands and energy sales are being achieved by a variety of utilities across the continent. While the details of large impact DSM program portfolios often differ significantly between utilities, several common elements have been identified by the analysis conducted:

- Large impacts are being realized from both commercial lighting and multi-product energy efficiency programs.
- Significant impacts are being achieved from commercial new construction energy efficiency programs.
- C&I custom rebate energy efficiency programs have been significant impact programs for some utilities.

The largest sources of uncertainty regarding the estimates that Summit Blue and Energy Insights have developed to date for KCP&L stems from using secondary information to profile KCP&L's C&I customers. Energy Insights' secondary data on Midwest customers' energy use and equipment is the best secondary information available, but still profiles KCP&L customers with a number of Midwest regional statistics. Also, the secondary end use estimates for electric use have higher than actual estimates for the amount of electricity that is used for "miscellaneous" purposes. This is due to the lack of precision in the end use estimates developed by the original sources of the data, such as the Department of Energy's Commercial Building Energy Consumption Survey.

Utilities that choose to significantly invest in DSM programs often make significant periodic investments to develop and update such data to aid their DSM program planning. For example, Xcel Energy in Minnesota conducts large-scale market assessments and DSM potential studies that include significant on-site customer data collection every five to ten years. The Iowa utilities conduct DSM potential studies about every five years to support their periodic DSM program filings with their regulators. These utilities collected significant customer data as part of their current DSM potential study.

If KCP&L wishes to improve its current customer and load data for DSM planning purposes, Summit Blue suggests that the Company conduct market assessment projects for its customers in a multi-phased approach:

1. Start with telephone surveys of representative samples of several hundred customers in each customer sector (residential, commercial, industrial). These surveys should collect both customer awareness and attitude information, as well as appliance and equipment saturation information, as much as possible.

2. Conduct on-site validation surveys that are done in-depth for representative sub-samples of 30-100 telephone survey respondents per sector. The focus of the on-site surveys is to collect detailed customer facility information and energy equipment inventories.

3. Develop building simulation models for representative customers in each building segment of interest, such as office buildings or single-family homes. Calibrate the simulation models to the customers' actual electric and fossil fuel consumption.

4. Conduct end-use metering for very small sub-samples of the on-site survey customers and use the results to further calibrate the building simulation models.

5. Document the results of the study, including:

    a. Billing statistics and customer counts by customer type for each customer sector and key market segment, such as office buildings.

    b. Develop end use peak demand and energy consumption profiles for each customer sector and key market segment.

    c. Develop DSM measure saturation estimates for each customer sector and key market segment.

    d. Develop detailed DSM potential estimates for each customer sector and key market segment.

This information would be very useful for long-term DSM program planning and also to help focus program resources on the key market segments in the near term. This type of market intelligence can also have applications far beyond DSM program planning if broader planning considerations are incorporated into the project designs.

1. INTRODUCTION

Kansas City Power and Light hired Summit Blue Consulting (Summit Blue) and Energy Insights in January 2007 to conduct a Commercial and Industrial (C&I) Energy Efficiency Measures Potential Study. KCP&L issued a request for proposal for this project in December 2006, and Summit Blue and Energy Insights submitted our proposal to KCP&L on January 10, 2007. This study was requested to help fulfill the goals of the DSM aspects of KCP&L's Comprehensive Energy Plan.

1.1 Study Strategy and Tactics

This project was conducted in two phases. Phase I was completed in March 2007, and included the following elements:

4. An avoided cost study, for both residential customers and C&I customers.

5. Baseline market profiles for large and small office buildings, education, and manufacturing.

6. A market potential study for energy efficiency for the C&I sector, based on the results of Summit Blue's DSM benchmarking analysis.

Phase II of the study was completed in July 2007, and included:

- Baseline market profiles for communications, health care, retail, grocery, entertainment, printing, data centers, petroleum, utilities, warehouses, lodging, churches, restaurants, apartments, and transportation.

- Characterization of C&I energy efficiency measures, including energy and peak demand savings, lifetimes, and costs.

- DSMore benefit-cost analysis for the C&I energy efficiency measures.

- Technical, economic, and market DSM potential estimates.

1.2 Current KCP&L Energy Efficiency Programs

KCP&L is currently conducting four C&I energy efficiency programs. These programs are described briefly below. The source of these program descriptions is a KCP&L document titled "Proposed Customer Focused Programs".

1.2.1 Online Energy Information and Analysis Program

The online energy information and analysis program allows all business and non-profit customers with computers to access their billing information and compare their usage on a daily, weekly, monthly or annual basis, analyze what end uses make up what percent of their usage, and access ways to save energy by end use through a searchable resource center. Targeted case studies provide ideas relevant to the customer's industry. This tool also allows the user to analyze why their bill may have changed from one month to another. A business comparison also displays usage benchmarking data versus similar types of businesses.

1.2.2 C&I Energy Audit

KCP&L offers rebates to customers to cover 50% of the cost of an energy audit. In order to receive the rebate, the customer must implement at least one of the audit recommendations that qualify for a KCP&L C&I custom rebate. The energy audit rebate will be set at 50% of the audit cost up to $300 for customers with facilities less than 25,000 square feet and up to $500 for customers with facilities over 25,000 square feet. Energy audits must be performed by certified commercial energy auditors. Customers may choose their own auditor or KCP&L can recommend one. Customers with multiple buildings will be eligible for multiple audit rebates.

1.2.3 C&I Custom Rebate—Retrofit and New Construction

The C&I Custom Rebate Retrofit program provides rebates to C&I customers that install, replace or retrofit qualifying electric savings measures including HVAC systems, motors, lighting, pumps, etc. All custom rebates are individually determined and analyzed to ensure that they pass the Societal Benefit/Cost Test. Any measure that is pre-qualified (evaluated prior to being installed) must produce a Societal Benefit/Cost test result of 1.0 or higher.

Custom rebates are calculated as the lesser of the following:

- A buydown to a two year payback
- 50% of the incremental cost

One customer may submit multiple rebate applications for different measures. Each individual measure will be evaluated on its own merits. Similar measures that are proposed in different facilities or buildings will be evaluated separately. However, no customer, including those with multiple facilities or buildings, may receive more then $40,000 in incentives for any program year.

Another component of this program is an online new construction guide that will provide information to commercial builders and developers on energy efficiency in new construction. It first allows the builder or developer to identify the type of new construction building that is being planned, i.e. office building, community center, fire station. It then lists a variety of environmental and energy efficiency options and guides the builder or developer in prioritizing investments for the best results. A sample of this software is available for viewing at http://seattle.bnim.com/. KCP&L proposes to build a similar site for the Kansas City metropolitan area but enhance it with features that tie into our rates and will allow developers and builders to plan buildings that can maximize our rates.

1.2.4 Building Operator Certification Program

The Building Operator Certification (BOC) Program is a market transformation effort to train facility operators in efficient building operations and management (O&M), establish recognition of and value for certified operators, support the adoption of resource-efficient O&M as the standard in building operations, and create a self-sustaining entity for administering and marketing the training. In year one of this program, KCP&L will work with the Missouri Department of Natural Resources to build a partnership with other Missouri stakeholders (sponsors). Once this has been accomplished, the program will begin to offer customers the Building Operator Training and Certification (BOC) program. The program will use a portion of its sponsor's funds (including the funds provided by KCP&L) to license the BOC curriculum from the Northwest Energy Efficiency Council (NEEC), its developer. Building operators that attend the training course will be expected to pay the cost of the course, less a $100 rebate that will be issued upon successful completion of all course requirements. The program is expected to attract customers with large facilities (over 250,000 sq. ft.) that employ full time building operators.

1.3 Organization of Report

This report is divided into the following major sections.

- Executive Summary
- Introduction
- Methodology
- Benchmarking and Best Practice Results
- Avoided Cost Analysis Results
- Baseline KCP&L Customer Profiles
- DSM Measure Summary Characterizations
- DSM Potential Methodology and Results
- DSM Cost Effectiveness Analysis Results

2. METHODOLOGY

This section of the report provides a high-level overview of the project methodology. Detailed descriptions regarding the specific analyses performed are included in each section of the report in which the analytical results are presented. Summit Blue and Energy Insights conducted a seven step process to complete this assignment:

1. **Conduct a project initiation meeting** with KCP&L staff. Summit Blue and Energy Insights held an initial in-person meeting with over 20 KCP&L staff in January 2007. Follow-up conference calls were conducted on a regular basis throughout the project.

2. **Conduct a Midwest-focused DSM benchmarking analysis**. The main purpose of this analysis is to ensure that the DSM potential estimates that Summit Blue develops for KCP&L are reasonable and appropriate, and to identify best practice utility and agency DSM program portfolios. For this analysis, Summit Blue collected information on 25 other utilities' and agencies' 2005 DSM program results. Slightly less than half of these organizations are located in the Midwest, and the other half span North America, from Vermont to California. The sources used for this analysis are generally utilities' 2005 DSM regulatory reports, as well as FERC Form 861 baseline data for 2005.

3. **Conduct an avoided cost analysis**. The goal of the study was to develop a stochastic analysis for future avoided energy and capacity costs, providing a 5% mean and 95% probability that reflect predicted volatility in these costs. The study period is from 2007 to 2027.

4. **Develop baseline market segment profiles and initial building simulation model specifications**. KCP&L supplied considerable input data for this task: customer counts and billing data by market segment, as well as sales forecasts for the Company's overall commercial and industrial customer sectors. Other data sources included Energy Insights' proprietary information. Energy Insights used the results of the market profile analysis to calibrate market segment versions of the eQuest building simulation model. eQuest is a widely used commercial building simulation model based on the DOE-2 model.

5. **Characterize energy efficiency measures that are appropriate for KCP&L's service area**. Characterizing measures includes estimating per unit energy and demand savings, incremental costs compared to standard efficiency measures, and measure lifetimes. Energy and demand savings for climate dependent measures such as insulation are estimated by the eQuest building simulation model for commercial customers. For DSM measures whose savings are not weather dependent, such as efficient water heaters, engineering estimates and other published sources such as the California DEER database were used to characterize those types of measures.

6. **Conduct DSMore benefit-cost analysis**. DSMore was developed by Integral Analytics (IA) in 2003 for application to DSM program design and evaluation within both regulated and deregulated markets. This application is unique in that it values DSM using a risk-based approach, in much the same way that asset planners approach their valuations. The covariance between prices and loads is captured at the hourly level to accurately measure the risk-based DSM value. Benefit-cost ratios were estimated for the participant test, the utility test, the total resource cost (TRC) test, and the rate impact (RIM) test.

7. **Estimate energy efficiency potentials for the 2008-2028 period for commercial/industrial customers** using a spreadsheet model. Summit Blue estimated technical, economic, and market DSM potentials by end use. Economic potential was defined using the TRC test as the criteria for whether DSM measures are cost effective. Summit Blue calibrated the DSM market potential estimates to the results of the benchmarking analysis discussed above.

3. BENCHMARKING AND BEST PRACTICE RESULTS

3.1 Benchmarking 2005 DSM Results

This section compares 2005 energy efficiency (EE) results for commercial and industrial (C&I) sector programs of other utilities and agencies in six regions (the Midwest, Northeast, Florida, Texas & Colorado, California, and Canada) and compares detailed program results of utilities identified as achieving high levels of C&I DSM savings for reasonable costs.

3.1.1 Methodology

This section describes the methodology to collect and analyze benchmark programs and compare levels of DSM achievements and costs of savings for C&I customers. Data and information were collected for 2005 DSM program results for twenty-five utilities and energy agencies (see Table 3-1 below). Many of these data were collected for previous projects with Texas utilities included specifically for this report.

Table 3-1. Benchmarked Utilities and Agencies

<table>
<tr><th>Midwest</th><th>Florida</th></tr>
<tr><td rowspan="3">Duke Energy Indiana [DUKE (IN)]
Duke Energy Kentucky [DUKE (KY)]
Interstate Power and Light [IP&L]
MidAmerican Energy [MEC]
Minnesota Power [MN PWR]
Otter Tail Power [OT]
Wisconsin Focus on Energy [WECC]
Xcel Energy (MN) [XCEL (MN)]</td><td>Florida Power & Light [FPL]
Gulf Power [GULF]
Progress Energy [PROGRESS]
Tampa Electric [TECO]</td></tr>
<tr><th>Texas & Colorado</th></tr>
<tr><td>AEP-Southwestern Electric Power Co [AEP-SWEPCO]
Entergy Gulf States [EGSI]
Southwestern Public Service Co – Xcel [SPS XCEL]
Xcel Energy (CO) [XCEL (CO)]</td></tr>
<tr><th>Northeast</th><th>California</th></tr>
<tr><td rowspan="3">Efficiency Maine [EME]
Efficiency Vermont [EVT]
New Jersey Office of Clean Energy [NJ-OCE]
NY State Research & Development Authority [NYSERDA]</td><td>Pacific Gas & Electric [PG&E]
San Diego Gas & Electric [SDG&E]
Southern California Edison [SCE]</td></tr>
<tr><th>Canada</th></tr>
<tr><td>British Columbia Hydro [BCH]
Manitoba Hydro [MBH]</td></tr>
</table>

In North America, DSM is delivered either through central agencies or utilities—either investor or government owned. In the Midwest, DSM is generally provided through vertically integrated investor owned utilities (IOUs); the exception is Wisconsin Focus on Energy, a central agency providing most DSM programs in the state. The utilities examined in the Northeast region all provide DSM through a central agency, except New Jersey which had delivered programs through utilities. In Florida, DSM is delivered through IOUs; most of these are winter peaking due to the high saturation of electric heat. In Canada, both BC Hydro and Manitoba Hydro are vertically integrated Crown corporations and serve the entire provinces. Both have extensive hydro-electric resources and export significant electricity; neither province is deregulated. BC Hydro targets only energy conservation (not demand reduction) as do all of the energy agencies included in this analysis. In the West, as in the Midwest, most DSM is delivered through investor owned utilities such as the several IOUs included in the analysis. Data here exclude demand response programs.

This analysis of DSM program results normalized the reported total program results for utility or agency size, sales to major customer class, and currency, where necessary.

The benchmarking data for these utilities and agencies were prepared as follows:

- For selected utilities and other organizations offering DSM programs, 2005 reported program results for the C&I sector were compiled—program descriptions, energy and demand savings, and costs. The sources for almost all of the data were utilities' and agencies' annual reports on their 2005 DSM program results.

- Normalized results by utility or state sales and peak demands to produce estimates of DSM savings as percentages of sales and peak demand (where data were available) for the C&I sector. The main source for the baseline sales and peak demand data was FERC Form 861 information, from the Energy Information Administration's web site (www.eia.doe.gov).

- Converted program spending to US dollars where needed using the average currency exchange of US$1=CDN$1.21, and divided spending by the DSM program energy and demand savings to determine each utility's cost of conserved energy and demand in terms of $/kWh and $/kW.

Although every effort is made to collect comparable data, given the inherent variation in organizations' evaluation and reporting practices, the results cannot be considered a strictly "apples-and-apples" comparison. The results are useful to provide calibration targets for DSM potential estimates and in identifying key programs and results for top-performing portfolios.

Table 3-2 below provides key characteristics by state or province such as the market structure and DSM targets, as well as the year that DSM programs began.

Table 3-2. DSM Environment in States & Provinces

STATE/ PROVINCE	YEAR BEGAN	MARKET STRUCTURE	DSM TARGETS & AUTHORIZED AMOUNT
British Columbia	2002	Traditional	All DSM that is cheaper than supply options.
California	1974	Partially restructured	Authorized budget based on funding levels necessary for utilities to meet CPUC savings targets by procuring cost-effective efficiency.
Florida	1974	Traditional	DSM programs that pass the RIM Test.
Indiana	1990	Traditional	No formal DSM requirements.
Iowa	1990	Traditional	Maximum achievable DSM potential.
Kentucky	1990	Traditional	No formal DSM requirements.
Maine	2002	Traditional	$1.5 million/year for SBC funded energy efficiency; 2006 budget of $9.6 million.
Manitoba	1979	Traditional	No formal DSM requirements.
Minnesota	1980	Traditional	Minimum spending – Xcel Energy (2% of electric revenues); non-nuclear utilities (1.5%). Also determined by IRP process.
New Jersey	Early 1980's	Deregulated	Balance cost-effective DSM with impact on rates; $1/MWh for economic DR.
New York	1996	Deregulated	$175 million/year for SBC funded energy efficiency.
Texas	2000	Deregulated	Utilities must meet 10% of forecasted growth in demand through efficiency or approved load management.
Vermont	2000	Traditional	Historically funded by a wires charged capped at 3%; cap removed in 2005.
Wisconsin	Mid 1980's	Traditional	Up to 3% of electric revenues.

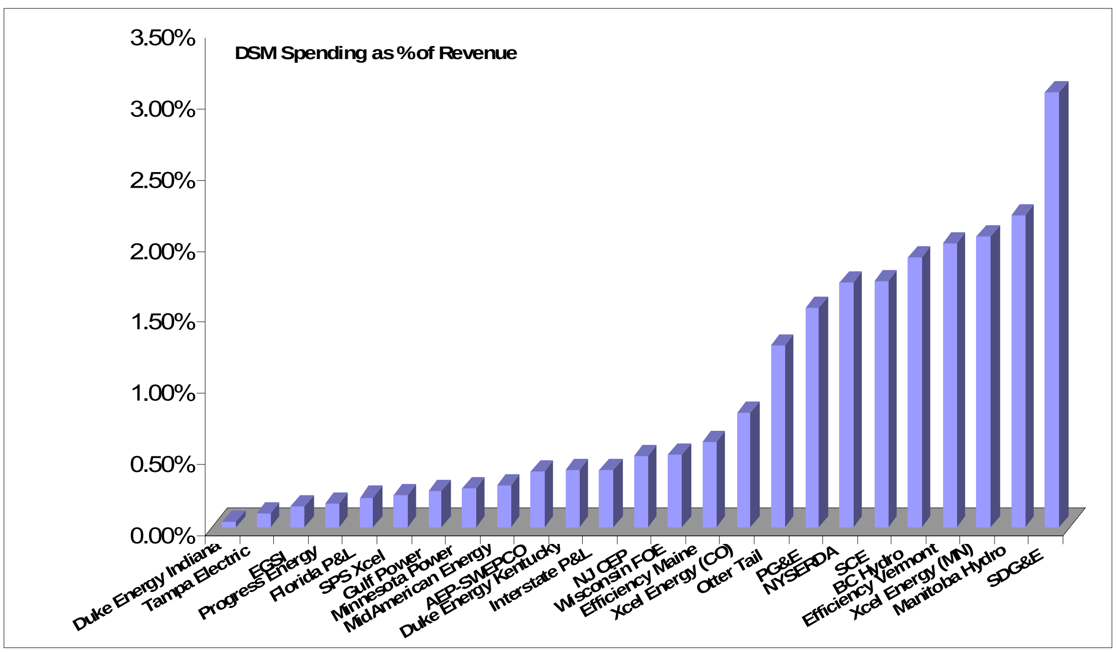
3.2 C&I Results

This section compares 2005 DSM program results for the C&I sector across the various locations. See the Appendix A for complete data and statistics.

3.2.1 C&I Spending as Percent of Revenue

The twenty-five organizations reviewed spent an average of 1% of annual sector revenues on DSM for C&I customers. Figure 3-1 below shows the distribution of spending on DSM as a percentage of annual revenues. Although the sample's distribution is not normal, for the purpose of this discussion, 95% confidence intervals are included which define a range of values within which the population mean is likely to lie (that is, there is a 95 % chance that the population mean will lie somewhere between the upper and lower confidence limits). The 95% confidence interval for C&I spending as a percentage of revenue is from is from 0.6% to 1.4%. In terms of DSM spending, SDG&E has the largest spending as a percentage of sales at about 3%.

Figure 3-1. C&I DSM Spending as % of Revenue



3.2.2 C&I Energy Savings

Figure 3-2 and Figure 3-3 show the energy savings as a percentage of sales and the cost of these savings across the various organizations. The mean energy savings as a percentage of sales is 0.5% (95% confidence interval is 0.3 % to 0.7%) and the mean cost of these energy savings is $0.16 per kWh (95% confidence interval is $0.10 to $0.22 per kWh).

Figure 3-2. C&I Energy Savings as % of Sales

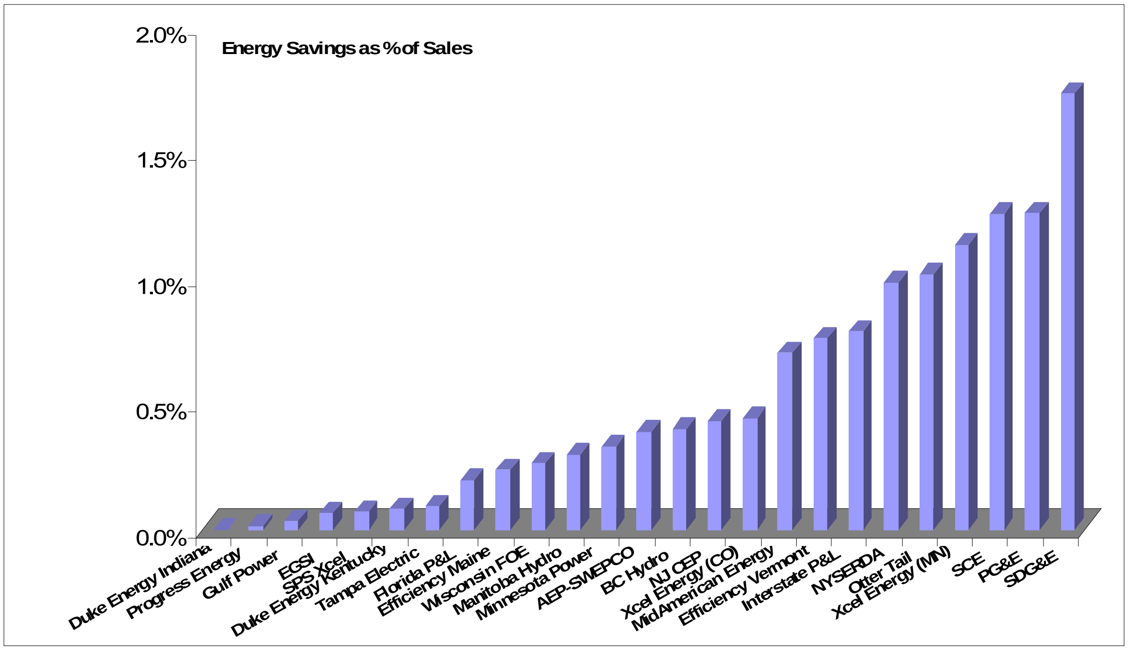
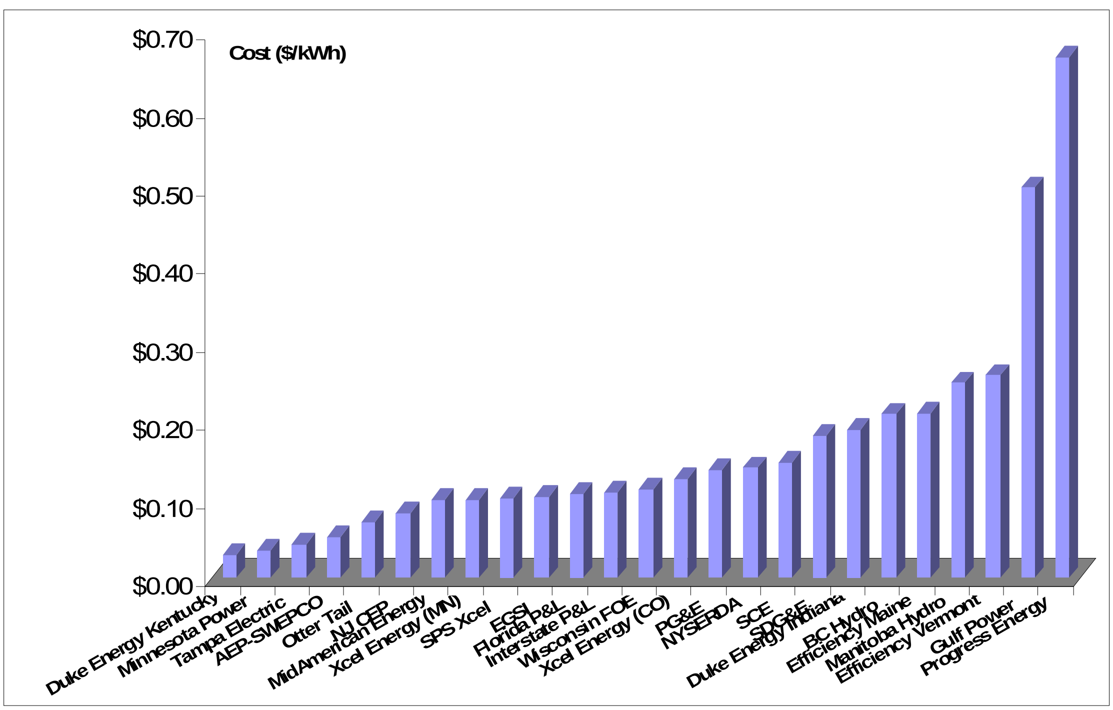


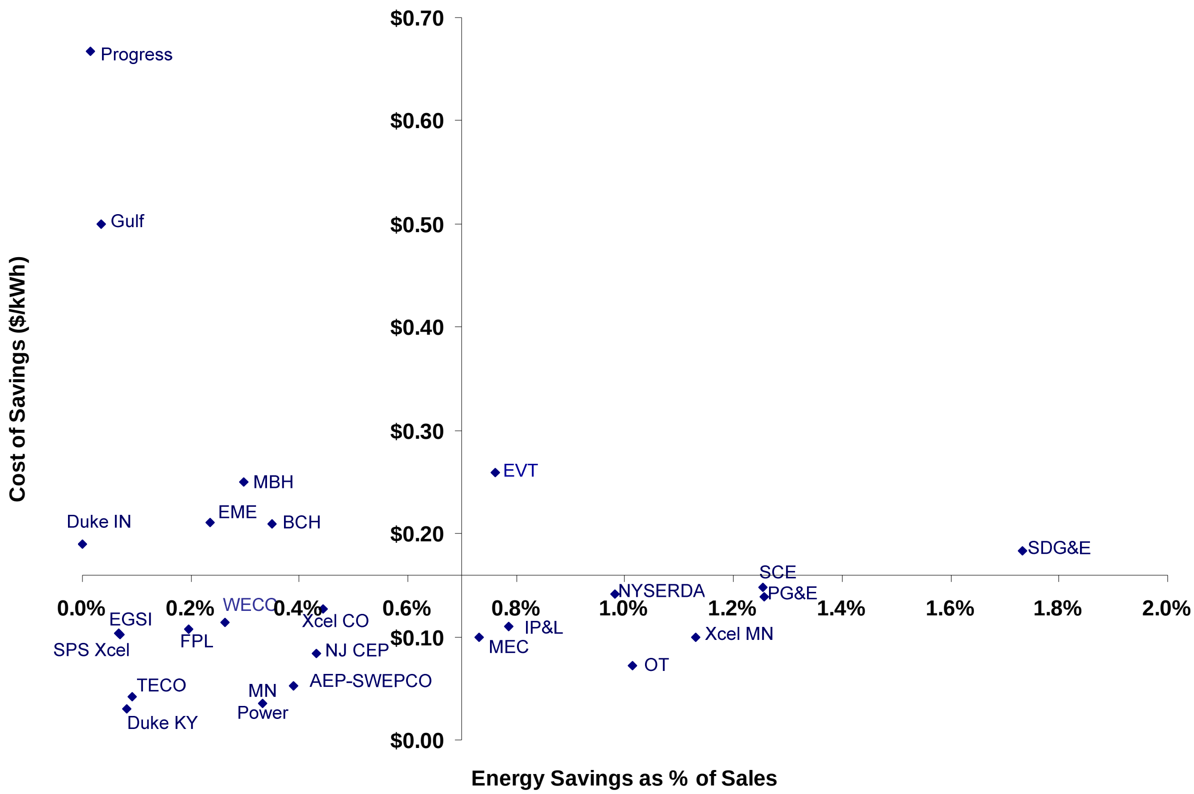
Figure 3-3. Cost of C&I Energy Savings ($/kWh)



The scatter plot shown in Figure 3-4 below illustrates where each organization falls relative to mean energy savings and mean costs. SDG&E achieved the greatest energy savings as percentage of sales, 1.7%, but achieved these savings at $0.18/kWh, costs above the average. The following utilities achieved higher than average energy savings as a percentage of sales at lower than average costs:

- PG&E: 1.3%, $0.14/kWh; SCE: 1.3%, $0.15/kWh
- Xcel Energy (MN): 1.1%, $0.10/kWh; Otter Tail Power: 1.0%, $0.07/kWh; NYSERDA: 1.0%, $0.14/kWh
- Interstate Power & Light: 0.8%, $0.11/kWh; MidAmerican Energy: 0.7%, $0.10/kWh

Figure 3-4 Scatter Plot of C&I Energy Savings and First Year Costs ($/kWh)



The horizontal funnel-like shape of the data illustrates the high variation in costs of energy savings among the organizations that have below average energy savings as a percentage of sales.

Specifically, these data suggest that

- An organization with above average energy savings as a percentage of sales (0.5%) is likely to save at below average costs ($0.16/kWh).

- The greater an organization's energy savings as percentage of sales, the greater the likelihood the savings will be at the average costs (and the converse: the lower the energy savings, the less likely the savings will be at the average costs).

Table 3-3 below shows results for programs delivered by the eight utilities/agencies that achieved a percentage of savings greater than the upper range of the confidence interval for savings as a percentage of sales (0.7%) and that have costs below the upper range of the confidence interval for costs ($0.22/kWh). These program results are not reported on an end use basis, and different organizations target customers in different ways; for example, NYSERDA targets the new construction and existing buildings markets with different portfolios of programs. Otter Tail Power, on the other hand, targets its programs based on DSM measure, e.g. lighting, motors and drives, etc., but achieved most savings from custom projects. Xcel Energy (MN), which had the highest Midwest energy savings as a percentage of sales, has an approach similar to Otter Tail's but also targets new construction, achieving most savings through this program, lighting, and custom projects. The two other high achievers in the Midwest, Interstate Power & Light and MidAmerican Energy, achieved most energy savings from existing buildings and product incentives, respectively. The California utilities achieved most of their savings from product incentives.

Table 3-3. C&I Energy Savings as % of Sales by Type of Program

	California IOUs			Midwest IOUs				
Program/Measures	**SDG&E**	**PG&E**	**SCE**	**Xcel (MN)**	**Otter Tail**	**Int. P& L**	**MEC**	**NYSERDA**
Lighting				0.28%	0.02%			0.01%
Cooling/Roofing/HP		0.04%	0.05%	0.05%	0.01%			
Refrigeration				0.03%	0.03%			
Motors and Drives				0.13%	0.06%			
Compressed Air				0.10%				
Custom/Cooking				0.20%	0.88%	0.14%	0.03%	
New Construction	0.20%	0.26%	0.26%	0.30%	0.04%		0.17%	0.23%
Existing Buildings		0.35%		0.04%		0.60%	0.07%	0.68%
Product Incentive	1.48%	0.62%	0.85%			0.05%	0.45%	
Energy Audits	0.06%		0.10%				0.02%	0.06%
Total Savings (GWh)	**208**	**651**	**719**	**250**	**14**	**93**	**86**	**1,295**
Annual Sales (GWh)	**12,013**	**51,841**	**57,314**	**22,103**	**1,382**	**11,841**	**11,760**	**131,969**
Savings as % of Sales	**1.73%**	**1.25%**	**1.25%**	**1.14%**	**1.05%**	**0.78%**	**0.73%**	**0.98%**

Table 3-4 shows the actual expenditures ($M) to achieve these savings, and Table 3-5 shows the costs in $/kWh. Comparing costs across programs is difficult as the program portfolios and target markets vary widely. For these organizations, spending is generally directly related to energy savings. Notable exceptions are PG&E and MidAmerican Energy which achieved significant energy savings from product incentives with relatively low expenditure and, at $0.05/kWh, well below average costs. Both Interstate Power & Light and NYSERDA achieved their significant energy savings from existing building programs with relatively low expenditures and below average costs, $0.11/kWh and $0.14/kWh, respectively. Otter Tail achieved its substantial energy savings through custom programs at $0.05/kWh, well below average.

Table 3-4. Expenditures of C&I Energy Savings by Type of Program ($M)

	California IOUs			Midwest IOUs				
Program/Measures	**SDG&E**	**PG&E**	**SCE**	**Xcel (MN)**	**Otter Tail**	**Int. P& L**	**MEC**	**NYSERDA**
Lighting				8.9	0.08			1.1
Cooling/Roofing/ HPs		6.4		1.6	0.01			
Refrigeration				0.4	0.03			
Motors and Drives				1.8	0.07			
Compressed Air				0.9				
Custom/Cooking				3.0	0.50	2.0	0.6	
New Construction	7.2	31.7	13.0	6.0	0.02		4.3	73.2
Existing Buildings		30.0		0.6		1.4	0.6	102.5
Product Incentive	30.0	17.4	93.0			6.4	2.5	
Energy Audits	0.4	4.1		0.2	0.02		0.3	3.1
Total Costs ($M)	**$38**	**$90**	**$106**	**$25**	**$1**	**$10**	**$8**	**$180**

Table 3-5. Costs of C&I Energy Savings by Type of Program ($/kWh)

	California IOUs			Midwest IOUs				
Program/Measures	**SDG&E**	**PG&E**	**SCE**	**Xcel (MN)**	**Otter Tail**	**Int. P& L**	**MEC**	**NYSERDA**
Lighting				$0.18	$0.33			$0.17
Cooling/Roofing/ HPs		$0.35		$0.20	$0.08			
Refrigeration				$0.07	$0.10			
Motors and Drives				$0.07	$0.10			
Compressed Air				$0.05				
Custom/Cooking				$0.08	$0.05	$0.09	$0.19	
New Construction	$0.30	$0.24	$0.09	$0.11	$0.05		$0.21	$0.29
Existing Buildings		$0.17		$0.09		$0.11	$0.15	$0.14
Product Incentive	$0.17	$0.05	$0.16			$0.22	$0.05	
Energy Audits	$0.06						$0.18	$0.05
Total Savings (GWh)	**208**	**651**	**719**	**250**	**14**	**93**	**86**	**1,295**
Total Costs ($m)	**$38**	**90**	**$106**	**$25**	**$1**	**$10**	**$8**	**$180**
Costs of Savings ($/kWh)	**$0.18**	**$0.14**	**$0.15**	**$0.10**	**$0.05**	**$0.11**	**$0.10**	**$0.14**

3.2.3 C&I Peak Demand Savings

Table 3-5 below shows total DSM peak kW savings for C&I customers for twenty-three locations; BC Hydro and Efficiency Maine neither target nor track demand savings. The mean peak demand savings as a percentage of peak demand is 0.5% with a 95% confidence interval of 0.3% to 0.7% - the same results as for energy savings. The average cost to achieve demand reductions is $803/kW (95% confidence interval $541/kW to $969/kW).

Figure 3-5. C&I Demand Savings as % of Peak Demand

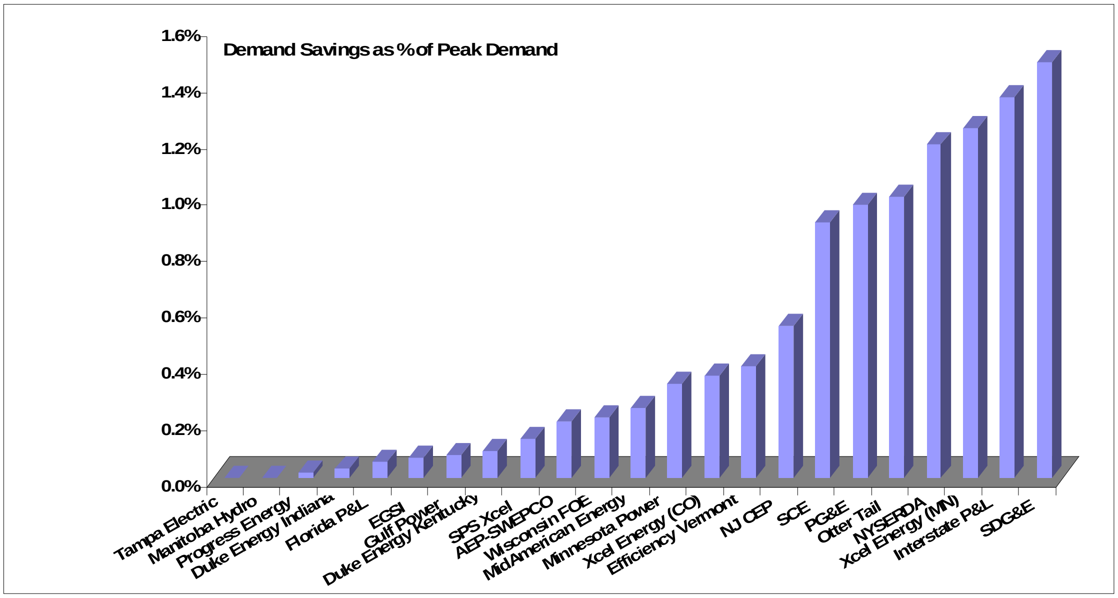
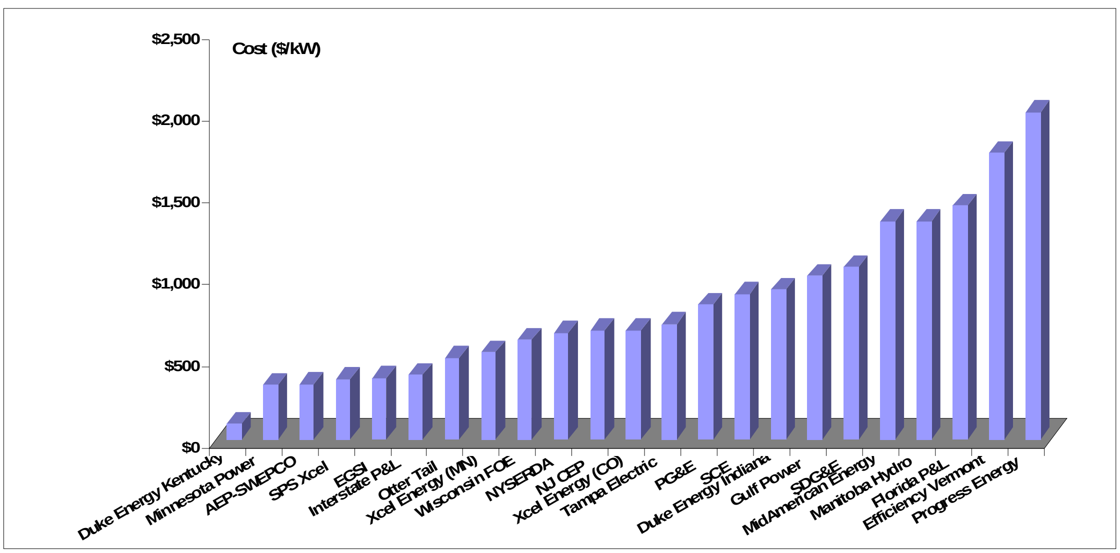


Figure 3-6. Cost of C&I Demand Savings ($/kW)



The scatter plot in Figure 3-7 below shows the distribution of results for demand savings as a percentage of peak demand compared to costs ($/kW) to achieve the savings. SDG&E achieved the greatest demand savings as a percentage of peak demand, 1.5%, but at $1,056/kW, costs above the top range of the confidence interval. The following utilities achieved higher than average demand savings at lower than average costs:

- In the Midwest, IP&L: 1.4%, $396/kW; Xcel Energy (MN): 1.2%, $532/kW; and Otter Tail Power: 1.0%, $500/kW.
- NYSERDA: 1.2%, $654/kW.

Analogous to the distribution of energy savings and first year costs, Figure 3-7 illustrates the high variation in costs of demand savings among the organizations that have below average demand savings as a percentage of peak demand.

Specifically, these data suggest that:

- An organization with above average demand savings as a percentage of peak demand (0.5%) is likely to save at below average costs ($803/kW).
- The greater an organization's demand savings as percentage of peak demand, the greater the likelihood the savings will be at the average costs (and the converse: the lower the energy savings, the less likely the savings will be at the average costs).

Figure 3-7. Scatter Plot of C&I Demand Savings and First Year Costs ($/kW)

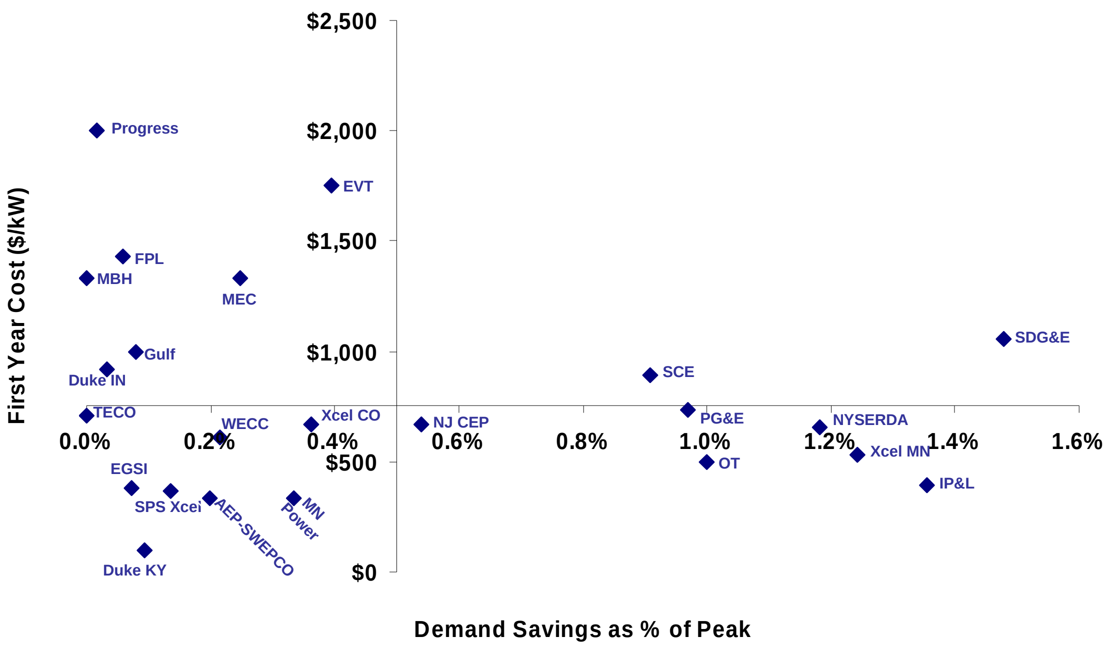


Table 3-6 below compares results by program for the six organizations that exceeded the upper range of the confidence interval for demand savings (0.7%) with costs below the upper range of the confidence interval ($969/kW). These are PG&E and SCE in California, IP&L, Otter Tail Power and Xcel Energy (MN) in the Midwest, and NYSERDA. Table 3-7 shows costs of demand savings in $/kW by program. Product incentive programs provided most of the demand savings for the California IOUs. In the Midwest, Otter Tail obtained most of its results from its custom programs, IP&L from targeting existing buildings and industrial processes, and Xcel Energy (MN) from new construction and lighting initiatives. NYSERDA also achieved significant savings from new construction programs but much more from programs aimed at existing buildings.

Table 3-6. C&I Demand Savings as a % of Peak Demand by Type of Program

Program/Measures	California IOUs		Midwest IOUs			
	PG&E	SCE	IP&L	Otter Tail	Xcel (MN)	NYSERDA
Lighting				0.15%	0.32%	0.01%
Cooling/Roofing/HPs	0.09%	0.08%		< 0.01%	0.18%	
Refrigeration				0.07%	0.02%	
Motors and Drives				0.05%	0.10%	
Compressed Air					0.07%	
Custom/Cooking				0.73%	0.13%	
Industrial Processes			0.35%			
New Construction	0.28%	0.16%		0.03%	0.41%	0.32%
Existing Buildings	0.21%		0.91%		0.02%	0.86%
Product Incentive	0.38%	0.58%	0.11%			
Energy Audits		0.09%				0.00%
Total Savings (MW)	**109**	**119**	**25**	**2**	**47**	**280**
Peak Demand (MW)	**11,253**	**13,081**	**1,846**	**212**	**3,781**	**23,669**
Savings as % of Peak Demand	**0.97%**	**0.90%**	**1.37%**	**1.03%**	**1.24%**	**1.18%**

Both Interstate Power & Light and NYSERDA achieved their demand savings from existing building programs with relatively low expenditures and, at $463/kW and $534/kW, respectively, below average costs. Although PG&E's overall costs of demand savings is just above average, and its demand savings is mostly from product incentives, its costs for product incentives is, at $405/kW, below average. Xcel's significant savings achieved by its new construction programs were achieved well below average costs at $384/kW. Otter Tail's custom programs achieved their demand savings at $407/kW.

Table 3-7. Costs of C&I Demand Savings by Type of Program ($/kW)

Program/Measures	California IOUs		Midwest IOUs			
	PG&E	SCE	IP&L	Otter Tail	Xcel (MN)	NYSERDA
Lighting				$333	$743	
Cooling/Roofing/HPs	$644			$1,633	$239	
Refrigeration				$261	$637	
Motors and Drives				$797	$485	
Compressed Air					$314	
Custom/Cooking			$220	$407	$621	
Industrial Processes						
Farm Energy Efficiency						
New Construction	$990	$604		$450	$384	$1,027
Existing Buildings	$1,251		$463		$1,037	$534
Product Incentive	$405	$1,168	$646			
Energy Audits						$257
Total Savings (MW)	**109**	**119**	**25**	**2**	**47**	**280**
Total Costs ($M)	**$90**	**$106**	**$10**	**$1**	**$23**	**$180**
Costs of Savings ($/kW)	**$823**	**$891**	**$392**	**$500**	**$532**	**$643**

3.3 Summary

For the twenty-five organizations reviewed, the mean energy savings as a percent of annual sales for 2005 is 0.5% (with a 95% confidence interval of 0.3-0.7%); but a significant number of top-performing organizations achieved energy savings of 1.0% of sales or more. Results are the same for demand savings as a percentage of peak demand; again, demand savings of 1% per year were achieved by the top-performing utilities and agencies.

The mean costs of savings for all organizations are $.016/kWh (95% confidence interval $0.10/kWh to $0.22/kWh) for energy saving and $803/kW (95% confidence interval $541/kW to $969/kW) for demand savings. The top performers achieved their savings at costs below the average costs of the total group, near the lower range of each confidence interval: $0.12/kWh and $630/kWh.

Table 3-8 and Table 3-9 below summarize the percentage of energy savings and peak demand savings by type of program for the top performing organizations in 2005.

Table 3-8. Percent of Energy Savings by Type of Program

	California IOUs			Midwest IOUs				
Program/Measures	**SDG&E**	**PG&E**	**SCE**	**Xcel (MN)**	**Otter Tail**	**Int. P& L**	**MEC**	**NYSERDA**
Custom/Cooking				18%	84%	18%	4%	
New Construction	12%	21%	21%	26%	4%		23%	23%
Product Incentive	85%	53%	72%	52%	12%	6%	62%	1%
Existing Buildings (includes Energy Audits)	3%	28%	8%	4%		77%	12%	76%

Product incentives and new construction initiatives provided most of the energy savings in the C&I sector. In California, SDG&E and SCE achieved most energy savings from product incentives and new construction; PG&E achieved half of its savings from product incentives, 28% from existing buildings, and 21% from new construction. In the Midwest, Xcel Energy (MN) and MidAmerican Energy achieved most savings from product incentives—52% and 62% respectively, and from new construction—26% and 23%. NYSERDA also achieved 23% of its energy savings from new construction and 76% from programs targeting existing buildings, which include product incentive programs such as Smart Equipment Choices. Interstate Power and Light achieved 77% of savings from existing buildings, which includes providing incentives for efficient products, and achieved almost 20% through custom projects. Otter Tail is unique in achieving close to 90% of savings from custom projects.

Table 3-9. Percent of Peak Demand Savings by Type of Program

Program/Measures	California IOUs		Midwest IOUs			**NYSERDA**
	PG&E	**SCE**	**IP&L**	**Otter Tail**	**Xcel (MN)**	
Custom/Cooking				71 %	10 %	
Industrial Processes			26 %			
New Construction	29 %	18 %		3 %	33 %	27 %
Product Incentive	49 %	73 %	8 %	26 %	56 %	< 1 %
Existing Buildings (includes Energy Audits)	22 %	9 %	66 %		1 %	73 %

Product incentives and existing buildings provided most of the demand savings in the C&I sector. In California, PG&E and SCE achieved most demand savings from product incentives and new construction; SCE achieved 73% of its savings from product incentives, and PG&E earned about half of its savings from product incentives, 29% from new construction, and 22% from existing buildings. In the Midwest, Xcel Energy (MN) also achieved most savings from product incentives, 56%, and achieved 33% of its total demand savings from new construction. IP&L and NYSERDA achieved most of their demand savings, 66% and 73% respectively, from existing buildings. Otter Tail achieved most of its demand savings from custom programs, 71%, and achieved 26% from product incentives.

3.4 Conclusions

Almost all of the benchmarked utilities and agencies have been conducting DSM programs for an extended period. Over the time these utilities have been conducting DSM programs, they have realized savings from a lot of the “low hanging fruit” among DSM measures, such as T12 lighting system conversions to T8 systems.

KCP&L should be able to achieve energy efficiency potential savings at least equal to the 1% of baseline sales and peak demands once its energy efficiency programs have achieved a moderate level of maturity. Summit Blue generally estimates this program ramp-up period to take two to three years. KCP&L has already started this ramp-up for some of its energy efficiency programs.

KCP&L’s 2005 C&I energy sales were about 9,540 GWh in Kansas and Missouri combined, from FERC Form 861 information[2]. So KCP&L’s full-scale expected energy efficiency program savings are about 95 GWh per year, 1% of the Company’s baseline C&I sales. KCP&L’s total 2005 summer peak demand was 3,512 MW according to FERC Form 861 information.[3] Assuming that KCP&L C&I customers account for 64% of the Company’s peak demand, KCP&L’s C&I customers’ percentage of the Company’s retail sales, the C&I customer’s 2005 summer peak demand was 2,248 MW. So the Company’s expected full-scale energy efficiency program peak demand savings are about 22 MW per year, 1% of the Company’s baseline C&I peak demand.

[2] FERC Form 861 data, File 2 is available on the Energy Information Administration’s web site: www.eia.doe.gov.

[3] FERC Form 861 data, File 1 is available on the Energy Information Administration’s web site: www.eia.doe.gov.

4. AVOIDED COST ANALYSIS RESULTS

4.1 Introduction

This section presents the methods used and results for the avoided cost study performed by Summit Blue for KCPL, as defined in KCPL's Work Order No. 2, dated January 25, 2007. The goal of the study was to develop a stochastic analysis for future avoided energy and capacity costs, providing a 5% mean and 95% probability that reflect predicted volatility in these costs. The study period is from 2007 to 2027.

As is the case with many utilities, KCP&L utilizes separate models for capacity and energy costs. In this study, separate approaches were taken to estimate avoided capacity and energy costs. The capacity model assesses fixed operation and maintenance (O&M) costs and capital construction costs for new generating plants, and the future least cost resource mix that will meet reserve requirements. The energy model, MIDAS, assesses production costs, dispatch, sales and purchases, weather, and other variables that affect market prices for energy.

Summit Blue and KCP&L personnel worked together to develop avoided capacity costs and avoided energy costs that will be used in a Demand-Side Management (DSM) planning model to assess the cost-effectiveness of different energy efficiency measures and programs.

4.2 Avoided Capacity Costs

4.2.1 General Approach

The approach to avoided capacity costs is that the value of Energy Efficiency (EE) is provided by the ability of EE to defer new additions to the resource mix (i.e., to defer by at least one year the building of new plant), and to avoid the purchase of Purchase Power Agreements (PPAs). The savings can be calculated by comparing a resource plan with EE (i.e., with reduced peak demand due to EE) with a resource plan without EE. This approach was taken in the analysis.

A model for calculating avoided capacity costs was developed by KCPL. The data used in the model is based on a high level review of KCPL's current capacity and load forecast. The model was expanded during this study so that uncertainty in avoided costs could be addressed.

4.2.2 Peak Demand Cases and Addition of EE

There are three different cases in the capacity model, based on forecasted peak demand – low, base, and high peak demand. These peak demand forecasts are weather normalized and were provided by the KCP&L planning department.[4] They represent the uncertainty around the rate of load growth.

Peak demand reductions from energy efficiency programs were added to the three peak demand cases, in a proportion estimated to be reasonable for a wide range of EE programs. The approach taken was to estimate potential savings from EE, as a percentage of total annual energy sales for the system, and then to estimate the demand savings associated with the energy savings.

[4] File named Load Data.xls, provided on accompanying CD of data files.

The amount of energy savings from EE programs was based on a Demand Side Management (DSM) benchmark study for North America.[5] In effect, programs that are aimed at technologies that run during summer peak demand periods will have a higher peak demand to energy savings ratio than technologies that save energy throughout the year, such as building envelope measure. As the development of these avoided costs is part of a DSM screening process, it is not clear exactly which programs will be included in the final DSM portfolio. Therefore, the demand savings associated with the energy savings was calculated based on a ratio between energy and demand savings taken from the results of several different EE programs.[6] The amount of EE added to the capacity spreadsheet model was calculated as follows:

- Energy savings were added at increments of 0.3% of total annual system MWh, ramping up to 3% of total system MWh after 10 years, and staying level at that percentage for the rest of the period.
- Peak demand savings were calculated as 0.0186% of energy savings.
- This resulted in peak demand savings that ranged from 0.2% to 2.5% of system peak demand.

The amounts of peak demand savings added to the model are shown in Table 4-1.

[5] Benchmarking 2005 DSM Results, Randy Gunn, Summit Blue Consulting.

[6] See file Ratio of Demand and EE Savings.xls, provided on accompanying CD of data files

Table 4-1: Peak Demand Savings Added to Capacity Model

Year	Low Peak Demand Case			Base Peak Demand Case			High Peak Demand Case		
	EE Savings as %	Peak Reduction MW	% Reduction in Peak	EE Savings as %	Peak Reduction MW	% Reduction in Peak	EE Savings as %	Peak Reduction MW	% Reduction in Peak
2007	0.3%	9	0.2%	0.3%	9	0.2%	0.3%	9	0.2%
2008	0.6%	19	0.5%	0.6%	19	0.5%	0.6%	19	0.5%
2009	0.9%	28	0.7%	0.9%	29	0.7%	0.9%	29	0.7%
2010	1.2%	39	1.0%	1.2%	39	1.0%	1.2%	39	1.0%
2011	1.5%	49	1.2%	1.5%	50	1.2%	1.5%	50	1.2%
2012	1.8%	60	1.5%	1.8%	61	1.5%	1.8%	61	1.5%
2013	2.1%	71	1.8%	2.1%	72	1.8%	2.1%	73	1.8%
2014	2.4%	82	2.0%	2.4%	84	2.0%	2.4%	85	2.0%
2015	2.7%	94	2.3%	2.7%	96	2.3%	2.7%	97	2.3%
2016	3.0%	106	2.5%	3.0%	108	2.5%	3.0%	110	2.5%
2017	3.0%	107	2.5%	3.0%	110	2.5%	3.0%	112	2.5%
2018	3.0%	108	2.5%	3.0%	111	2.5%	3.0%	113	2.5%
2019	3.0%	109	2.5%	3.0%	113	2.5%	3.0%	115	2.5%
2020	3.0%	110	2.5%	3.0%	114	2.5%	3.0%	116	2.5%
2021	3.0%	111	2.5%	3.0%	115	2.5%	3.0%	118	2.5%
2022	3.0%	112	2.5%	3.0%	117	2.5%	3.0%	120	2.5%
2023	3.0%	113	2.5%	3.0%	118	2.5%	3.0%	121	2.5%

Source: Load Data.xls

4.2.3 Structure of Capacity Model

The capacity model consists of four main analyses, or steps:

Step 1 – Define Capacity Costs

Define the levelized construction costs and fixed O&M costs for coal and gas units, in $/kW-yr.

Step 2 – Analyze Scenarios

In this step, the peak demand, the capacity responsibility, the net accredited capacity, and new Combustion Turbine (CT), Coal Plant, and PPA adds are defined. There are three cases – low, base, and high peak demand. Each case has a "with EE" and "without EE" scenario. The balance of capacity deficit is shown for each case and each scenario. Adjustments to generating unit additions are made so that the capacity responsibility is met in each year (i.e. the deficit is negative or zero). This process requires in-depth knowledge of the KCP&L system and was done by KCP&L personnel.[7]

Step 3 – Define Annual Avoided Costs

In this step, the range in costs for coal plant, gas plant, and PPA capacity are defined on an annual basis. Costs are escalated each year based on the 2007 value (or 2010 in the case of coal) defined in Step 1. Escalation rates are provided by Global Insights. A probability distribution for the range of uncertainty in these costs is implemented with the use of Crystal Ball[8] software. There is one distribution for each of the annual costs for gas, coal, and PPA.

Step 4 – Resource Additions

In this step, the resource additions from the six scenarios are converted to dollar values. Costs are taken from step 3. The total net present value (NPV) cost for each scenario is calculated, and then the cost for the "with EE" scenario is subtracted from the "without EE" scenario cost, for each peak demand case. Finally, this difference in NPV is levelized to an annual cost in 2007 dollars and then divided by the annualized amount of EE peak reductions in each case, to give a $/kW-yr value.

4.2.4 Assumptions Used

Listed here are the assumptions used to create and adjust the scenarios in the model:

- Capacity Responsibility = (Current long-term load forecast - EE contributions) + 12% Capacity Margin.
- Projected Accredited Capacity includes 465 MW share of Iatan-2 in 2010.
- Future resource additions are assumed to be CT's (added in pairs at 154 MW) and/or Coal (added in 400MW increments).

---

[7] Randy Hughes performed this process of defining PPA, gas plant, and coal plant adds for the six scenarios.

[8] Crystal Ball is a software package that performs Monte Carlo simulations, published by Descisioneering Inc.

- Small annual capacity shortfalls are assumed to be met through purchased capacity and energy contracts priced at expected market costs.

- For annual excess capacity, it is assumed that 50% of the excess is sold at prevailing market prices resulting in additional revenues.

4.2.5 Crystal Ball

Crystal Ball was used to create probability distributions around factors that were deemed to contribute to uncertainty in avoided capacity costs – levelized construction and fixed O&M costs for coal and gas, and cost of PPAs. Ranges for the distributions were provided by KCP&L staff, based on available data. It was assumed that there is only a small chance that construction costs will be less than projected.

Normal distributions were used for the coal and gas costs, truncated at the minimum and maximum shown in the table below. Triangular distributions were used for the PPA prices, based on min, mid, and max values at 10%, 75%, and 15% probabilities, respectively. The ranges for the distributions are shown in Table 4-2. (Note: PPA ranges shown are the average over 20 years, as the range varies in each year).

Table 4-2: Ranges for Crystal Ball Probability Distributions

Capacity Costs	min (below mean)	max (above mean)
Coal	-1%	20%
Gas	-1%	10%
PPA	-17%	170%

Source: Final KCP&L Avoided Capacity Model.xls

A Crystal Ball simulation was run for 10,000 trials, in Monte Carlo mode. The $/kW-yr avoided cost value for each case can be viewed as a distribution of possible costs, or as a single value, which is the mean of the distribution.

4.2.6 Results

Data from the Crystal Ball forecasts for the levelized savings for each case was extracted. This data included the value at 5th percentile increments, plus the standard deviation of the distribution. A weighted average was calculated based on the probability of each peak demand case occurring (15%, 55%, and 30% for the low, base, and high cases, respectively). These probabilities are based on the knowledge of the system of KCP&L staff. Table 4-3 shows a summary of the model results.

Table 4-3: Summary of Capacity Model Results

Case	Probability	Annualized NPV Savings	Annualized MW from EE	Mean	5%	95%	Std. Dev.
Low Demand	15%	$6,092,293	85.1	$71.57	64.59	78.69	4.29
Base Demand	55%	$9,624,582	88.0	$109.32	89.59	129.74	12.13
High Demand	30%	$11,930,391	89.9	$132.75	113.95	151.80	11.46
Weighted Average				110.69	93.15	128.70	10.75

Source: Final KCP&L Avoided Capacity Model.xls

4.2.7 Avoided T&D Costs

At this time, avoided T&D costs have not been included in this study.

4.3 Avoided Energy Costs

4.3.1 General Approach

The simple approach to avoided energy costs is to assume that the costs of serving 1 MW can be avoided due to the implementation of 1 MW of EE. This is true when energy is being purchased from the market by KCP&L – KCP&L can avoid that cost of purchase. Then the market prices produced by the MIDAS model can be used directly as the avoided energy costs for the hour in which the energy is saved due to EE.

However, this approach is not valid when KCP&L is not buying from the market. When it has excess capacity and is selling energy into the market, then the value of energy saved by EE is the market price less the cost of producing the energy. That is, the value of the energy saved is equal to the marginal income that KCP&L gains by selling the energy into the market instead of selling the energy within its own system.

The MIDAS prices will be adjusted to reflect the fact that some of the energy produced is sold. Details of this calculation are given in section 3.5.

4.3.2 MIDAS Model Data

KCP&L uses the MIDAS model, provided by MS Gerber, to forecast energy prices. Data from 35 model runs was provided by the resource planning department, representing 35 different sets of price driver values. Volatility due to weather is included in all the model runs. The model was run for the period 2006 to 2023.

The drivers that were put into MIDAS to create a range of uncertainty are listed below:

- Gas price
- Coal price

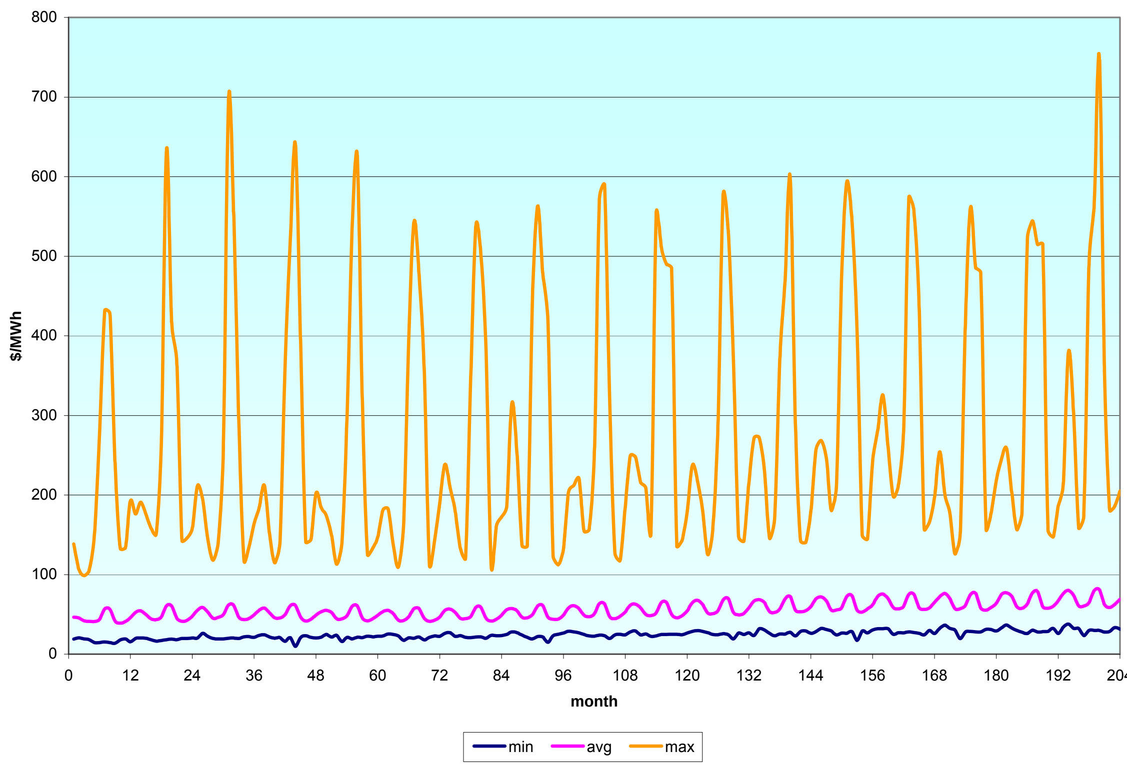
- Nuclear availability
- Coal availability
- Load shape year
- Peak Demand
- Energy Demand

The prices produced by the model in the 35 runs, for each hour of the year, were analyzed. A minimum, maximum, and average price for each hour of the day, for each month of the year, was produced for 2007 to 2023. The ratio of maximum price per month to average price per month varies from 2.2 to 11.27, with the average ratio being 4.75. On an hourly basis, the ratio of maximum price to average (out of the 35 runs) ranges from around 1.2 to around 4.

The Summit Blue team examined the ranges of prices in conjunction with KCP&L personnel, and the ranges were determined to capture what may be viewed as extreme events. As a result, the data was viewed as representing a 95% confidence interval, based on the ranges of the price drivers used in the modeling.

Figure 4-1 shows the minimum, mean, and maximum from the 35 runs for all months in the modeling period. The general trend of the minimum and average is upwards over the years, and the maximum tends downwards after 2009.

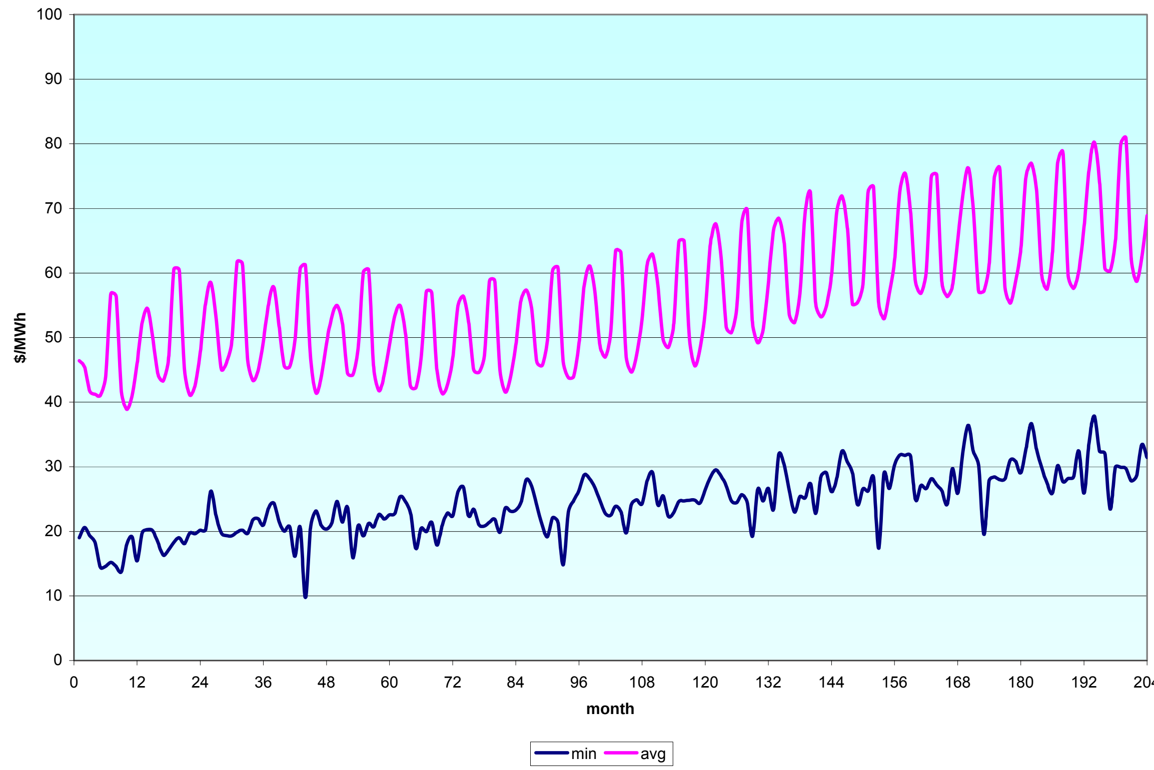
Figure 4-1: Min, Mean, and Max of Prices for 2007 to 2023



Source: All Years Analysis.xls

Figure 4-2 shows the minimum and mean values in more detail. The average prices are always higher in the summer, but the difference between summer and winter is not more than around $20 in each year. Also, the trend in prices over the whole time period of 17 years leads to an increase of approximately 50% of average 2007 prices.

Figure 4-2. Min, Mean, and Max of Prices for 2007 to 2023



4.3.3 Multipliers

There is a unique multiplier value for each month of the modeling period, for each of the drivers. The multipliers are ratios between the base case and the other 35 cases. The multipliers were calculated with a hypercube generator and a normal distribution was used. The correlation of peak and energy is an input to the Latin Hypercube logic, and this correlation affects the resulting peak and energy multipliers. There is no correlation over time in the multipliers.[9] Table 4-4 shows a summary of the ranges of the multipliers for five of the drivers.

---

[9] Information about the modeling process was provided by Roger Powell of KCPL.

Table 4-4: Ranges of Multipliers for Price Drivers

Year	Gas		Coal		Coal Availability		Energy		Peak	
	min	Max	min	max	Min	max	min	max	min	Min
2007	0.54	2.90	0.93	1.07	0.91	1.08	0.83	1.18	0.73	1.27
2008	0.48	2.99	0.93	1.08	0.90	1.08	0.85	1.19	0.74	1.26
2009	0.50	2.75	0.93	1.06	0.91	1.08	0.82	1.17	0.75	1.27
2010	0.52	2.82	0.94	1.07	0.91	1.09	0.81	1.16	0.75	1.26
2011	0.58	2.91	0.93	1.08	0.91	1.09	0.81	1.15	0.74	1.23
2012	0.58	3.02	0.93	1.08	0.91	1.07	0.79	1.17	0.75	1.25
2013	0.58	3.17	0.93	1.08	0.91	1.09	0.78	1.20	0.64	1.36
2014	0.58	4.28	0.93	1.07	0.91	1.08	0.82	1.18	0.72	1.25
2015	0.58	3.30	0.93	1.07	0.91	1.09	0.82	1.23	0.72	1.31
2016	0.58	3.11	0.94	1.07	0.93	1.09	0.84	1.17	0.75	1.30
2017	0.58	2.78	0.93	1.07	0.91	1.09	0.77	1.16	0.73	1.24
2018	0.58	3.26	0.94	1.08	0.91	1.08	0.81	1.19	0.77	1.26
2019	0.58	3.29	0.93	1.06	0.92	1.09	0.81	1.20	0.69	1.32
2020	0.58	3.01	0.93	1.07	0.92	1.09	0.81	1.15	0.64	1.29
2021	0.58	2.91	0.93	1.08	0.93	1.08	0.79	1.17	0.76	1.29
2022	0.58	3.07	0.93	1.08	0.90	1.10	0.78	1.16	0.71	1.33
2023	0.58	3.49	0.93	1.08	0.91	1.09	0.82	1.21	0.74	1.32

Source: Multipliers.xls

4.3.4 CO2 MIDAS Runs

The MIDAS model was also run with three alternative scenarios that included possible future carbon allowance payments. These three scenarios do not include any uncertainty or volatility; the only difference is the additional requirement that CO2 allowances will need to be obtained –beginning in 2012 in the "Medium CO2" case and in 2010 in the "High CO2" case. The model inputs for the three cases include an estimated price for a carbon allowance in terms of $/Ton of carbon, and the overall emissions cap. A summary of these inputs is shown in Table 4-5.

Table 4-5. Allowances and Emissions Caps for CO2 MIDAS Runs

Year	Low Case		Medium Case		High Case	
	Allowance Price ($/ton)	Emissions Cap (tons)	Allowance Price ($/Ton)	Emissions Cap (tons)	Allowance Price ($/ton)	Emissions Cap (tons)
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	44	11,553,000
2011	0	0	0	0	45	11,553,000
2012	7	0	12	12,392,000	46	11,553,000
2013	7	0	12	12,392,000	47	11,553,000
2014	7	0	13	12,392,000	49	11,553,000
2015	10	0	13	12,392,000	50	11,553,000
2016	10	0	13	12,392,000	51	11,553,000
2017	11	0	14	12,392,000	52	11,553,000
2018	11	0	14	12,392,000	54	11,553,000
2019	11	0	14	12,392,000	55	11,553,000
2020	11	0	15	12,392,000	56	11,553,000
2021	12	0	15	12,392,000	58	11,553,000
2022	12	0	16	12,392,000	59	11,553,000
2023	12	0	16	12,392,000	61	11,553,000

Source: CO2 Prices.xls

A comparison was done between the market prices from the three different CO2 runs and the market prices from the other 35 MIDAS model runs, which used multipliers to address uncertainty across factors other than CO2. It was found that values from the three CO2 cases are not always higher than the maximum of the other 35 cases, because the uncertainties included in the 35 MIDAS model runs are not included in the CO2 runs. The CO2 runs represent additional market price uncertainty, in addition to the uncertainties included in the 35 MIDAS runs, and this uncertainty needs to be added onto the prices from the 35 MIDAS runs. The CO2 scenario runs were used to develop a "price adder" to the price distributions from 35 MIDAS model runs.

Table 4-6 shows a summary of the CO2 data analysis. This table includes the number of hours that the CO2 mid and high case is higher than the maximum of the 35 cases, and the average price increase for those hours in each year.

Table 4-6. Price Increase from Max of 35 Runs to CO2 Runs

Summary of increase from max of 35 runs to Mid and High CO2 cases				
Year	**Mid CO2**		**High CO2**	
	Count	**Average**	**Count**	**Average**
2012	646	7%	3536	28%
2013	336	7%	2735	26%
2014	863	9%	3616	23%
2015	53	3%	2196	25%
2016	34	10%	419	12%
2017	44	8%	919	17%
2018	8	11%	667	14%
2019	29	9%	413	15%
2020	34	10%	419	12%
2021	14	3%	474	9%
2022	48	10%	234	9%
2023	32	12%	12	5%
		8%		16%

Source: Max CO2 Scenarios.xls

It should be noted that the prices produced by the model for the low, mid, and high CO2 scenarios are not always ranked in that order. There are instances where price for the low CO2 scenario is higher than the price for the high CO2 case, for a given hour. There are two possible reasons for this:

- The low price scenario grants no emissions cap and trade, so in effect it can be more expensive to system operations than the medium case, as it functions more like a tax on all CO2 emissions. [10]

[10] This insight was provided by Mr. Doug Jasa of KCPL.

- There is an anomaly that occurs in some hours as a result of the model planning (MRX) logic. When generation costs increase dramatically, that will encourage the addition of more low cost generation. This has a tendency to minimize the scarcity premium in higher priced hours and "choke-out" the dispatch of inefficient units in all hours. For instance, in a high CO2 scenario, a coal unit with a very high heat rate could be displaced from the market altogether.[11]

The likely introduction of CO2 emission allowances in the next few years, which will probably include a cap and trade scheme for utilities, is one uncertainty that should be included as a potential price driver. It was decided to combine the basic 35 MIDAS runs with these CO2 runs by adding a percent increase to the 35 runs. The average increases shown above for the mid and high CO2 cases – 8% for the mid case and 16% for the high case – will be used to generate two additional sets of energy prices that reflect these CO2 scenarios.

Thus, three sets of avoided energy costs will be used in the EE screening process:

- base 35 MIDAS runs with multipliers to capture uncertainty in price drivers
- base plus incremental costs from mid CO2 run
- base plus incremental costs from high CO2 run

It was decided to use only the mid and high CO2 scenarios, and not the low CO2 scenario, due to the need to limit the number of scenarios that will eventually be analyzed in the EE cost-effectiveness screening analyses, and also due to the fact that the avoided costs were not expected to change that much for the low CO2 scenario.

4.3.5 Adjustments for Energy Sales

As noted in Section 3.1, the avoided cost for MWh sold by KCP&L into the market is the market price less the cost of producing the energy. Therefore, the MIDAS prices will need to be adjusted to reflect the fact that some of the energy saved by the implementation of EE is sold. This adjustment will be applied to the prices for each hour of the year. Prices for coal generation will be used, as this is the dominant type of generation for the hours in which energy is typically sold.

The following assumptions will be made about the energy saved through EE[12]:

- 75% of the avoided energy is sold, and is generated from coal. Then the avoided cost is the market price less the coal marginal production costs, which is $13.67/MWh in 2007 dollars.

- The remaining 25% of avoided energy is avoided purchases. Then the avoided cost is the full market price

- Coal production costs will be escalated at 3% per year.

The prices will be adjusted as follows:

adjusted cost = 25% * market price + 75% * (market price – production cost)

---

[11] This insight was provided by Mr. Roger Powell of KCPL.

[12] These assumptions and percentages were provided by Mr. Randy Hughes of KCPL

4.3.6 Format of Avoided Energy Cost Data

The required format for the avoided energy cost data, as used by the DSMore model to be used for the DSM screening is a lognormal probability distribution for each hour of the year, for the entire modeling period (21 years). This data will be generated with the use of Crystal Ball software from the adjusted MIDAS price data. Three sets of these data will be generated:

1. **A Base Uncertainty Case** using the results from the 35 MIDAS model runs incorporating the multipliers to capture uncertainty in electricity prices.

2. **A Medium CO2 Case** where the incremental costs for CO2 from the medium CO2 scenario are added to the prices from the base uncertainty case (this method is described in Section 3.4).

3. **A High CO2 Case** where the incremental costs for CO2 from the high CO2 scenario are added to the prices from the base uncertainty case (this method is described in Section 3.4).

4.4 Summary and Next Steps

4.4.1 Summary

Summaries of the approaches taken to produce avoided costs and some of the results are presented here:

Avoided capacity costs are calculated with a capacity spreadsheet model. There are three cases in the model – low, base, and high peak demand – and each case has a “with EE” and “without EE” scenario. The difference in NPV of capital costs between the two scenarios for each case gives the avoided costs, presented as levelized $/kW-yr. A weighted average of the three cases is calculated to give a final single value, as shown in Table 4-7.

Table 4-7. Summary of Capacity Model Results

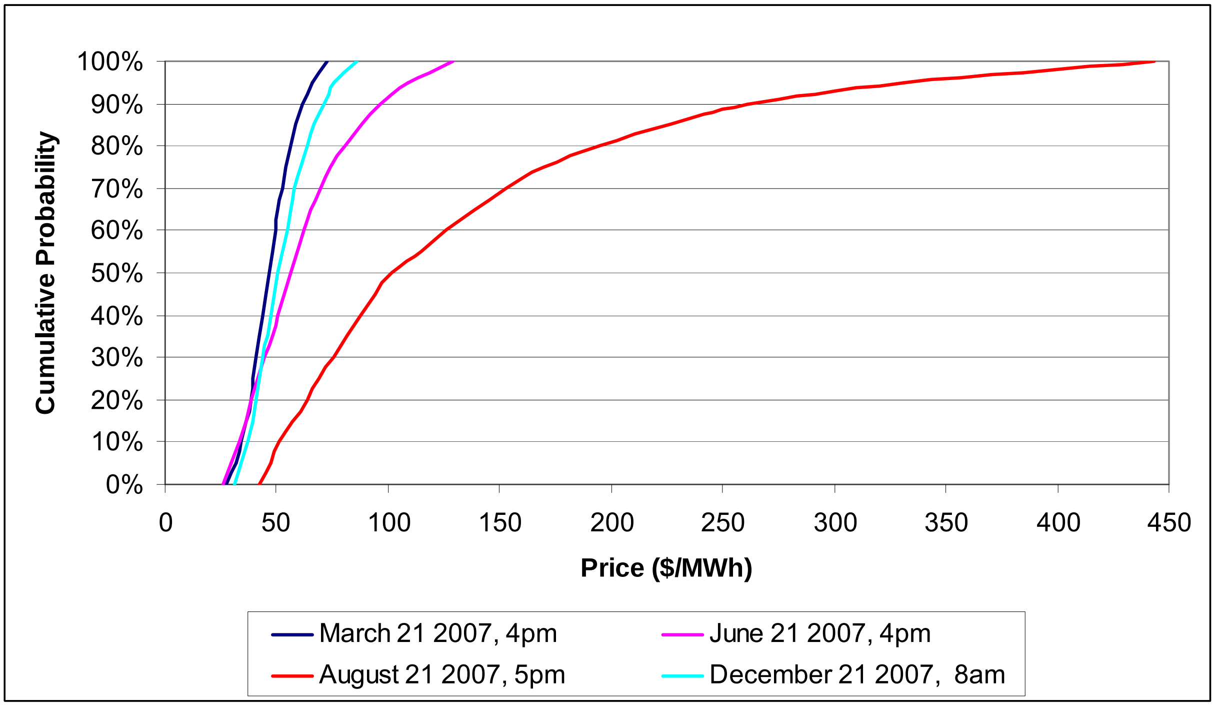
Case	Probability	Annualized NPV Savings	Annualized MW from EE	Mean	5%	95%	Std. Dev.
Low Demand	15%	$6,092,293	85.1	$71.57	64.59	78.69	4.29
Base Demand	55%	$9,624,582	88.0	$109.32	89.59	129.74	12.13
High Demand	30%	$11,930,391	89.9	$132.75	113.95	151.80	11.46
Weighted Average				110.69	93.15	128.70	10.75

Source: Final KCP&L Avoided Capacity Model.xls

Avoided energy costs are derived from the MIDAS market prices, in $/MWh. These prices are adjusted to reflect the fact that a proportion of energy is sold by the system, and then formatted into unique probability distributions for each hour of the year. These distributions represent the 35 cases of price drivers run through the model. Three sets of these distributions will be produced. The values in the 2nd and 3rd sets will be adjusted to reflect the mid CO2 and high CO2 cases from the CO2 MIDAS runs.

As the final data set of avoided energy costs is large (distributions for 8760 hours times 20 years), it is not possible to show the data in this report. Instead, four sample hours are shown here to give an idea of the spread of prices in the 35 values for one hour (Note: these prices have not yet been adjusted to reflect energy sales). Figure 4-3 below shows cumulative probability for four different hours, and the range of possible prices for those hours.

Figure 4-3. Cumulative Probability for Ranges of Prices, for Four Different Hours



4.4.2 Next Steps - Input to the EE Screening Model DSMore

The avoided capacity and avoided energy costs produced in this study will be used during the second phase of this project, in which specific EE measures and EE programs will be screened for cost effectiveness. Avoided capacity costs will be represented by a single annualized value. Avoided energy costs will be added to the model in the form of unique probability distributions for each hour of each year. There will be three sets of the energy price data – base, mid CO2, and high CO2. Details of this process will be provided in later documentation.

5. KCP&L BASELINE ENERGY PROFILES

In this section, we describe the development of baseline market segment profiles and initial building simulation model specifications. KCP&L supplied considerable input data for this task including customer counts and billing data by market segment and sales forecasts for the Company's overall commercial and industrial customer sectors. Other data sources included Energy Insights' proprietary Energy Market Profiles data, available to KCP&L through their Load Analysis Strategies subscription. Energy Insights used the results of the market profile analysis to calibrate market segment versions of the eQuest building simulation model. eQuest is a widely used commercial building simulation model based on the DOE-2 model. The remainder of this section describes each step in more detail.

- **Develop 2006 electricity use by for each customer segment**. KCP&L provided a list of customer segments as well as estimates of energy use for 2006. These data are summarized at the end of this section.

- **Map KCP&L segments to Energy Market Profile segments**. Using analyst judgment, Energy Insights assigned each KCP&L customer segment to the best match among the Energy Market Profile segments. The mapping is presented in Table 5-1 for Phase I segments and Table 5-2 for Phase II segments.

- **Calibrate baseline energy use**. In this step, the energy use estimates by end use were calibrated to total segment electricity use. The calibration variable is building floor space. The resulting calibrated energy use by end use for each segment is presented at the end of this section.

- **Develop eQuest simulation files**. In this final step, Energy Insights calibrated eQuest prototypes for the Phase I segments to the calibrated energy profiles. This involved adjusting the equipment inventories in the eQuest files to be consistent with the annual energy use by end use from the baseline usage profile. This involved adjustments to five end uses: space heating, space cooling, water heating, interior lighting, and miscellaneous use.

Table 5-1. Phase I KCP&L customer segments

KCP&L Segment	# Accounts	2006 MWH	MWH/Account	Energy Market Profile Segment
DTN, OFC, GOV, and PUB accounts with annual use less than 850,000 kWh	8,788	530,700	60	Small office
DTN, OFC, GOV, and PUB accounts with annual use greater than or equal to 850,000 kWh	500	1,980,300	3,961	Large office
Education	1,226	572,800	467	Schools and colleges combined
Manufacturing	216	1,460,800	6,763	Manufacturing total

Table 5-2. Phase II KCP&L customer segments

KCP&L Segment	# Accounts	2006 MWH	MWH/Account	Energy Market Profile Segment
Apartments	2,112	55,517	26.29	Lodging
Churches	429	67,484	157.31	Public assembly
Communications	3,855	446,937	115.94	Small office
Data Centers	53	86,551	1633.04	Large office
Entertainment	341	177,545	520.66	Public assembly
Grocery	246	293,341	1192.44	Grocery
Health	499	473,049	947.99	Hospitals
Lodging	275	131,429	477.92	Lodging
Petroleum	306	104,761	342.36	Petroleum industries
Print	136	210,597	1548.51	Printing
Restaurant	636	185,192	291.18	Restaurant
Retail	1,226	613,652	500.53	Retail
Transportation	317	19,971	63.00	Transportation
Utilities	949	47,374	49.92	Services
Warehousing	224	97,912	437.11	Warehouse
All	11,604	3,011,312	259.51	

5.1 Phase I Baseline Market Profiles

This section presents the baseline market profiles for the Phase I market segments.

5.1.1 Phase I

Table 5-3. Small Office

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	24.6%	4.07	1.00	31.5
Space Cooling	90.1%	2.50	2.26	70.8
Water Heating	54.5%	0.59	0.32	10.1
Ventilation	100.0%	0.36	0.36	11.4
Cooking	1.5%	0.19	0.00	0.1
Lighting	100.0%	2.81	2.81	88.2
Refrigeration	5.1%	0.09	0.00	0.1
Office Equipment (PC)	89.4%	1.30	1.16	36.5
Office Equipment (non-PC)	100.0%	3.13	3.13	98.0
Other Uses	100.0%	5.87	5.87	184.1
Total			16.92	530.7

Table 5-4. Large Office

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	29.7%	2.87	0.85	88.4
Space Cooling	91.1%	2.70	2.46	255.0
Water Heating	53.9%	0.55	0.29	30.6
Ventilation	100.0%	0.75	0.75	77.7
Cooking	19.2%	0.09	0.02	1.8
Lighting	100.0%	3.46	3.46	358.6
Refrigeration	44.9%	0.08	0.03	3.5
Office Equipment (PC)	89.4%	1.64	1.47	152.2
Office Equipment (non-PC)	100.0%	2.63	2.63	272.7
Other Uses	100.0%	7.14	7.14	740.0
Total			19.10	1,980.3

Table 5-5. Education

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	8.3%	4.42	0.37	22.5
Space Cooling	51.5%	1.62	0.83	50.8
Water Heating	21.3%	1.38	0.29	17.9
Ventilation	100.0%	0.46	0.46	27.7
Cooking	20.0%	0.24	0.05	3.0
Lighting	100.0%	3.88	3.88	236.3
Refrigeration	57.9%	0.16	0.09	5.6
Office Equipment (PC)	89.4%	0.46	0.41	24.9
Office Equipment (non-PC)	100.0%	0.73	0.73	44.6
Other Uses	100.0%	2.29	2.29	139.6
Total			9.41	572.8

Table 5-6. Total Manufacturing

End use	Midwest EMP Total GWh	KCP&L GWh
Indirect Uses-Boiler Fuel	1,454	30,785.0
Process Heating	37,128	786,279.0
Process Cooling and Refrigeration	17,093	361,991.5
Machine Drive	134,961	2,858,139.8
Electro-Chemical Processes	19,085	404,172.1
Other Process Use	1,382	29,272.9
Facility HVAC (f)	23,164	490,561.9
Facility Lighting	20,425	432,545.5
Other Facility Support	4,562	96,609.3
Onsite Transportation	515	10,898.0
Conventional Electricity Generation	-	-
Other Nonprocess Use	487	10,312.4
End Use Not Reported	7,897	167,249.7
Total	268,153	5,678,817.2

5.1.2 Phase II Commercial

This section presents the baseline market profiles for the Phase II commercial market segments.

Table 5-7. Churches Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	9.3%	2.28	0.21	1.8
Space Cooling	70.8%	1.11	0.78	6.7
Water Heating	33.7%	0.94	0.32	2.7
Ventilation	100.0%	0.23	0.23	1.9
Cooking	13.6%	0.13	0.02	0.2
Lighting	100.0%	2.77	2.77	23.7
Refrigeration	30.2%	0.07	0.02	0.2
Office Equipment (PC)	89.4%	0.15	0.13	1.1
Office Equipment (non-PC)	100.0%	0.24	0.24	2.0
Other Uses	100.0%	3.18	3.18	27.2
Total			7.89	67.5

Table 5-8. Communications Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	24.6%	4.07	1.00	26.5
Space Cooling	90.1%	2.50	2.26	59.6
Water Heating	54.5%	0.59	0.32	8.5
Ventilation	100.0%	0.36	0.36	9.6
Cooking	1.5%	0.19	0.00	0.1
Lighting	100.0%	2.81	2.81	74.3
Refrigeration	5.1%	0.09	0.00	0.1
Office Equipment (PC)	89.4%	1.30	1.16	30.7
Office Equipment (non-PC)	100.0%	3.13	3.13	82.5
Other Uses	100.0%	5.87	5.87	155.1
Total			16.92	446.9

Table 5-9. Data Centers Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	0.0%	-	-	-
Space Cooling	100.0%	20.00	20.00	30.4
Water Heating	0.0%	-	-	-
Ventilation	100.0%	-	-	-
Cooking	0.0%	-	-	-
Lighting	100.0%	5.00	5.00	7.6
Refrigeration	0.0%	-	-	-
Office Equipment (PC)	100.0%	5.00	5.00	7.6
Office Equipment (non-PC)	100.0%	20.00	20.00	30.4
Other Uses	100.0%	7.00	7.00	10.6
Total			57.00	86.6

Table 5-10. Entertainment Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	9.3%	2.28	0.21	4.8
Space Cooling	70.8%	1.11	0.78	17.6
Water Heating	33.7%	0.94	0.32	7.2
Ventilation	100.0%	0.23	0.23	5.1
Cooking	13.6%	0.13	0.02	0.4
Lighting	100.0%	2.77	2.77	62.3
Refrigeration	30.2%	0.07	0.02	0.5
Office Equipment (PC)	89.4%	0.15	0.13	3.0
Office Equipment (non-PC)	100.0%	0.24	0.24	5.3
Other Uses	100.0%	3.18	3.18	71.5
Total			7.89	177.5

Table 5-11. Grocery Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	26.9%	9.72	2.62	12.4
Space Cooling	82.0%	8.72	7.16	34.0
Water Heating	34.8%	5.54	1.93	9.2
Ventilation	100.0%	2.41	2.41	11.4
Cooking	24.5%	1.54	0.38	1.8
Lighting	100.0%	18.95	18.95	90.0
Refrigeration	98.9%	15.81	15.64	74.3
Office Equipment (PC)	89.4%	1.04	0.93	4.4
Office Equipment (non-PC)	100.0%	1.67	1.67	7.9
Other Uses	100.0%	10.06	10.06	47.8
Total			61.74	293.3

Table 5-12. Health Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	0.9%	7.46	0.07	1.0
Space Cooling	88.8%	3.93	3.49	53.0
Water Heating	4.2%	3.31	0.14	2.1
Ventilation	100.0%	1.54	1.54	23.3
Cooking	28.0%	0.89	0.25	3.8
Lighting	100.0%	5.06	5.06	76.9
Refrigeration	90.4%	0.18	0.16	2.5
Office Equipment (PC)	89.4%	1.13	1.01	15.4
Office Equipment (non-PC)	100.0%	1.81	1.81	27.5
Other Uses	100.0%	17.62	17.62	267.6
Total			31.15	473.0

Table 5-13. Lodging Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	44.0%	2.48	1.09	8.5
Space Cooling	87.8%	1.62	1.42	11.0
Water Heating	14.0%	3.96	0.55	4.3
Ventilation	100.0%	0.53	0.53	4.1
Cooking	13.5%	0.33	0.04	0.3
Lighting	100.0%	5.06	5.06	39.4
Refrigeration	58.9%	0.29	0.17	1.3
Office Equipment (PC)	89.4%	0.26	0.23	1.8
Office Equipment (non-PC)	100.0%	0.41	0.41	3.2
Other Uses	100.0%	7.39	7.39	57.4
Total			16.91	131.4

Table 5-14. Restaurant Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	14.4%	6.60	0.95	4.5
Space Cooling	84.2%	8.44	7.10	33.6
Water Heating	16.4%	19.82	3.25	15.4
Ventilation	100.0%	2.56	2.56	12.1
Cooking	28.7%	7.28	2.09	9.9
Lighting	100.0%	9.47	9.47	44.9
Refrigeration	97.3%	4.83	4.70	22.2
Office Equipment (PC)	89.4%	0.28	0.25	1.2
Office Equipment (non-PC)	100.0%	0.45	0.45	2.1
Other Uses	100.0%	8.28	8.28	39.2
Total			39.10	185.2

Table 5-15. Retail Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	25.3%	4.94	1.25	50.1
Space Cooling	74.9%	2.39	1.79	71.6
Water Heating	46.8%	1.01	0.47	19.0
Ventilation	100.0%	0.57	0.57	23.0
Cooking	17.5%	0.32	0.06	2.3
Lighting	100.0%	4.74	4.74	189.8
Refrigeration	52.4%	0.40	0.21	8.5
Office Equipment (PC)	89.4%	0.54	0.49	19.5
Office Equipment (non-PC)	100.0%	0.87	0.87	34.9
Other Uses	100.0%	4.87	4.87	195.1
Total			15.33	613.7

Table 5-16. Utilities Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	9.7%	3.34	0.32	1.3
Space Cooling	30.7%	2.74	0.84	3.4
Water Heating	34.9%	0.78	0.27	1.1
Ventilation	100.0%	0.44	0.44	1.8
Cooking	3.0%	0.25	0.01	0.0
Lighting	100.0%	4.07	4.07	16.2
Refrigeration	12.4%	0.31	0.04	0.2
Office Equipment (PC)	89.4%	0.52	0.47	1.9
Office Equipment (non-PC)	100.0%	0.84	0.84	3.3
Other Uses	100.0%	4.58	4.58	18.3
Total			11.88	47.4

Table 5-17. Warehousing Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	4.2%	4.58	0.19	2.5
Space Cooling	18.9%	1.21	0.23	3.0
Water Heating	39.8%	0.22	0.09	1.2
Ventilation	100.0%	0.10	0.10	1.3
Cooking	0.9%	0.05	0.00	0.0
Lighting	100.0%	2.26	2.26	29.9
Refrigeration	10.1%	0.39	0.04	0.5
Office Equipment (PC)	89.4%	0.22	0.20	2.6
Office Equipment (non-PC)	100.0%	0.35	0.35	4.7
Other Uses	100.0%	3.95	3.95	52.2
Total			7.41	97.9

Table 5-18. Apartment Segment

End use	Shares of floor space	EUIs (kWh/ conditioned sq. ft.)	Intensities (kWh/sq.ft.)	Sales (GWh)
Space Heating	44.0%	2.48	1.09	3.6
Space Cooling	87.8%	1.62	1.42	4.7
Water Heating	14.0%	3.96	0.55	1.8
Ventilation	100.0%	0.53	0.53	1.7
Cooking	13.5%	0.33	0.04	0.1
Lighting	100.0%	5.06	5.06	16.6
Refrigeration	58.9%	0.29	0.17	0.6
Office Equipment (PC)	89.4%	0.26	0.23	0.7
Office Equipment (non-PC)	100.0%	0.41	0.41	1.3
Other Uses	100.0%	7.39	7.39	24.3
Total			16.91	55.5

5.1.3 Phase II Manufacturing

This section presents the baseline market profiles for the Phase II manufacturing segments.

Table 5-19. Petroleum Segment

End use	Midwest EMP Total GWh	KCP&L GWh
Indirect Uses-Boiler Fuel	51	0.8
Process Heating	571	8.7
Process Cooling and Refrigeration	282	4.3
Machine Drive	5,482	83.8
Electro-Chemical Processes	6	0.1
Other Process Use	23	0.4
Facility HVAC (f)	219	3.3
Facility Lighting	186	2.8
Other Facility Support	28	0.4
Onsite Transportation	0	0.0
Conventional Electricity Generation	-	-
Other Nonprocess Use	2	0.0
End Use Not Reported	3	0.1
Total	6,854	105

Table 5-20. Printing Segment

End use	Midwest EMP Total GWh	KCP&L GWh
Indirect Uses-Boiler Fuel	5	0.2
Process Heating	146	5.6
Process Cooling and Refrigeration	244	9.3
Machine Drive	2,785	106.0
Electro-Chemical Processes	10	0.4
Other Process Use	10	0.4
Facility HVAC (f)	972	37.0
Facility Lighting	648	24.6
Other Facility Support	150	5.7
Onsite Transportation	13	0.5
Conventional Electricity Generation	-	-
Other Nonprocess Use	2	0.1
End Use Not Reported	548	20.9
Total	5,534	211

Table 5-21. Transportation Segment

End use	Midwest EMP Total GWh	KCP&L GWh
Indirect Uses-Boiler Fuel	68	0.0
Process Heating	2,881	1.9
Process Cooling and Refrigeration	1,323	0.9
Machine Drive	12,715	8.6
Electro-Chemical Processes	305	0.2
Other Process Use	394	0.3
Facility HVAC (f)	5,423	3.7
Facility Lighting	4,433	3.0
Other Facility Support	1,030	0.7
Onsite Transportation	179	0.1
Conventional Electricity Generation	-	-
Other Nonprocess Use	72	0.0
End Use Not Reported	738	0.5
Total	29,561	20

6. DSM MEASURE CHARACTERIZATION

6.1 Baseline Consumption Profiles and Initial Building Simulation Model Specifications

This section of the report describes the analysis conducted and the analytical results for the baseline consumption profiles task. Energy Insights conducted this task to provide several deliverables specified in the project RFP as part of the market assessment scope of work, including:

- A reference data base of electric energy usage by customer class created with Kansas City Power & Light specific data. This includes information on the Company's C&I market by market segment.
- Energy usage modeling for estimating electricity sales to these customers, in terms of basic electric energy end uses such as space heat/cooling, lighting, water heating, cooking, clothes washers/dryers, and process energy and other identified measures, etc.

To support this task, Kansas City Power & Light supplied energy sales data by sector for calendar year 2006, which is summarized in the table below.

Table 6-1. KCP&L 2006 Summary C&I Customer Statistics[13]

	Commercial	Industrial
Customers	56,750	2,190
Energy Sales (GWh)	6,163	2,147
Average Energy Use/Customer (kWh)	108,600	980,400

6.1.1 Industrial Sector

KCP&L has a relatively small manufacturing sector, and most of these customers are in the category of light manufacturing. Thus their end-use profile is more like that of commercial customers, particularly warehouses and offices, than heavy manufacturing.[14] Specific measure types are difficult to define for the diverse manufacturing segments and Summit Blue limited the measure to generic motors and variable frequency drive controls, high-bay lighting, and broadly defined 'custom measures.'

6.1.2 Commercial Sector

In order to estimate the savings for climate-dependent or interactive measures for KCP&L's commercial customers, Energy Insights created basic building simulation models using eQUEST v. 3.6. Three models were developed as proxies for the Commercial segment: large office building, small office building and education. Together these three segments represent more than 40% of the GWH sold in the commercial sector.

[13] *Report-1: Comparative Billed Electric Revenues – Year-to-date December 31,* Kansas City Power & Light Company January 11, 2007

[14] *Load Forecast Documentation 2006-2025 Load Forecast*, Kansas City Power and Light, July 2006.

Large Office

The baseline simulation for the large office segment was prepared by Energy Insights based on market profile data they have compiled for the distribution of energy use among end-uses at a typical commercial office building. The baseline large office building simulation has the following attributes:

- Kansas City weather data is used.
- Gross building area is about 250,000 ft^2.
- Square footprint; approximately 176 feet on each side; 8 stories and about 31,250 ft^2 per floor.
- 4000 annual hours of operation.
- Windows are double-pane clear on the north side and tinted on the East, South, and West.
- Lighting systems average efficiency, 1.4 W/ ft^2 lighting power density. This LPD falls between standard T8 and T12 systems for office uses.
- Cooling is provided by a pair of equal-sized centrifugal water cooled chillers – 0.67 kW/ton.
- Chilled and condenser water are pumped by single speed pumps.
- The cooling tower is open-loop with an induced-draft configuration.
- The heating plant is modeled either as an electric boiler or natural gas fired boiler in order to capture the different interactive electric effects of lighting retrofits.
- Air distribution is variable air volume, modulated with dampers
- Air-side economizers are used.

These attributes and others such as load profiles, schedules and system setpoints are largely based on default settings in eQuest. Energy Insights calibrated the simulation against their end-use distribution.

Small Office

The baseline simulation for the small office segment was prepared by Energy Insights based on market profile data they have compiled for the distribution of energy use among end-uses at a typical small commercial office building. The baseline small office building simulation has the following attributes:

- Kansas City weather data is used.
- Gross building area is about 25,000 ft^2.
- Square footprint; approximately 110 feet on each side; 2 stories and about 12,500 ft^2 per floor.
- 3500 annual hours of operation
- Windows are double-pane clear on the north side and tinted on the East, South, and West.
- Lighting systems average 1.2 W/ ft^2 lighting power density. This LPD is slightly higher than typical T8 systems for office uses.
- Packaged split-system air-cooled direct-expansion coolers (9.5 EER) provide air-conditioning.
- The heating plant is modeled either as an electric boiler or natural gas fired boiler in order to capture the different interactive electric effects of lighting retrofits.
- Air distribution is single-zone, constant volume

- Air-side economizers are used.

These attributes and others such as load profiles, schedules and system setpoints are largely based on default settings in eQuest. Energy Insights calibrated the simulation against their end-use distribution.

Education

The baseline simulation for the education segment was prepared by Energy Insights based on market profile data they have compiled for the distribution of energy use among end-uses at a typical Education segment building. The baseline building simulation has the following attributes:

- Kansas City weather data is used.
- Gross building area is about 150,000 ft2.
- An H-shaped footprint; 2 stories and 75,000 ft2 per floor.
- 3050 annual hours of operation.
- Windows are double-pane clear on the north side and tinted on the East, South, and West.
- Lighting systems average 1.6 W/ ft2 lighting power density. This LPD is slightly higher than typical T8 systems for education uses.
- Packaged split-system air-cooled direct-expansion coolers (10.0 EER) provide air-conditioning.
- The heating plant is modeled either as an electric boiler or natural gas fired boiler in order to capture the different interactive electric effects of lighting retrofits.
- Air distribution is single-zone, constant volume
- Air-side economizers are used.

These attributes and others such as load profiles, schedules and system set points are largely based on default settings in eQuest. Energy Insights calibrated the simulation against their end-use distribution.

Summit Blue modified each of the baseline models to simulate various energy efficiency measures (EEMs). If the baseline simulation parameters did not match the measure baseline, Summit Blue modified the baseline twice for the measure –first to estimate energy use from the *in*-efficient technology and the second time to model the efficient technology. For example, if general lighting in the baseline model is 1.5 W/ft^2; typical T12 systems are about 1.8 W/ft^2 and T8 systems with the same illumination require about 1.2W/ft^2. Summit Blue modified the baseline to reflect 1.8 W/ft^2 and then again to reflect 1.2 W/ft^2, and the measure savings is the difference between the model results.

6.2 Commercial and Industrial DSM Measure Characterizations

This section describes the commercial and industrial energy efficiency measures analyzed for this study and the methods used to estimate savings. The section is organized by major end-uses such as HVAC, lighting and hot water. This section focuses on prescriptive measures, which are generally simple measures that have largely uniform energy and demand savings on a per unit basis from application to application. However, even prescriptive measures' savings will have some variability, depending on the specific application and baseline equipment replaced. Custom measures have more variable energy and demand savings on a per unit basis from application to application. Having the energy and demand savings for custom measures calculated on a site-specific basis will significantly improve the accuracy of the energy and demand savings estimates for these measures, versus developing standard per unit estimates for these measures.

All of the energy and demand savings estimates presented below are generation savings, accounting for transmission and distribution losses between the generator and the end-use.

6.2.1 Lighting Measures

The following lighting measures are often part of utilities' prescriptive commercial and industrial lighting energy efficiency programs. In our potential analysis we assume include operating hours for lighting systems as indicated above unless otherwise noted. We also assume a peak coincidence factor of 90%. Most savings are estimated by calculating the difference between the input watts for the efficient technology and the standard technology and multiplying by coincidence factor for peak demand savings and annual hours of operation for energy savings. Exceptions to this general rule apply in two cases: (1) lighting controls and (2) general lighting systems in areas that are both heated and cooled. In the latter case the high number of connected Watts impacts the heating and cooling loads in the building. In both cases computer simulations are used to determine the combined effects of direct lighting efficiency savings, and the cross-impacts on heating and cooling loads. The size of the electric cross-impacts depend on the heating energy source, i.e. electricity or natural gas.

Measure costs are based on the California DEER database adjusted to the Kansas City area by regional cost factors from *RS Means Mechanical Cost Databook*[15].

T8 Lamps and Electronic Ballasts- Regular

T8 lamps and electronic ballasts are the most common alternative for standard T12 lamp and magnetic ballast tubular fluorescent lighting systems. T8 fluorescent lamps are one inch in diameter, and are thinner than T12 lamps, which are 1.5 inches in diameter. T8 systems are approximately 30% more efficient than standard T12 systems. This measure qualifies under the general lighting category, and direct lighting savings and indirect heating and cooling impacts are estimated by eQuest simulations.

T8 Lamps and Electronic Ballasts- Premium

Premium T8 lamps and electronic ballasts have the same market as regular T8 systems. They gain efficiency over regular T8 systems by the co-development of lamps and ballasts that optimize the efficiency of both when used together. This measure qualifies under the general lighting category, and direct lighting savings and indirect heating and cooling impacts are estimated by eQuest simulations.

T5 Lamps and Electronic Ballasts

T5 lamps and electronic ballasts are a newer alternative tubular fluorescent lighting system. T5 fluorescent lamps are 5/8 of an inch in diameter, thinner than both T8 lamps and T12 lamps. T5 lighting systems are primarily used in new construction, and are not appropriate for most retrofit situations, as the lamps are only generally available in metric lengths. This measure qualifies under the general lighting category, and direct lighting savings and indirect heating and cooling impacts are estimated by eQuest simulations.

[15] R.S. Means, "Mechanical Cost Data 2006" (RS Means Publishing).

Compact Fluorescent Lamp – Screw-in and Fixtures

Compact fluorescent lamps (CFLs) are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. CFLs can either be screw-in replacements for incandescent lamps or plug-in lamps in fixtures specifically designed around CFL technology. Savings is determined by subtracting the input CFL Wattage from the lamp or fixture Wattage of the incandescent lamps they are replacing. The measure life for a screw-in CFL is the life of the bulb or 2-3 years depending on the application. Plug-in lamps in CFL fixtures are assumed to last the life of the fixture, because failed lamps must be replaced with comparable CFLs.

Occupancy Sensors

Occupancy sensors automatically turn off the lights in a room or an area when the area is unoccupied. Occupancy sensors are an alternative to standard wall mounted on/off lighting switches. Savings were determined by eQuest simulation assuming that 10% of lighting is controlled by occupancy sensors with an average reduction of 4 hours of use per day. HVAC interactions are included in the estimates.

Daylight Sensors

Lighting systems are designed assuming no contribution from ambient daylight. In areas where daylight is available, artificial light is unnecessary and possibly detrimental to occupant comfort. Daylight sensors measure the contribution of ambient daylight and either turn-off or dim the lamps of the artificial lighting system. Savings were determined by eQuest simulations, assuming that perimeter zone (less than 12 feet from an exterior fenestrated wall) lighting is controlled by daylight sensors to maintain required lighting levels with continuous lighting level control. eQuest input data include location specification for the solar incidence angles and hourly cloud cover to describe available sunlight. HVAC interactions are included in the estimates.

Pulse Start Metal Halide / High-Bay T8 / High-Bay T5 / High-Bay CFL

Traditional metal halide lamps are the standard for most high-bay applications, but alternatives are making inroads for several reasons. Fluorescent lamps are less expensive, have better color rendition and lumen maintenance and can be adapted to on/off and dimming controls for photocells and occupancy sensor applications. Pulse start metal halide lamps are a newer type of metal halide systems that use formed body arc tubes and require an ignitor to start the lamps. Pulse start metal halide lamps are more efficient than standard metal halide systems, and also provide better light output maintenance over the lifetime of the lamp, as well as a longer lamp lifetime. Since much high-bay lighting is in un-conditioned space or in temperature-stratified air at the top of the illuminated space, we do not include HVAC interactive effects in the savings estimates. Savings is determined by spreadsheet calculation using efficient system Watts, standard system Watts, 90% peak coincidence and hours of operation.

Delamping

The definition of delamping used for this project is replacing a four lamp, four foot fluorescent lighting fixture with a similar two lamp or three lamp fixtures. This measure is intended for areas that are currently over-lit. Lighting reflectors are often used as part of delamping projects. The measure life for this measure is shorter because the fixture is assumed to have been in place for a period of time already. Savings were determined by eQuest simulation. HVAC interactions are included in the estimates.

LED Exit Signs

LED exit signs are one of the most efficient types of exit signs on the market. They generally only draw about two to three watts of power, compared to 10 watts or more for CFLs, or 20 watts or more for incandescent exit signs.

Table 6-2. Commercial Lighting Measure Characteristics

Meas ID	Meas Name	Segment	Heat Source	Unit Value	Avg Peak Demand Savings Per Unit - Summer (kW)	Avg Annual Energy Savings Per Unit (kWh)	Incremental Measure Cost ($)	Measure Life (yrs)
1000 Series - Lighting								
	CFLs (20W)	Large Office	Electric	lamp	0.059	216	$7	2
	CFL engineered can (27W)	Large Office	Electric	Fixture	0.072	264	$90	15
	T5 w/ EB	Large Office	Electric	Fixture	0.062	141	$45	20
	Regular T8 w/ EB (3-lamp)	Large Office	Electric	Fixture	0.060	193	$44	12
	Premium T8 w/ EB (3-lamp)	Large Office	Electric	Fixture	0.079	290	$51	12
	Delamping w/ Reflectors (2-lamp)	Large Office	Electric	Fixture	0.037	109	$30	12
	LED Exit Signs	Large Office	Electric	Fixture	0.024	170	$40	20
	Occupancy Sensors (8 hrs/day)	Large Office	Electric	sensor	0.098	276	$85	12
	Daylighting (perimeter zone)	Large Office	Electric	sensor	2.174	2775	$800	15
	CFLs (20W)	Large Office	Gas	lamp	0.065	266	$7	2
	CFL engineered can (27W)	Large Office	Gas	Fixture	0.079	325	$90	15
	T5 w/ EB	Large Office	Gas	Fixture	0.039	113	$45	20
	Regular T8 w/ EB (3-lamp)	Large Office	Gas	Fixture	0.064	285	$44	12
	Premium T8 w/ EB (3-lamp)	Large Office	Gas	Fixture	0.081	344	$51	12
	Delamping w/ Reflectors (2-lamp)	Large Office	Gas	Fixture	0.039	132	$30	12
	LED Exit Signs	Large Office	Gas	Fixture	0.025	210	$40	20
	Occupancy Sensors (8 hrs/day)	Large Office	Gas	sensor	0.098	506	$85	12
	Daylighting (perimeter zone)	Large Office	Gas	sensor	1.982	3092	$800	15
	CFLs (20W)	Small Office	Electric	lamp	0.060	178	$7	2
	CFL engineered can (27W)	Small Office	Electric	Fixture	0.073	218	$90	15
	T5 w/ EB	Small Office	Electric	Fixture	0.028	63	$45	20
	Regular T8 w/ EB (3-lamp)	Small Office	Electric	Fixture	0.060	234	$44	12
	Premium T8 w/ EB (3-lamp)	Small Office	Electric	Fixture	0.064	254	$51	12
	Delamping w/ Reflectors (2-lamp)	Small Office	Electric	Fixture	0.029	99	$30	12
	LED Exit Signs	Small Office	Electric	Fixture	0.024	159	$40	20
	Occupancy Sensors (8 hrs/day)	Small Office	Electric	sensor	0.102	253	$85	12
	Daylighting (perimeter zone)	Small Office	Electric	sensor	1.536	2896	$800	15
	CFLs (20W)	Small Office	Gas	lamp	0.060	219	$7	2
	CFL engineered can (27W)	Small Office	Gas	Fixture	0.073	267	$90	15
	T5 w/ EB	Small Office	Gas	Fixture	0.030	101	$45	20
	Regular T8 w/ EB (3-lamp)	Small Office	Gas	Fixture	0.050	266	$44	12
	Premium T8 w/ EB (3-lamp)	Small Office	Gas	Fixture	0.065	313	$51	12
	Delamping w/ Reflectors (2-lamp)	Small Office	Gas	Fixture	0.026	122	$30	12
	LED Exit Signs	Small Office	Gas	Fixture	0.024	195	$40	20
	Occupancy Sensors (8 hrs/day)	Small Office	Gas	sensor	0.102	253	$85	12
	Daylighting (perimeter zone)	Small Office	Gas	sensor	1.515	3660	$800	15
	CFLs (20W)	Education	Electric	lamp	0.049	144	$7	3
	CFL engineered can (27W)	Education	Electric	Fixture	0.060	176	$90	15
	T5 w/ EB	Education	Electric	Fixture	0.038	76	$45	20
	Regular T8 w/ EB (4-lamp)	Education	Electric	Fixture	0.074	204	$42	12
	Premium T8 w/ EB (4-lamp)	Education	Electric	Fixture	0.071	213	$51	12
	Delamping w/ Reflectors (3-lamp)	Education	Electric	Fixture	0.038	79	$30	12
	LED Exit Signs	Education	Electric	Fixture	0.029	147	$40	20
	Occupancy Sensors (8 hrs/day)	Education	Electric	sensor	0.144	407	$85	12
	Daylighting (perimeter zone)	Education	Electric	sensor	1.297	1837	$800	15
	CFLs (20W)	Education	Gas	lamp	0.060	177	$7	3
	CFL engineered can (27W)	Education	Gas	Fixture	0.073	216	$90	15
	T5 w/ EB	Education	Gas	Fixture	0.030	93	$45	20
	Regular T8 w/ EB (4-lamp)	Education	Gas	Fixture	0.050	250	$42	12
	Premium T8 w/ EB (4-lamp)	Education	Gas	Fixture	0.065	262	$51	12
	Delamping w/ Reflectors (3-lamp)	Education	Gas	Fixture	0.026	98	$30	12
	LED Exit Signs	Education	Gas	Fixture	0.024	181	$40	20
	Occupancy Sensors (8 hrs/day)	Education	Gas	sensor	0.102	500	$85	12
	Daylighting (perimeter zone)	Education	Gas	sensor	1.515	2257	$800	15
	PS Metal Halides	Industrial	NA	Fixture	0.020	106	$126	8
	HB T5	Industrial	NA	Fixture	0.057	557	$140	8
	HB CFL	Industrial	NA	Fixture	0.057	557	$277	8

6.2.2 Water Heating Measures

These measures are essentially more efficient replacements for residential water heaters, which are often also installed in commercial facilities. Typical commercial hot water use is much lower than residential use – about 1.5 gallons per occupant per day. For applications where water use is high, for example in food preparation or clean-up, these measures might be considered custom measures analyzed with site-specific data.

Measure costs are based on the California DEER database adjusted to the Kansas City area by regional cost factors from *RS Means Cost Data.*

Efficient Water Heaters

Traditional electric water heaters have an overall efficiency of about 90% including standby and distribution losses. High efficiency units achieve 95% efficiency with improved insulation and heat traps that minimize convection into under insulated distribution pipes. The savings estimate for the high-efficiency unit is calculated from the total hot water energy use and the unit efficiencies.

Heat Pump Water Heaters

Heat pump water heaters use compressed refrigerants to extract heat from ambient air (or water) and move that heat to stored hot water. During warm weather these machines can move 4 units of heat for every one comparable unit of input energy, thus achieving a coefficient of performance (COP) up to 4.0. COP decreases as ambient air temperature decreases. At about 10-20°F, heat pumps become ineffective. At cold ambient temperatures, traditional electric resistance heating elements back-up the heat pump compressor. Savings was determined using engineering estimates with a linear relationship between COP and outdoor air temperature until 20°F at which point we assumed electric resistance heat would take over.

Tankless Water Heaters

Tankless water heaters are more efficient than standard water heaters since they avoid the energy lost from the hot water that is stored in conventional tanks. Tankless water heaters have "energy factors" of about 98%. The savings estimate for the high-efficiency unit is calculated from the total hot water energy use and the unit efficiencies. The longer measure life for this measure reflects the cost hurdle for re-piping water distribution for reverting to the standard tank water heater.

Table 6-3. Commercial Hot Water Measure Characteristics

Meas ID	Meas Name	Segment	Heat Source	Unit Value	Avg Peak Demand Savings Per Unit - Summer (kW)	Avg Annual Energy Savings Per Unit (kWh)	Incremental Measure Cost ($)	Measure Life (yrs)
4000 Series- Water Heat								
	HE WH (94%)	Large Office	Electric	water heater	0.061	784	$83	10
	HPWH	Large Office	Electric	water heater	0.116	1504	$1,288	10
	Tankless WH (98%)	Large Office	Electric	water heater	0.784	10136	$497	10
	HE WH (94%)	Small Office	Electric	water heater	0.048	627	$83	10
	HPWH	Small Office	Electric	water heater	0.093	1202	$1,288	10
	Tankless WH (98%)	Small Office	Electric	water heater	0.627	8098	$497	10
	HE WH (94%)	Education	Electric	water heater	0.081	1046	$83	10
	HPWH	Education	Electric	water heater	0.155	2008	$1,288	10
	Tankless WH (98%)	Education	Electric	water heater	1.047	13526	$497	10

6.2.3 HVAC Measures

In the Kansas City Power & Light service territory most space heating is done by natural gas. Savings can occur through reducing the amount of heating/cooling required with insulation and setting back thermostat settings or by improving the efficiency of the equipment and/or distribution process.

Since HVAC savings is climate dependent, all of the savings for the following measures were determined with eQuest computer energy simulations. Savings is the difference between the simulation with the efficient technology and the simulation with the standard technology. Incremental costs are mostly based on *RS Means Mechanical Cost Data* adjusted with 'location factors' to reflect Kansas City labor and/or equipment costs.[16]

Efficient Water-Cooled Chilled Water Systems

Standard efficiency units are specified as units with an efficiency rating of 0.67 kW/ton cooling capacity. Efficient units are specified as units with an efficiency rating of 0.52 kW/ton.

Efficient Air-Cooled Chilled Water Systems

Standard efficiency units are specified as units with an efficiency rating of 1.35 kW/ton cooling capacity. Efficient units are specified as units with an efficiency rating of 1.10 kW/ton.

Efficient Packaged Commercial Air Conditioning Systems

Standard efficiency units are specified as units with EER ratings of 9.0. Efficient units are specified as units with EER ratings of 10.4-13.0 depending on the equipment size. Summit Blue characterized a high efficiency unit with an EER of 11.0.

Economizers

Economizers use outside air for cooling instead of operating the air conditioning compressors on mild days, particularly during the spring and early fall seasons. The analysis assumed an integrated economizer where 100% outdoor air is used up to 65°F ambient temperature. During peak summer conditions economizers do not have measurable benefits.

Programmable Thermostats

Programmable thermostats allow temperatures to be automatically set warmer or colder during unoccupied periods to reduce heating and cooling energy use when facilities are unoccupied. We analyzed 5°F setbacks (set-ups in the summer). Since the impact of set-backs is typically off-peak, these thermostats do not have discernable peak benefits.

High Efficiency HVAC Motors

Premium efficiency motors used in HVAC fan and pump applications. These motors typically exceed mandated EPACT efficiencies by 1-3%.

Variable Speed Drives Used in HVAC Fan and Pump Applications

Variable frequency drives (VFDs) or adjustable speed drives (ASDs) vary the speed of motors so that their speeds are proportionate to the loads the motors are serving. This saves energy because motor energy use varies with the cube of the speed for applications such as HVAC fans and pumps. This application of variable speed drives (VFDs) has more predictable energy and demand savings impacts

[16] *RS Means Mechanical Cost Databook, 2006*.

than many VFD applications. So some utilities include this measure as part of prescriptive HVAC programs.

Table 6-4. Commercial HVAC Measure Characteristics

Meas ID	Meas Name	Segment	Heat Source	Unit Value	Avg Peak Demand Savings Per Unit - Summer (kW)	Avg Annual Energy Savings Per Unit (kWh)	Incremental Measure Cost ($)	Measure Life (yrs)
2000 Series - HVAC								
2001	Hi-E Air-Cooled Chillers (1.1 kW.ton)	Large Office	Electric	Ton Cooling	0.266	391	$40	25
	Hi-E Water-Cooled Chillers (0.52 kW/ton)	Large Office	Electric	Ton Cooling	0.148	261	$91	25
	VFD Ventilation Fans	Large Office	Electric	bhp	0.212	1528	$160	20
	VFD Variable primary pumping - chw	Large Office	Electric	bhp	0.333	3112	$180	20
	Programmable Thermostats	Large Office	Electric	1000 sqft	0.000	7388	$50	15
	Integrated economizer control	Large Office	Electric	Ton Cooling	0.000	19	$8	20
	Programmable Thermostats	Large Office	Gas	1000 sqft	0.000	1630	$50	15
	Integrated economizer control	Large Office	Gas	Ton Cooling	0.000	25	$8	20
	Packaged cooling 11.0 EER	Small Office	Electric	Ton Cooling	0.236	207	$101	25
	Programmable Thermostats	Small Office	Electric	1000 sqft	0.000	2250	$50	15
	Integrated economizer control	Small Office	Electric	Ton Cooling	0.000	266	$170	20
	Programmable Thermostats	Small Office	Gas	1000 sqft	0.000	615	$50	15
	Integrated economizer control	Small Office	Gas	Ton Cooling	0.000	237	$170	20
	Packaged cooling 11.0 EER	Education	Electric	Ton Cooling	0.214	163	$101	25
	Programmable Thermostats	Education	Electric	1000 sqft	0.000	2995	$142	15
	Integrated economizer control	Education	Electric	Ton Cooling	0.000	99	$170	20
	Programmable Thermostats	Education	Gas	1000 sqft	0.000	819	$142	15
	Integrated economizer control	Education	Gas	Ton Cooling	0.000	88	$170	20

6.2.4 Process and Custom Measures

Refrigeration measures are the predominant category in this class of measures. The refrigeration measure impacts can be quantified in a prescriptive sense. Non-HVAC and custom application of premium motors and ASDs and other 'custom measures' are more application specific. For these measures we have included reported impacts from midwestern utility custom applications.

High-Efficiency Evaporator Fan Motors

This measure is a specific application of efficient motors. It is broken out separately for its consistent applicability in refrigeration applications.

High-Efficiency Refrigeration Compressors

This measure is comparable to more efficiency packaged HVAC equipment. More efficient compressors and controls reduce waste in the compression cycle. Better heat rejection via evaporative or water-coolers also can be employed to improve efficiency.

Strip Curtains

In grocery and convenience stores open vertical refrigeration cases permit excess cooling loads even when the store is closed. Strip curtains cover the product at night to keep cold air on the product and reduce the cooling loads.

Night Covers

In grocery and convenience stores open horizontal refrigeration cases permit excess cooling loads even when the store is closed. Use of night covers t keeps cold air on the product and reduces the cooling loads.

Premium Efficiency Motors

Unlike HVAC applications of these motors, Custom applications have widely divergent savings depending on the baseline efficiency and hours of use. The estimates used assume 2% efficiency improvements and 5000 annual hours of use.

Non-HVAC VFDs Motors

Unlike HVAC applications of VFDs, Custom applications have widely divergent savings depending on the baseline efficiency and hours of use. HVAC applications are mostly for centrifugal loads such as moving fluids like air and water. VFDs can be applied to many industrial processes such as conveyors and injection molding.

Custom Measures

This measure is a generic name for consumer-specific conservation projects. The magnitude of savings is scaled to kW saved and is based on Midwestern utility custom program results.

Table 6-5. Commercial Refrigeration and Custom Measure Characteristics

Meas ID	Meas Name	Segment	Heat Source	Unit Value	Avg Peak Demand Savings Per Unit - Summer (kW)	Avg Annual Energy Savings Per Unit (kWh)	Incremental Measure Cost ($)	Measure Life (yrs)
3000 Series- refrigeration								
	Hi-E Evaporator Fan Motors	Industrial	NA	HP	0.008	65	$15	15
	Hi-E Refrigeration Compressors	Industrial	NA	HP	0.054	434	$583	15
	Hi-E Ice Makers	Industrial	NA	ton capacity	0.035	375	$173	12
	Strip Curtains	Industrial	NA	lin foot	0.004	414	$18	4
	Night Covers	Industrial	NA	lin foot	0.000	333	$42	4
5000 Series - Custom								
	Premium Efficiency Motors (HP)	Industrial	NA	HP	0.007	48	$10	15
	Variable Frequency Drives (HP)	Industrial	NA	HP	0.000	2198	$278	15
	Custom Efficiency	Industrial	NA	kw	1.064	5319	$1,400	15

7. DSM POTENTIAL METHODOLOGY AND RESULTS

This section presents a summary of the methodology and results for the DSM potential aspect of the project.

7.1 Methodology

This section describes Summit Blue's DSM potential analysis approach and methods. The DSM potential analysis used the results of the customer baseline profiles and the DSM measure characterization, along with the DSM benchmarking results, as inputs to the DSM potential spreadsheets.

The general approach for estimating DSM resource potentials consisted of three steps: (1) estimate technical and economic DSM potential; (2) estimate preliminary market penetrations and the resulting achievable potential for each measure; and (3) calibrate the achievable DSM potential estimates using the benchmarking information described in a previous section. **This third step is the most important step in Summit Blue's DSM potential estimation process.** For this benchmarking analysis, the average annual DSM potential values for each end use and sector were compared to actual program results for corresponding top performing programs and portfolios.

Technical DSM potential means the amount of DSM savings that could be achieved, not considering economic and market barriers to customers installing DSM measures. Technical potential is calculated as the product of the DSM measures' savings per unit, the quantity of applicable equipment in each facility, the number of facilities in KCP&L's service area, and 100% - the measure's current market saturation. Technical potential estimates include DSM measures that are not cost effective, and technical potential does not consider market barriers such as customers' lack of awareness of DSM measures. Therefore, technical DSM potential estimates do not provide a realistic basis for setting DSM program goals.

Economic DSM potential means the amount of technical DSM potential that is "cost-effective," as defined by the results of the Total Resource Cost (TRC) test. Measures had to pass the TRC test in order to be considered to be cost effective, which screened out very few EE measures. The program benefits for the TRC test include the avoided costs of generation, transmission and distribution investments and avoided fuel costs due to the conserved energy caused by the DSM programs. The costs for the TRC test are the DSM measure costs plus the DSM program administration costs. The TRC test does not consider economic or market barriers to customers installing DSM measures. Summit Blue used DSMore to calculate the benefit-cost ratios of DSM measures.

Achievable potential is an estimate of the amount of DSM potential that could be captured by realistic DSM programs over the twenty- year forecast period (2008-2027) covered by this DSM potential analysis. The key parameter that must be estimated to forecast achievable DSM potential is the percentage of economic potential that is likely to be realized for each DSM measure at the end of the forecast period in 2027. This percentage is similar to the ultimate DSM measure saturations at the end of the forecast period. Summit Blue estimated these parameters for each DSM measure based primarily on the DSM benchmarking analysis, as well as our previous DSM potential projects.

For most non-lighting measures, maximum market penetrations of 50% over the forecast period were assumed, while mainstream lighting DSM measure saturations were generally assumed to reach 70%-80% saturation by 2028, as that range of lighting measure saturations are widely expected to be achieved over the long term. However, it is important to emphasize that Summit Blue's assumptions regarding end of period DSM measure saturation estimates were made so as to produce DSM potential estimates for each sector and end use that are consistent with the utility and agency DSM program benchmarking results discussed in a previous section.

7.2 Commercial/Industrial EE Potential Results

This section provides the DSM potential results for the commercial and industrial sector. The total and annual residential achievable DSM potential results for the first 10 years are shown in Table 7-x below. The energy values shown below are for the DSM measures' first-year generator energy savings, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs. Therefore, the annual values in the table below are in the same format as the DSM goals that most utilities and agencies propose or report on through their DSM regulatory filings.

Table 7-1. Total 20 Year C&I Achievable Potential Estimates, and Years 1-10

Commercial	20 Year Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Lighting											
Achievable Potential Demand Savings (kW)	307,746	3,077	6,155	12,310	15,387	16,926	16,926	16,926	16,926	16,926	16,926
Achievable Potential Energy Savings (kWh)	1,267,173,588	12,671,736	25,343,472	50,686,944	63,358,679	69,694,547	69,694,547	69,694,547	69,694,547	69,694,547	69,694,547
Measure Costs	$228,317,854	$2,283,179	$4,566,357	$9,132,714	$11,415,893	$12,557,482	$12,557,482	$12,557,482	$12,557,482	$12,557,482	$12,557,482
Program Costs	$123,098,333	$1,230,983	$2,461,967	$4,923,933	$6,154,917	$6,770,408	$6,770,408	$6,770,408	$6,770,408	$6,770,408	$6,770,408
HVAC											
Achievable Potential Demand Savings (kW)	145,384	1,454	2,908	5,815	7,269	7,996	7,996	7,996	7,996	7,996	7,996
Achievable Potential Energy Savings (kWh)	433,712,894	4,337,129	8,674,258	17,348,516	21,685,645	23,854,209	23,854,209	23,854,209	23,854,209	23,854,209	23,854,209
Measure Costs	$67,918,370	$679,184	$1,358,367	$2,716,735	$3,395,919	$3,735,510	$3,735,510	$3,735,510	$3,735,510	$3,735,510	$3,735,510
Program Costs	$51,742,915	$517,429	$1,034,858	$2,069,717	$2,587,146	$2,845,860	$2,845,860	$2,845,860	$2,845,860	$2,845,860	$2,845,860
Refrigeration											
Achievable Potential Demand Savings (kW)	220	2	4	9	11	12	12	12	12	12	12
Achievable Potential Energy Savings (kWh)	22,881,940	228,819	457,639	915,278	1,144,097	1,258,507	1,258,507	1,258,507	1,258,507	1,258,507	1,258,507
Measure Costs	$2,088,118	$20,881	$41,762	$83,525	$104,406	$114,847	$114,847	$114,847	$114,847	$114,847	$114,847
Program Costs	$867,032	$8,670	$17,341	$34,681	$43,352	$47,687	$47,687	$47,687	$47,687	$47,687	$47,687
Water Heating											
Achievable Potential Demand Savings (kW)	100	1	2	4	5	6	6	6	6	6	6
Achievable Potential Energy Savings (kWh)	1,295,571	12,956	25,911	51,823	64,779	71,256	71,256	71,256	71,256	71,256	71,256
Measure Costs	$150,991	$1,510	$3,020	$6,040	$7,550	$8,305	$8,305	$8,305	$8,305	$8,305	$8,305
Program Costs	$30,081	$301	$602	$1,203	$1,504	$1,654	$1,654	$1,654	$1,654	$1,654	$1,654
Custom											
Achievable Potential Demand Savings (kW)	58,163	582	1,163	2,327	2,908	3,199	3,199	3,199	3,199	3,199	3,199
Achievable Potential Energy Savings (kWh)	538,912,472	5,389,125	10,778,249	21,556,499	26,945,624	29,640,186	29,640,186	29,640,186	29,640,186	29,640,186	29,640,186
Measure Costs	$107,541,101	$1,075,411	$2,150,822	$4,301,644	$5,377,055	$5,914,761	$5,914,761	$5,914,761	$5,914,761	$5,914,761	$5,914,761
Program Costs	$42,957,364	$429,574	$859,147	$1,718,295	$2,147,868	$2,362,655	$2,362,655	$2,362,655	$2,362,655	$2,362,655	$2,362,655
Total											
Achievable Potential Demand Savings (kW)	511,613	5,116	10,232	20,465	25,581	28,139	28,139	28,139	28,139	28,139	28,139
Achievable Potential Energy Savings (kWh)	2,263,976,465	22,639,765	45,279,529	90,559,059	113,198,823	124,518,706	124,518,706	124,518,706	124,518,706	124,518,706	124,518,706
Measure Costs	$406,016,436	$4,060,164	$8,120,329	$16,240,657	$20,300,822	$22,330,904	$22,330,904	$22,330,904	$22,330,904	$22,330,904	$22,330,904
Program Costs	$218,695,725	$2,186,957	$4,373,914	$8,747,829	$10,934,786	$12,028,265	$12,028,265	$12,028,265	$12,028,265	$12,028,265	$12,028,265

The total estimated commercial and industrial energy efficiency potential over the 20 year forecast period is about 2,300 GWh and 510 peak MW. Slightly more than half of this energy efficiency potential is projected to come from energy efficient lighting products, about 20% is projected to come from energy efficient HVAC equipment and controls, and about 25% of the total potential is expected to come from custom and motors measures. The total C&I energy efficiency potential amounts to approximately 17% of KCP&L's forecast 2028 C&I energy consumption of about 13,700 GWh. This is equal to annual average energy savings of about 115 GWh, or 1.2% of KCP&L's forecast 2007 C&I sales. The peak demand reduction potential is about 19% of KCP&L's forecast 2028 C&I peak demand of 2,700 MW. The total C&I energy efficiency program costs over the 20 year forecast period are estimated at about $220 million, or about $11 million per year on average.

The calibration target for C&I energy conservation potential from the benchmarking analysis that Summit Blue used to estimate KCP&L's EE potential was about 1% of KCP&L's annual baseline energy and peak demands, which were achieved in the short-term by the top C&I DSM portfolios reviewed. The slightly lower impacts are mainly due to the fact that Summit Blue estimates that a four year ramp-up period will be required until the full-scale annual EE impacts will be able to be achieved by KCP&L. It takes utilities that are new to DSM and their customers several years until they become most effective and receptive to implementing DSM measures. This assessment is based on the histories of the benchmark utilities and energy agencies. It is estimated that the annual achievements of the total DSM potential will follow an s-shaped curve, with impacts of 1% of the total DSM potential in the first year, 2% in the second year, 4% in the third year, 5% in the fourth year, and 5.5% in the fifth year and beyond to the end of the 20-year forecast period.

7.2.1 C&I Energy Efficiency Results by End Use

C&I lighting measures account for about half of the total estimated C&I energy conservation potential, a total of about 307 MW of coincident peak demand reduction and 1,267 GWh of first year energy savings over the twenty-year forecast period. This amounts to an average of about 15 peak MW and 63 GWh per year.

T8 lamps and electronic ballasts in regular and high-bay applications are expected to account for the largest share of C&I lighting energy efficiency potential, about 80% of the total. CFL lamps and fixtures, T5 lamps and electronic ballasts, LED exit signs, and simple lighting controls such as occupancy sensors are expected to account for most of the other C&I lighting potential.

Custom measures such as energy management systems, and process motor measures are expected to account for the second largest share of C&I energy savings at about 539 GWh of first year energy savings and 58 MW of peak demand reduction in total over the 20 year forecast period. Variable speed drives in process applications are expected to account for the largest amount of energy efficiency potential in this category, at about one-third of the total.

Efficient HVAC and control systems are estimated to account for the third largest share of C&I energy efficiency potential, 433 GWh of first year energy savings, and 145 MW of peak demand reduction, over the 20 year forecast period. Efficient chillers and packaged cooling systems such as rooftop units are expected to account for the largest amount of energy savings in this category at about one-third of the total potential. Variable speed drives in ventilation fan applications are also expected to account for about one-third of the energy efficiency potential in this category. Programmable thermostats are expected to account for the largest share of energy savings from HVAC control measures.

Efficient refrigeration and water heating equipment are expected to account for relatively small amounts of energy efficiency potential over the forecast period due to the limited baseline saturations and energy consumptions for these end uses in the C&I market, and the limited impacts that these types of measures have realized in regional and national energy efficiency programs.

8. COST-EFFECTIVENESS ANALYSIS

The cost-effectiveness analysis of C&I energy conservation measures involved developing a list of possible measures, quantifying the necessary data inputs for the DSMore model, placing this information within the model, and running the model. The model produces four types of cost-effectiveness test values for each measure. This section of the report summarizes this procedure and presents the results of the cost-effectiveness analysis.

8.1 Key General Inputs

Key general inputs (i.e., inputs that are common across all measures) in the cost-effectiveness analysis include the following:

- Base Energy Price
- Avoided transmission and distribution costs
- Ask adder above wholesale and base charge
- Supply, load following, and risk management fee
- Reserve margin adder
- Avoided Market-based ancillary service charges
- Bills, Generation, and T&D annual escalators

Other general inputs include such information as C&I electricity rates, tax rate, line losses, and the utility discount rate. The values for these general inputs are presented in the table below.

Table 8-1. Key General Cost-Effectiveness Inputs

Input	Value
Base Energy Price Year 1	 $52.51/MWh
Avoided T&D	$25.00/kW
Ask Adder	5%
Supply, Load, Risk Adder	40%
Reserve Margin Adder (summer)	13.6%
Avoided Market-Based Ancillary Service Charges All months Peak Months Off-Peak Months	 $1.00 /kW $1.00 /kW $1.00 /kW

Several measure-level values were created as inputs to the model, to define the measures that were evaluated. These inputs are presented in the measure characterization chapter. The key inputs for each measure were:

- Demand savings
- Energy savings
- Measure lifetime
- Measure cost
- Percentage of savings achieved in each month

Program-level inputs that were added to the model included program administrative costs. These cost assumptions are given in the table below for each group of measures.

Table 8-2. KCP&L C&I EE Program Costs—2005 Basis

	Total Cost	Admin Cost	Incentive
Program Type	**Peak kW**	**Peak kW**	**Peak kW**
Lighting	$400	$100	$300
HVAC	$300	$45	$255
Motors/Compressed Air	$500	$150	$350
Refrigeration	$650	$325	$325
Custom	$600	$300	$300
Water Heating	$400	$98	$302

8.2 Cost-Effectiveness Results – Measures

This section summarizes the measure-level results of the cost-effectiveness analysis. DSMore produces the following four cost-effectiveness test results:

- **Utility Test (UT)** – The benefits for the utility test are the avoided costs of generation, transmission, and distribution investments, and avoided fuel costs from the conserved energy due to the DSM programs. The costs for the UT are just the DSM program costs.
- **Total Resource Cost Test (TRC)** – The benefits for the TRC test are the avoided costs of generation, transmission, and distribution investments, and avoided fuel costs from the conserved energy due to the DSM programs. The costs for the TRC test are the DSM measure costs plus the DSM program administration costs.
- **Ratepayer Impact Test (RIM)** – The benefits for the RIM test are the avoided costs of generation, transmission, and distribution investments, and avoided fuel costs from the conserved energy due to the DSM programs. The costs for the RIM test are the DSM program costs plus the "lost revenues" due to the DSM programs.
- **Participant Test (PT)** – The benefits for the participant test include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The costs for the PT are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s).

The results for each measure, classified as Large Office, Small Office, Educational, or Other, are presented in the tables below.

Table 8-3. Small Office Measures Cost-Effectiveness Results

Measure	Utility	TRC	RIM	Participant Test
SmOff CFL engineered can (27W) Elec	10.01	3.02	2.16	1.43
SmOff CFL engineered can (27W) Gas	12.29	3.70	2.25	1.70
SmOff CFLs (20W) Elec	1.85	3.42	1.11	4.88
SmOff CFLs (20W) Gas	2.27	4.20	1.25	5.41
SmOff Daylighting (perimeter zone) Elec	6.38	4.11	1.93	2.35
SmOff Daylighting (perimeter zone) Gas	8.16	5.20	2.06	2.81
SmOff Delamping w Reflectors (2-lamp) Elec	9.96	3.49	2.16	1.68
SmOff Delamping w Reflectors (2-lamp) Gas	13.88	4.35	2.30	1.97
SmOff LED Exit Signs Elec	27.06	6.01	2.49	2.49
SmOff LED Exit Signs Gas	33.22	7.37	2.54	3.02
SmOff T5 w EB Elec	8.84	2.09	2.10	0.99
SmOff T5 w EB Gas	13.54	3.37	2.29	1.50
SmOff Occupancy Sensors (8 hrs day) Elec	7.22	3.09	2.00	1.61
SmOff Occupancy Sensors (8 hrs day) Gas	7.22	3.09	2.00	1.61
SmOff Premium T8 w EB (3-lamp) Elec	11.47	5.18	2.22	2.50
SmOff Premium T8 w EB (3-lamp) Gas	13.89	6.35	2.30	2.99
SmOff Regular T8 w EB (3-lamp) Elec	11.25	5.49	2.21	2.69
SmOff Regular T8 w EB (3-lamp) Gas	15.25	6.33	2.33	2.92
SmOff Integrated economizer control Elec	46.59	2.47	2.59	0.95
SmOff Integrated economizer control Gas	46.53	2.21	2.59	0.85
SmOff Packaged cooling 11.0 EER Elec	5.33	3.39	1.83	1.94
SmOff Programmable Thermostats Elec	39.19	49.29	2.56	23.49
SmOff Programmable Thermostats Gas	39.18	15.62	2.56	6.42
SmOff HE WH (94%) Elec	32.66	7.22	2.53	2.96
SmOff HPWH Elec	32.67	0.94	2.53	0.37
SmOff Tankless WH (98%) Elec	32.67	14.66	2.53	6.39

Table 8-4. Large Office Measures Cost-Effectiveness Results

Measure	Utility	TRC	RIM	Participant Test
LgOff CFL engineered can (27W) Elec	11.54	3.44	2.56	1.37
LgOff CFL engineered can (27W) Gas	12.99	4.20	2.63	1.65
LgOff CFLs (20W) Elec	2.13	3.92	1.29	4.74
LgOff CFLs (20W) Gas	2.40	4.62	1.39	5.48
LgOff Daylighting (perimeter zone) Elec	4.08	3.49	1.80	2.20
LgOff Daylighting (perimeter zone) Gas	4.98	3.95	1.96	2.27
LgOff Delamping w Reflectors (2-lamp) Elec	8.06	3.54	2.33	1.58
LgOff Delamping w Reflectors (2-lamp) Gas	9.26	4.23	2.43	1.84
LgOff Occupancy Sensors (8 hrs day) Elec	7.69	3.18	2.30	1.43
LgOff Occupancy Sensors (8 hrs day) Gas	14.05	5.80	2.68	2.30
LgOff Premium T8 w EB (3-lamp) Elec	9.99	5.41	2.48	2.37
LgOff Premium T8 w EB (3-lamp) Gas	11.54	6.39	2.57	2.73
LgOff T5 w EB Elec	8.58	4.14	2.37	1.85
LgOff T5 w EB Gas	10.96	3.46	2.53	1.40
LgOff LED Exit Signs Elec	26.17	6.03	2.94	2.11
LgOff LED Exit Signs Gas	31.00	7.40	3.00	2.56
LgOff Regular T8 w EB (3-lamp) Elec	8.82	4.25	2.39	1.88
LgOff Regular T8 w EB (3-lamp) Gas	12.15	6.22	2.60	2.60
LgOff Hi-E Air-Cooled Chillers (1.1 kW.ton) Elec	8.32	12.80	2.33	6.85
LgOff Hi-E Water-Cooled Chillers (0.52 kwton) Elec	9.99	4.53	2.45	1.91
LgOff Integrated economizer control Elec	43.48	3.38	3.10	1.09
LgOff Integrated economizer control Gas	43.82	4.49	3.10	1.46
LgOff Programmable Thermostats Elec	36.81	106.26	3.06	60.47
LgOff Programmable Thermostats Gas	36.82	35.38	3.06	13.34
LgOff Tankless WH (98%) Elec	30.69	16.77	3.00	6.30
LgOff HE WH (94%) Elec	30.68	8.37	3.00	2.92
LgOff HPWH Elec	30.69	1.10	3.00	0.36
LgOff VFD Variable primary pumping - chw Elec	28.04	20.31	2.97	8.46
LgOff VFD Ventilation Fans Elec	21.68	11.97	2.88	4.79

Table 8-5. Educational Measures Cost-Effectiveness Results

Measure	Utility	TRC	RIM	Participant Test
Edu CFL engineered can (27W) Elec	9.78	2.46	2.14	1.16
Edu CFL engineered can (27W) Gas	9.88	2.98	2.15	1.42
Edu CFLs (20W) Elec	2.64	4.37	1.35	4.84
Edu CFLs (20W) Gas	2.67	4.93	1.35	5.92
Edu Daylighting (perimeter zone) Elec	4.79	2.67	1.75	1.61
Edu Daylighting (perimeter zone) Gas	5.04	3.21	1.78	1.95
Edu Delamping w Reflectors (3-lamp) Elec	6.09	2.72	1.89	1.49
Edu Delamping w Reflectors (3-lamp) Gas	11.02	3.46	2.19	1.62
Edu LED Exit Signs Elec	20.00	5.47	2.41	2.36
Edu LED Exit Signs Gas	30.63	6.80	2.51	2.81
Edu Occupancy Sensors (8 hrs day) Elec	8.14	4.73	2.05	2.52
Edu Occupancy Sensors (8 hrs day) Gas	14.14	6.05	2.29	2.84
Edu Regular T8 w EB (4-lamp) Elec	7.93	4.81	2.04	2.60
Edu Regular T8 w EB (4-lamp) Gas	19.09	6.58	2.39	2.84
Edu Premium T8 w EB (4-lamp) Elec	8.68	4.28	2.08	2.20
Edu Premium T8 w EB (4-lamp) Gas	11.60	5.30	2.22	2.57
Edu T5 w EB Elec	10.62	2.59	2.18	1.19
Edu T5 w EB Gas	16.58	3.20	2.35	1.37
Edu Integrated economizer control Elec	46.31	0.92	2.58	0.36
Edu Integrated economizer control Gas	46.51	0.82	2.58	0.32
Edu Packaged cooling 11.0 EER Elec	4.63	2.69	1.74	1.60
Edu Programmable Thermostats Elec	39.03	25.43	2.55	10.95
Edu Programmable Thermostats Gas	39.02	7.48	2.55	2.99
Edu HE WH (94%) Elec	32.53	11.59	2.52	4.94
Edu HPWH Elec	32.53	1.55	2.52	0.61
Edu Tankless WH (98%) Elec	32.53	22.70	2.52	10.67

Table 8-6. Other Measures Cost-Effectiveness Results

Measure	Utility	TRC	RIM	Participant Test
Other HB CFL Elec	17.11	1.39	2.01	0.68
Other HB T5 Elec	17.11	2.69	2.01	1.35
Other PS Metal Halides Elec	9.48	0.59	1.84	0.31
Other LED traffic signals Elec	16.58	1.20	2.00	0.59
Other Hi-E Evaporator Fan Motors Elec	17.89	4.45	2.02	2.30
Other Hi-E Ice Makers Elec	15.78	1.95	1.99	0.98
Other Hi-E Refrigeration Compressors Elec	13.77	0.80	1.96	0.39
Other Strip Curtains Elec	67.72	8.34	2.20	3.97
Other Night Covers Elec	5.25	2.37	1.59	1.64
Other Premium Efficiency Motors (HP) Elec	14.83	4.83	1.98	2.60
Other Variable Frequency Drives (HP) Elec	19.46	7.73	2.04	4.17
Other Custom Efficiency Elec	9.30	3.45	1.83	2.08

These results show that most of the measures are very cost-effective from all aspects (utility, TRC, RIM, and Participant). Eighty measures pass all four tests and 13 measures have at least one test that did not pass.

This result is common for the utility test and the TRC test results, but is uncommon for the RIM test results, which often are less than one for energy conservation measures. These results indicate that there are many clearly cost-effective DSM measures that KCP&L can implement.

8.3 Cost-Effectiveness Results – Program-Level

This section summarizes the program-level results of the cost-effectiveness analysis.

To find total cost effectiveness for each program, the results of the potential by measure runs were rolled up using the DSMore Roll-Up tool. This tool recalculates the tests based on the "rolled-up" dollar numbers. The costs and savings are aggregated across the measures and the cost-effectiveness tests (e.g., TRC test) are calculated again.

In addition, DSMore was used to evaluate a New Construction program, with estimated totals from the program entered into the model, in terms of savings and costs. The model was run with the Large Commercial load shape.

The table below shows the aggregated cost-effectiveness tests for each program.

Table 8-7. Results of Roll-up By Program

Program-level (From Roll- up Files)	Custom	Lighting	HVAC	New Construction
Utility Test	20.48	14.33	10.82	12.37
TRC Test	6.62	6.01	7.36	4.86
RIM Test	2.25	2.47	2.37	2.60
RIM (Net Fuel)	2.25	2.47	2.37	2.60
Societal Test	7.52	6.74	8.20	5.44
Participant Test	3.05	2.49	3.20	2.08

The roll-up procedure produced results for each program that are well above cost-effectiveness and that are higher than the average of the tests for individual measures.

APPENDIX A: 2005 C&I DSM RESULTS BY REGION

Region	Utility/Agency	DSM Results			Customers	Annual GWh	Peak MW	Revenue ($M)	Spending as % of Revenue	Energy Savings as % of Sales	Demand Savings as % of Peak	Cost of Savings	
		GWh	MW	Costs ($M)								$/kWh	$/kW
Midwest	Duke Energy Indiana	2	0.434	< 1	84,527	5,448	1,308	97	< 0.1%	< 0.1%	< 0.1%	0.19	917
	Duke Energy Kentucky	2	0.5	< 1	14,247	2,470	535	139	0.4%	0.1%	0.1%	0.03	97
	Interstate P&L	93	25	11	82,234	11,841	1,846	484	1.4%	0.8%	1.4%	0.11	396
	MidAmerican Energy	86	6	8	83,009	11,760	2,424	675	1.2%	0.7%	0.2%	0.10	1,333
	Minnesota Power	28	3	1	2,000	8,457	899	361	0.3%	0.3%	0.3%	0.04	333
	Otter Tail	14	2	1	11,745	1,382	212	78	1.3%	1.0%	1.0%	0.07	500
	Wisconsin (WECC)	123	23	14	311,259	46,784	10,648	2,754	0.5%	0.3%	0.2%	0.11	609
	Xcel Energy (MN)	250	47	25	128,815	22,103	3,781	1,220	2.0%	1.1%	1.2%	0.10	532
Northeast	Efficiency Maine	19	N/A	4	94,291	8,037	1,294	671	0.6%	0.2%	N/A	0.21	-
	Efficiency Vermont	27	4	7	46,978	3,554	1,013	351	2.0%	0.8%	0.4%	0.26	1,750
	NJ CEP	288	36	24	472,641	66,695	6,665	4,782	0.5%	0.4%	0.5%	0.08	667
	NYSERDA	1,295	280	183	1,083,954	131,969	23,669	10,640	1.7%	1.0%	1.2%	0.14	654
Florida	Florida P&L	93	7	10	490,367	47,364	12,114	4,738	0.2%	0.2%	0.1%	0.11	1,429
	Gulf Power	2	1	1	53,696	5,897	1,274	396	0.3%	0.0%	0.1%	0.50	1,000
	Progress Energy	3	1	2	196,002	19,283	6,079	1,232	0.2%	0.0%	0.0%	0.67	2,000
	Tampa Electric	8	0.48	< 1	71,249	8,700	2,455	681	0.1%	0.1%	0.0%	0.04	706
Canada	BC Hydro	124	N/A	26	190,716	35,391	N/A	1,395	1.9%	0.4%	N/A	0.21	-
	Manitoba Hydro	40	7.5	10	62,826	13,411	2,488	457	2.2%	0.3%	0.0%	0.25	1,333
California	PG&E	651	109	90	617,603	51,841	11,253	5,835	1.5%	1.3%	1.0%	0.14	826
	SCE	719	119	106	588,742	57,314	13,081	6,118	1.7%	1.3%	0.9%	0.15	891
	SDG&E	208	36	38	145,066	12,013	2,435	1,244	3.1%	1.7%	1.5%	0.18	1,056
Texas & Colorado	AEP-SWEPCO	20	3	1	31,127	5,059	1,544	262	0.4%	0.4%	0.2%	0.05	337
	EGSI	5	2	1	46,865	8,248	2,082	392	0.1%	0.1%	0.1%	0.10	377
	SPS Xcel	7	2	1	59,620	9,704	1,398	313	0.2%	0.1%	0.1%	0.10	369
	Xcel Energy (CO)	79	15	10	209,941	17,857	4,156	1,241	0.8%	0.4%	0.4%	0.13	667

APPENDIX B: DSM PROGRAM DESCRIPTIONS

KCP&L Commercial and Industrial Lighting DSM Program

Program Concept and Description

The Commercial and Industrial (C&I) Lighting DSM Program provides prescriptive incentives to C&I customers for the installation of energy-efficiency lighting equipment and controls. Prescriptive incentives are offered for a schedule of measures in each of these categories. Innovative lighting energy efficiency measures will be covered as part of the separate Custom Rebate Program. This program will pertain to existing facilities only. New construction lighting measures will be covered by the separate C&I New Construction Program.

The viability of each of the prescriptive measures covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the lighting systems in their facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient lighting measures in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility owners and operators for the installation of high-efficiency lighting equipment and controls.
- Provide a marketing mechanism for electrical contractors, lighting contractors, and lighting distributors to promote energy efficient lighting equipment to end users.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and costs of lighting energy efficiency improvements.
    - Performance uncertainty associated with energy efficiency lighting projects.
    - Additional first costs for energy efficient lighting measures.
- Ensure that the participation process is clear, easy to understand and simple.

Program Rationale

Certain barriers exist to the adoption of lighting energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of lighting energy efficiency measures in the C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a broadly applicable C&I prescriptive rebate program since the energy and demand savings for many common lighting energy efficiency measures are similar across many C&I market segments. Having a simple program structure and rebate schedule provides customers with certainty and ease of use regarding the incentives they will receive for installing a wide variety of lighting measures.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial customers are eligible for the program. However, the main target markets are:

- Customers in existing buildings. New construction applications are covered by the separate New Construction program.
- Other utilities have found that the following types of larger commercial customers participate with the highest frequency in their C&I lighting DSM programs: large office buildings, education facilities, grocery stores, health care facilities, and warehouses.
- Small business customers are the most difficult market segment to reach with DSM programs in general, but such customers tend to more readily participate in lighting DSM programs than other types of DSM programs.

Products and Services Provided

The C&I Lighting DSM Program is a customer incentive program that provides rebates for the installation of lighting energy efficiency measures in existing non-residential facilities. More specifically, the program offers the following products and services:

- Education and promotional materials aimed at building owners and operators about the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content.

- Educational and promotional efforts aimed at trade allies such as electrical contractors, building supply firms, and lighting distributors to help them promote efficient lighting measures to their customers.
- Rebates for building owners and managers to adopt the measures recommended by the program. Rebates will be approximately $300/kW for each measure provided by the program. Specific rebates for each size and type of lighting DSM measure will be developed.
- The majority of program impacts are expected to come from customers replacing standard efficiency fluorescent lighting systems (T12 lamps and magnetic ballasts) with T8 lamps and electronic ballasts.
- Other eligible lighting retrofits include:
    - Replacing standard fluorescent lighting systems with T5 lamps and electronic ballasts.
    - Replacing incandescent lamps with compact fluorescent lamps or efficient HID systems.
    - Replacing mercury vapor systems with metal halide or high pressure sodium systems.
    - Replacing incandescent exit signs with LED exit signs.
    - Installing lighting occupancy sensors.

Delivery Strategy and Administration

- Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support.
- KCP&L account representatives are expected to promote the program to their customers.
- Alternatively, KCP&L could outsource the program to an "implementation contractor" such as Honeywell DMC or ICF.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including the architecture/engineering and contractor community, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).

  - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
  - Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
  - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
  - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
  - KCP&L customer account representatives trained to promote the program to their customers.
  - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
  - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted Summit Blue's suggested integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management -** As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection** – KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** – KCP&L's evaluation contractor will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values** – KCP&L will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimate the savings being achieved by the program.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total 2008 program budget is approximately $954,000.
- The total 2009 program budget is approximately $1.91 million.
- Approximately 75% of program budgets are for customer rebates and 25% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing includes a full-time program manager, a half-time program administrative/data support person, a half-time trade ally liaison, and the equivalent of about 1 FTE of account reps time to promote the program to their customers.
- Program design and set-up costs will be approximately $25,000.
- Program evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions are 2.4 MW in 2008 and 4.8 MW in 2009.
- The estimated peak coincidence-loss factor is 90%.
- The estimated average annual operating hours are 4,100, except for exit signs, which operate 8,760 hours per year.
- The annual generator energy savings are 9.8 GWh in 2008 and 19.6 GWh in 2009.

Program Benefit-Cost Results

Based on the September 2007 DSMore results, the program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Participant Test: 2.50.
- Utility Test: 11.65.
- RIM Test: 2.28
- TRC Test: 5.53.
- Societal Test: 6.21.

KCP&L Commercial and Industrial HVAC DSM Program

Program Concept and Description

The Commercial and Industrial (C&I) HVAC DSM Program provides prescriptive incentives to C&I customers for the installation of energy-efficiency heating, ventilation and air conditioning (HVAC) equipment and controls. Prescriptive incentives are offered for a schedule of measures in each of these categories. Innovative HVAC energy efficiency measures will be covered as part of the separate Custom Rebate Program. This program will pertain to existing facilities only. New construction HVAC measures will be covered by the separate C&I New Construction Program.

The viability of each of the prescriptive measures covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the HVAC systems in their facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient HVAC measures in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility owners and operators for the installation of high-efficiency HVAC equipment and controls.
- Provide a marketing mechanism for mechanical and HVAC contractors and HVAC distributors to promote energy efficient equipment to end users.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and costs of HVAC energy efficiency improvements.
    - Performance uncertainty associated with energy efficient HVAC projects.
    - Additional first costs for energy efficient HVAC measures.
- Ensure that the participation process is clear, easy to understand and simple.

Program Rationale

Certain barriers exist to the adoption of HVAC energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of HVAC energy efficiency measures in the C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a broadly applicable C&I prescriptive rebate program since the energy and demand savings for many common HVAC energy efficiency measures are similar across many C&I market segments. Having a simple program structure and rebate schedule provides customers with certainty and ease of use regarding the incentives they will receive for installing a wide variety of measures.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial customers are eligible for the program. However, the main target markets are:

- Customers in existing buildings. New construction applications are covered by the separate New Construction program.
- Other utilities have found that the following types of larger commercial customers participate with the highest frequency in their C&I HVAC DSM programs: large office buildings, education facilities, and health care facilities.

Products and Services Provided

The C&I HVAC DSM Program is a customer incentive program that provides rebates for the installation of HVAC energy efficiency measures in existing non-residential facilities. More specifically, the program offers the following products and services:

- Education and promotional materials aimed at building owners and operators about the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content.
- Educational and promotional efforts aimed at trade allies such as mechanical contractors and distributors to help them promote efficient HVAC measures to their customers.
- Rebates for building owners and managers to adopt the measures recommended by the program. Rebates will be approximately $250/kW for each measure provided by the program. Specific rebates for each size and type of HVAC DSM measure will be developed.

- Eligible HVAC retrofits include:
    - Efficient air cooled and water cooled chillers.
    - Efficient packaged (rooftop) air conditioners.
    - Variable speed drives in ventilation fan and variable pumping applications.
    - Efficient motors in HVAC applications.
    - Integrated economizer controls.
    - Programmable thermostats.

Delivery Strategy and Administration

- Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support.
- KCP&L account representatives are expected to promote the program to their customers.
- Alternatively, KCP&L could outsource the program to an "implementation contractor" such as Honeywell DMC or ICF.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including the architecture/engineering and contractor community, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).
    - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
    - Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
    - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.

  - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
  - KCP&L customer account representatives trained to promote the program to their customers.
  - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
  - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted Summit Blue's suggested integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management -** As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection** – KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** – KCP&L's evaluation contractor will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values** – KCP&L will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimate the savings being achieved by the program.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

KCP&L Commercial and Industrial HVAC DSM Program

Budget and Staffing

- The total 2008 program budget is approximately $401,000.
- The total 2009 program budget is approximately $802,000.
- Approximately 85% of program budgets are for customer rebates and 15% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Program design and set-up costs will be approximately $25,000.
- Program evaluation costs will be about five percent of the total budget.
- Suggested initial KCP&L staffing includes a half-time program manager, a part-time program administrative/data support person, a part time trade ally liaison, and the equivalent of less than one FTE of account reps time to promote the program to their customers.

Program Impact Summaries

- Total estimated program peak demand reductions are 1.1 MW in 2008 and 2.3 MW in 2009.
- The annual generator energy savings are 3.4 GWh in 2008 and 6.7 GWh in 2009.

Program Benefit-Cost Results

Based on the September 2007 DSMore results, the program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Participant Test: 3.20.
- Utility Test: 10.82.
- RIM Test: 2.37
- TRC Test: 7.36.
- Societal Test: 8.20.

KCP&L Commercial and Industrial Custom and Motors DSM Program

Program Concept and Description

The Commercial and Industrial (C&I) Custom and Motors DSM Program provides mainly custom incentives to C&I customers for the installation of innovative and non-standard energy-efficiency equipment and controls. Prescriptive incentives are also offered for energy efficient motors. This program will pertain to existing facilities only. Standard lighting and HVAC measures are covered by the separate Lighting and HVAC DSM programs. New construction measures will be covered by the separate C&I New Construction Program.

The viability of each of the prescriptive measures covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the process, refrigeration and other energy using systems in their facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient process, refrigeration, and controls measures in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility owners and operators for the installation of high-efficiency process, refrigeration and other equipment and controls.
- Provide a marketing mechanism for consulting engineers, process and refrigeration vendors and distributors to promote energy efficient equipment to end users.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and cost of energy efficiency improvements.
    - Performance uncertainty associated with energy efficiency projects.
    - Additional first costs for energy efficient measures.
- Ensure that the participation process is clear, easy to understand and simple.

KCP&L Commercial and Industrial Custom and Motors DSM Program

Program Rationale

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of process, refrigeration, and other types of energy efficiency measures in the C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a broadly applicable C&I custom rebate program since the energy and demand savings for many common energy efficiency measures vary considerably across C&I market segments and between customers. Having a simple program structure and rebate schedule provides customers with ease of use regarding the incentives they will receive for installing a wide variety of efficiency measures.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial customers are eligible for the program. However, the main target markets are:

- Customers in existing buildings. New construction applications are covered by the separate New Construction program.
- Industrial customers, grocery stores, and other large commercial customers are expected to be the primary target markets for this program.

KCP&L Commercial and Industrial Custom and Motors DSM Program

Products and Services Provided

The C&I Custom and Motors DSM Program is a customer incentive program that provides rebates for the installation of energy efficiency measures in existing non-residential facilities. More specifically, the program offers the following products and services:

- Education and promotional materials aimed at building owners and operators about the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content.
- Educational and promotional efforts aimed at trade allies such as consulting engineers, process and refrigeration vendors distributors to help them promote efficiency measures to their customers.
- Rebates for building owners and managers to adopt the measures recommended by the program. Rebates will be approximately $300/kW for each measure provided by the program.
- The largest impact measures covered by the program are expected to be:
    - Adjustable speed drives.
    - Energy management systems.
    - Innovative lighting systems replacements.
- Other eligible energy efficiency measures include:
    - Energy efficient motors.
    - Innovative process efficiency measures.
    - Efficient refrigeration measures.
    - Efficient HVAC system measures, not component replacements.
    - Specialized control systems.

Delivery Strategy and Administration

- Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support.
- KCP&L account representatives are expected to promote the program to their customers.
- Alternatively, KCP&L could outsource the program to an “implementation contractor” such as Honeywell DMC or ICF.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including consulting architects and engineering firms, process and refrigeration contractors and distributors, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the

KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).
    - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
    - Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
    - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
    - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
    - KCP&L customer account representatives trained to promote the program to their customers.
    - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
    - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted Summit Blue's suggested integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management -** As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.

- **Integrated implementation data collection** – KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** – KCP&L's evaluation contractor will conduct field verification of the ex ante and ex post conditions for at least the largest projects and a sample of medium sized projects throughout the implementation of the program.
- **Tracking of savings using estimated savings values** – The participating customers or their consultants or vendors will develop estimated savings values for each application submitted through the program. The M&V process will verify or revise the initial estimated savings values.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total 2008 program budget is approximately $406,000.
- The total 2009 program budget is approximately $812,000.
- Approximately 50% of program budgets are for customer rebates and 50% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing includes a full-time program manager, a half-time program administrative/data support person, a half-time trade ally liaison, and the equivalent of about 1 FTE of account reps time to promote the program to their customers.
- Program design and set-up costs will be approximately $25,000.
- Program evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions are 0.5 MW in 2008 and 1.1 MW in 2009.
- The annual generator energy savings are 5.2 GWh in 2008 and 10.4 GWh in 2009.

Program Benefit-Cost Results

Based on the September 2007 DSMore results, the program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Participant Test: 3.05.
- Utility Test: 20.48.
- RIM Test: 2.25
- TRC Test: 6.62.
- Societal Test: 7.52.

KCP&L Commercial and Industrial New Construction DSM Program

Program Concept and Description

The Commercial and Industrial (C&I) New Construction DSM Program provides design assistance and custom incentives to C&I customers for building more efficient new buildings and installing energy-efficiency equipment and controls that are not required by building energy codes. This program will pertain to new buildings and major remodeling projects only. Standard lighting and HVAC measures for existing buildings are covered by the separate Lighting and HVAC DSM programs.

The viability of each of the measures covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the lighting, HVAC, building envelope, refrigeration, and other energy using systems in their new facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives

The primary goal of the program is to encourage KCP&L's C&I customers to build more efficient new buildings and to install energy efficient lighting, HVAC, building envelope, refrigeration, and controls measures in new buildings. More specifically, the program is designed to:

- Provide design assistance to the architects and engineers that are designing new buildings. The key design assistance tool is building simulation modeling of more efficient building designs.
- Provide incentives to new facility owners for the installation of high-efficiency lighting, HVAC, building envelope, refrigeration and other equipment and controls.
- Provide a marketing mechanism for architects and engineers to promote energy efficient new buildings and equipment to end users.
- Overcome market barriers, including:
  - Customers' lack of awareness and knowledge about the benefits and costs of energy efficiency improvements.
  - Performance uncertainty associated with energy efficiency projects.
  - Additional first costs for energy efficient measures.
- Ensure that the participation process is clear, easy to understand and simple.

KCP&L Commercial and Industrial New Construction DSM Program

Program Rationale

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of energy efficiency measures in the new construction C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is targeted towards larger C&I new construction facilities. Customer rebates are calculated on a custom $/kW basis, since the energy and demand savings for many common energy efficiency measures vary considerably between customers. Having a simple program and rebate structure provides customers with ease of use regarding the incentives they will receive for installing a wide variety of efficiency measures.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial customers that are building new facilities or extensively remodeling existing facilities are eligible for the program. However, the main target markets are:

- Larger new commercial and institutional customers of KCP&L.
- Primary target markets are expected to be office buildings, educational buildings, and health care facilities. Other building types are eligible to participate as well.

Products and Services Provided

The C&I New Construction DSM Program is a customer incentive program that provides design assistance for architects and engineers designing new buildings and customer rebates for the installation of energy efficiency measures in new C&I facilities. More specifically, the program offers the following products and services:

- Education and promotional materials aimed at building owners and operators about the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content.
- Educational and promotional efforts aimed at trade allies such as architect and engineers to help them promote efficiency measures to their customers.
- Rebates for building owners and managers to adopt the measures recommended by the program. Rebates will be approximately $250/kW for each measure covered by the program.
- DSM measures that will be covered by the program include:
  - Efficient lighting systems.
  - Efficient HVAC and controls systems, including energy management systems.
  - Efficient motors and variable speed drives, primarily for HVAC applications.
  - Building envelope measures such as insulation and efficient windows.
  - Efficient electric water heating measures.
  - Efficient refrigeration systems.

Delivery Strategy and Administration

- Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support.
- KCP&L account representatives are expected to promote the program to their customers.
- KCP&L should strongly consider outsourcing building simulation modeling to a firm that specializes in providing this service. Several of the top-performing utility new construction DSM programs in the Midwest also outsource a lot of program promotion and marketing to architects and engineers at the modeling firm.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including architects and engineering firms, contractors and distributors, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).
    - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
    - Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
    - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
    - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
    - KCP&L customer account representatives trained to promote the program to their customers.
    - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
    - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted Summit Blue's suggested integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management -** As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.

- **Integrated implementation data collection** – KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** – KCP&L's evaluation contractor will conduct field verification of the ex post conditions compared to the modeled conditions for at least the largest projects and a sample of medium sized projects throughout the implementation of the program.
- **Tracking of savings using estimated savings values** – The building simulation modeling process will develop estimated savings values for each application and measure submitted through the program. The M&V process will verify or revise the initial estimated savings values.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total 2008 program budget is approximately $430,000.
- The total 2009 program budget is approximately $850,000.
- Approximately 50% of program budgets are for customer rebates and 50% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing includes a half-time program manager, a part-time program administrative/data support person, a part-time trade ally liaison, and less than one FTE of account reps time to promote the program to their customers.
- Program design and set-up costs will be approximately $25,000.
- Program evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions are 1.1 MW in 2008 and 2.1 MW in 2009.
- The annual generator energy savings are 4.2 GWh in 2008 and 8.5 GWh in 2009.

Program Benefit-Cost Results

Based on the September 2007 DSMore results, the program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Participant Test: 2.08.
- Utility Test: 12.37.
- RIM Test: 2.60.
- TRC Test: 4.86.
- Societal Test: 5.44.

MMP
Morgan Marketing Partners

KANSAS CITY POWER & LIGHT

C&I ENERGY EFFICIENCY PROGRAMS

FINDINGS AND DOCUMENTATION

Prepared for:

Joe O'Donnell

Technical Consultant, Energy Solutions

Kansas City Power and Light
P.O. Box 418679
Kansas City, MO 64141

Jan. 4, 2008

Prepared by:

Morgan Marketing Partners
Franklin Energy Services
Architectural Energy Corporation

Rick Morgan, Principal
608-277-9518
Morgan@MorganMP.com

Table of Contents

Introduction

Morgan Marketing Partners (MMP) and its subcontractors Architectural Energy Corporation (AEC) and Franklin Energy Services (FES), were retained by Kansas City Power and Light (KCPL) to determine cost effective Commercial and Industrial (C&I) programs and measures for its energy efficiency programs. This report is the summary of that effort with the main purpose of documenting the assumptions and results of the study.

This study had several steps. The first was to review the initial high level work of Summit Blue. Their task was to develop a high level market potential analysis and high level programs for the C&I sector. While this work provided great insights and direction, it required additional definition and program design to get the results to an implementation and filing level.

Step two was to develop more detailed program designs that included incentives for the measures and more refined guidelines for implementation. These recommended programs were developed based on the Summit Blue report, review of other programs nationally, and the experience of MMP in designing and implementing efficiency programs for more than 30 years.

Step three was to determine what technologies and measures might fit into each of these program designs, specifically the prescriptive program where specific measures are analyzed for inclusion. Each of these technologies then needed an engineering analysis to determine savings over a baseline, potential incentives and incremental costs for the cost effectiveness analysis.

Step four is a cost effectiveness analysis looking at the individual measures and programs to determine if they can be cost effectively offered by KCPL when incentives and program implementation/administration costs are included. Four scenarios were developed looking at both standard and high incentive levels and expected and aggressive participation rates. Using the DSMore tool with KCPL specific prices, weather and loads, each measure and program was analyzed to determine the cost effectiveness scores utilizing the California Standard Practice Manual guidelines. Results are then used to fine tune which measures are included and the incentive amounts available to the customers. Probabilities were then assigned to each scenario to develop the expected outcome.

Step five is the consolidation of all the results including budgets and savings into the programs overall for a final portfolio of programs to be recommended to KCPL. This document is a part of that final step.

The balance of this report provides the summary of this work. Section 1 describes the programs and why they were designed in a specific way. Section 2 provides the DSMore cost effectiveness results. Section 3 provides the documentation for the HVAC savings modeling used for measure savings determination and Section 4 provides the documentation for the non weather sensitive loads. Appendix A & B provide further detail by measure.

Section 1: Program Designs

There are four C&I program designs proposed to be included within the KCPL portfolio. MMP believes that these four programs are broad enough to cover the primary market opportunities yet give KCPL control over the budgets and results. These four programs are described below.

Prescriptive Incentive Program

Program Concept and Description

The Commercial and Industrial (C&I) Prescriptive Incentive Program provides prescriptive incentives to C&I customers for the installation of energy-efficiency equipment for numerous applications including lighting equipment, controls, heating, ventilation and air conditioning (HVAC) equipment, motors, refrigeration, and food service equipment. Prescriptive incentives are offered for a schedule of measures in each of these categories. Innovative energy efficiency measures or measures with large variability in application will be covered as part of the separate Custom Rebate Program. Application to existing facilities and/or new facilities will vary by measure depending on the codes and standards within new construction. New construction design assistance will be covered by the separate C&I New Construction Program.

The viability of each of the prescriptive measures covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), Societal (ST) and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs. Measures will be added or eliminated from the program based on cost effectiveness, market acceptance and standard practice. Measures will also be added as new products/measures emerge in the market.

The key to program success is the engagement of the market actors throughout the delivery channel that currently exists. These actors include manufacturers, distributors, consultants, engineers and contractors. The program will have staff specifically dedicated to educating, partnering and engaging these important players in the program. Through these existing market actors who have relationships with C&I customers, the new high efficient technology will be offered to customers as a viable option. To support the market actors, the program also includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the systems in their facilities.

Program Objectives & Rationale

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient measures in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility owners and operators for the installation of high-efficiency equipment and controls.
- Provide a marketing mechanism for electrical contractors, mechanical contractors, and their distributors to promote energy efficient equipment to end users.
- Overcome market barriers, including:
  - Customers' lack of awareness and knowledge about the benefits and costs of energy efficiency improvements.
  - Performance uncertainty associated with energy efficiency projects.
  - Additional first costs for energy efficient measures.
- Ensure that the participation process is clear, easy to understand and simple.

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of energy efficiency measures in the C&I market. The theory of the program is that through engagement and education with the market actors and through customer incentives to reduce first costs, the risks to energy efficiency will be reduced and the rewards from the savings will become more apparent thus increasing adoption.
In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a broadly applicable C&I prescriptive incentive program since the energy and demand savings for many common energy efficiency measures are similar across many C&I market segments. Having a simple program structure and incentive schedule provides customers with certainty and ease of use regarding the incentives they will receive for installing a wide variety of lighting measures.
The program's actual energy and demand savings will be determined through the program evaluation strategy. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial retail customers are eligible for the program. However, the main target markets are:

- Customers in both existing buildings and new construction depending on the technology and code requirements. New construction design incentives are covered by the separate New Construction program.
- Other utilities have found that the following types of larger commercial customers participate with the highest frequency in their C&I EE programs: large office buildings, education facilities, grocery stores, health care facilities, and warehouses.
- Small business customers are the most difficult market segment to reach with EE programs in general, but such customers tend to more readily participate in the lighting EE programs than other types of EE programs.

Technology Categories

The C&I Lighting EE Program is a customer incentive program for the installation of energy efficiency measures in non-residential facilities. More specifically, the program offers incentives for the following technology categories. Specific listings of technologies will change over time based on codes & standards, market need, introduction of new technologies and market adoption.

- High efficiency lighting
- HVAC equipment
- Motors/Pumps
- Refrigeration Equipment
- Food Service Equipment
- Controls
- Other

Market Barriers

Market barriers vary by technology and customer segment. They include but are not limited to:

- Lack of investment funds or high costs
- Competition for funds with other projects
- Lack of awareness/knowledge by both customers and contractors
- Lack of time
- Increased perceived risk from a newer technology in performance
- High transaction and information search costs

Working with the market actors and providing incentives, KCP&L expects to reduce many of these barriers and stimulate installation of these measures.

Components of Delivery

Incentives:
Incentives for each technology will vary based on cost effectiveness and market response. A full listing of the current proposed technologies and their incentives is attached in Appendix A. The program strives to cover at least 50% of the incremental cost of the measure to stimulate the market if it is cost effective. Additional guidelines may be established such as total incentives available per customer per year to assure that funds are allocated across all customer opportunities.

Ed/Instructions:
Education and promotional materials will be developed for building owners and operators on the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content. Specific educational and promotional efforts aimed at market actors such as electrical contractors, building supply firms, and distributors to help them promote efficient measures to their customers. This education will be through a combination of mailings and direct meetings with key market actors in the area.

Marketing and Communications Strategy
The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and market actors including the architecture/engineering and contractor community, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCP&L.com and will be available for various public awareness events (presentations, seminars etc).
    - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.

- o Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
- o Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
- o KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
- o KCP&L customer account representatives trained to promote the program to their customers.
- o Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
- o Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.

- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Delivery
Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support. There will be specific staff assigned to work with the market actors/channels to promote the program and support the markets sales efforts. As well KCP&L account representatives will be expected to promote the program to their customers directly and cross promote other programs. Based on the ultimate size of the program and other issues KCP&L may outsource the program to an “implementation contractor”.

Evaluation, Measurement and Verification (EM&V) (Quality Control & Monitoring)

KCP&L has already adopted an integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management** - As part of program operation, KCP&L’s evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection** – KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support

effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.

- **Field verification –** KCP&L's evaluation contractor will conduct field verification of the installation of a sample of measures throughout the implementation of the program. The verification protocol will be a random sample of 5% of the applications up to $10,000 and a 10% sampling of projects from $10,000 to $30,000. All projects over $30,000 will be verified. If a contractor has unresolved or ongoing problems, their next three projects will be verified. If these are not corrected, they can be removed from the program at KCP&L's discretion.
- **Tracking of savings using deemed savings values –** KCP&L will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimate the savings being achieved by the program.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Materials

Materials will be developed for both the market actors and the customers. They will include but not be limited to:

- Incentive Forms and Guidelines
- Brochures
- Technology information
- Case Studies
- Web Support Materials
- Direct Mail pieces

Budget and Staffing

- The total five year program budget is approximately $8 -$12.5 million depending on the expected or aggressive participation scenario adopted.
- Approximately 65% of program budgets are for customer incentives and 35% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing includes a full-time program manager, a full time program administrative/data support person, three trade ally liaisons one each for lighting, HVAC and other technologies, and the equivalent of about 1 FTE of account reps time to promote the program to their customers.
- Program monitoring, verification and evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions are 18.8 – 31.8 MW in year five.
- Total estimated lifetime kWh savings from the 5 year program are 670,000,000 – 1,103,000,000 kWh.

Program Benefit-Cost Results

Based on the DSMore results, the expected program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Utility Test: 8.21
- TRC Test: 3.80
- RIM Test: 2.08
- Societal Test: 4.25
- Participant Test: 1.98

C&I Custom Incentive Program

Program Concept and Description

The Commercial and Industrial (C&I) Custom Incentive Program provides custom incentives to C&I customers for the installation of innovative and non-standard energy-efficiency equipment and controls. This program will pertain to existing facilities only. Standard high efficiency measures are covered by the separate Prescriptive Incentive program. New construction design measures will be covered by the separate C&I New Construction Program.

The incentive levels set for the custom measures covered by the program have been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), Societal Test (ST) and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings, the associated avoided costs and net benefits to KCP&L, the incremental or installed costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the process, refrigeration and other energy using systems in their facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives & Rationale

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient process, refrigeration, and other efficient equipment & controls in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility owners and operators for the installation of high-efficiency process, refrigeration and other equipment and controls.
- Provide a marketing mechanism for consulting engineers, process and equipment contractors and distributors to promote energy efficient equipment to end users.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and cost of energy efficiency improvements.
    - Performance uncertainty associated with energy efficiency projects.
    - Additional first costs for energy efficient measures.
- Ensure that the participation process is clear, easy to understand and simple.

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of custom measures that are not easily covered in a prescriptive program such as process, refrigeration, compressed air systems and other types of unique energy efficiency measures in the C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a broadly applicable C&I custom incentive program since the energy and demand savings for many common energy efficiency measures vary considerably across C&I market segments and between customers. Having a simple program structure and incentive schedule provides customers with ease of use regarding the incentives they will receive for installing a wide variety of efficiency measures. The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial retail customers are eligible for the program. However, the main target markets are:

- Customers in existing buildings. New construction design applications are covered by the separate New Construction program.
- Industrial customers, grocery stores, and other large commercial customers are expected to be the primary target markets for this program.

Technology Categories

With a custom program, flexibility is the key. Technologies that are unique to that customer, new to the market or have a wide range of savings based on their application cannot be included in a prescriptive program due to their variability. However these variable energy savings technologies can be significant and encouraged through a custom incentive program.

Market Barriers

Market barriers vary by technology and customer segment. They include but are not limited to:

- Lack of investment funds or high costs
- Cost to analyze potential savings from a project through assessments/audits
- Competition for funds with other projects
- Lack of awareness/knowledge by customers, engineers and contractors
- Lack of time
- Increased perceived risk from a newer technology in performance
- High transaction and information search costs

Working with the market actors, increasing awareness and providing incentives, KCP&L expects to reduce many of these barriers and stimulate installation of these measures.

Components of Delivery

Incentives:
The C&I Custom Incentive Program is a financial assistance and education program that provides incentives for the installation of energy efficiency measures in existing non-residential facilities. Customers/Contractors will submit their project savings estimates during the planning process prior to project initiation. KCP&L staff or its subcontractor will review these savings estimates and confirm the savings prior to committing to the incentive levels. This check on the savings analysis helps assure that KCP&L funds are being cost effectively used to promote efficiency.

Incentives will be set using a per kWh and per kW basis so that both energy and demand savings will be rewarded. Levels of incentives will vary over time based on costs and market need but will typically be established in one year increments. KCP&L will use a two tier custom incentive approach. The first tier is at a lower rate for technologies that are established and known in the market but need financial help to get them implemented. The second tier will be technologies that are newer to the market or have more significant risk or other barriers that need higher stimulation and awareness. Most new technologies will start at the second higher incentive tier and migrate to the first lower incentive tier over time as they get accepted within the market. This approach gives appropriate signals to the market about new technologies or riskier technologies that have significant savings potential. The initial tier levels proposed and the technology categories that fit within these tiers are outlined in Appendix A. Other guidelines to reduce free ridership will also be established. These include years of payback, total incentive dollars per customer per year and percent of total project cost.

One barrier to getting measures identified and installed is getting customers to spend funds to analyze the opportunity and savings. To help address this issue, *assessment/audit grants* will be available to customers for up to 25% of the analysis cost not to exceed $300 for facilities less than 25,000 square feet and not to exceed $500 for larger facilities. If the customer implements that project an additional bonus will be included in the incentive to cover an additional 25% of the assessment cost using the same caps.

Education & Instruction:
Education and promotional materials will be developed for building owners and operators on the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content. Specific educational and promotional efforts aimed at market actors such as electrical contractors, building supply firms, and distributors to help them promote efficient measures to their customers. This education will be through a combination of mailings and direct meetings with key market actors in the area.

Program Marketing and Communications Strategy
The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. Certain key customer segments will be targeted based on energy savings potential and technology. Initial market segments will include hospitality, food service, health care, grocery, large industrial and large office. The strategy will also include outreach to key equipment partners and trade allies including consulting architects and engineering firms, process and refrigeration contractors and distributors, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
  - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).
  - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
  - Customer and trade partner outreach and presentations (e.g. Restaurant Association, BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
  - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
  - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
  - KCP&L customer account representatives trained to promote the program to their customers.
  - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
  - Presentations by the program manager to key target market segment customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Delivery Strategy and Administration

Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support. There will be specific staff assigned to work with the market actors/channels to promote the program and support the markets sales efforts. This market channel work crosses over with the Prescriptive Program activities so that both are promoted to these key market actors. As well KCP&L account representatives will be expected to promote the program to their customers directly and cross promote other programs. Initially these target market segments will include hospitality, food service, health care, grocery, large industrial and large office. Based on the ultimate size of the program and other issues KCP&L may outsource the program to an "implementation contractor".

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted an integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management** - As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection –** KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification –** For the custom program all projects will be reviewed by KCP&L's staff engineers or subcontractors for determining the incentives each project will receive. This will help assure cost effectiveness of the projects. It will also act in the first step of quality control. After project completion KCP&L's evaluation contractor will conduct field verification of the ex ante and ex post conditions for at least the largest projects and a sample of medium sized projects throughout the implementation of the program. The verification protocol will be a random sample of 5% of the applications up to $10,000 and a 10% sampling of projects from $10,000 to $30,000. All projects over $30,000 will be verified. If a contractor has unresolved or ongoing problems, they can be removed from the program at KCP&L's discretion.
- **Tracking of savings using estimated savings values –** The participating customers or their consultants or vendors will develop estimated savings values for each application submitted through the program. These will be reviewed prior to the project implementation and entered in the database as pending. After project completion the actual installed information will be entered and compared to the initial project estimate. Further, the M&V process will verify or revise the initial estimated savings values.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total five year Custom, New Construction and RFP program budget is approximately $11.5 - $17.9 Million depending on whether the expected or aggressive participation is adopted. These three programs cannot at this time be separated as the participant mix can't be determined between them.
- Approximately 50% of program budgets are for customer incentives and 50% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing for the Custom program only includes a full-time program manager, a full time program administrative/data support person, a full time trade ally liaison, four market segment managers to develop relationships with the market and the equivalent of about 1 FTE of account reps time to promote the program to their customers.
- Program monitoring, verification and evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions for the combined Custom, New Construction and RFP programs are 11.8 – 18.4 MW in year five.
- Total estimated lifetime kWh savings for the combined Custom, New Construction and RFP programs for the 5 year program are 711,000,000 – 1,106,000,000 kWh.

Program Benefit-Cost Results

Based on the DSMore results, the expected Custom, New Construction and RFP program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Utility Test: 5.62
- TRC Test: 3.80
- RIM Test: 1.92
- Societal Test: 4.22
- Participant Test: 2.48

C&I New Construction Program

Program Concept and Description

The Commercial and Industrial (C&I) New Construction Program provides design assistance and custom incentives to C&I customers for building more efficient new buildings and installing energy-efficiency equipment and controls that are not required by building energy codes and are above standard construction practices. This program will pertain to new buildings and major remodeling projects only. It will have two components to the program. Standard high efficiency technologies that are upgraded beyond code or standard practices, such as standard lighting and HVAC measures, are covered within the separate Prescriptive program. The second component of the program will be design assistance and the upgrade of the whole building. Incentives will be based on the percent improvement above Kansas building code and for Missouri above the ASHRAE 90.1 standards as determined by DOE 2 or equivalent building simulation modeling.

The viability of the incentives covered by the program has been assessed through a cost-effectiveness analysis using the DSMore model that evaluated the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), Societal Test (ST) and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings of each measure, the associated avoided costs and net benefits to KCP&L, the incremental or installed measure costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to improve the energy efficiency of the lighting, HVAC, building envelope, refrigeration, and other energy using systems in their new facilities. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives & Rationale

The primary goal of the program is to encourage KCP&L's C&I customers to build more efficient new buildings and to install energy efficient lighting, HVAC, building envelope, refrigeration, and controls measures in new buildings. More specifically, the program is designed to:

- Provide design assistance to the architects and engineers that are designing new buildings. The key design assistance tool is building simulation modeling of more efficient building designs.
- Provide incentives to new facility owners for the installation of high-efficiency lighting, HVAC, building envelope, refrigeration and other equipment and controls. Standard high efficiency equipment will be covered through the Prescriptive Program when no modeling is completed. When modeling is completed, they will be considered within the total savings percent and provided incentives as a total package.
- Provide a marketing mechanism for architects and engineers to promote energy efficient new buildings and equipment to end users.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and costs of energy efficiency improvements.

- Performance uncertainty associated with energy efficiency projects.
- Additional first costs for energy efficient measures.
- Lack of time, resources and motivation by the designer/engineer to consider efficient alternatives and model these results for the owner's consideration.

- Ensure that the participation process is clear, easy to understand and simple.

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. If the building is not designed and constructed with electric efficiency in mind, there might not be the opportunity to make these improvements until many years later when the equipment fails or further building remodeling occurs. Avoiding this lost opportunity at the time of design and construction allows energy efficiency to be optimized and is usually less costly than equipment replacement or redesign. This program is designed to help overcome these market barriers and encourage greater adoption of energy efficiency measures in the new construction C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is targeted towards larger C&I new construction facilities. Customer incentives are calculated on a custom $/kW and $/kWh basis, since the energy and demand savings for many common energy efficiency measures vary considerably between customers. Having a simple program and incentive structure provides customers with ease of use regarding the financial rewards they will receive for installing a wide variety of efficiency measures.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial retail customers that are building new facilities or extensively remodeling existing facilities are eligible for the program. However, the main target markets are:

- Larger new commercial and institutional customers of KCP&L.
- Primary target markets are expected to be office buildings, educational buildings, and health care facilities. Other building types are eligible to participate as well.

Technology Categories

The technologies to be included within this program are flexible and include all that will save electrical energy and demand. Participants can choose to use the existing Prescriptive technologies without going through the design modeling process. These technologies applicable to new construction will be processed through normal prescriptive incentive application forms. For those who are willing to complete design modeling comparisons, any electrical improvements will be included.

Market Barriers

Market barriers vary by technology and customer segment. They include but are not limited to:

- Lack of investment funds or high costs
- Competition for funds with other projects
- Lack of awareness/knowledge by both customers and architects/engineers
- Lack of time and resources during the design process
- Increased perceived risk from a newer technology in performance
- High transaction and information search costs

Working with the building owners and the architects/engineers and providing incentives, KCP&L expects to reduce many of these barriers and stimulate installation of these measures.

Components of Delivery

Incentives:
The incentives for the program can come through two different options. The first option is a prescriptive incentive for technologies above code that are within the Prescriptive program listing. This situation will be used if the building simulation modeling is not used. These technologies will receive incentives at the same levels as the prescriptive program. This keeps the communications with the market actors and suppliers clear and makes processing easy. To get architects and engineers to model and encourage efficiency in their buildings, incentives will be provided for the initial design comparisons and building simulation modeling. Incentives will also be available for the building owner to install the high efficiency equipment. These installation incentives will be based on three levels of performance above Kansas building code or ASHRAE 90.1 standards; 10-20% above baseline code, 20-30% above code and 30% or more and will change over the program life as the market responds. The initial incentive levels are described in Appendix A.

Ed/Instructions:
Education and promotional materials will be developed for building owners, architects, engineers and operators on the benefits of energy efficiency improvements and improved

systems performance, including educational brochures, program promotional material, and website content. Specific educational and promotional efforts aimed at architects and engineers to help them promote efficient measures to their customers. This education will be through a combination of mailings, workshops and direct meetings with key market actors in the area.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including architects and engineering firms, contractors and distributors, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;
- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com. They will also be available through various public awareness events (presentations, seminars etc).
    - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can apply.
    - Customer and trade partner outreach and presentations (e.g. BOMA and other customer organizations) informing interested parties about the benefits of the program and how to participate.
    - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
    - KCP&L website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources.
    - KCP&L customer account representatives trained to promote the program to their customers.
    - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
    - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.

- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Delivery
The C&I New Construction Program is a customer incentive program that provides design assistance for architects and engineers (A&E) designing new buildings and customer incentives for the installation of energy efficiency measures in new C&I facilities. More specifically, the program offers the following products and services:

- Education and promotional materials aimed at building owners and operators about the benefits of energy efficiency improvements and improved systems performance, including educational brochures, program promotional material, and website content.
- Educational and promotional efforts aimed at architect and engineers to help them promote efficiency measures to their customers through workshops and direct visits.
- Incentives for building owners and managers to adopt the measures recommended by the program.
- Incentives for design modeling to consider energy efficiency in the building and building systems. When appropriate the program will help with LEED certification requirements.
- EE measures that will be covered by the program include:
    - Efficient lighting systems and controls.
    - Efficient HVAC and controls systems, including energy management systems.
    - Efficient motors and variable speed drives, primarily for HVAC applications.
    - Building envelope measures such as insulation and efficient windows.
    - Efficient electric water heating measures.
    - Efficient refrigeration systems.

To deliver these services, KCP&L will hire or subcontract with energy efficiency design and engineering experts to talk with the A&E community about the program and educate them on its benefits. These experts will also provide technical assistance to the designers concerning the building simulation modeling of the high efficient alternatives. In addition, designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support. To help promote the program to building owners KCP&L account representatives will promote the program during their normal contacts.

Evaluation, Measurement and Verification (EM&V) (Quality Control & Monitoring)

KCP&L has already adopted an integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management** - As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection –** KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification –** All the modeling design projects will be reviewed by KCP&L's staff engineers or subcontractors to determine the incentives each project will receive based on the building simulations. This will help assure cost effectiveness of the projects. It will also act in the first step of quality control. After project completion KCP&L's evaluation contractor will conduct field verification of the ex ante and ex post conditions for all projects of a new A&E involved in the program to determine as built conditions. After successful participation by an A&E, the field verifications will occur on the largest projects and a sample of medium sized projects throughout the implementation of the program to determine as built conditions. The verification protocol will be a random sample of 5% of the applications up to $10,000 and a 10% sampling of projects from $10,000 to $30,000. All projects with over $30,000 in incentives will be verified. If a A&E or contractor has unresolved or ongoing problems, they can be removed from the program at KCP&L's discretion. Prescriptive measures will be inspected and verified using the Prescriptive protocols.
- **Tracking of savings using estimated savings values –** The building simulation modeling process will develop estimated savings values for each application and measure submitted through the program. The M&V process will verify or revise the initial estimated savings values.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total five year Custom, New Construction and RFP program budget is approximately $11.5 - $17.9 Million depending on whether the expected or aggressive participation is adopted. These three programs cannot at this time be separated as the participant mix can't be determined between them.

- Suggested initial KCP&L staffing for the New Construction program includes a half-time program manager, a part-time program administrative/data support person, a full time trade ally liaison, and less than one FTE of account reps time to promote the program to their customers.
- Approximately 50% of program budgets are for customer incentives and 50% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Program monitoring, verification and evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions for the combined Custom, New Construction and RFP programs are 11.8 – 18.4 MW in year five.
- Total estimated lifetime kWh savings for the combined Custom, New Construction and RFP programs for the 5 year program are 711,000,000 – 1,106,000,000 kWh.

Program Benefit-Cost Results

Based on the DSMore results, the expected Custom, New Construction and RFP program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Utility Test: 5.62
- TRC Test: 3.80
- RIM Test: 1.92
- Societal Test: 4.22
- Participant Test: 2.48

Targeted RFP Program

Program Concept and Description

The Commercial and Industrial (C&I) RFP Program provides custom incentives to C&I customers on a very targeted and limited time basis for the installation of innovative and non-standard energy-efficiency equipment and controls. This program will pertain to existing facilities only. This program will be offered through Requests for Proposals (RFP) to targeted customer and markets with very specific criteria. The purpose of the program is to have special offers that stimulate larger package projects, not just measures or specific systems. It will have a limited time with a specific max budget. Through having limited offerings, customers and contractors are more motivated to move stalled projects. It also allows KCP&L to throttle projects and spending up and down based on other program spending and results towards goals. The RFP program also has the flexibility to push specific technologies or types of projects. As well this flexibility permits KCP&L to provide incentives at higher levels if required without disturbing the other programs and their communications with the market.

The incentive levels set for the custom measures covered by the program will be assessed for each RFP response through a cost-effectiveness analysis using the DSMore model that evaluates the Total Resource Cost (TRC), Utility Cost (UC), Ratepayer Impact Measure (RIM), Societal Test (ST) and Participant (PT) tests. The cost-effectiveness tests account for the energy and demand savings, the associated avoided costs and net benefits to KCP&L, the incremental or installed costs, and the program costs.

The program includes customer educational and promotional pieces designed to assist facility owners, operators and decision makers with the information necessary to respond to the RFP with proposals. The program also includes customer and trade ally education to assist with understanding the technologies that are being promoted, the incentives that are offered, and how the program functions.

Program Objectives & Rationale

The primary goal of the program is to encourage KCP&L's C&I customers to install energy efficient process, refrigeration, and other efficient equipment & controls in existing facilities beyond what they would have installed without the program. More specifically, the program is designed to:

- Stimulate the market and move stalled efficiency projects within a certain timeframe.
- Provide incentives to facility owners and operators for the installation of high-efficiency process, refrigeration and other equipment and controls.
- Provide a marketing mechanism for consulting engineers, process and equipment contractors and distributors to promote energy efficient equipment to end users.
- Allow KCP&L to increase spending and activity to reach goals.
- Allow KCP&L the flexibility to promote certain technologies or systems, or market to certain market sub segments.
- Overcome market barriers, including:
    - Customers' lack of awareness and knowledge about the benefits and cost of energy efficiency improvements.
    - Performance uncertainty associated with energy efficiency projects.
    - Additional first costs for energy efficient measures.
- Ensure that the participation process is clear, easy to understand and simple.

Certain barriers exist to the adoption of energy efficiency measures, including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of custom measures that are not easily covered in a prescriptive program such as process, refrigeration, compressed air systems and other types of unique energy efficiency measures in the C&I market.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits. These include reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

The program is structured as a very specific offer for a limited time to motivate C&I customers to take action by offering incentives. Having a specific RFP structure with a limited time will push projects sooner improving the efficiency of the facility.

The program's actual energy and demand savings will be determined through the program evaluation strategy discussed in a subsequent section. Evaluation activities should be planned at the same time as overall program planning, and implemented when the overall program is implemented, as will be discussed in more detail in the evaluation section.

Target Market and Eligibility Requirements

All KCP&L commercial and industrial retail customers are eligible for the program. However, the RFP's will only be issued to certain sub segments and with certain types of projects/technologies accepted. Some sample targets include:

- Hospitals and Health Care institutions HVAC equipment and controls.
- Printing industry process projects.

Technology Categories

These RFP measures will not include prescriptive technologies unless they are bundled together with custom measures and/or controls. All other cost effective electric efficiency improvements will be considered.

Market Barriers

Market barriers vary by technology and customer segment. They include but are not limited to:

- Lack of investment funds or high costs
- Cost to analyze potential savings from a project through assessments/audits
- Competition for funds with other projects
- Lack of awareness/knowledge by customers, engineers and contractors
- Lack of time
- Increased perceived risk from a newer technology in performance
- High transaction and information search costs

Working with the market actors, increasing awareness and providing incentives, KCP&L expects to reduce many of these barriers and stimulate installation of these measures.

Components of Delivery

Incentives:
The C&I RFP Program is a financial assistance and education program that provides incentives for the installation of energy efficiency measures in existing non-residential facilities in response to the unique specifications of the RFP. Customers/Contractors will submit their project proposals in response to the RFP including savings estimates. KCP&L staff or its subcontractor will review these proposals and savings estimates and determine if they qualify for a financial award. This review of the savings analysis helps assure that KCP&L funds are being cost effectively used to promote efficiency.

Incentives will be identified within the RFP on a per kWh and per kW basis so that both energy and demand savings will be rewarded. Levels of incentives will vary depending on the specific RFP. The initial incentives will be established for each RFP separately based on DSMore cost effectiveness modeling. Other guidelines to reduce free ridership will also be established. These include years of payback, total incentive dollars per customer per year and percent of total project cost.

Education & Instruction:
Education and promotional materials will be developed for building owners and operators on the RFP program, including educational brochures, program promotional material, and website content. Specific educational and promotional efforts aimed at market actors such as electrical contractors, building supply firms, and distributors to help them promote the RFP efficient measures to their customers. This education will be through a combination of mailings and direct meetings with key market actors in the area.

Program Marketing and Communications Strategy
The marketing and communications strategy will be designed to inform customers of the availability and benefits of the RFP program and how they can participate in the program. Certain key customer segments will be targeted based on their qualifications in the targeted market segment, energy savings potential and technology. The strategy will also include outreach to key equipment partners and trade allies including consulting architects and engineering firms, process and refrigeration contractors and distributors, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the KCP&L website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market targeted by the RFP to provide details about how to participate in the Program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;

- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
  - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and www.KCPL.com and will be available for various public awareness events (presentations, seminars etc).
  - Targeted direct mailings used to educate customers on the benefits of the program and explaining how they can submit a proposal.
  - Customer and trade partner outreach and presentations (e.g. Restaurant Association, BOMA and other customer organizations) informing targeted parties about the benefits of the program and how to participate.
  - Print advertisements to promote the program placed in selected local media including the Kansas City area newspapers and trade publications.
  - KCP&L website content providing program information resources, contact information, downloadable RFP application forms and worksheets, and links to other relevant service and information resources.
  - KCP&L customer account representatives trained to promote the program to their customers.
  - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials.
  - Presentations by the program manager to key target market segment customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing, and will prepare specific outreach activities for these customers.
- KCP&L will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program.

Delivery Strategy and Administration

Designated KCP&L staff person(s) will provide program administration, marketing, vendor referrals, application and incentive processing, coordination of education and training activities, participation tracking and reporting, quality control, and technical support. There will be specific staff assigned to work with the market actors/channels to promote the program and support the markets sales efforts. This market channel work crosses over with the Prescriptive Program activities so that both are promoted to these key market actors. As well KCP&L account representatives will be expected to promote the program to their customers directly and cross promote other programs. Based on the ultimate size of the program and other issues KCP&L may outsource the program to an "implementation contractor".

Evaluation, Measurement and Verification (EM&V)

KCP&L has already adopted an integrated data collection EM&V strategy that is designed to provide a quality data resource for program tracking, management and evaluation. This approach integrates program evaluation planning with overall program planning, and starts program evaluation activities at the same time as the program is implemented. This approach entails the following primary activities:

- **Database management** - As part of program operation, KCP&L's evaluation contractor will collect the necessary data elements to populate the tracking database and provide periodic reporting.
- **Integrated implementation data collection –** KCP&L will work with the evaluation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification –** For the RFP program all projects will be reviewed by KCP&L's staff engineers or subcontractors for determining qualification under the RFP guidelines and the incentives for each project. This will help assure cost effectiveness of the projects. It will also act in the first step of quality control. After project completion KCP&L's evaluation contractor will conduct field verification of the ex ante and ex post conditions for at least the largest projects and a sample of medium sized projects throughout the implementation of the program. The verification protocol will be a random sample of 5% of the applications up to $10,000 and a 10% sampling of projects from $10,000 to $30,000. All projects over $30,000 will be verified. If a contractor has unresolved or ongoing problems, they can be removed from the program at KCP&L's discretion.
- **Tracking of savings using estimated savings values –** The participating customers or their consultants or vendors will develop estimated savings values for each application submitted through the program. These will be reviewed prior to the project implementation and entered in the database as pending. After project completion the actual installed information will be entered and compared to the initial project estimate. Further, the M&V process will verify or revise the initial estimated savings values.

This approach will provide KCP&L with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Budget and Staffing

- The total five year Custom, New Construction and RFP program budget is approximately $11.5 - $17.9 Million depending on whether the expected or aggressive participation is adopted. These three programs cannot at this time be separated as the participant mix can't be determined between them.
- Approximately 50% of program budgets are for customer incentives and 50% of the program budgets are for program delivery, administration, marketing, and evaluation.
- Suggested initial KCP&L staffing for the RFP program includes a half-time program manager, a half-time program administrative/data support person, a half-time trade ally liaison, and the equivalent of about 1 FTE of account reps time to promote the program to their customers.
- Program monitoring, verification and evaluation costs will be about five percent of the total budget.

Program Impact Summaries

- Total estimated program peak demand reductions for the combined Custom, New Construction and RFP programs are 11.8 – 18.4 MW in year five.
- Total estimated lifetime kWh savings for the combined Custom, New Construction and RFP programs for the 5 year program are 711,000,000 – 1,106,000,000 kWh.

Program Benefit-Cost Results

Based on the DSMore results, the expected Custom, New Construction and RFP program level benefit cost ratios for each of the five main California Standard Practice tests are:

- Utility Test: 5.62
- TRC Test: 3.80
- RIM Test: 1.92
- Societal Test: 4.22
- Participant Test: 2.48

Section 2: Cost Effectiveness Analysis

Methodology

KCP&L wants to assure its ratepayers, its shareholders, the regulatory agencies and the whole community that its programs are cost effective. There are many perspectives from which to judge cost effectiveness and with this analysis MMP is providing all the California Standard Practice Manual tests showing these different perspectives.

- Utility Cost Test (UCT)
- Total Resource Cost Test (TRC)
- Ratepayer Impact Test (RIM)
- Participant Test
- Societal Test

To make this analysis, MMP used the DSMore modeling tool. The leading cost effectiveness modeling tool in the country. . DSMore was developed by Integral Analytics (IA) for application to DSM program design and evaluation within both regulated and deregulated markets. This application is unique in that it values DSM using a risk-based approach, in much the same way that asset planners approach their valuations. The covariance between prices and loads is captured at the hourly level to accurately measure the risk-based DSM value. This model was also used by Summit Blue in its high level studies.

The DSMore model was used to analyze individual measures that might be included within the program, groups of measures, measures rolled up into programs and finally the portfolio of programs for KCPL. For the measure analysis, engineering estimates and modeling of savings was completed by Architectural Energy Corporation (AEC) and Franklin Energy Services (FES) under subcontract to MMP. The basic inputs needed for the modeling of each measure include:

- Energy Savings
- Demand savings
- Effective Useful Life
- Incremental Cost for the Efficient Measure
- Proposed Incentives
- Administrative & Implementation Costs for the Program
- Operating Hours
- Participation/Installation Rates per Year
- Expected Net Results (net of free riders and spillover)

MMP also worked with KCPL to develop the utility inputs required. These inputs include the rates, prices, escalation rates. Those assumptions will be provided under a separate document due to the potential sensitive and proprietary information within.

One of the most sensitive assumptions within the model is the participation rates for the programs. MMP used the Summit Blue analysis, experience from other similar programs in the Midwest, and its experience in designing and implementing these programs to determine potential participation by measure. There were four scenarios developed, a baseline “expected” scenario and an “aggressive” scenario at both high and normal incentive levels. The aggressive scenario assumed additional focus, resources, marketing and other influencers that might increase the amount of program participation over the five year planning period. This aggressive scenario assumed a 25% increase over the baseline in year one and a 20% increase in participation per year (versus a 10% increase in the expected scenario). While the aggressive scenario is still achievable, it would be a stretch in MMP’s professional opinion to reach that level of participation. The normal incentive levels are based on what other similar programs are doing elsewhere in the country and the judgments of the planners on what level of incentives are needed to stimulate the market. The higher incentives were based on increasing the incentives until they supply 50% of the incremental cost of the measure or the customer has a two year payback on that incremental cost whichever is less. It is anticipated that this will help increase participation to the aggressive participation levels modeled. By having this range of results and costs, KCPL can better make a judgment on the range of expectations from the programs and the risks involved in achievement. Probabilities were applied to each scenario on the expected results.

To verify the assumed participation was realistic, Franklin Energy Services compared these projections to actual results from two existing programs in Wisconsin; the Focus on Energy program and the WE Energies program. As FES implements all or portions of each of those two programs, their experience provides added validity to the assumptions used for KCPL.

Results

The results of the analysis by measure are included in Appendix A. Over 130 C&I technologies of various sizes and configurations were analyzed under both the expected and aggressive scenarios for cost effectiveness. Proposed incentive levels for the prescriptive program were adjusted within each measure to be cost effective yet move the market. The results show all measures to be cost effective. Note that over time measures offered within a prescriptive program should change as new technologies are developed and as market acceptance changes so this technology listing should be considered the initial offerings and reviewed annually for updates or changes.

To better understand cost effectiveness of all technologies these individual test results were “rolled-up” into a program portfolio using DSMore to get their aggregate cost effectiveness scores across all four programs. You can see below the results for each of the four scenarios, High Incentives/Aggressive Participation, Normal Incentives/Aggressive Participation, High Incentives/Expected Participation and Low Incentives/Expected Participation.

	ALL			
	ALL - HIGH AGG	ALL - Normal AGG	ALL - High Expected	ALL Normal Expected
Utility Test	6.66	8.38	6.52	8.36
TRC Test	4.41	4.41	4.35	4.35
RIM Test	2.00	2.13	1.99	2.13
Societal Test	4.91	4.91	4.84	4.84
Participant Test	2.46	2.30	2.44	2.26

These results clearly show that a cost effective portfolio of measures/programs and their recommended incentives have been developed and should be implemented by KCPL.

As part of the portfolio, the Custom program incentive levels were developed using DSMore to assure cost effectiveness. Custom measures by definition cannot have their energy savings defined so that measure level cost effectiveness cannot be determined and cannot be included within the Prescriptive program. Two levels of incentives are proposed within the Custom program. Based on DSMore analysis both are cost effective, however, two incentive levels are provided to respond to market need while being sensitive to potential free rider levels and budget constraints. The higher level incentives are to be used on technologies that are newer to the marketplace, have higher perceived risk, higher market barriers or higher costs and thus need higher incentives to stimulate the participation. The lower incentives are to be used for technologies that have been proven in the marketplace but need the incentives to improve cost effectiveness or to help stimulate the market.

The New Construction program will use the two Custom incentive levels plus an intermediate level between the two to give more range to the incentive options. Based on our analysis, this as well is cost effective.

The RFP program incentives are not yet defined. MMP recommends that KCPL utilize the DSMore model as part of the review of various proposals when received to determine cost effectiveness and the final incentive levels. This process will insure cost effectiveness of the program.

Budgets & Savings

Also during the DSMore analysis, total expected savings based on participation, incentives and the program designs were developed. These budgets/costs and energy savings are used as part of the determination of the tests. We have summarized the results below for all four scenarios.

	ALL			
	ALL - HIGH AGG	ALL - Normal AGG	ALL - High Expected	ALL Normal Expected
kWh Gross - Lifetime	3,268,350,121	3,268,350,121	2,037,845,892	2,037,845,892
kW Gross Yr 5	71,565	71,565	43,872	43,872
Program Costs	$ 34,072,381	$ 27,175,909	$ 21,474,058	$ 16,843,878

MMP then assigned probabilities to each scenario occurring based on experience and the planning process results. The probability assigned to each are:

High Incentive/Expected Participation = 90%
Normal Incentive/Expected Participation = 80%
High Incentive/Aggressive Participation = 70%
Normal Incentive/Aggressive Participation = 60%

Given all these weightings of probability the results are:

Average Probability Weighted Results

kWh Gross - Lifetime	2,571,064,391
kW Gross	55,872
Program Costs	$ 24,319,322

KCPL will need to finalize this program budgets based on its strategic goals, regulatory and management needs. MMP stands ready to help with this process.

Section 3: Weather Sensitive/ HVAC Measures

Study Methodology

HVAC measure energy and demand savings were established by using a set of prototypical building models developed for the DOE-2.2 building energy simulation program. Prototype models were developed for small retail, big-box retail, small office, large office, fast food restaurant, full service restaurant, school, assembly and light industrial buildings. These buildings represent the types of customers that are expected to participate in the program. The prototypes are based on the models used in the California DEER study, with appropriate modifications to adapt these models to local design practices and climate. Energy savings estimates were developed from the prototype models for entry into the DSMore cost-effectiveness tool.

The HVAC measures for small commercial buildings include single package rooftop air conditioners and heat pumps, split system air conditioners and heat pumps, packaged terminal air conditioners and heat pumps, and ground source and water loop heat pumps. The HVAC measures for the large office building include air cooled chillers, water cooled chillers, variable frequency drives (VFD) applied to fans and pumps, and chilled water temperature reset controls. The program baseline is defined by the National Appliance Energy Conservation Act (NAECA) minimum efficiency for single phase equipment and ASHRAE 90.1 – 2004 minimum efficiency for three phase equipment. HVAC measures cover the upgrade of standard efficiency packaged HVAC systems with high efficiency versions of the same equipment. The calculations do not address HVAC system type changes (e.g. the energy savings from changing from a rooftop AC system to a ground-source heat pump system).

Measure Efficiency Assumptions

The equipment covered, the size ranges, and the program baseline and measure efficiency assumptions are shown in Table .

Table 1. HVAC Equipment Efficiency Assumptions

Equipment Category	Capacity Range Btu/hr	Baseline Efficiency Value	Baseline Efficiency Units	Source	Measure Efficiency Value	Measure Efficiency Units
Packaged Terminal A/C	All	8.9	EER	ASHRAE 90.1-2004	9.2	EER
Packaged Terminal HP	All	8.7	EER	ASHRAE 90.1-2004	9	EER
Rooftop A/C (1) phase	<65,000 1 Ph	13	SEER	NAECA	14	SEER
Rooftop A/C (3) phase	<65,000 3 Ph	12	SEER	ASHRAE 90.1-2004	13	SEER
Rooftop A/C (3) phase	65,000 - 135,000	10.1	EER	ASHRAE 90.1-2004	11	EER
Rooftop A/C (3) phase	135,000 - 240,000	9.5	EER	ASHRAE 90.1-2004	11	EER
Rooftop A/C (3) phase	240,000 - 760,000	9.3	EER	ASHRAE 90.1-2004	10	EER
Rooftop A/C (3) phase	>760,000	9	EER	ASHRAE 90.1-2004	10	EER
Rooftop HP (1) phase	<65,000 1 Ph	13	SEER	NAECA	14	SEER
Rooftop HP (3) phase	<65,000 3 Ph	12	SEER	ASHRAE 90.1-2004	13	SEER
Rooftop HP (3) phase	65,000 - 135,000	9.9	EER	ASHRAE 90.1-2004	11	EER
Rooftop HP (3) phase	135,000 - 240,000	9.1	EER	ASHRAE 90.1-2004	10	EER
Rooftop HP (3) phase	>240,000	8.8	EER	ASHRAE 90.1-2004	10	EER
Ground Source HP Closed Loop	<135,000 & 59 F EWT	16.2	EER	ASHRAE 90.1-2004	16.5	EER
Ground Source HP Closed Loop	<135,000 & 77 F EWT	13.4	EER	ASHRAE 90.1-2004	13.7	EER
Water Source Heat Pump	<17,000	11.2	EER	ASHRAE 90.1-2004	11.5	EER
Water Source Heat Pump	17,000 - 65,000	12	EER	ASHRAE 90.1-2004	12.3	EER
Water Source Heat Pump	65,000 - 135,000	12	EER	ASHRAE 90.1-2004	12.3	EER
Air Cooled Chillers	All	1.33	kW/ton	ASHRAE 90.1-2004	1.16	kW/ton
Water Cooled Chillers	< 150 ton	0.835	kW/ton	ASHRAE 90.1-2004	0.78	kW/ton
Water Cooled Chillers	150 - 300 ton	0.74	kW/ton	ASHRAE 90.1-2004	0.56	kW/ton
Water Cooled Chillers	> 300 ton	0.69	kW/ton	ASHRAE 90.1-2004	0.54	kW/ton

Additional measure modeling assumptions are summarized in Table.

Table 2. Measure Assumptions for Controls ,Tune-up and Economizer Measures

Measure	Baseline Assumption	Measure Assumption	Comments
Economizer	Fixed outdoor air.	Dual sensor enthalpy economizer	Maximum efficiency economizer control strategy assumed.
AC tuneup	14% degradation in efficiency for un-tuned unit	Unit runs at rated efficiency (EER=8)	Tuneup applied to existing equipment only
VFD fan motor	Central VAV system with inlet vane air volume control	Central VAV system with VFD air volume control	Applied to large office prototype only
VFD pump control	Constant volume chilled water system with 3-way control valves at cooling coils	Variable volume chilled water system with 2 way control valves at cooling coils	Applied to chilled water pumps in large office prototype only
Chilled water reset control	Constant chilled water temperature setpoint control	Chilled water temperature controlled by coil demanding the most cooling	Applied to large office prototype only

Secondary Research Review

Secondary research review was conducted to obtain estimates of engineering parameters used to develop the simulation models. The review incorporated research conducted in support of the California Database for Energy Efficiency Resources (DEER) study and the US Energy Information Agency (EIA) Commercial Building Energy Consumption Sudy (CBECS). Building characterstics data from the CBECS study for the West North Central census region were used to update the DEER prototype model. Insulation levels and glazing properties for existing buildings were set according the provisions of ASHRAE Standard 90A-1980. Insulation levels, glazing properties and lighting power densities for new construction were set according to ASHRAE Standard 90.1-2004. A description of each prototype simulation model follows.

Small Retail

A prototypical building energy simulation model for a small retail building was developed using the DOE-2.2 building energy simulation program. The characteristics of the small retail building prototype are summarized in Table .

Table 3. Small Retail Prototype Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	6400 square foot sales area 1600 square foot storage area

Characteristic	Value
	8000 square feet total
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Lighting power density	Existing building: Sales area: 3.4 W/SF Storage area: 0.9 W/SF New construction: Sales area: 1.7 W/SF Storage area: 0.9 W/SF
Plug load density	Sales area: 1.2 W/SF Storage area: 0.2 W/SF
Operating hours	10 – 10 Monday-Saturday 10 – 8 Sunday
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: Sales floor: 221 SF/ton Storage area: 349 SF/ton New building Sales floor: 275 SF/ton Storage area: 460 SF/ton
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

A computer-generated sketch of the small retail building prototype is shown in Figure 1.

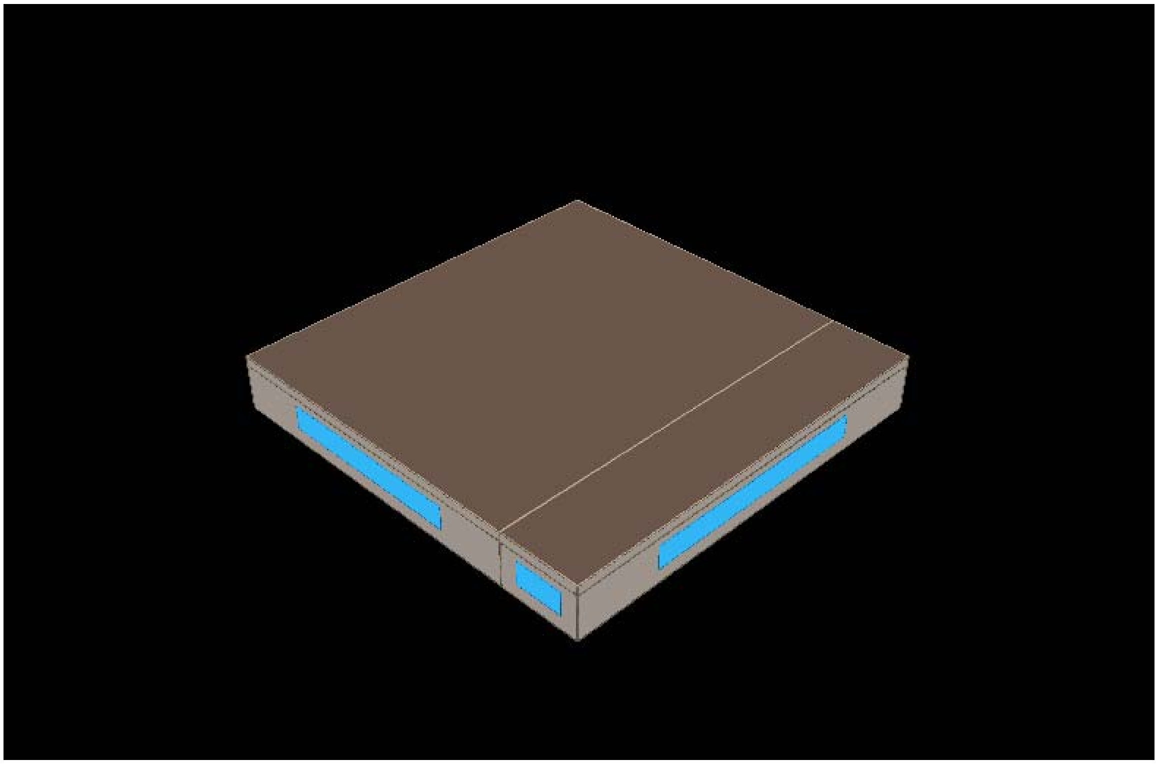


Figure 1. Small Retail Prototype Building Rendering

Full-service Restaurant

A prototypical building energy simulation model for a full-service restaurant was developed using the DOE-2.2 building energy simulation program. The characteristics of the full service restaurant prototype are summarized in Table .

Table 4. Full Service Restaurant Prototype Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	2000 square foot dining area 600 square foot entry/reception area 1200 square foot kitchen 200 square foot restrooms
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)

Characteristic	Value
Lighting power density	Existing building: Dining area: 1.7 W/SF Entry area: 2.5 W/SF Kitchen: 4.3 W/SF Restrooms: 1.0 W/SF New construction: Dining area: 2.1 W/SF Entry area: 1.1 W/SF Kitchen: 1.2 W/SF Restrooms: 0.9 W/SF
Plug load density	Dining area: 0.6 W/SF Entry area: 0.6 W/SF Kitchen: 3.1 W/SF Restrooms: 0.2 W/SF
Operating hours	9am – 12am
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: Dining area: 136 SF/ton Entry area: 76 SF/ton Kitchen: 189 SF/ton Restrooms: 159 SF/ton New construction: Dining area: 144 SF/ton Entry area: 84 SF/ton Kitchen: 239 SF/ton Restrooms: 173 SF/ton
Thermostat setpoints	Occupied hours: 77 cooling, 72 heating Unoccupied hours: 82 cooling, 67 heating

A computer-generated sketch of the full-service restaurant prototype is shown in Figure 2.

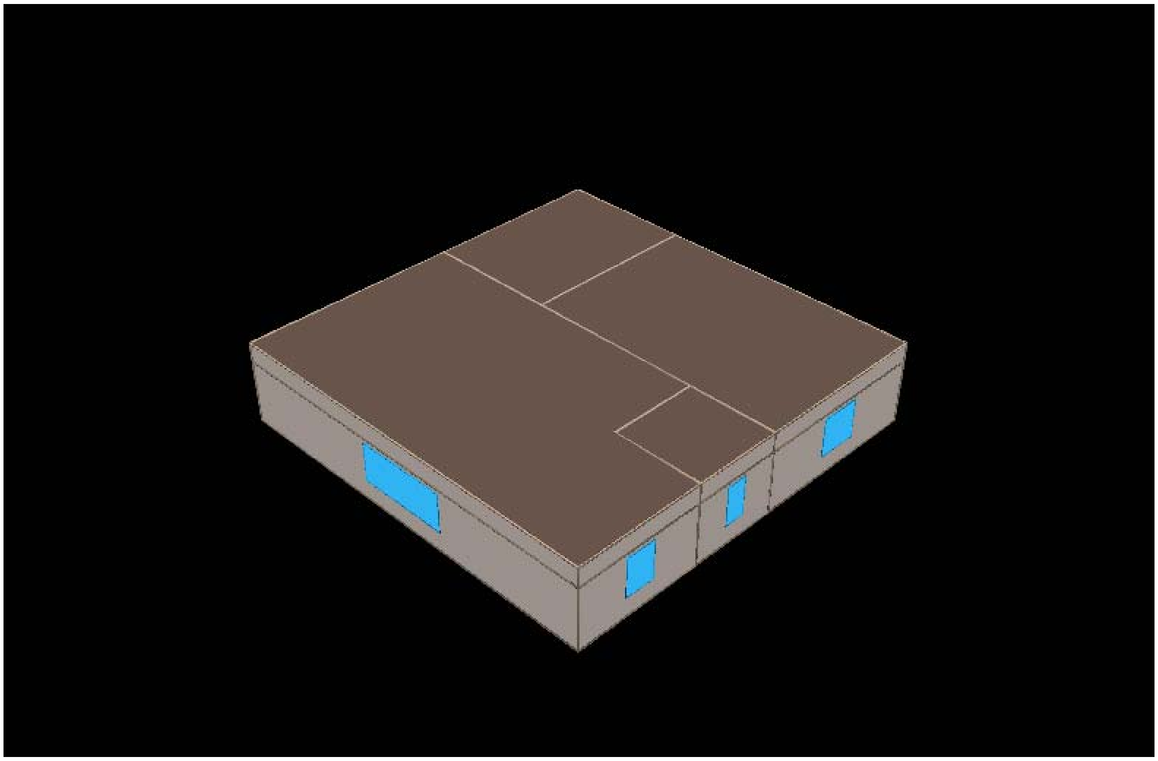


Figure 2. Full Service Restaurant Prototype Rendering

Small Office

A prototypical building energy simulation model for a small office was developed using the DOE-2.2 building energy simulation program. The characteristics of the small office prototype are summarized in Table .

Table 5. Small Office Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	10,000 square feet
Number of floors	2
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)

Characteristic	Value
Lighting power density	Existing building: Perimeter offices: 2.2 W/SF Core offices: 1.5 W/SF New construction: Perimeter offices: 1.1 W/SF Core offices: 1.1 W/SF
Plug load density	Perimeter offices: 1.6 W/SF Core offices: 0.7 W/SF
Operating hours	Mon-Sat: 9am – 6pm Sun: Unoccupied
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 171 SF/ton New construction: 236 SF/ton
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

A computer-generated sketch of the small office prototype is shown in Figure 3.

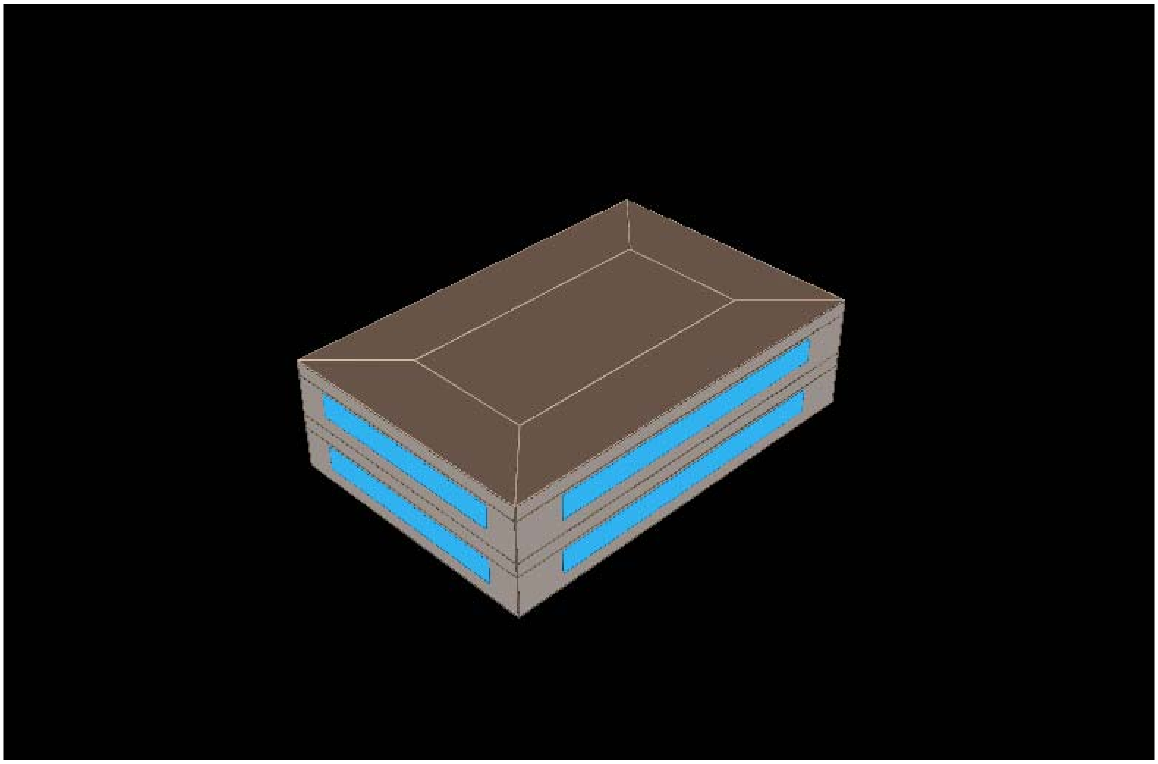


Figure 3. Small Office Prototype Building Rendering

Light Industrial

A prototypical building energy simulation model for a light industrial building was developed using the DOE-2.2 building energy simulation program. The characteristics of the prototype are summarized in Table .

Table 6. Light Industrial Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	100,000 square feet total 80,000 SF factory 20,000 SF warehouse
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Lighting power density	Existing building: Factory – 2.1 W/SF Warehouse – 0.9 W/SF New construction: Factory – 1.7 W/SF Warehouse – 0.9 W/SF
Plug load density	Factory – 1.2 W/SF Warehouse – 0.2 W/SF
Operating hours	Mon-Fri: 6am – 6pm Sat Sun: Unoccupied
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 478 SF/ton New construction: 523 SF/ton
Thermostat setpoints	Occupied hours: 78 cooling, 70 heating Unoccupied hours: 83 cooling, 65 heating

A computer-generated sketch of the prototype is shown in Figure 4.

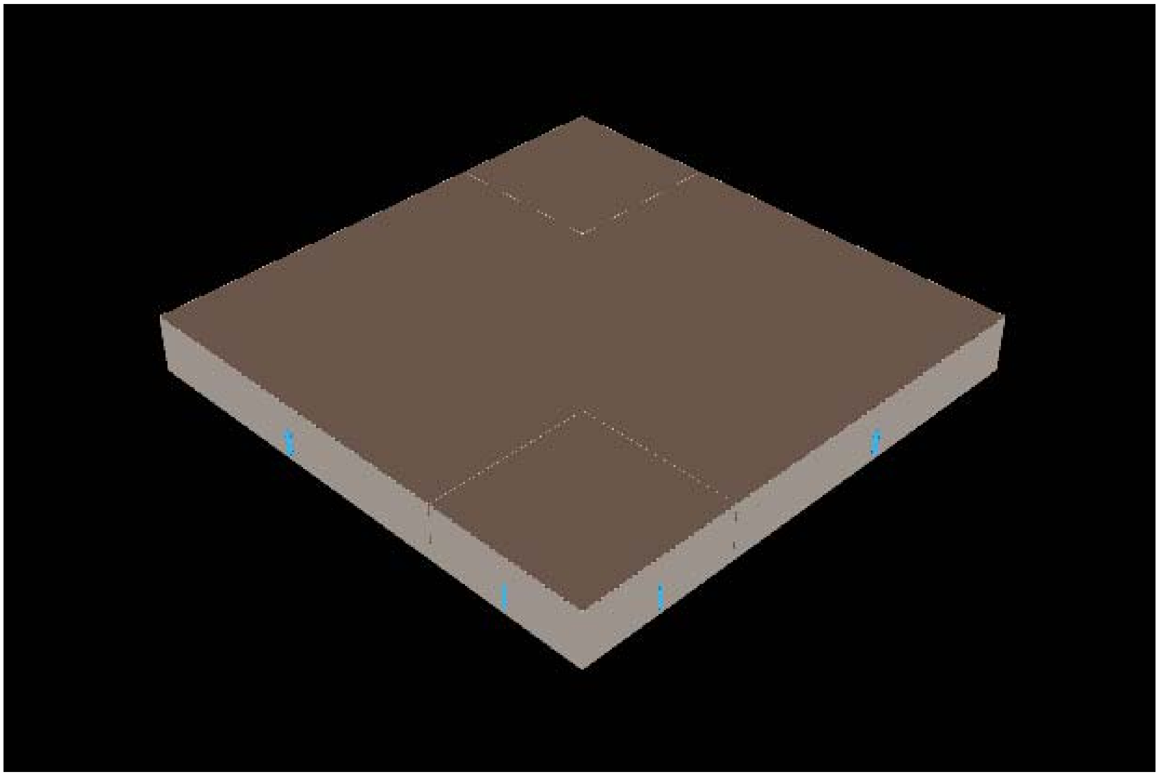


Figure 4. Light Industrial Building Rendering

Big Box Retail

A prototypical building energy simulation model for a big box retail building was developed using the DOE-2.2 building energy simulation program. The characteristics of the prototype are summarized in Table .

Table 7. Big Box Retail Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	130,500 square feet Sales: 107,339 SF Storage: 11,870 SF Office: 4,683 SF Auto repair: 5,151 SF Kitchen: 1,459 SF
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15

Characteristic	Value
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Lighting power density	Existing building: Sales: 3.36 W/SF Storage: 0.88 W/SF Office: 2.2 W/SF Auto repair: 2.15 W/SF Kitchen: 4.3 W/SF New construction: Sales: 1.7 W/SF Storage: 0.9 W/SF Office: 1.1 W/SF Auto repair: 0.7 W/SF Kitchen: 1.2 W/SF
Plug load density	Sales: 1.15 W/SF Storage: 0.23 W/SF Office: 1.73 W/SF Auto repair: 1.15 W/SF Kitchen: 3.23 W/SF
Operating hours	Mon-Sun: 10am – 9pm
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 256 SF/ton New construction: 309 SF/ton
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

A computer-generated sketch of the prototype is shown in Figure 5.

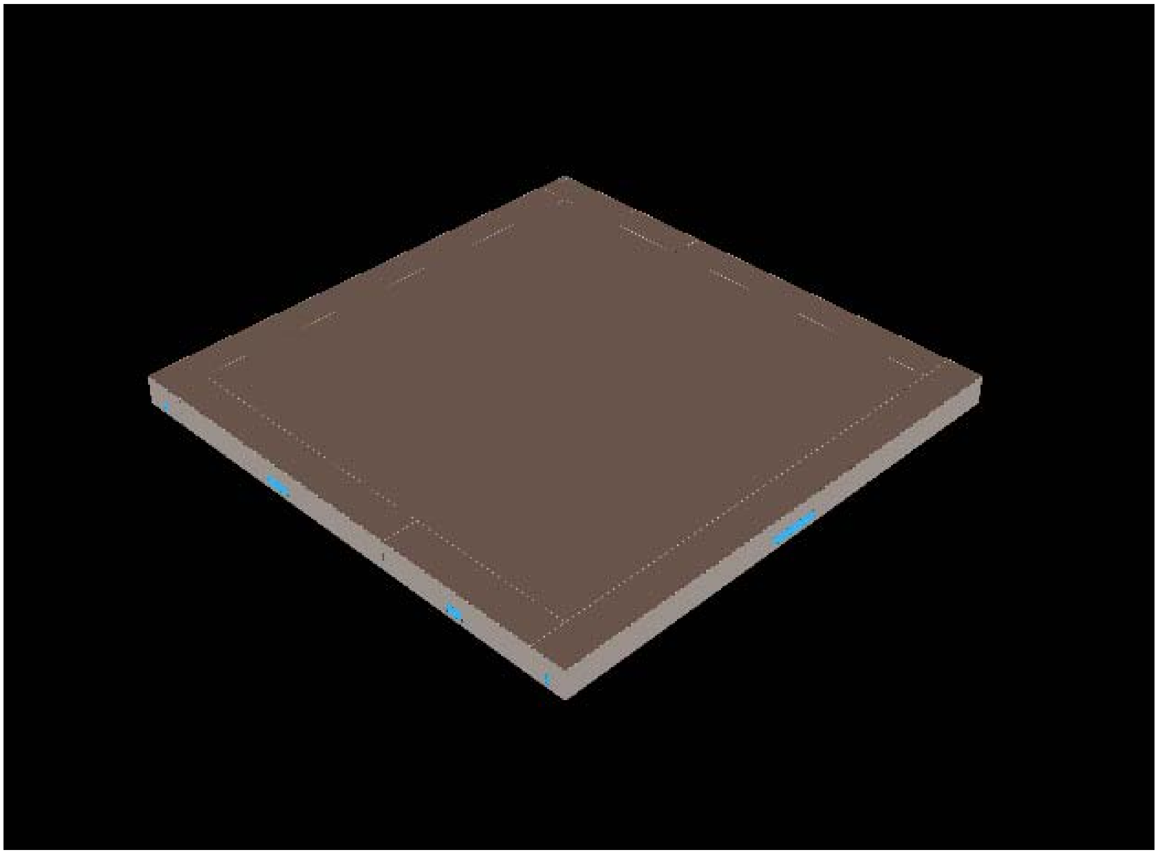


Figure 5. Big Box Retail Building Rendering

Fast Food Restaurant

A prototypical building energy simulation model for a fast food restaurant was developed using the DOE-2.2 building energy simulation program. The characteristics of the prototype are summarized in Table .

Table 8. Fast Food Restaurant Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	2000 square feet 1000 SF dining 600 SF entry/lobby 300 SF kitchen 100 SF restroom
Number of floors	Concrete block with brick veneer. Insulation R-value = 5.7
Wall construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15

Characteristic	Value
Roof construction and R-value	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Glazing type	Single pane clear
Lighting power density	Existing building: 1.7 W/SF dining 2.5 W/SF entry/lobby 4.3 W/SF kitchen 1.0 W/SF restroom New construction: 0.9 W/SF dining 1.1 W/SF entry/lobby 1.2 W/SF kitchen 0.9 W/SF restroom
Plug load density	0.6 W/SF dining 0.6 W/SF entry/lobby 4.3 W/SF kitchen 0.2 W/SF restroom
Operating hours	Mon-Sun: 6am – 11pm
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 89 SF/ton New construction: 105 SF/ton
Thermostat setpoints	Occupied hours: 77 cooling, 72 heating Unoccupied hours: 82 cooling, 67 heating

A computer-generated sketch of the prototype is shown in Figure 6.

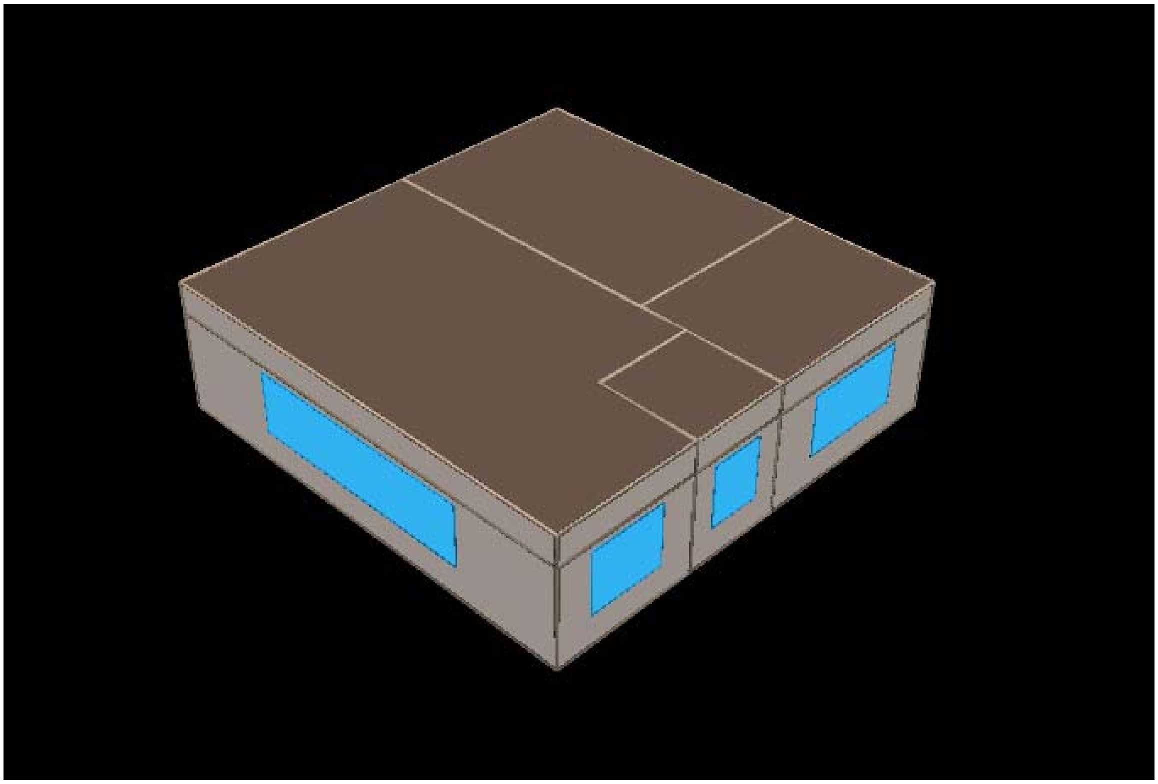


Figure 6. Fast Food Restaurant Building Rendering

School

A prototypical building energy simulation model for an elementary school was developed using the DOE-2.2 building energy simulation program. The model is really of two identical buildings oriented in two different directions. The characteristics of the prototype are summarized in Table .

Table 9. Elementary School Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	2 buildings, 25,000 square feet each; oriented 90° from each other Classroom: 15,750 SF Cafeteria: 3,750 SF Gymnasium: 3,750 SF Kitchen: 1,750 SF
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15

Characteristic	Value
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Lighting power density	Existing building: Classroom: 4.4 W/SF Cafeteria: 1.7 W/SF Gymnasium: 2.1 W/SF Kitchen: 4.3 W/SF New construction: Classroom: 1.4 W/SF Cafeteria: 0.9 W/SF Gymnasium: 1.4 W/SF Kitchen: 1.2 W/SF
Plug load density	Classroom: 1.2 W/SF Cafeteria: 0.6 W/SF Gymnasium: 0.6 W/SF Kitchen: 4.2 W/SF
Operating hours	Mon-Fri: 8am – 6pm Sun: 8am – 4pm
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 195 SF/ton average New construction: 235 SF/ton average
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

A computer-generated sketch of the prototype is shown in Figure 7.

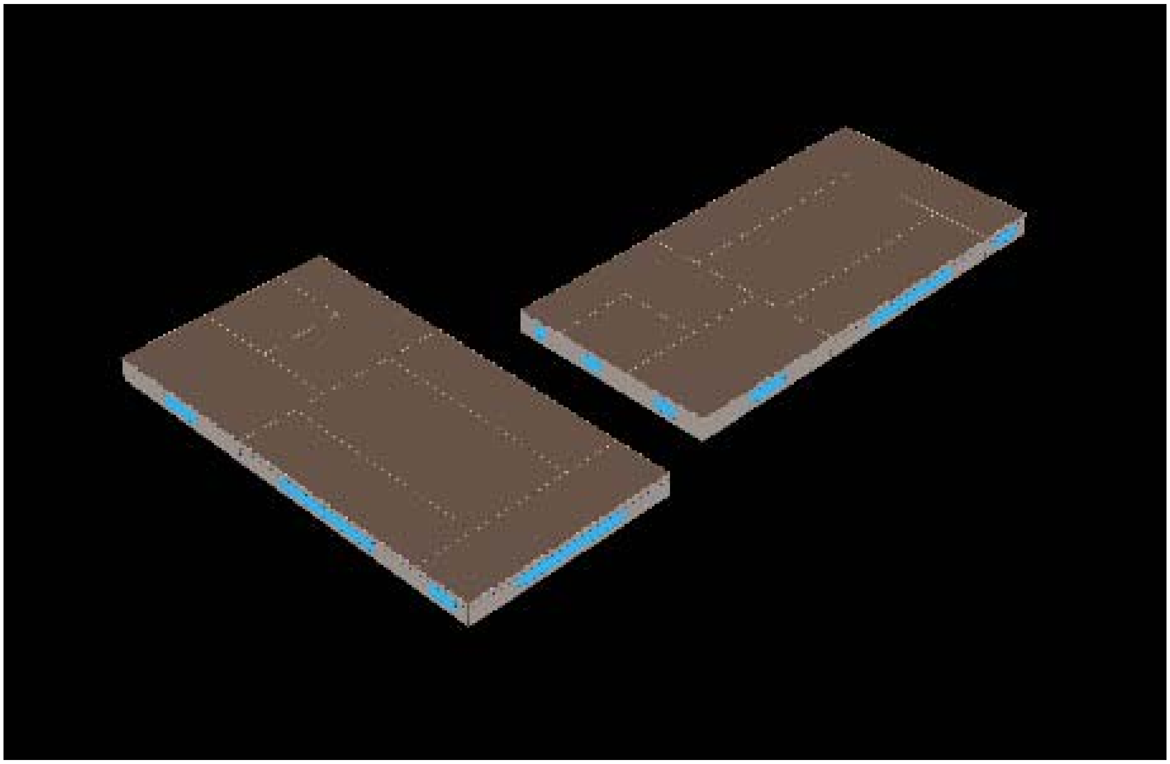


Figure 7. School Building Rendering

Assembly

A prototypical building energy simulation model for an assembly building was developed using the DOE-2.2 building energy simulation program. The characteristics of the prototype are summarized in Table .

Table 10. Assembly Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	34,000 square feet Auditorium: 33,240 SF Office: 760 SF
Number of floors	1
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)

Characteristic	Value
Lighting power density	Existing building: Auditorium: 3.4 W/SF Office: 2.2 W/SF New construction: Auditorium: 1.7 W/SF Office: 1.1 W/SF
Plug load density	Auditorium: 1.2 W/SF Office: 1.7 W/SF
Operating hours	Mon-Sun: 8am – 9pm
HVAC system type	Packaged single zone, no economizer
HVAC system size	Existing building: 91 SF/ton New construction: 98 SF/ton
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

A computer-generated sketch of the prototype is shown in Figure 8.

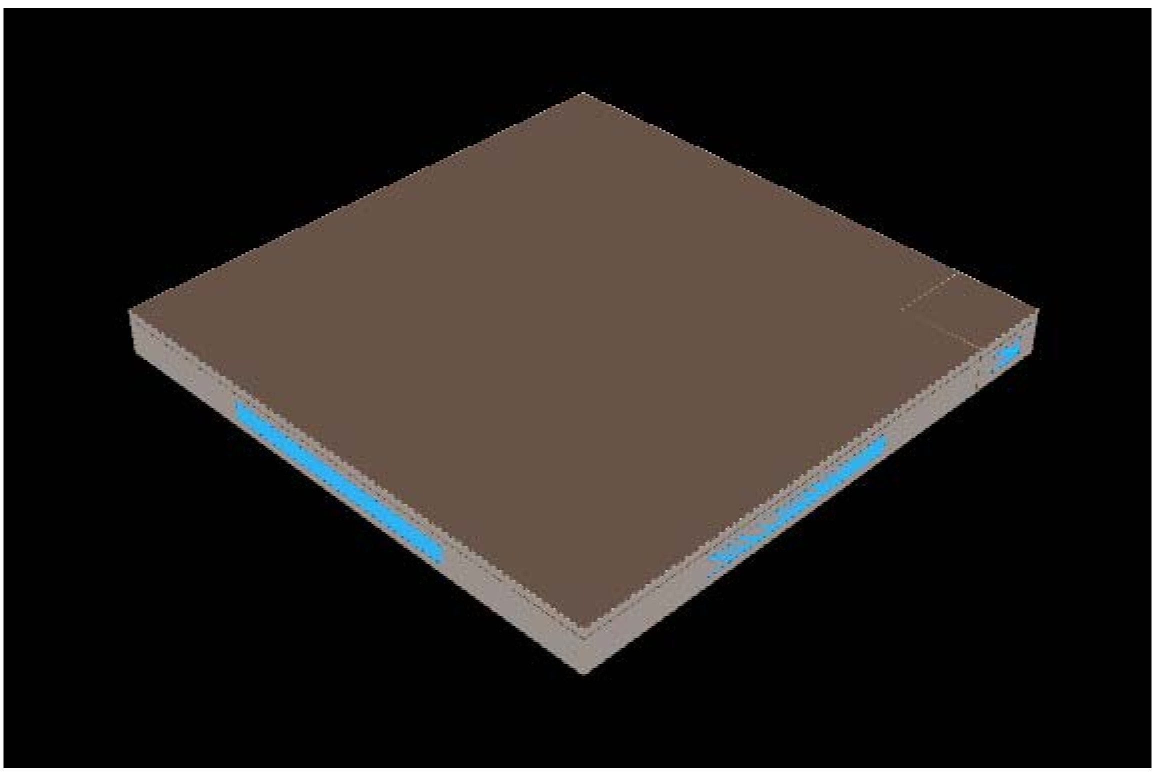


Figure 8. Assembly Building Rendering

Large Office

A prototypical building energy simulation model for a small office was developed using the DOE-2.2 building energy simulation program. The characteristics of the large office prototype are summarized in Table .

Table 11. Large Office Prototype Building Description

Characteristic	Value
Vintage	Existing (1980s) vintage and new construction
Size	175,000 square feet
Number of floors	10
Wall construction and R-value	Concrete block with brick veneer. Insulation R-value = 5.7
Roof construction and R-value	Wood frame with built-up roof Existing building insulation: R- 8.4 New construction insulation R-15
Glazing type	Existing building: Double pane clear (SC=0.84, U-value=0.72) New construction: Double low-e tint (SC=0.45, U-value=0.57)
Lighting power density	Existing building: Perimeter offices: 2.2 W/SF Core offices: 1.5 W/SF New construction: Perimeter offices: 1.1 W/SF Core offices: 1.1 W/SF
Plug load density	Perimeter offices: 1.6 W/SF Core offices: 0.7 W/SF
Operating hours	Mon-Sat: 9am – 6pm Sun: Unoccupied
HVAC system type	Central built-up VAV system with water cooled centrifugal chiller and boiler.
HVAC system size	Existing building: 235 SF/ton New construction: 284 SF/ton
Thermostat setpoints	Occupied hours: 76 cooling, 72 heating Unoccupied hours: 81 cooling, 67 heating

Energy and Peak Demand Savings Estimates

Energy and peak demand savings estimates were developed based on difference the simulated HVAC energy consumption and peak demand at the baseline and the measure efficiency levels. Energy and demand savings were normalized per ton of cooling capacity. The simulations used TMY2 long-term average weather data for Kansas City, Missouri. The results for each of the prototype building and HVAC system type and size combinations are shown in Table through Table .

Schedule JMO-3

Table 12. Assembly Building HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.079	74	0.079	71
AC <65,000 3 Ph	0.059	56	0.059	53
AC 65,000 - 135,000	0.081	77	0.082	74
AC 135,000 - 240,000	0.144	136	0.144	130
AC 240,000 - 760,000	0.076	71	0.076	68
AC >760,000	0.112	105	0.112	101
HP <65,000 1 Ph	0.085	138	0.085	140
HP <65,000 3 Ph	0.059	77	0.059	77
HP 65,000 - 135,000	0.103	149	0.103	150
HP 135,000 - 240,000	0.101	175	0.101	179
HP >240,000	0.139	211	0.139	213
GSHP <135,000	0.009	7	0.009	6
WLHP <17,000	0.024	32	0.024	31
WLHP 17,000-65,000	0.021	28	0.021	27
WLHP 65,000-135,000	0.021	28	0.021	27
Economizer	0.081	96	0.000	13
AC Tuneup	0.175	165		

Table 13. Big Box Retail HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.077	83	0.077	76
AC <65,000 3 Ph	0.058	62	0.058	56
AC 65,000 - 135,000	0.171	184	0.079	76
AC 135,000 - 240,000	0.141	152	0.140	135
AC 240,000 - 760,000	0.074	80	0.074	71
AC >760,000	0.109	117	0.109	105
HP <65,000 1 Ph	0.082	113	0.082	116
HP <65,000 3 Ph	0.058	71	0.058	69
HP 65,000 - 135,000	0.100	130	0.100	129
HP 135,000 - 240,000	0.098	140	0.098	145
HP >240,000	0.135	180	0.135	181
Economizer	0.080	166	0.079	118
Tuneup	0.171	184		

Table 14. Fast Food Restaurant HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.077	67	0.073	57
AC <65,000 3 Ph	0.058	50	0.058	44
AC 65,000 - 135,000	0.080	69	0.080	60
AC 135,000 - 240,000	0.141	122	0.141	106
AC 240,000 - 760,000	0.074	64	0.074	56
AC >760,000	0.109	94	0.109	82
HP <65,000 1 Ph	0.083	116	0.083	119
HP <65,000 3 Ph	0.058	66	0.058	64
HP 65,000 - 135,000	0.101	126	0.101	126
HP 135,000 - 240,000	0.098	146	0.099	151
HP >240,000	0.136	178	0.136	179
GSHP <135,000	0.009	10	0.008	8
Economizer	0.080	95	0.080	67
AC tuneup	0.171	148		

Table 15. Light Industrial HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.077	49	0.076	50
AC <65,000 3 Ph	0.058	37	0.057	37
AC 65,000 - 135,000	0.079	51	0.079	51
AC 135,000 - 240,000	0.140	90	0.140	91
AC 240,000 - 760,000	0.073	47	0.073	48
AC >760,000	0.108	69	0.108	70
HP <65,000 1 Ph	0.081	90	0.081	89
HP <65,000 3 Ph	0.057	51	0.057	50
HP 65,000 - 135,000	0.099	97	0.099	96
HP 135,000 - 240,000	0.097	114	0.097	113
HP >240,000	0.134	138	0.133	137
Economizer	0.079	75	0.079	77
AC tuneup	0.170	109		

Table 16. Nursing Home HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.077	67	0.076	59
AC <65,000 3 Ph	0.057	50	0.057	44
AC 65,000 - 135,000	0.079	69	0.079	60
AC 135,000 - 240,000	0.140	123	0.139	107
AC 240,000 - 760,000	0.073	64	0.073	56
AC >760,000	0.108	95	0.108	83
HP <65,000 1 Ph	0.082	121	0.082	129
HP <65,000 3 Ph	0.058	69	0.057	68
HP 65,000 - 135,000	0.100	131	0.100	135
HP 135,000 - 240,000	0.098	153	0.098	166
HP >240,000	0.135	186	0.135	194
Economizer	0.079	88	0.079	62
Tuneup	0.170	149		

Table 17. School HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.075	25	0.075	21
AC <65,000 3 Ph	0.056	18	0.056	16
AC 65,000 - 135,000	0.078	25	0.077	21
AC 135,000 - 240,000	0.138	45	0.137	38
AC 240,000 - 760,000	0.072	24	0.072	20
AC >760,000	0.106	35	0.106	29
HP <65,000 1 Ph	0.080	50	0.080	53
HP <65,000 3 Ph	0.056	27	0.056	27
HP 65,000 - 135,000	0.098	53	0.098	54
HP 135,000 - 240,000	0.096	64	0.096	68
HP >240,000	0.132	76	0.132	78
GSHP <135,000	0.009	3	0.009	2
WLHP <17,000	0.024	11	0.024	10
WLHP 17,000-65,000	0.021	10	0.021	9
WLHP 65,000-135,000	0.021	10	0.021	9
PTAC	0.006	13	0.006	11
PTAC-HP	0.007	28	0.007	30
Economizer	0.078	55	0.077	36
Tuneup	0.167	54		

Table 18. Full Service Restaurant HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.077	62	0.077	58
AC <65,000 3 Ph	0.058	46	0.058	43
AC 65,000 - 135,000	0.080	64	0.079	60
AC 135,000 - 240,000	0.141	113	0.140	105
AC 240,000 - 760,000	0.074	59	0.074	55
AC >760,000	0.109	88	0.109	82
HP <65,000 1 Ph	0.082	117	0.082	118
HP <65,000 3 Ph	0.058	65	0.058	64
HP 65,000 - 135,000	0.100	125	0.100	125
HP 135,000 - 240,000	0.098	148	0.098	151
HP >240,000	0.135	178	0.135	179
GSHP <135,000	0.009	9	0.009	8
Economizer	0.080	82	0.079	66
AC tuneup	0.171	137		

Table 19. Small Retail Building HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.078	82	0.077	71
AC <65,000 3 Ph	0.058	61	0.057	53
AC 65,000 - 135,000	0.080	84	0.079	73
AC 135,000 - 240,000	0.142	149	0.140	129
AC 240,000 - 760,000	0.075	78	0.073	68
AC >760,000	0.110	115	0.108	100
HP <65,000 1 Ph	0.083	120	0.082	123
HP <65,000 3 Ph	0.058	73	0.057	70
HP 65,000 - 135,000	0.101	135	0.100	134
HP 135,000 - 240,000	0.099	149	0.097	155
HP >240,000	0.136	188	0.134	189
GSHP <135,000	0.011	13	0.009	10
PTAC	0.006	40	0.006	35
PTAC-HP	0.006	63	0.007	67
Economizer	0.080	149	0.079	99
Tuneup	0.172	181		

Table 20. Small Office Building HVAC Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.072	62	0.072	55
AC <65,000 3 Ph	0.054	47	0.054	41
AC 65,000 - 135,000	0.074	64	0.074	57
AC 135,000 - 240,000	0.131	114	0.132	101
AC 240,000 - 760,000	0.069	60	0.069	53
AC >760,000	0.101	88	0.102	78
HP <65,000 1 Ph	0.076	83	0.076	86
HP <65,000 3 Ph	0.053	52	0.053	51
HP 65,000 - 135,000	0.092	95	0.093	96
HP 135,000 - 240,000	0.091	102	0.091	108
HP >240,000	0.125	131	0.125	134
GSHP <135,000	0.011	11	0.010	9
WLHP <17,000	0.025	29	0.024	25
WLHP 17,000-65,000	0.022	25	0.021	22
WLHP 65,000-135,000	0.022	25	0.021	22
PTAC	0.005	31	0.005	27
PTAC-HP	0.005	44	0.006	48
Economizer	0.074	189	0.074	134
Tuneup	0.159	138		

Weights were developed for each of the buildings above that utilize packaged HVAC systems from customer data supplied by KCP&L. The KCP&L data show number of accounts by building type. Weights for the buildings addressed by this study were derived from the KCP&L customer account data and are shown in Table .

Table 21. Weights for Buildings with Packaged HVAC Systems

Building Type	Weight
Assembly	0.065
Big Box Retail	0.093
Fast Food	0.048
Light Industrial	0.021
Nursing Home	0.020
School	0.030
Full Service Restaurant	0.048
Small Retail	0.093
Small Office	0.583

The weights were applied to the results for each of the prototypes to estimate the average savings for each packaged HVAC system measure. The average savings are shown in Table .

Schedule JMO-3

Table 22. Weighted Packaged HVAC System Measure Savings

	Existing		New	
	kW/ton	kWh/ton	kW/ton	kWh/ton
AC <65,000 1 Ph	0.074	66	0.074	59
AC <65,000 3 Ph	0.056	49	0.056	44
AC 65,000 - 135,000	0.085	77	0.076	60
AC 135,000 - 240,000	0.135	120	0.135	107
AC 240,000 - 760,000	0.071	63	0.071	56
AC >760,000	0.105	93	0.105	83
HP <65,000 1 Ph	0.079	96	0.079	99
HP <65,000 3 Ph	0.055	58	0.055	57
HP 65,000 - 135,000	0.096	108	0.096	108
HP 135,000 - 240,000	0.094	119	0.094	124
HP >240,000	0.129	150	0.129	153
GSHP <135,000	0.010	9	0.009	7
WLHP <17,000	0.024	24	0.024	22
WLHP 17,000-65,000	0.021	21	0.021	19
WLHP 65,000-135,000	0.021	21	0.021	19
PTAC	0.006	28	0.006	24
PTAC-HP	0.006	45	0.006	48
Economizer	0.076	159	0.071	109
Tuneup	0.164	145		

Energy and demand savings for built up HVAC system measures calculated from the large office building prototype are shown in Table .

Table 23. Large Office Building HVAC Measure Savings

	Existing		New	
Chillers and controls	kW/ton	kWh/ton	kW/ton	kWh/ton
Air-cooled Chiller	0.150	154	0.143	136
Water-Cooled Chiller < 150 ton	0.049	56	0.049	53
Water-Cooled Chiller 150-300 ton	0.158	187	0.159	177
Water-Cooled Chiller >300 ton	0.131	156	0.133	148
Chilled water reset	0.030	87	0.040	86
VFDs on HVAC motors	kW/hp	kWh/hp	kW/hp	kWh/hp
VFD Fan Motor (per hp)	0.001	868	0.005	969
VFD chilled water pump (per hp)	0.496	1430	0.615	1398

Typical HVAC Unit sizes

For the DSMore runs, typical HVAC unit sizes were chosen from each of the unit size categories above to estimate a "per unit" savings. The typical unit size assumed in the DSMore runs is summarized in Table 1.

Table 1. Typical HVAC Unit Sizes by Type and Size Category

HVAC Measure Type and Size Category	Typical Unit Size
AC <65,000 1 Ph	5 ton
AC <65,000 3 Ph	5 ton
AC 65,000 - 135,000	10 ton
AC 135,000 - 240,000	20 ton
AC 240,000 - 760,000	25 ton
AC >760,000	65 ton
HP <65,000 1 Ph	5 ton
HP <65,000 3 Ph	5 ton
HP 65,000 - 135,000	10 ton
HP 135,000 - 240,000	20 ton
HP >240,000	65 ton
GSHP <135,000	10 ton
WLHP <17,000	1 ton
WLHP 17,000-65,000	3 ton
WLHP 65,000-135,000	7.5 ton
PTAC	1 ton
PTAC-HP	1 ton
Economizer	10 ton
Tuneup	10 ton
Air-cooled Chiller	200 ton
Water-Cooled Chiller < 150 ton	80 ton
Water-Cooled Chiller 150-300 ton	230 ton
Water-Cooled Chiller >300 ton	1000 ton

Section 4: Non-Weather Sensitive Measures

Study Methodology

This section addresses measures which are affected by operating practice and hours rather than the weather. These measures savings estimates are made using standard engineering practice operating comparisons versus an interactive weather building model such as DOE 2. The non weather sensitive measures include lighting (46 measures), motors/drives/pumps (24 measures), refrigeration (13 measures) and an “other” category (14 measures). Appendix B provides a written description, the assumptions used, the sources or reference baselines and spreadsheets with the calculations for future reference.

A key component of each calculation is determining an appropriate baseline assumption. Some technologies lend themselves more to a baseline assumption of “existing equipment” while “new equipment” may be a better baseline assumption for others. For example for one-for-one replacement of light fixtures the analysis used fixture, ballast, lamp combinations that are typically in current operation in the commercial market. The theory being that light fixtures have a long life and don’t wear out all at once. Energy and cost savings are usually a large component of the decision making process.

For equipment such as air compressors the analysis generally assumed standard new equipment as a baseline, not existing/old equipment. The theory here is that equipment failure, maintenance costs and added plant capacity requirements are often key decision making factors in addition to energy savings. Looking at the incremental cost and savings of new efficient equipment compared to new standard equipment is a better baseline than old, likely worn out equipment. Individual projects, technologies and customer situations vary, and we attempt to take a likely mixture of projects into account in the calculations.

FES used a variety of information sources including Energy Star, ASHRAE and numerous others to establish baselines and develop calculations. Equipment specifications, testing data and other web based information were also utilized. A benefit of using an organization like FES to do this analysis is that their staff of engineers has processed thousands of incentive applications and visited thousands of customer sites reviewing energy efficiency projects for various other utility programs. This history provides very practical information based on real conditions for validation of savings, equipment cost and other variables.

Appendix A: DSMore Measure Cost Effectiveness Results

Reference File:

DSMore Batch Tool run six by state ALL only new rate Old Inc.xls

DSMore Batch Tool run six by state AGG ALL only new rate.xls

Appendix B: Non-Weather Sensitive Measures Detail Analysis

This appendix provides the detailed information on the energy savings and other assumptions used as input into the DSMore model. Technologies that are very similar except for size or configuration are grouped together such as T-8 lighting which varies in length and number of bulbs per fixture. Calculations are either explained in the text or in a separate spreadsheet within this document. The technologies included are:

- FES-C1 Energy Star Commercial Clothes Washers.doc
- FES-C1 Energy Star Commercial Clothes Washers.xls
- FES-C2 Occupancy Sensors for document stations.doc
- FES-C2 Plug Load Occupancy Sensors for Document Stations.xls
- FES-C3 Cold Beverage Vending Machine Controllers.doc
- FES-C4 Window Film.doc
- FES-C5 80Plus Desktop and Server Units.doc
- FES-G1 Multiplex Compressors.doc
- FES-G1 Multiplex Compressors.xls
- FES-G2 Anti-sweat Heater Controls.doc
- FES-G3 Efficient Condensers.xls
- FES-G3 Efficient Refrigeration Condenser.doc
- FES-G4 Night Covers.doc
- FES-G5 Head Pressure Control.doc
- FES-G5 Head Pressure Control.xls
- FES-G6 ENERGY STAR Refrig and Freezer.doc
- FES-G6 Refrigerators Freezers.xls
- FES-G7 Ice Machines.doc
- FES-H1 Room AC.doc
- FES-H1 Room AC.xls
- FES-H2B CI Heat Pump Water Heaters.doc
- FES-H2B CI Heat Pump Water Heaters.xls
- FES-I1 EngineeredNozzles.xls
- FES-I1 - Engineered Nozzles.doc
- FES-I2 - Barrel Wraps.xls
- FES-I2 - Barrel Wraps.doc
- FES-I3 - Pellet Dryer Duct Insulation.xls
- FES-I3 - Insulated Pellet Dryer Ducts.doc
- FES-L1 T8 Replacement of T12s.doc
- FES-L1 T8sforT12s.xls
- FES-L10 centralized lighting controls.doc
- FES-L11 Multilevel Lighting Control.doc
- FES-L12 Daylight Sensor lighting control.doc
- FES-L2 - Replace T12s with T5s.doc
- FES-L2 - T5sforT12s.xls

- FES-L3 - HighBay Fluorescents.doc
- FES-L3- Hi Bay Fluorescents.xls
- FES-L5 LED Exit Signs.doc
- FES-L6 CFLs.doc
- FES-L6 Compact Fluorescent Lamps and Fixtures.xls
- FES-L7 Occupany Sensors.doc
- FES-L8 LED Traffic Lights.doc
- FES-L9 Light Tubes.doc
- FES-M1 Premium Eff Motors.xls
- FES-M1 - Premium Efficiency Motors.doc
- FES-M2 VFDs.xls
- FES-M2 - VFD's for Pumps.doc
- FES-M3 HE Pumps.xls
- FES-M3 - High Efficiency Pumps.doc

FILES ATTACHED.

A
Renewable Energy System
Performance
Analysis Report
For
Kansas City Power & Light

June 1, 2009

Table of Contents

Contact Information

Bob Solger
The Energy Savings Store
8201 Rosewood Drive
Prairie Village, KS 66208
913-221-6253 -- KC
bsolger@theenergysavingsstore.com
www.theenergysavingsstore.com

1 Introduction

The Energy Savings Store has been commissioned to prepare renewable energy systems performance models for Kansas City Power & Light. The information provided is to be used in the preparation of tariffs for offering renewable energy rebates.

1.1 Deliverables

A total of 24 models have been prepared and consist of the following.

- Eight (8) Solar Photovoltaic project models sized as 2kW and 3.2 KW systems, with two site locations Northeast and Southwest of Kansas City, St. Joseph, MO and Sedalia, MO.

- Eight (8) Wind energy models illustrating the production of wind systems small and medium sized, with four site locations; Northeast and Southwest of Kansas City, St. Joseph, MO and Sedalia, MO.

- Four (4) Solar Hot Water System project models with two site locations Northeast and Southwest of Kansas City, St. Joseph, MO and Sedalia, MO.

- Four (4) Solar Air Heating System or Trombe wall projects with two site locations Northeast and Southwest of Kansas City, St. Joseph, MO and Sedalia, MO.

All models will illustrate an estimate of installed cost, with a report on the monthly kWh saved, peak demand kW and typical load profile and financial analysis from a customer's perspective. When possible an hourly break down analysis of energy produced will be shown for a weekday and weekend.

1.2 Approach

This renewable energy systems performance report was prepared using pricing information from actual renewable energy systems installed by The Energy Savings Store over the last four (4) years in the Kansas City area. The analysis tools used in preparing this report are used in preparing project designs.

The financial analysis performed illustrates a Return-on- Investment analysis. The current federal solar tax credit of 30% is used as an incentive for solar PV systems, solar hot water heating system and a wind turbine systems.

1.3 Analysis Tools

The following tools were used in preparing the analysis:

HOMER, developed by the National Renewable Energy Laboratory (NREL), is a renewable energy system design optimization software design tool.

HOMER is a computer model that simplifies the task of evaluating design options for both off-grid and grid-connected power systems for remote, stand-alone, and distributed generation (DG) applications. HOMER's optimization and sensitivity analysis algorithms allow you to evaluate the economic and technical feasibility of a large number of technology options and to account for variation in technology costs and energy resource availability. HOMER models both conventional and renewable energy technologies:

Power sources:
- solar photovoltaic (PV)
- wind turbine
- run-of-river hydro power
- generator: diesel, gasoline, biogas, alternative and custom fuels, coal fired
- electric utility grid
- microturbine
- fuel cell

Storage:
- battery bank
- hydrogen

Loads:
- daily profiles with seasonal variation
- deferrable (water pumping, refrigeration)
- thermal (space heating, crop drying)
- efficiency measures

HOMER was used to create the analysis models for the wind turbine and solar PV systems.

The RETScreen International Clean Energy Project Analysis Software is a unique decision support tool developed with the contribution of numerous experts from government, industry, and academia. The software, provided free-of-charge, can be used worldwide to evaluate the energy production and savings, life-cycle costs, emission reductions, financial viability and risk for various types of energy efficient and renewable energy technologies (RETs). The software also includes product, cost and climate databases, and a detailed online user manual.

RETScreen International is managed under the leadership and ongoing financial support of Natural Resources Canada's (NRCan) CANMET Energy Technology Centre - Varennes (CETC-Varennes).

1.4 Rate Schedules Used in Analysis

The following rate schedule and rate increase schedule were used in preparing this analysis.

2009 Winter Electricity Cost ($/kWh):	$0.0629
2009 Summer Electric Cost ($/kWh):	$0.0994
2010 Electric Rate Increase (%):	16%
2011 Electric Rate Increase (%):	10%
2012 - 2038 Electric Rate Increase (%):	3%

1.5 Annual KWH Usage

Annual residential energy usage is assumed to be 11,400 kWh with a daily usage of 31.2 KWH and a peak load 9.1 KW.

1.6 Solar and Wind System Configurations and Pricing

1.6.1 2.0 KW Solar PV

- 10 – 200 Watt Panels with an install price of $15,000

1.6.2 3.2 KW Solar PV

- 16 – 200 Watt Panels with an install price of $21,000

1.6.3 2.4 KW Wind Turbine System

- Southwest Windpower Skystream 3.7 wind turbine system with an install price of $15,000

1.6.4 6.0 KW Wind Turbine System

- Proven 6.0 KW wind turbine system with an install price of $45,000

1.6.5 Solar Hot Water Heating System

- Solar Hot Water Heating system with an install price of $9,500

1.6.6 Solar Air Heating System

- SolarSheat with an install price of $4,900

1.7 Financial Analysis Methodology

1.7.1 Federal Incentives

With the passage of the Emergency Economic Stabilization Act of 2008, the $2,000 cap on the Personal Tax Credit (PTC) for Solar PV tax credits for solar were extended for 8 years. Residential grid-tied PV systems installed between January 1, 2009 and December 31, 2016 qualify for a full 30% tax credit. The American Recovery and Reinvestment Act of 2009 (H.R. 1) extended this incentive to solar hot water heating systems, as well as wind turbine systems.

The following table, from the Database of State Incentives for Renewables and Efficiency, summarizes the Federal Incentives for Renewable Energy.

Residential Renewable Energy Tax Credit

Last DSIRE Review: 02/19/2009

Incentive Type:	Personal Tax Credit
Eligible Renewable/Other Technologies:	Solar Water Heat, Photovoltaics, Wind, Fuel Cells, Geothermal Heat Pumps, Other Solar Electric Technologies
Applicable Sectors:	Residential
Amount:	30%
Maximum Incentive:	Solar-electric systems placed in service before 2009: $2,000 Solar-electric systems placed in service after 2008: no maximum Solar water heaters placed in service before 2009: $2,000 Solar water heaters placed in service after 2008: no maximum Wind turbines placed in service in 2008: $4,000 Wind turbines placed in service after 2008: no maximum Geothermal heat pumps placed in service in 2008: $2,000 Geothermal heat pumps placed in service after 2008: no maximum Fuel cells: $500 per 0.5 kW
Carryover Provisions:	Excess credit may be carried forward to succeeding tax year
Eligible System Size:	Fuel cells: 0.5 kW minimum
Equipment/Installation Requirements:	Solar water heating property must be certified by SRCC or by comparable entity endorsed by the state in which the system is installed. At least half the energy used to heat the dwelling's water must be from solar. Geothermal heat pumps must meet federal Energy Star requirements. Fuel cells must have electricity-only generation efficiency greater than 30%.
Authority 1:	26 USC § 25D
Date Enacted:	8/8/2005 (subsequently amended)
Date Effective:	1/1/2006
Expiration Date:	12/31/2016
Authority 2:	IRS Form 5695 & Instructions: Residential Energy Credits

Business Energy Investment Tax Credit (ITC)

Last DSIRE Review: 02/18/2009

Incentive Type:	Corporate Tax Credit
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, CHP/Cogeneration, Solar Hybrid Lighting, Direct Use Geothermal, Microturbines
Applicable Sectors:	Commercial, Industrial, Utility
Amount:	30% for solar, fuel cells and small wind; 10% for geothermal, microturbines and CHP
Maximum Incentive:	Fuel cells: $1,500 per 0.5 kW Microturbines: $200 per kW Small wind turbines placed in service 10/4/08 - 12/31/08: $4,000 Small wind turbines placed in service after 12/31/08: no limit All other eligible technologies: no limit
Eligible System Size:	Small wind turbines: 100 kW or less Fuel cells: 0.5 kW or greater Microturbines: 2 MW or less CHP: 50 MW or less
Equipment/Installation Requirements:	Fuel cells, microturbines and CHP systems must meet specific energy-efficiency criteria
Authority 1:	26 USC § 48

Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2009)

Last DSIRE Review: 02/19/2009

Incentive Type:	Corporate Depreciation
Eligible Renewable/Other Technologies:	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Renewable Transportation Fuels, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Hybrid Lighting, Direct Use Geothermal, Anaerobic Digestion, Microturbines
Applicable Sectors:	Commercial, Industrial
Authority 1:	26 USC § 168
Date Effective:	1986
Authority 2:	26 USC § 48

Under the federal Modified Accelerated Cost-Recovery System (MACRS), businesses may recover investments in certain property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. A number of renewable energy technologies are classified as five-year property (26 USC § 168(e)(3)(B)(vi)) under the MACRS, which refers to 26 USC § 48(a)(3)(A), often known as the energy investment tax credit or ITC to define eligible property. Such property currently includes:

- a variety of solar electric and solar thermal technologies
- fuel cells and microturbines

- geothermal electric
- direct-use geothermal and geothermal heat pumps
- small wind (100 kW or less)
- combined heat and power (CHP).
- The provision which defines ITC technologies as eligible also adds the general term "wind" as an eligible technology, extending the five-year schedule to large wind facilities as well.

In addition, for certain other biomass property, the MACRS property class life is seven years. Eligible biomass property generally includes assets used in the conversion of biomass to heat or to a solid, liquid or gaseous fuel, and to equipment and structures used to receive, handle, collect and process biomass in a waterwall, combustion system, or refuse-derived fuel system to create hot water, gas, steam and electricity.

The 5-year schedule for most types of solar, geothermal, and wind property has been in place since 1986. The federal Energy Policy Act of 2005 (EPAct 2005) classified fuel cells, microturbines and solar hybrid lighting technologies as five-year property as well by adding them to § 48(a)(3)(A). This section was further expanded in October 2008 by the addition of geothermal heat pumps, combined heat and power, and small wind under the The Energy Improvement and Extension Act of 2008.

The federal Economic Stimulus Act of 2008, enacted in February 2008, included a 50% bonus depreciation (26 USC § 168(k)) provision for eligible renewable-energy systems acquired and placed in service in 2008. This provision was extended (retroactively to the entire 2009 tax year) under the same terms by The American Recovery and Reinvestment Act of 2009 enacted in February 2009. To qualify for bonus depreciation, a project must satisfy these criteria:

- the property must have a recovery period of 20 years or less under normal federal tax depreciation rules;
- the original use of the property must commence with the taxpayer claiming the deduction;
- the property generally must have been acquired during 2008 or 2009; and
- the property must have been placed in service during 2008 or 2009 (or, in certain limited cases, in 2010).

If property meets these requirements, the owner is entitled to deduct 50% of the adjusted basis of the property in 2008 and 2009. The remaining 50% of the adjusted basis of the property is depreciated over the ordinary depreciation schedule. The bonus depreciation rules do not override the depreciation limit applicable to projects qualifying for the federal business energy tax credit. Before calculating depreciation for such a project, including any bonus depreciation, the adjusted basis of the project must be reduced by one-half of the amount of the energy credit for which the project qualifies.

For more information on the federal MACRS, see *IRS Publication 946, IRS Form 4562: Depreciation and Amortization*, and *Instructions for Form 4562*. The IRS web site provides a search mechanism for forms and publications. Enter the relevant form, publication name or number, and click "GO" to receive the requested form or publication.

1.7.2 Missouri Proposition C Utility Incentive

In November 2008, Missouri Proposition C - The Missouri Clean Energy Initiative, established the frame work for investor owned utilities to offer a $2.00 watt incentive in the form of a rebate for Solar PV systems. Size of Solar PV systems is limited to 25 KW. The Missouri Public Service Commission is in the process of developing rules for implementing of the Proposition C incentive.

1.7.3 Financial Analysis Calculation

The following assumptions were used in the financial incentive calculations:

- All analysis were performed for residential applications only;
- The cost basis for each of the systems was based on current market prices;
- The initial cost basis for Solar PV systems only was first reduced by the Proposition C incentive of $2.00 a watt;
    - No provisions for Renewable Energy Certificates (REC) were applied.
- The Federal PTC was applied to the cost basis of Solar PV systems only after the Proposition C incentive. (System Cost Basis – Proposition C Incentive) = Adjusted Cost Basis before application of Federal PTC.
    - Final Solar PV System Cost Basis = Adjusted Cost Basis - (Adjusted Cost Basis * 30%)
    - Final Solar Hot Water Cost Basis = System Cost Basis – (System Cost Basis * 30%)
    - Final Wind System Cost Basis = System Cost Basis – (System Cost Basis * 30%)
    - No incentives currently apply to Solar Air Heating for Residential Applications.

- Energy Escalation Rates per KCPL
  - 2010 Electric Rate Increase (%): 16%
  - 2011 Electric Rate Increase (%): 10%
  - 2012 - 2038 Electric Rate Increase (%): 3%*

* The energy escalation rate for this period of time was derived from Department of Energy Projected fuel price indices with assumed general price inflation rates. A more realistic approach would be to use 5.5% - 6.5% as an electric escalation rate for purposes of financial analysis of renewable energy systems. This is based on national average rate increases over the last 5 years and a common practice in the renewable energy industry.

2 Solar PV System Analysis 2.0 KW – Northeast Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH**/**Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter efficiency 96%;

2.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,784 KWH**
- First year value of the power produced by the system for consumer **$212.16**
- Cash purchase system install price **$15,000.00** does not include tax;
- KCPL incentive value **$4,000**;
- Federal Investment Tax Credit value **$3,300**;
- Adjusted system cost basis **$7,700**;
- **IRR 2.7 % Simple Payback 22 years**

2.2 System Report - KCPL2.0 KW North East.hmr

2.2.1 Sensitivity case

Primary Load 1 Scaled Average: 31.2 kWh/d

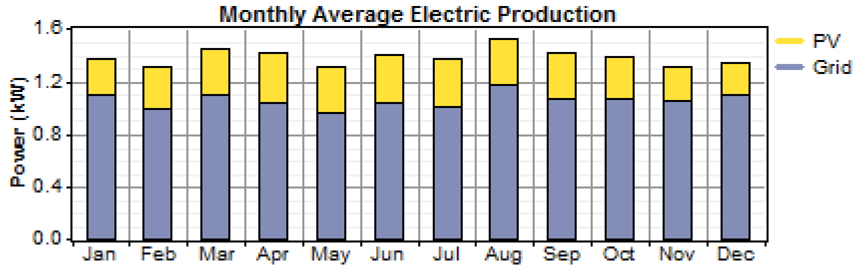
2.2.2 System architecture

PV Array	2 kW
Grid	1,000 kW

Inverter	2 kW
Rectifier	2 kW

2.2.3 Electrical

Component	Production	Fraction
	(kWh/yr)	
PV array	2,900	24%
Grid purchases	9,238	76%
Total	12,138	100%



Load	Consumption	Fraction
	(kWh/yr)	
AC primary load	11,399	95%
Grid sales	623	5%
Total	12,022	100%

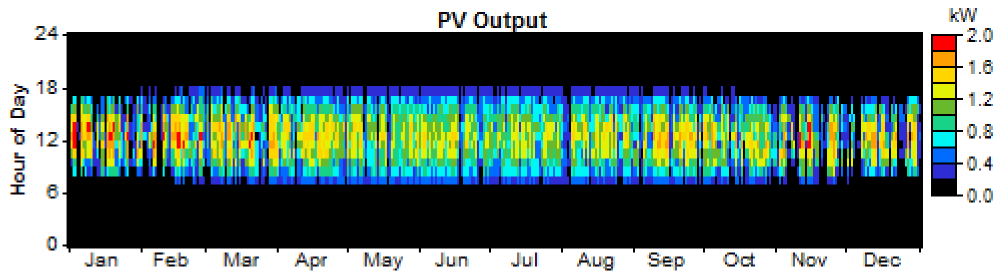
Quantity	Value	Units
Excess electricity	0.0000468	kWh/yr

Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.239	

2.2.4 PV

Quantity	Value	Units
Rated capacity	2.00	kW
Mean output	0.331	kW
Mean output	7.95	kWh/d
Capacity factor	16.6	%
Total production	2,900	kWh/yr

Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	1.99	kW
PV penetration	25.4	%
Hours of operation	4,387	hr/yr
Levelized cost	0.405	$/kWh

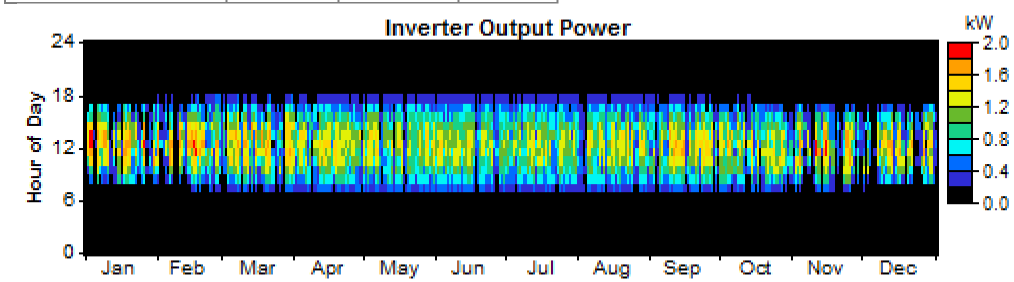


Schedule JMO-4

2.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	2.00	2.00	kW
Mean output	0.32	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	1.91	0.00	kW
Capacity factor	15.9	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,387	0	hrs/yr
Energy in	2,900	0	kWh/yr
Energy out	2,784	0	kWh/yr
Losses	116	0	kWh/yr



Schedule JMO-4

2.2.6 Energy Produced

Month	Energy Produced	Net Purchases	Energy Charge
	(kWh)	(kWh)	($)
Jan	199	-199	-13
Feb	201	-201	-13
Mar	255	-255	-16
Apr	260	-260	-16
May	255	-255	-16
Jun	253	-253	-25
Jul	262	-262	-26
Aug	252	-252	-25
Sep	248	-248	-25
Oct	233	-233	-15
Nov	185	-185	-12
Dec	181	-181	-11
Annual	2,784	-2,784	-212

2.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	812	59	753	8	47	0
Feb	668	53	615	7	39	0
Mar	811	59	753	8	47	0
Apr	744	55	689	9	43	0
May	710	57	653	7	41	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	790	46	745	7	47	0
Nov	754	50	705	7	44	0
Dec	814	46	768	9	48	0
Annual	6,105	425	5,680	9	357	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	749	50	699	9	69	0
Jul	751	49	702	7	70	0
Aug	869	44	825	8	82	0
Sep	763	54	709	8	71	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,133	198	2,935	9	292	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	812	59	753	8	47	0
Feb	668	53	615	7	39	0
Mar	811	59	753	8	47	0
Apr	744	55	689	9	43	0
May	710	57	653	7	41	0
Jun	749	50	699	9	69	0

Jul	751	49	702	7	70	0
Aug	869	44	825	8	82	0
Sep	763	54	709	8	71	0
Oct	790	46	745	7	47	0
Nov	754	50	705	7	44	0
Dec	814	46	768	9	48	0
Annual	9,238	623	8,615	9	649	0

2.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,445
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	23.6
Nitrogen oxides	11.5

2.3 Financial Analysis

Solar PV Analysis 2.0 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**1,769**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**1,015**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($7,700)**	**($7,700)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$212.16**	**$0**	**$0**	**$0**	**$212**	**($7,488)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$246.11**	**$0**	**$0**	**$0**	**$246**	**($7,242)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$270.72**	**$0**	**$0**	**$0**	**$271**	**($6,971)**
Interest Rate (%):	**7**	**2012**	**4**	**$278.84**	**$0**	**$0**	**$0**	**$279**	**($6,692)**
Loan Term (Years):	**10**	**2013**	**5**	**$287.20**	**$0**	**$0**	**$0**	**$287**	**($6,405)**
Month Installed:	**0**	**2014**	**6**	**$295.82**	**$0**	**$0**	**$0**	**$296**	**($6,109)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$304.70**	**$0**	**$0**	**$0**	**$305**	**($5,804)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$313.84**	**$0**	**$0**	**$0**	**$314**	**($5,491)**
O & M Cost ($/kWh):	**$0.000**	**2017**	**9**	**$323.25**	**$0**	**$0**	**$0**	**$323**	**($5,167)**

Schedule JMO-4

O & M Inflation Rate (%):	0	2018	10	$332.95	$0	$0	$0	$333	($4,834)
State Rebate (%):	0	2019	11	$342.94	$0	$0	$0	$343	($4,491)
State Tax Credit (%):	0	2020	12	$353.23	$0	$0	$0	$353	($4,138)
Federal Tax Credit (%):	30	2021	13	$363.82	$0	$0	$0	$364	($3,774)
Less KCPL Incentive	$4,000	2022	14	$374.74	$0	$0	$0	$375	($3,400)
Renewable Certificates ($KWH)	$0.0000	2023	15	$385.98	$0	$0	$0	$386	($3,014)
Results		2024	16	$397.56	$0	$0	$0	$398	($2,616)
Loan Payments		2025	17	$409.48	$0	$0	$0	$409	($2,207)
Monthly Payment ($):	$0	2026	18	$421.77	$0	$0	$0	$422	($1,785)
Value of Interest Deduction ($):	$0	2027	19	$434.42	$0	$0	$0	$434	($1,350)
Net Monthly Payment ($):	$0	2028	20	$447.45	$0	$0	$0	$447	($903)
		2029	21	$460.88	$0	$0	$0	$461	($442)
Ave. Monthly Savings on Bill		2030	22	$474.70	$0	$0	$0	$475	$33
Year 1 ($):	$5	2031	23	$488.95	$0	$0	$0	$489	$521
Year 10 ($):	$23	2032	24	$503.61	$0	$0	$0	$504	$1,025
Year 20 ($):	$104	2033	25	$518.72	$0	$0	$0	$519	$1,544
Year 30 ($):	$457	2034	26	$534.28	$0	$0	$0	$534	$2,078
		2035	27	$550.31	$0	$0	$0	$550	$2,628
Internal Rate of Return		2036	28	$566.82	$0	$0	$0	$567	$3,195
Years 1 - 30:	2.7%	2037	29	$583.83	$0	$0	$0	$584	$3,779
		2038	30	$601.34	$0	$0	$0	$601	$4,380

3 Solar PV System Analysis 3.2 KW – Northeast Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter Efficiency 96%;

3.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **4,455 KWH**
- First year value of the power produced by the system for consumer **$339.57**
- Cash purchase system install price **$21,000.00** does not include tax;
- KCPL incentive value **$6,400**;
- Federal Investment Tax Credit value **$4,380**;
- Adjusted system cost basis **$10,220**;
- **IRR 4.0 % Simple Payback 20 years**

3.2 System Report - KCPL3.2 KW North East.hmr

3.2.1 Sensitivity case

Primary Load 1 Scaled Average: 31.2 kWh/d

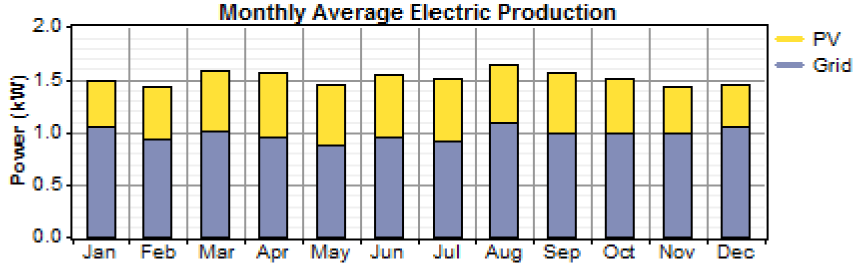
3.2.2 System architecture

PV Array	3.2 kW

Grid	1,000 kW
Inverter	3 kW
Rectifier	3 kW

3.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	4,641	35%
Grid purchases	8,613	65%
Total	13,254	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	87%
Grid sales	1,670	13%
Total	13,069	100%

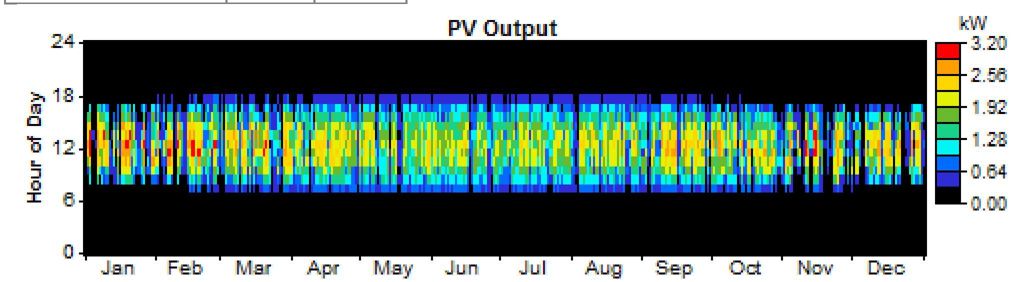
Quantity	Value	Units
Excess electricity	0.0706	kWh/yr

Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.350	

3.2.4 PV

Quantity	Value	Units
Rated capacity	3.20	kW
Mean output	0.530	kW
Mean output	12.7	kWh/d
Capacity factor	16.6	%
Total production	4,641	kWh/yr

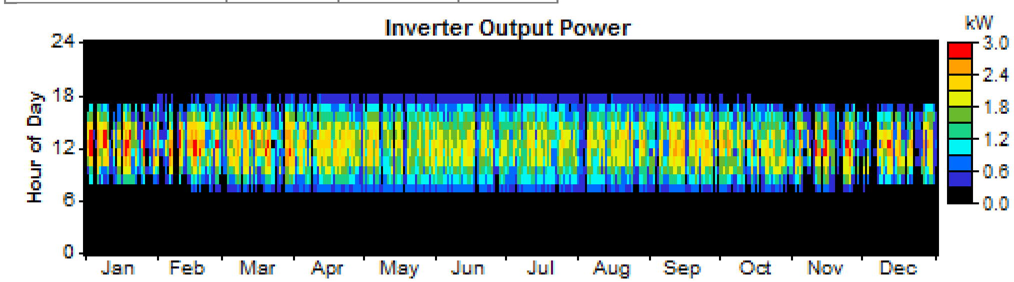
Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	3.17	kW
PV penetration	40.7	%
Hours of operation	4,387	hr/yr
Levelized cost	0.354	$/kWh



3.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	3.00	3.00	kW
Mean output	0.51	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	3.00	0.00	kW
Capacity factor	17.0	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,387	0	hrs/yr
Energy in	4,641	0	kWh/yr
Energy out	4,455	0	kWh/yr
Losses	186	0	kWh/yr



3.2.6 Energy Produced

Month	Energy Produced	Net Purchases	Energy Charge
	(kWh)	(kWh)	($)
Jan	318	-318	-20
Feb	322	-322	-20
Mar	408	-408	-26
Apr	416	-416	-26
May	409	-409	-26
Jun	405	-405	-40
Jul	420	-420	-42
Aug	404	-404	-40
Sep	397	-397	-39
Oct	372	-372	-23
Nov	295	-295	-19
Dec	289	-289	-18
Annual	4,455	-4,455	-340

3.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)

Schedule JMO-4

Jan	776	142	634	8	40	0
Feb	628	133	495	7	31	0
Mar	756	156	599	8	38	0
Apr	689	156	533	9	34	0
May	649	150	499	7	31	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	737	132	605	7	38	0
Nov	717	123	594	7	37	0
Dec	779	118	661	9	42	0
Annual	5,730	1,110	4,619	9	291	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0

Jun	684	137	547	9	54	0
Jul	687	143	544	7	54	0
Aug	804	131	673	8	67	0
Sep	708	147	560	8	56	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,883	559	2,324	9	231	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	776	142	634	8	40	0
Feb	628	133	495	7	31	0
Mar	756	156	599	8	38	0
Apr	689	156	533	9	34	0
May	649	150	499	7	31	0
Jun	684	137	547	9	54	0
Jul	687	143	544	7	54	0
Aug	804	131	673	8	67	0
Sep	708	147	560	8	56	0
Oct	737	132	605	7	38	0

Nov	717	123	594	7	37	0
Dec	779	118	661	9	42	0
Annual	8,613	1,670	6,944	9	522	0

3.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	4,388
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	19
Nitrogen oxides	9.3

3.3 *Financial Analysis*

Solar PV Analysis 3.2 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$21,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,829**								
Summer Energy Usage (kWh):	**1,626**		**Year**	**Net Energy**	**O&M Costs**	**Net Deprec.**	**Net Loan Payments**	**Annual Cash Flow**	**Total Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,220)**	**($10,220)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$339.57**	**$0**	**$0**	**$0**	**$340**	**($9,880)**
Down Payment ($):	**$21,000**	**2010**	**2**	**$393.90**	**$0**	**$0**	**$0**	**$394**	**($9,487)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$433.29**	**$0**	**$0**	**$0**	**$433**	**($9,053)**
Interest Rate (%):	**7**	**2012**	**4**	**$446.29**	**$0**	**$0**	**$0**	**$446**	**($8,607)**
Loan Term (Years):	**10**	**2013**	**5**	**$459.68**	**$0**	**$0**	**$0**	**$460**	**($8,147)**
Month Installed:	**0**	**2014**	**6**	**$473.47**	**$0**	**$0**	**$0**	**$473**	**($7,674)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$487.67**	**$0**	**$0**	**$0**	**$488**	**($7,186)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$502.30**	**$0**	**$0**	**$0**	**$502**	**($6,684)**
O & M Cost ($/kWh):	**$0.000**	**2017**	**9**	**$517.37**	**$0**	**$0**	**$0**	**$517**	**($6,166)**

O & M Inflation Rate (%):	0	2018	10	$532.89	$0	$0	$0	$533	($5,634)
State Rebate (%):	0	2019	11	$548.88	$0	$0	$0	$549	($5,085)
State Tax Credit (%):	0	2020	12	$565.34	$0	$0	$0	$565	($4,519)
Federal Tax Credit (%):	30	2021	13	$582.30	$0	$0	$0	$582	($3,937)
Less KCPL Incentive	$6,400	2022	14	$599.77	$0	$0	$0	$600	($3,337)
Renewable Certificates ($KWH)	$0.0000	2023	15	$617.77	$0	$0	$0	$618	($2,720)
Results		2024	16	$636.30	$0	$0	$0	$636	($2,083)
Loan Payments		2025	17	$655.39	$0	$0	$0	$655	($1,428)
Monthly Payment ($):	$0	2026	18	$675.05	$0	$0	$0	$675	($753)
Value of Interest Deduction ($):	$0	2027	19	$695.30	$0	$0	$0	$695	($57)
Net Monthly Payment ($):	$0	2028	20	$716.16	$0	$0	$0	$716	$659
		2029	21	$737.65	$0	$0	$0	$738	$1,396
Ave. Monthly Savings on Bill		2030	22	$759.78	$0	$0	$0	$760	$2,156
Year 1 ($):	$9	2031	23	$782.57	$0	$0	$0	$783	$2,939
Year 10 ($):	$38	2032	24	$806.05	$0	$0	$0	$806	$3,745
Year 20 ($):	$166	2033	25	$830.23	$0	$0	$0	$830	$4,575
Year 30 ($):	$732	2034	26	$855.13	$0	$0	$0	$855	$5,430
		2035	27	$880.79	$0	$0	$0	$881	$6,311
Internal Rate of Return		2036	28	$907.21	$0	$0	$0	$907	$7,218
Years 1 - 30:	4.0%	2037	29	$934.43	$0	$0	$0	$934	$8,153
		2038	30	$962.46	$0	$0	$0	$962	$9,115

4 Solar PV System Analysis 2.0 KW – Southwest Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter efficiency 96%;

4.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,725 KWH**
- First year value of the power produced by the system for consumer **$207.36**
- Cash purchase system install price **$15,000.00** does not include tax;
- KCPL incentive value **$4,000**;
- Federal Investment Tax Credit value **$3,300**;
- Adjusted system cost basis **$7,700**;
- **IRR 2.6 % Simple Payback 22 years**

4.2 System Report - KCPL2.0KW Southwest.hmr

4.2.1 Sensitivity case

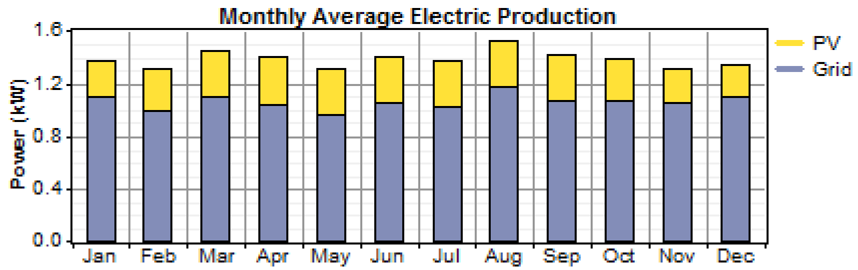
Primary Load 1 Scaled Average: 31.2 kWh/d

4.2.2 System architecture

PV Array	2 kW
Grid	1,000 kW
Inverter	2 kW
Rectifier	2 kW

4.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	2,838	23%
Grid purchases	9,272	77%
Total	12,110	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	95%

Grid sales	597	5%
Total	11,996	100%

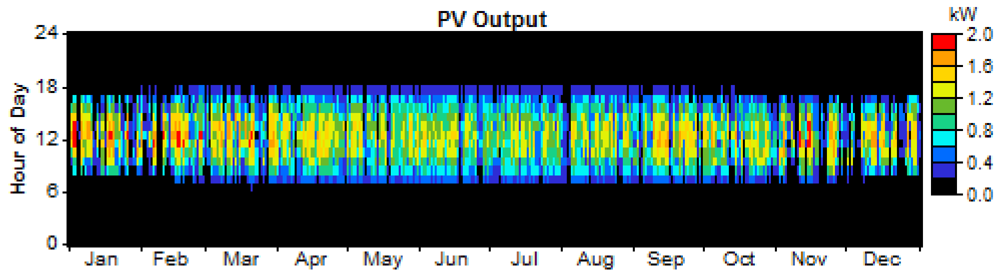
Quantity	Value	Units
Excess electricity	0.000519	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.234	

4.2.4 PV

Quantity	Value	Units
Rated capacity	2.00	kW
Mean output	0.324	kW
Mean output	7.78	kWh/d
Capacity factor	16.2	%
Total production	2,838	kWh/yr

Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	1.98	kW
PV penetration	24.9	%
Hours of operation	4,386	hr/yr

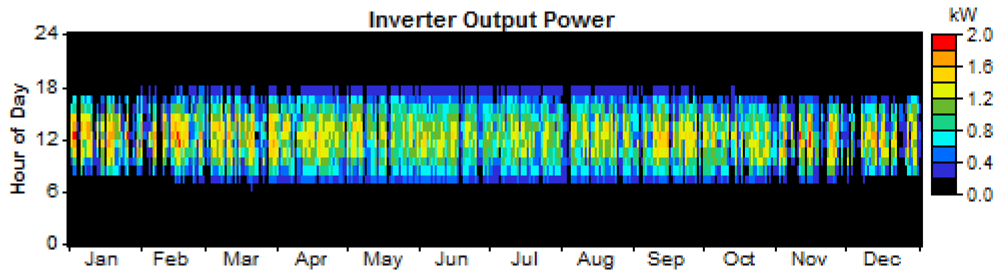
Levelized cost	0.413	$/kWh



4.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	2.00	2.00	kW
Mean output	0.31	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	1.90	0.00	kW
Capacity factor	15.6	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,386	0	hrs/yr
Energy in	2,838	0	kWh/yr
Energy out	2,725	0	kWh/yr
Losses	114	0	kWh/yr



4.2.6 Energy Produced

Month	Energy Produced (kWh)	Energy Charge ($)
Jan	198	-12
Feb	197	-12
Mar	252	-16
Apr	255	-16
May	250	-16
Jun	247	-25
Jul	251	-25
Aug	244	-24
Sep	242	-24
Oct	225	-14
Nov	184	-12

Dec	180	-11
Annual	2,725	-207

4.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Purchases (kWh)	Peak Demand (kW)	Energy Charge ($)	Demand Charge ($)
Jan	813	58	754	8	47	0
Feb	671	51	620	7	39	0
Mar	814	57	756	8	48	0
Apr	747	53	694	9	44	0
May	713	55	658	7	41	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	795	43	752	7	47	0
Nov	754	49	705	7	44	0
Dec	815	45	769	9	48	0

Annual	6,120	411	5,709	9	359	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	752	48	705	9	70	0
Jul	758	45	712	7	71	0
Aug	875	42	833	8	83	0
Sep	767	51	716	8	71	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,152	186	2,965	9	295	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	813	58	754	8	47	0
Feb	671	51	620	7	39	0
Mar	814	57	756	8	48	0
Apr	747	53	694	9	44	0
May	713	55	658	7	41	0
Jun	752	48	705	9	70	0
Jul	758	45	712	7	71	0
Aug	875	42	833	8	83	0
Sep	767	51	716	8	71	0
Oct	795	43	752	7	47	0
Nov	754	49	705	7	44	0
Dec	815	45	769	9	48	0
Annual	9,272	597	8,674	9	654	0

4.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,482
Carbon monoxide	0
Unburned hydocarbons	0

Particulate matter	0
Sulfur dioxide	23.8
Nitrogen oxides	11.6

4.3 Financial Analysis

Solar PV Analysis 2.0 KW Southwest

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) / **Annual Cash Flow Model**

Total Installed Cost ($):	**$15,000**									
Allocation to Business (%):	**0**									
Winter Energy Usage (kWh)	**1,740**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**985**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($7,700)**	**($7,700)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$207.36**	**$0**	**$0**	**$0**	**$207**	**($7,493)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$240.53**	**$0**	**$0**	**$0**	**$241**	**($7,252)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$264.58**	**$0**	**$0**	**$0**	**$265**	**($6,988)**
Interest Rate (%):	**7**	**2012**	**4**	**$272.52**	**$0**	**$0**	**$0**	**$273**	**($6,715)**
Loan Term (Years):	**10**	**2013**	**5**	**$280.70**	**$0**	**$0**	**$0**	**$281**	**($6,434)**
Month Installed:	**0**	**2014**	**6**	**$289.12**	**$0**	**$0**	**$0**	**$289**	**($6,145)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$297.79**	**$0**	**$0**	**$0**	**$298**	**($5,847)**

Net State Tax Rate (%):	8	2016	8	$306.73	$0	$0	$0	$307	($5,541)
O & M Cost ($/kWh):	$0.000	2017	9	$315.93	$0	$0	$0	$316	($5,225)
O & M Inflation Rate (%):	0	2018	10	$325.41	$0	$0	$0	$325	($4,899)
State Rebate (%):	0	2019	11	$335.17	$0	$0	$0	$335	($4,564)
State Tax Credit (%):	0	2020	12	$345.22	$0	$0	$0	$345	($4,219)
Federal Tax Credit (%):	30	2021	13	$355.58	$0	$0	$0	$356	($3,863)
Less KCPL Incentive	$4,000	2022	14	$366.25	$0	$0	$0	$366	($3,497)
Renewable Certificates ($KWH)	$0.0000	2023	15	$377.23	$0	$0	$0	$377	($3,120)
Results		2024	16	$388.55	$0	$0	$0	$389	($2,731)
Loan Payments		2025	17	$400.21	$0	$0	$0	$400	($2,331)
Monthly Payment ($):	$0	2026	18	$412.21	$0	$0	$0	$412	($1,919)
Value of Interest Deduction ($):	$0	2027	19	$424.58	$0	$0	$0	$425	($1,494)
Net Monthly Payment ($):	$0	2028	20	$437.32	$0	$0	$0	$437	($1,057)
		2029	21	$450.44	$0	$0	$0	$450	($607)
Ave. Monthly Savings on Bill		2030	22	$463.95	$0	$0	$0	$464	($143)
Year 1 ($):	$5	2031	23	$477.87	$0	$0	$0	$478	$335
Year 10 ($):	$23	2032	24	$492.21	$0	$0	$0	$492	$827
Year 20 ($):	$100	2033	25	$506.97	$0	$0	$0	$507	$1,334
Year 30 ($):	$443	2034	26	$522.18	$0	$0	$0	$522	$1,857
		2035	27	$537.85	$0	$0	$0	$538	$2,394
Internal Rate of Return		2036	28	$553.98	$0	$0	$0	$554	$2,948
Years 1 - 30:	2.6%	2037	29	$570.60	$0	$0	$0	$571	$3,519
		2038	30	$587.72	$0	$0	$0	$588	$4,107

5 Solar PV System Analysis 3.2 KW – Southwest Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter Efficiency 96%;

5.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **4,367 KWH**
- First year value of the power produced by the system for consumer **$332.24**
- Cash purchase system install price **$21,000.00** does not include tax;
- KCPL incentive value **$6,400**;
- Federal Investment Tax Credit value **$4,380**;
- Adjusted system cost basis **$10,220**;
- **IRR 3.8 % Simple Payback 20 years**

5.2 System Report - KCPL3.2 KW Southwest.hmr

5.2.1 Sensitivity case

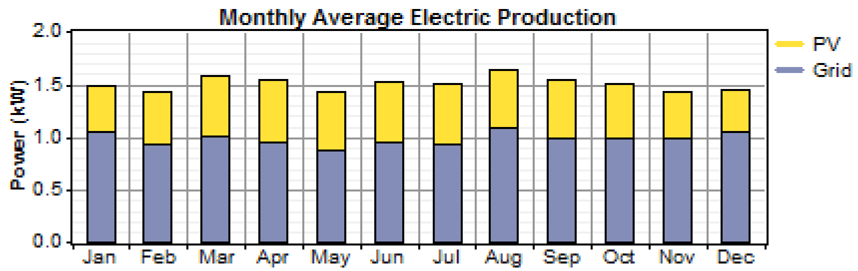
Primary Load 1 Scaled Average: 31.2 kWh/d

5.2.2 System architecture

PV Array	3.2 kW
Grid	1,000 kW
Inverter	3 kW
Rectifier	3 kW

5.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	4,549	34%
Grid purchases	8,647	66%
Total	13,196	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	88%

Grid sales	1,615	12%
Total	13,014	100%

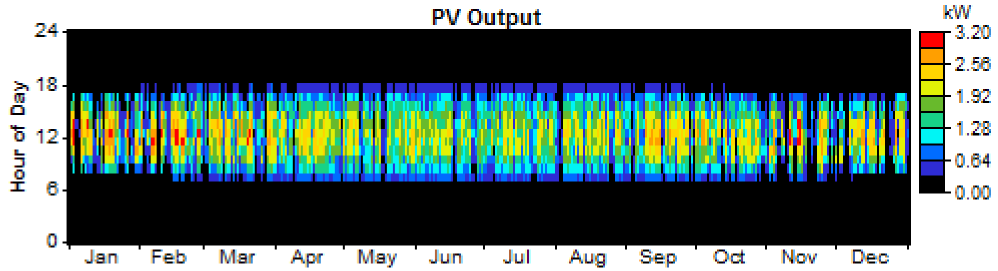
Quantity	Value	Units
Excess electricity	0.0660	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.345	

5.2.4 PV

Quantity	Value	Units
Rated capacity	3.20	kW
Mean output	0.519	kW
Mean output	12.5	kWh/d
Capacity factor	16.2	%
Total production	4,549	kWh/yr

Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	3.17	kW
PV penetration	39.9	%
Hours of operation	4,387	hr/yr

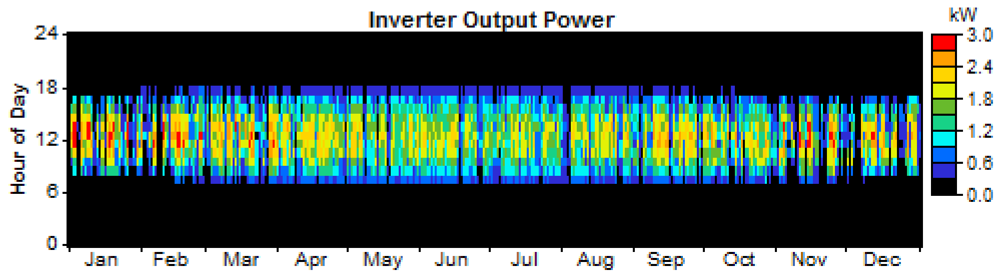
Levelized cost	0.361	$/kWh



5.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	3.00	3.00	kW
Mean output	0.50	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	3.00	0.00	kW
Capacity factor	16.6	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,387	0	hrs/yr
Energy in	4,549	0	kWh/yr
Energy out	4,367	0	kWh/yr
Losses	182	0	kWh/yr



5.2.6 Energy Produced

Month	Energy Produced	Energy Charge
	(kWh)	($)
Jan	317	-20
Feb	316	-20
Mar	403	-25
Apr	409	-26
May	400	-25
Jun	395	-39
Jul	402	-40
Aug	391	-39
Sep	388	-39
Oct	361	-23
Nov	295	-19

Dec	289	-18
Annual	4,367	-332

5.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	776	142	634	8	40	0
Feb	629	128	501	7	32	0
Mar	757	153	605	8	38	0
Apr	691	151	540	9	34	0
May	653	145	508	7	32	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	741	125	616	7	39	0
Nov	717	123	594	7	37	0
Dec	778	117	661	9	42	0

Annual	5,743	1,084	4,659	9	293	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	688	132	556	9	55	0
Jul	694	133	561	7	56	0
Aug	810	125	686	8	68	0
Sep	712	142	570	8	57	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,904	531	2,373	9	236	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	776	142	634	8	40	0
Feb	629	128	501	7	32	0
Mar	757	153	605	8	38	0
Apr	691	151	540	9	34	0
May	653	145	508	7	32	0
Jun	688	132	556	9	55	0
Jul	694	133	561	7	56	0
Aug	810	125	686	8	68	0
Sep	712	142	570	8	57	0
Oct	741	125	616	7	39	0
Nov	717	123	594	7	37	0
Dec	778	117	661	9	42	0
Annual	8,647	1,615	7,032	9	529	0

5.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	4,444
Carbon monoxide	0
Unburned hydocarbons	0

Particulate matter	0
Sulfur dioxide	19.3
Nitrogen oxides	9.42

5.3 Financial Analysis

Solar PV Analysis 3.2 KW Southwest

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$21,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,790**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**1,577**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,220)**	**($10,220)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	1	**$332.24**	**$0**	**$0**	**$0**	**$332**	**($9,888)**
Down Payment ($):	**$21,000**	**2010**	2	**$385.40**	**$0**	**$0**	**$0**	**$385**	**($9,502)**
Amount of Loan ($):	**$0**	**2011**	3	**$423.94**	**$0**	**$0**	**$0**	**$424**	**($9,078)**
Interest Rate (%):	**7**	**2012**	4	**$436.66**	**$0**	**$0**	**$0**	**$437**	**($8,642)**
Loan Term (Years):	**10**	**2013**	5	**$449.76**	**$0**	**$0**	**$0**	**$450**	**($8,192)**
Month Installed:	**0**	**2014**	6	**$463.26**	**$0**	**$0**	**$0**	**$463**	**($7,729)**
Net Federal Tax Rate (%):	**28**	**2015**	7	**$477.15**	**$0**	**$0**	**$0**	**$477**	**($7,252)**
Net State Tax Rate (%):	**8**	**2016**	8	**$491.47**	**$0**	**$0**	**$0**	**$491**	**($6,760)**
O & M Cost ($/kWh):	**$0.000**	**2017**	9	**$506.21**	**$0**	**$0**	**$0**	**$506**	**($6,254)**

O & M Inflation Rate (%):	0	2018	10	$521.40	$0	$0	$0	$521	($5,732)
State Rebate (%):	0	2019	11	$537.04	$0	$0	$0	$537	($5,195)
State Tax Credit (%):	0	2020	12	$553.15	$0	$0	$0	$553	($4,642)
Federal Tax Credit (%):	30	2021	13	$569.75	$0	$0	$0	$570	($4,073)
Less KCPL Incentive	$6,400	2022	14	$586.84	$0	$0	$0	$587	($3,486)
Renewable Certificates ($KWH)	$0.0000	2023	15	$604.44	$0	$0	$0	$604	($2,881)
Results		2024	16	$622.58	$0	$0	$0	$623	($2,259)
Loan Payments		2025	17	$641.25	$0	$0	$0	$641	($1,617)
Monthly Payment ($):	$0	2026	18	$660.49	$0	$0	$0	$660	($957)
Value of Interest Deduction ($):	$0	2027	19	$680.31	$0	$0	$0	$680	($277)
Net Monthly Payment ($):	$0	2028	20	$700.72	$0	$0	$0	$701	$424
		2029	21	$721.74	$0	$0	$0	$722	$1,146
Ave. Monthly Savings on Bill		2030	22	$743.39	$0	$0	$0	$743	$1,889
Year 1 ($):	$8	2031	23	$765.69	$0	$0	$0	$766	$2,655
Year 10 ($):	$36	2032	24	$788.66	$0	$0	$0	$789	$3,444
Year 20 ($):	$161	2033	25	$812.32	$0	$0	$0	$812	$4,256
Year 30 ($):	$710	2034	26	$836.69	$0	$0	$0	$837	$5,093
		2035	27	$861.79	$0	$0	$0	$862	$5,954
Internal Rate of Return		2036	28	$887.65	$0	$0	$0	$888	$6,842
Years 1 - 30:	3.8%	2037	29	$914.27	$0	$0	$0	$914	$7,756
		2038	30	$941.70	$0	$0	$0	$942	$8,698

6 Solar PV System Analysis 2.0 KW – St. Joseph

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter efficiency 96%;

6.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,741 KWH**
- First year value of the power produced by the system for consumer **$208.47**
- Cash purchase system install price **$15,000.00** does not include tax;
- KCPL incentive value **$4,000**;
- Federal Investment Tax Credit value **$3,300**;
- Adjusted system cost basis **$7,700**;
- **IRR 2.6 % Simple Payback 22 years**

6.2 System Report - KCPL2.0KW St. Joseph.hmr

6.2.1 Sensitivity case

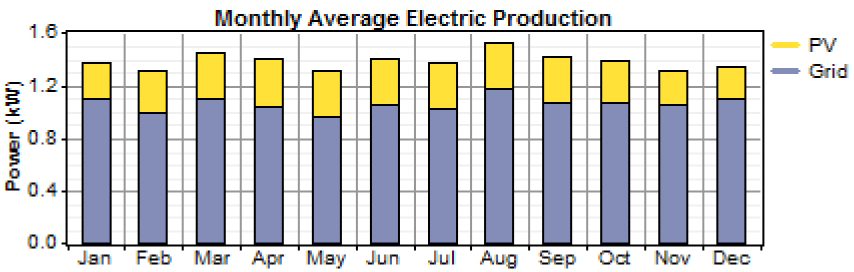
Primary Load 1 Scaled Average: 31.2 kWh/d

6.2.2 System architecture

PV Array	2 kW
Grid	1,000 kW
Inverter	2 kW
Rectifier	2 kW

6.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	2,856	24%
Grid purchases	9,266	76%
Total	12,122	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	95%
Grid sales	609	5%

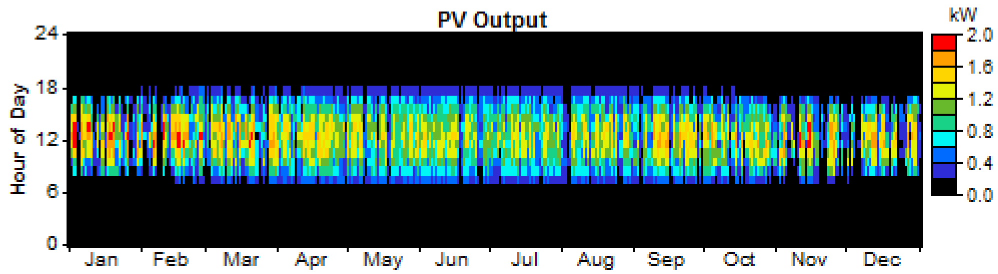
Total	12,008	100%

Quantity	Value	Units
Excess electricity	0.000389	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.236	

6.2.4 PV

Quantity	Value	Units
Rated capacity	2.00	kW
Mean output	0.326	kW
Mean output	7.83	kWh/d
Capacity factor	16.3	%
Total production	2,856	kWh/yr

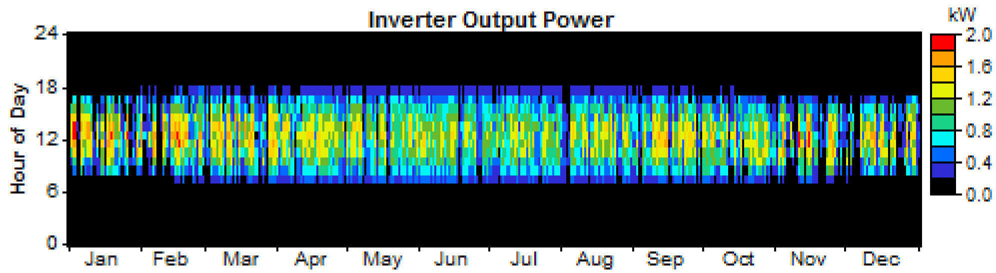
Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	1.99	kW
PV penetration	25.1	%
Hours of operation	4,386	hr/yr
Levelized cost	0.411	$/kWh



6.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	2.00	2.00	kW
Mean output	0.31	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	1.91	0.00	kW
Capacity factor	15.7	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,386	0	hrs/yr
Energy in	2,856	0	kWh/yr
Energy out	2,742	0	kWh/yr
Losses	114	0	kWh/yr



6.2.6 Energy Produced

Month	Energy Produced (kWh)	Net Purchases (kWh)	Energy Charge ($)
Jan	200	-200	-13
Feb	201	-201	-13
Mar	253	-253	-16
Apr	257	-257	-16
May	251	-251	-16
Jun	245	-245	-24
Jul	255	-255	-25
Aug	244	-244	-24
Sep	243	-243	-24
Oct	231	-231	-15
Nov	181	-181	-11

Schedule JMO-4

Dec	179	-179	-11
Annual	2,742	-2,742	-209

6.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	811	60	751	8	47	0
Feb	669	53	616	7	39	0
Mar	813	58	755	8	47	0
Apr	746	54	692	9	44	0
May	712	55	657	7	41	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	792	45	746	7	47	0
Nov	756	49	708	7	45	0
Dec	816	46	770	9	48	0

Annual	6,116	420	5,695	9	358	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	754	47	706	9	70	0
Jul	755	47	708	7	70	0
Aug	875	42	833	8	83	0
Sep	767	52	714	8	71	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,150	188	2,962	9	294	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	811	60	751	8	47	0
Feb	669	53	616	7	39	0
Mar	813	58	755	8	47	0
Apr	746	54	692	9	44	0
May	712	55	657	7	41	0
Jun	754	47	706	9	70	0
Jul	755	47	708	7	70	0
Aug	875	42	833	8	83	0
Sep	767	52	714	8	71	0
Oct	792	45	746	7	47	0
Nov	756	49	708	7	45	0
Dec	816	46	770	9	48	0
Annual	9,266	609	8,657	9	653	0

6.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,471
Carbon monoxide	0
Unburned hydocarbons	0

Particulate matter	0
Sulfur dioxide	23.7
Nitrogen oxides	11.6

6.3 Financial Analysis

Solar PV Analysis 2.0 KW St. Joseph

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**1,753**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**988**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($7,700)**	**($7,700)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$208.47**	**$0**	**$0**	**$0**	**$208**	**($7,492)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$241.83**	**$0**	**$0**	**$0**	**$242**	**($7,250)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$266.01**	**$0**	**$0**	**$0**	**$266**	**($6,984)**
Interest Rate (%):	**7**	**2012**	**4**	**$273.99**	**$0**	**$0**	**$0**	**$274**	**($6,710)**
Loan Term (Years):	**10**	**2013**	**5**	**$282.21**	**$0**	**$0**	**$0**	**$282**	**($6,427)**

Month Installed:	0	2014	6	$290.68	$0	$0	$0	$291	($6,137)
Net Federal Tax Rate (%):	28	2015	7	$299.40	$0	$0	$0	$299	($5,837)
Net State Tax Rate (%):	8	2016	8	$308.38	$0	$0	$0	$308	($5,529)
O & M Cost ($/kWh):	$0.000	2017	9	$317.63	$0	$0	$0	$318	($5,211)
O & M Inflation Rate (%):	0	2018	10	$327.16	$0	$0	$0	$327	($4,884)
State Rebate (%):	0	2019	11	$336.97	$0	$0	$0	$337	($4,547)
State Tax Credit (%):	0	2020	12	$347.08	$0	$0	$0	$347	($4,200)
Federal Tax Credit (%):	30	2021	13	$357.49	$0	$0	$0	$357	($3,843)
Less KCPL Incentive	$4,000	2022	14	$368.22	$0	$0	$0	$368	($3,474)
Renewable Certificates ($KWH)	$0.0000	2023	15	$379.27	$0	$0	$0	$379	($3,095)
Results		2024	16	$390.64	$0	$0	$0	$391	($2,705)
Loan Payments		2025	17	$402.36	$0	$0	$0	$402	($2,302)
Monthly Payment ($):	$0	2026	18	$414.43	$0	$0	$0	$414	($1,888)
Value of Interest Deduction ($):	$0	2027	19	$426.87	$0	$0	$0	$427	($1,461)
Net Monthly Payment ($):	$0	2028	20	$439.67	$0	$0	$0	$440	($1,021)
		2029	21	$452.86	$0	$0	$0	$453	($568)
Ave. Monthly Savings on Bill		2030	22	$466.45	$0	$0	$0	$466	($102)
Year 1 ($):	$5	2031	23	$480.44	$0	$0	$0	$480	$378
Year 10 ($):	$23	2032	24	$494.85	$0	$0	$0	$495	$873
Year 20 ($):	$101	2033	25	$509.70	$0	$0	$0	$510	$1,383
Year 30 ($):	$445	2034	26	$524.99	$0	$0	$0	$525	$1,908
		2035	27	$540.74	$0	$0	$0	$541	$2,449
Internal Rate of Return		2036	28	$556.96	$0	$0	$0	$557	$3,006
Years 1 - 30:	2.6%	2037	29	$573.67	$0	$0	$0	$574	$3,579
		2038	30	$590.88	$0	$0	$0	$591	$4,170

7 Solar PV System Analysis 3.2 KW – St. Joseph

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter Efficiency 96%;

7.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **4,383 KWH**
- First year value of the power produced by the system for consumer **$333.36**
- Cash purchase system install price **$21,000.00** does not include tax;
- KCPL incentive value **$6,400**;
- Federal Investment Tax Credit value **$4,380**;
- Adjusted system cost basis **$10,220**;
- **IRR 3.8 % Simple Payback 20 years**

7.2 System Report - KCPL3.2 KW St. Joseph.hmr

7.2.1 Sensitivity case

Primary Load 1 Scaled Average: 31.2 kWh/d

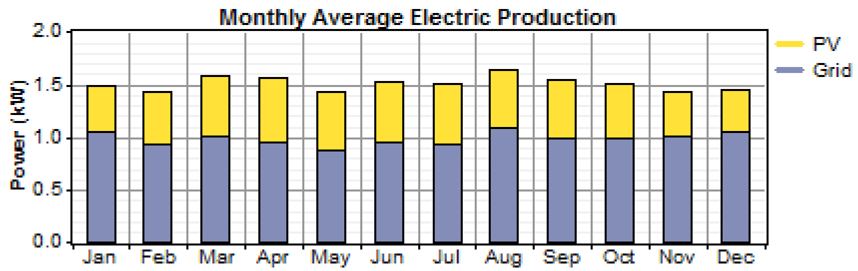
7.2.2 System architecture

PV Array	3.2 kW

Grid	1,000 kW
Inverter	3 kW
Rectifier	3 kW

7.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	4,566	35%
Grid purchases	8,646	65%
Total	13,212	100%



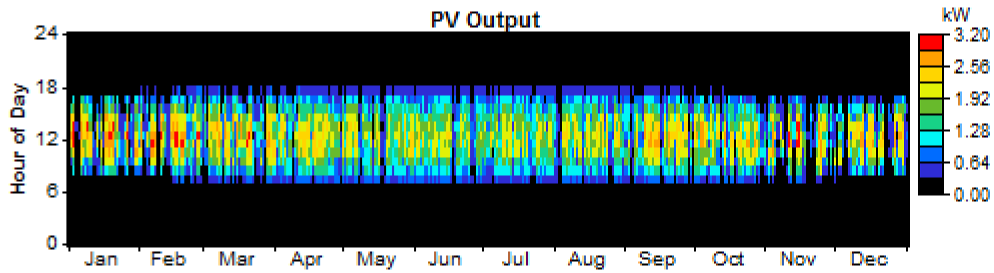
Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	87%
Grid sales	1,630	13%
Total	13,029	100%

Quantity	Value	Units
Excess electricity	0.108	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.346	

7.2.4 PV

Quantity	Value	Units
Rated capacity	3.20	kW
Mean output	0.521	kW
Mean output	12.5	kWh/d
Capacity factor	16.3	%
Total production	4,566	kWh/yr

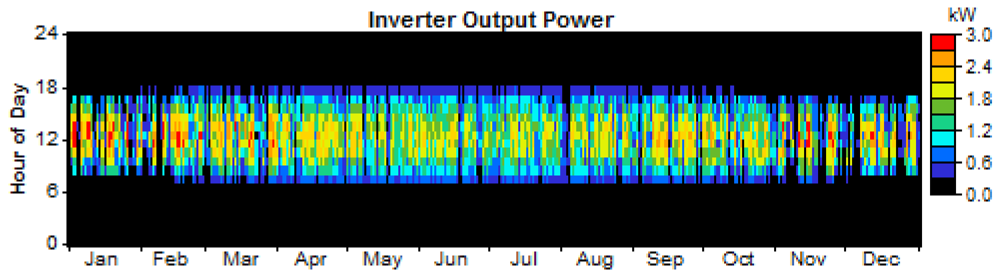
Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	3.18	kW
PV penetration	40.1	%
Hours of operation	4,386	hr/yr
Levelized cost	0.360	$/kWh



7.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	3.00	3.00	kW
Mean output	0.50	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	3.00	0.00	kW
Capacity factor	16.7	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,386	0	hrs/yr
Energy in	4,566	0	kWh/yr
Energy out	4,383	0	kWh/yr
Losses	183	0	kWh/yr



7.2.6 Energy Produced

Rate: All

Month	Energy Produced (kWh)	Energy Charge ($)
Jan	320	-20
Feb	322	-20
Mar	405	-25
Apr	411	-26
May	401	-25
Jun	392	-39
Jul	408	-41
Aug	391	-39
Sep	389	-39
Oct	369	-23
Nov	290	-18

Dec	286	-18
Annual	4,383	-333

7.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	775	144	631	8	40	0
Feb	628	133	495	7	31	0
Mar	757	154	603	8	38	0
Apr	691	153	538	9	34	0
May	652	145	507	7	32	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	739	130	608	7	38	0
Nov	720	121	600	7	38	0
Dec	781	117	663	9	42	0
Annual	5,743	1,097	4,646	9	292	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	689	130	560	9	56	0
Jul	691	136	555	7	55	0
Aug	811	124	686	8	68	0
Sep	712	143	569	8	57	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,903	533	2,370	9	236	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)

Schedule JMO-4

Jan	775	144	631	8	40	0
Feb	628	133	495	7	31	0
Mar	757	154	603	8	38	0
Apr	691	153	538	9	34	0
May	652	145	507	7	32	0
Jun	689	130	560	9	56	0
Jul	691	136	555	7	55	0
Aug	811	124	686	8	68	0
Sep	712	143	569	8	57	0
Oct	739	130	608	7	38	0
Nov	720	121	600	7	38	0
Dec	781	117	663	9	42	0
Annual	8,646	1,630	7,016	9	528	0

7.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	4,434
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0

Sulfur dioxide	19.2
Nitrogen oxides	9.4

7.3 Financial Analysis

Solar PV Analysis 3.2 KW St. Joseph

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$21,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,803**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**1,580**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,220)**	**($10,220)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$333.36**	**$0**	**$0**	**$0**	**$333**	**($9,887)**
Down Payment ($):	**$21,000**	**2010**	**2**	**$386.70**	**$0**	**$0**	**$0**	**$387**	**($9,500)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$425.37**	**$0**	**$0**	**$0**	**$425**	**($9,075)**
Interest Rate (%):	**7**	**2012**	**4**	**$438.13**	**$0**	**$0**	**$0**	**$438**	**($8,636)**

Loan Term (Years):	10	2013	5	$451.27	$0	$0	$0	$451	($8,185)
Month Installed:	0	2014	6	$464.81	$0	$0	$0	$465	($7,720)
Net Federal Tax Rate (%):	28	2015	7	$478.76	$0	$0	$0	$479	($7,242)
Net State Tax Rate (%):	8	2016	8	$493.12	$0	$0	$0	$493	($6,748)
O & M Cost ($/kWh):	$0.000	2017	9	$507.91	$0	$0	$0	$508	($6,241)
O & M Inflation Rate (%):	0	2018	10	$523.15	$0	$0	$0	$523	($5,717)
State Rebate (%):	0	2019	11	$538.84	$0	$0	$0	$539	($5,179)
State Tax Credit (%):	0	2020	12	$555.01	$0	$0	$0	$555	($4,624)
Federal Tax Credit (%):	30	2021	13	$571.66	$0	$0	$0	$572	($4,052)
Less KCPL Incentive	$6,400	2022	14	$588.81	$0	$0	$0	$589	($3,463)
Renewable Certificates ($KWH)	$0.0000	2023	15	$606.47	$0	$0	$0	$606	($2,857)
Results		2024	16	$624.67	$0	$0	$0	$625	($2,232)
Loan Payments		2025	17	$643.41	$0	$0	$0	$643	($1,589)
Monthly Payment ($):	$0	2026	18	$662.71	$0	$0	$0	$663	($926)
Value of Interest Deduction ($):	$0	2027	19	$682.59	$0	$0	$0	$683	($243)
Net Monthly Payment ($):	$0	2028	20	$703.07	$0	$0	$0	$703	$460
		2029	21	$724.16	$0	$0	$0	$724	$1,184
Ave. Monthly Savings on Bill		2030	22	$745.89	$0	$0	$0	$746	$1,930
Year 1 ($):	$8	2031	23	$768.26	$0	$0	$0	$768	$2,698
Year 10 ($):	$37	2032	24	$791.31	$0	$0	$0	$791	$3,489
Year 20 ($):	$161	2033	25	$815.05	$0	$0	$0	$815	$4,304
Year 30 ($):	$711	2034	26	$839.50	$0	$0	$0	$840	$5,144
		2035	27	$864.69	$0	$0	$0	$865	$6,009
Internal Rate of Return		2036	28	$890.63	$0	$0	$0	$891	$6,899
Years 1 - 30:	3.8%	2037	29	$917.35	$0	$0	$0	$917	$7,817

8 Solar PV System Analysis 2.0 KW – Sedalia

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter efficiency 96%;

8.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,725 KWH**
- First year value of the power produced by the system for consumer **$204.25**
- Cash purchase system install price **$15,000.00** does not include tax;
- KCPL incentive value **$4,000**;
- Federal Investment Tax Credit value **$3,300**;
- Adjusted system cost basis **$7,700**;
- **IRR 2.5 % Simple Payback 22 years**

8.2 System Report - KCPL2.0KW Sedalia.hmr

8.2.1 Sensitivity case

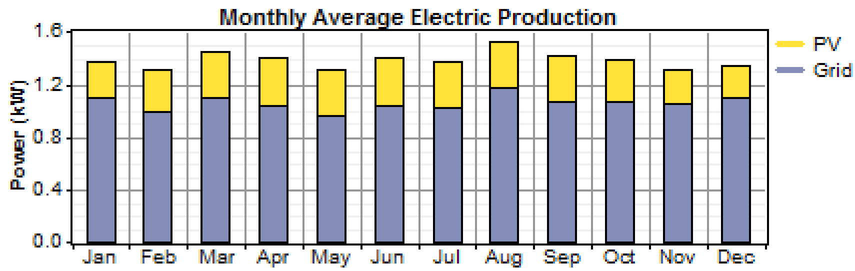
Primary Load 1 Scaled Average: 31.2 kWh/d

8.2.2 System architecture

PV Array	2 kW
Grid	1,000 kW
Inverter	2 kW
Rectifier	2 kW

8.2.3 Electrical

Component	Production (kWh/yr)	Fraction
PV array	2,846	24%
Grid purchases	9,263	76%
Total	12,110	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	95%

Grid sales	597	5%
Total	11,996	100%

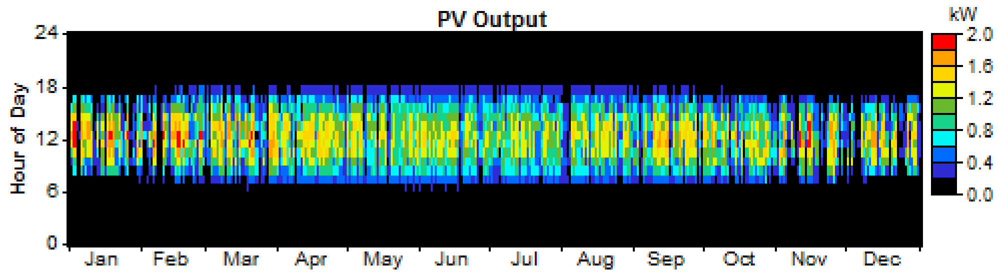
Quantity	Value	Units
Excess electricity	0.0000495	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.235	

8.2.4 PV

Quantity	Value	Units
Rated capacity	2.00	kW
Mean output	0.325	kW
Mean output	7.80	kWh/d
Capacity factor	16.2	%
Total production	2,846	kWh/yr

Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	1.98	kW
PV penetration	25.0	%
Hours of operation	4,388	hr/yr

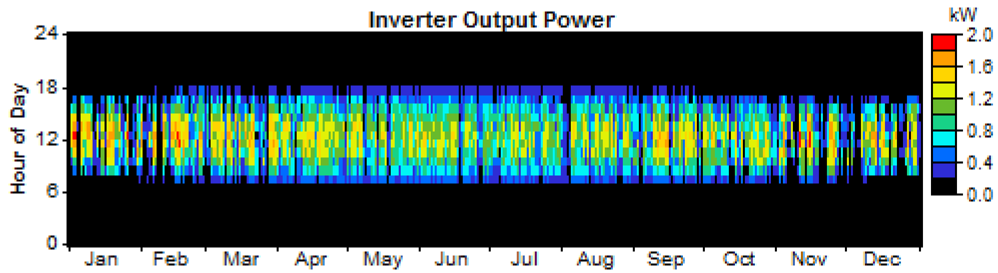
Levelized cost	0.412	$/kWh



8.2.5 Converter

Quantity	Inverter	Rectifier	Units
Capacity	2.00	2.00	kW
Mean output	0.31	0.00	kW
Minimum output	0.00	0.00	kW
Maximum output	1.90	0.00	kW
Capacity factor	15.6	0.0	%

Quantity	Inverter	Rectifier	Units
Hours of operation	4,388	0	hrs/yr
Energy in	2,846	0	kWh/yr
Energy out	2,733	0	kWh/yr
Losses	114	0	kWh/yr



8.2.6 Energy Produced

Month	Energy Produced	Energy Charge
	(kWh)	($)
Jan	196	-12
Feb	198	-12
Mar	250	-16
Apr	261	-16
May	253	-16
Jun	251	-25
Jul	253	-25
Aug	249	-25
Sep	242	-24
Oct	225	-14
Nov	181	-11

Dec	174	-11
Annual	2,733	-208

8.2.7 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	813	58	755	8	48	0
Feb	670	51	619	7	39	0
Mar	814	56	758	8	48	0
Apr	743	55	688	9	43	0
May	711	55	655	7	41	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	795	43	752	7	47	0
Nov	756	47	708	7	45	0
Dec	818	43	775	9	49	0

Annual	6,120	409	5,711	9	359	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	750	49	700	9	70	0
Jul	756	46	710	7	71	0
Aug	871	43	828	8	82	0
Sep	767	51	716	8	71	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,144	188	2,955	9	294	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	813	58	755	8	48	0
Feb	670	51	619	7	39	0
Mar	814	56	758	8	48	0
Apr	743	55	688	9	43	0
May	711	55	655	7	41	0
Jun	750	49	700	9	70	0
Jul	756	46	710	7	71	0
Aug	871	43	828	8	82	0
Sep	767	51	716	8	71	0
Oct	795	43	752	7	47	0
Nov	756	47	708	7	45	0
Dec	818	43	775	9	49	0
Annual	9,263	597	8,666	9	653	0

8.2.8 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,477
Carbon monoxide	0
Unburned hydocarbons	0

Particulate matter	0
Sulfur dioxide	23.7
Nitrogen oxides	11.6

8.3 Financial Analysis

Solar PV Analysis 2.0 KW Sedalia

Grid Tied
Prepared for: **Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) — **Annual Cash Flow Model**

Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**1,738**		**Year**	**Net Energy**	**O&M Costs**	**Net Deprec.**	**Net Loan Payments**	**Annual Cash Flow**	**Total Cash Flow**
Summer Energy Usage (kWh):	**955**								
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($7,700)**	**($7,700)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$204.25**	**$0**	**$0**	**$0**	**$204**	**($7,496)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$236.93**	**$0**	**$0**	**$0**	**$237**	**($7,259)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$260.62**	**$0**	**$0**	**$0**	**$261**	**($6,998)**
Interest Rate (%):	**7**	**2012**	**4**	**$268.44**	**$0**	**$0**	**$0**	**$268**	**($6,730)**
Loan Term (Years):	**10**	**2013**	**5**	**$276.49**	**$0**	**$0**	**$0**	**$276**	**($6,453)**

Month Installed:	0	2014	6	$284.79	$0	$0	$0	$285	($6,168)
Net Federal Tax Rate (%):	28	2015	7	$293.33	$0	$0	$0	$293	($5,875)
Net State Tax Rate (%):	8	2016	8	$302.13	$0	$0	$0	$302	($5,573)
O & M Cost ($/kWh):	$0.000	2017	9	$311.19	$0	$0	$0	$311	($5,262)
O & M Inflation Rate (%):	0	2018	10	$320.53	$0	$0	$0	$321	($4,941)
State Rebate (%):	0	2019	11	$330.14	$0	$0	$0	$330	($4,611)
State Tax Credit (%):	0	2020	12	$340.05	$0	$0	$0	$340	($4,271)
Federal Tax Credit (%):	30	2021	13	$350.25	$0	$0	$0	$350	($3,921)
Less KCPL Incentive	$4,000	2022	14	$360.76	$0	$0	$0	$361	($3,560)
Renewable Certificates ($KWH)	$0.0000	2023	15	$371.58	$0	$0	$0	$372	($3,189)
Results		2024	16	$382.73	$0	$0	$0	$383	($2,806)
Loan Payments		2025	17	$394.21	$0	$0	$0	$394	($2,412)
Monthly Payment ($):	$0	2026	18	$406.04	$0	$0	$0	$406	($2,006)
Value of Interest Deduction ($):	$0	2027	19	$418.22	$0	$0	$0	$418	($1,587)
Net Monthly Payment ($):	$0	2028	20	$430.76	$0	$0	$0	$431	($1,157)
		2029	21	$443.69	$0	$0	$0	$444	($713)
Ave. Monthly Savings on Bill		2030	22	$457.00	$0	$0	$0	$457	($256)
Year 1 ($):	$5	2031	23	$470.71	$0	$0	$0	$471	$215
Year 10 ($):	$22	2032	24	$484.83	$0	$0	$0	$485	$700
Year 20 ($):	$97	2033	25	$499.37	$0	$0	$0	$499	$1,199
Year 30 ($):	$430	2034	26	$514.35	$0	$0	$0	$514	$1,713
		2035	27	$529.79	$0	$0	$0	$530	$2,243
Internal Rate of Return		2036	28	$545.68	$0	$0	$0	$546	$2,789
Years 1 - 30:	2.5%	2037	29	$562.05	$0	$0	$0	$562	$3,351
		2038	30	$578.91	$0	$0	$0	$579	$3,930

9 Solar PV System Analysis 3.2 KW – Sedalia

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;
- Solar collectors sloped at 39 degrees;
- Inverter Efficiency 96%;

9.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **4,373 KWH**
- First year value of the power produced by the system for consumer **$333.17**
- Cash purchase system install price **$21,000.00** does not include tax;
- KCPL incentive value **$6,400**;
- Federal Investment Tax Credit value **$4,380**;
- Adjusted system cost basis **$10,220**;
- **IRR 3.8 % Simple Payback 20 years**

9.2 System Report - KCPL3.2 KW Sedalia.hmr

9.2.1 Sensitivity case

Primary Load 1 Scaled Average: 31.2 kWh/d

9.2.2 System architecture

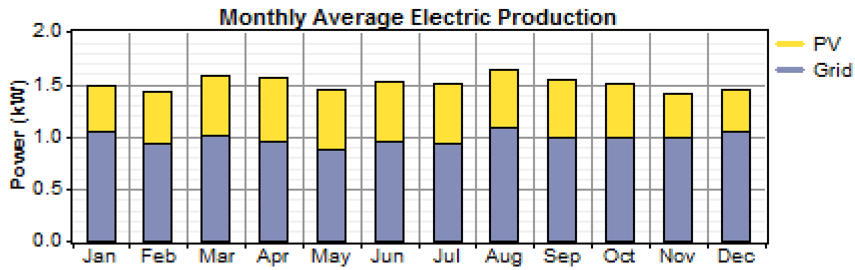
PV Array	3.2 kW
Grid	1,000 kW
Inverter	3 kW
Rectifier	3 kW

9.2.3 Cost summary

Total net present cost	$ 27,751
Levelized cost of energy	$ 0.190/kWh
Operating cost	$ 528/yr

9.2.4 Electrical

Component	Production (kWh/yr)	Fraction
PV array	4,554	35%
Grid purchases	8,639	65%
Total	13,193	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,399	88%
Grid sales	1,612	12%
Total	13,011	100%

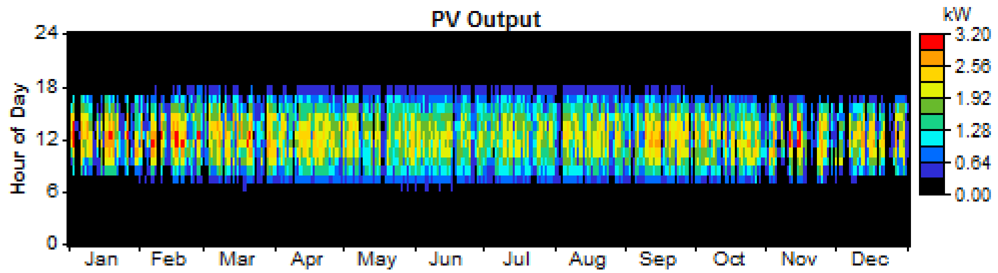
Quantity	Value	Units
Excess electricity	0.0443	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.345	

9.2.5 PV

Quantity	Value	Units
Rated capacity	3.20	kW
Mean output	0.520	kW

Mean output	12.5	kWh/d
Capacity factor	16.2	%
Total production	4,554	kWh/yr

Quantity	Value	Units
Minimum output	0.00	kW
Maximum output	3.16	kW
PV penetration	40.0	%
Hours of operation	4,388	hr/yr
Levelized cost	0.361	$/kWh

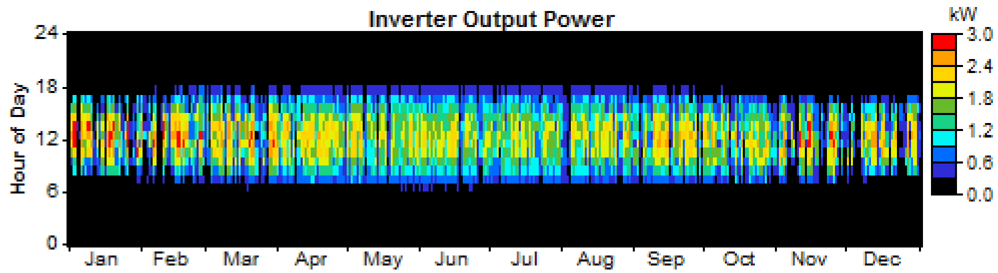


9.2.6 Converter

Quantity	Inverter	Rectifier	Units
Capacity	3.00	3.00	kW
Mean output	0.50	0.00	kW
Minimum output	0.00	0.00	kW

Schedule JMO-4

Quantity	Inverter	Rectifier	Units
Maximum output	3.00	0.00	kW
Capacity factor	16.6	0.0	%
Hours of operation	4,388	0	hrs/yr
Energy in	4,554	0	kWh/yr
Energy out	4,372	0	kWh/yr
Losses	182	0	kWh/yr



9.2.7 Energy Produced

Month	Energy Sold (kWh)	Energy Charge ($)
Jan	314	-20
Feb	316	-20
Mar	400	-25
Apr	417	-26

May	405	-25
Jun	402	-40
Jul	405	-40
Aug	398	-40
Sep	387	-38
Oct	360	-23
Nov	289	-18
Dec	279	-18
Annual	4,372	-333

9.2.8 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	777	139	637	8	40	0
Feb	630	129	501	7	31	0
Mar	758	150	608	8	38	0
Apr	687	156	532	9	33	0
May	650	147	503	7	32	0

Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	741	124	617	7	39	0
Nov	719	119	600	7	38	0
Dec	782	112	670	9	42	0
Annual	5,744	1,076	4,668	9	294	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	685	135	550	9	55	0
Jul	692	134	559	7	56	0
Aug	807	127	679	8	68	0

Sep	712	141	571	8	57	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,895	537	2,359	9	234	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	777	139	637	8	40	0
Feb	630	129	501	7	31	0
Mar	758	150	608	8	38	0
Apr	687	156	532	9	33	0
May	650	147	503	7	32	0
Jun	685	135	550	9	55	0
Jul	692	134	559	7	56	0
Aug	807	127	679	8	68	0
Sep	712	141	571	8	57	0
Oct	741	124	617	7	39	0
Nov	719	119	600	7	38	0

Dec	782	112	670	9	42	0
Annual	8,639	1,612	7,027	9	528	0

9.2.9 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	4,441
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	19.3
Nitrogen oxides	9.42

9.3 Financial Analysis

Solar PV Analysis 3.2 KW Sedalia

Grid Tied
Prepared for: **Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$21,000**									
Allocation to Business (%):	**0**									
Winter Energy Usage (kWh)	**2,781**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**

			Year	Energy	Costs	Deprec.	Payments	Cash Flow	Cash Flow
Summer Energy Usage (kWh):	1,592								
2009 Winter Electricity Cost ($/kWh):	$0.0629		0					($10,220)	($10,220)
2009 Summer Electric Cost ($/kWh):	$0.0994								
2010 Electric Rate Increase (%):	16								
2011 Electric Rate Increase (%):	10								
2012 - 2038 Electric Rate Increase (%):	3								
Loan Down payment (%):	100	2009	1	$333.17	$0	$0	$0	$333	($9,887)
Down Payment ($):	$21,000	2010	2	$386.48	$0	$0	$0	$386	($9,500)
Amount of Loan ($):	$0	2011	3	$425.12	$0	$0	$0	$425	($9,075)
Interest Rate (%):	7	2012	4	$437.88	$0	$0	$0	$438	($8,637)
Loan Term (Years):	10	2013	5	$451.01	$0	$0	$0	$451	($8,186)
Month Installed:	0	2014	6	$464.55	$0	$0	$0	$465	($7,722)
Net Federal Tax Rate (%):	28	2015	7	$478.48	$0	$0	$0	$478	($7,243)
Net State Tax Rate (%):	8	2016	8	$492.84	$0	$0	$0	$493	($6,750)
O & M Cost ($/kWh):	$0.000	2017	9	$507.62	$0	$0	$0	$508	($6,243)
O & M Inflation Rate (%):	0	2018	10	$522.85	$0	$0	$0	$523	($5,720)
State Rebate (%):	0	2019	11	$538.54	$0	$0	$0	$539	($5,181)
State Tax Credit (%):	0	2020	12	$554.69	$0	$0	$0	$555	($4,627)
Federal Tax Credit (%):	30	2021	13	$571.33	$0	$0	$0	$571	($4,055)
Less KCPL Incentive	$6,400	2022	14	$588.47	$0	$0	$0	$588	($3,467)
Renewable Certificates ($KWH)	$0.0000	2023	15	$606.13	$0	$0	$0	$606	($2,861)
Results		2024	16	$624.31	$0	$0	$0	$624	($2,237)
Loan Payments		2025	17	$643.04	$0	$0	$0	$643	($1,593)
Monthly Payment ($):	$0	2026	18	$662.33	$0	$0	$0	$662	($931)

Value of Interest Deduction ($):	$0	2027	19	$682.20	$0	$0	$0	$682	($249)
Net Monthly Payment ($):	$0	2028	20	$702.67	$0	$0	$0	$703	$454
		2029	21	$723.75	$0	$0	$0	$724	$1,177
Ave. Monthly Savings on Bill		2030	22	$745.46	$0	$0	$0	$745	$1,923
Year 1 ($):	$8	2031	23	$767.82	$0	$0	$0	$768	$2,691
Year 10 ($):	$37	2032	24	$790.86	$0	$0	$0	$791	$3,482
Year 20 ($):	$162	2033	25	$814.58	$0	$0	$0	$815	$4,296
Year 30 ($):	$716	2034	26	$839.02	$0	$0	$0	$839	$5,135
		2035	27	$864.19	$0	$0	$0	$864	$5,999
Internal Rate of Return		2036	28	$890.12	$0	$0	$0	$890	$6,889
Years 1 - 30:	3.8%	2037	29	$916.82	$0	$0	$0	$917	$7,806
		2038	30	$944.32	$0	$0	$0	$944	$8,751

10 Wind Turbine Analysis 2.4 KW System Northeast

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

10.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,858 KWH**
- First year value of the power produced by the system for consumer **$204.59**
- Cash purchase system install price **$15,000.00** does not include tax;
- Federal Investment Tax Credit value **$4,500**;
- Adjusted system cost basis **$10,500**;
- **IRR .6 % Simple Payback 28 years**

10.2 System Production Report

10.2.1 Sensitivity case

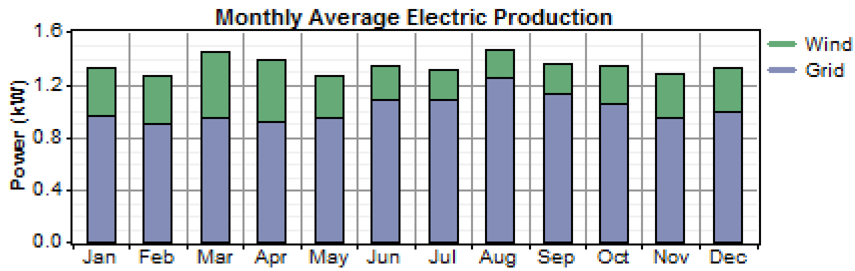
Primary Load 1 Scaled Average: 31.2 kWh/d

10.2.2 System architecture

Wind turbine	1 SW Skystream 3.7
Grid	1,000,000 kW

10.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	2,858	24%
Grid purchases	8,901	76%
Total	11,759	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	97%
Grid sales	371	3%
Total	11,759	100%

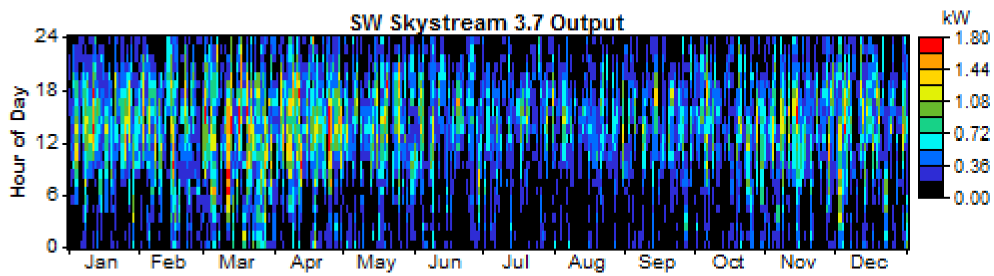
Quantity	Value	Units
Excess electricity	0.0000344	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.243	

10.2.4 AC Wind Turbine: SW Skystream 3.7

Variable	Value	Units
Total rated capacity	1.82	kW
Mean output	0.326	kW
Capacity factor	17.9	%
Total production	2,858	kWh/yr

Variable	Value	Units
Minimum output	0.00	kW
Maximum output	1.77	kW
Wind penetration	25.1	%
Hours of operation	7,348	hr/yr
Levelized cost	0.411	$/kWh



Schedule JMO-4

10.2.5 Energy Produced

Month	Energy Produced (kWh)	Value of Energy ($)
Jan	271	-17
Feb	244	-15
Mar	370	-23
Apr	342	-21
May	240	-15
Jun	190	-19
Jul	170	-17
Aug	157	-16
Sep	164	-16
Oct	210	-13
Nov	247	-16
Dec	255	-16
Annual	2,858	-205

10.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	715	35	680	8	43	0
Feb	604	33	572	6	36	0
Mar	704	67	637	7	40	0
Apr	661	54	606	7	38	0
May	699	31	667	6	42	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	786	20	766	7	48	0
Nov	679	38	642	7	40	0
Dec	733	39	693	8	44	0
Annual	5,581	317	5,264	8	331	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	776	15	761	8	76	0
Jul	809	15	793	7	79	0
Aug	928	8	919	8	91	0
Sep	807	15	793	8	79	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,320	53	3,266	8	325	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	715	35	680	8	43	0
Feb	604	33	572	6	36	0
Mar	704	67	637	7	40	0
Apr	661	54	606	7	38	0

May	699	31	667	6	42	0
Jun	776	15	761	8	76	0
Jul	809	15	793	7	79	0
Aug	928	8	919	8	91	0
Sep	807	15	793	8	79	0
Oct	786	20	766	7	48	0
Nov	679	38	642	7	40	0
Dec	733	39	693	8	44	0
Annual	8,901	371	8,530	8	656	0

10.3 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,391
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	23.4
Nitrogen oxides	11.4

10.4 Financial Analysis

Skystream Analysis 2.4 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Assumptions (Inputs)			Year	Net Energy	O&M Costs	Net Deprec.	Net Loan Payments	Annual Cash Flow	Total Cash Flow
Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,178**								
Summer Energy Usage (kWh):	**680**								
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,500)**	**($10,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$204.59**	**$0**	**$0**	**$0**	**$205**	**($10,295)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$237.32**	**$0**	**$0**	**$0**	**$237**	**($10,058)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$261.05**	**$0**	**$0**	**$0**	**$261**	**($9,797)**
Interest Rate (%):	**7**	**2012**	**4**	**$268.89**	**$0**	**$0**	**$0**	**$269**	**($9,528)**
Loan Term (Years):	**10**	**2013**	**5**	**$276.95**	**$0**	**$0**	**$0**	**$277**	**($9,251)**
Month Installed:	**0**	**2014**	**6**	**$285.26**	**$0**	**$0**	**$0**	**$285**	**($8,966)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$293.82**	**$0**	**$0**	**$0**	**$294**	**($8,672)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$302.63**	**$0**	**$0**	**$0**	**$303**	**($8,369)**
O & M Cost ($/kWh):	**$0.000**	**2017**	**9**	**$311.71**	**$0**	**$0**	**$0**	**$312**	**($8,058)**

O & M Inflation Rate (%):	0	2018	10	$321.06	$0	$0	$0	$321	($7,737)
State Rebate (%):	0	2019	11	$330.70	$0	$0	$0	$331	($7,406)
State Tax Credit (%):	0	2020	12	$340.62	$0	$0	$0	$341	($7,065)
Federal Tax Credit (%):	30	2021	13	$350.84	$0	$0	$0	$351	($6,715)
		2022	14	$361.36	$0	$0	$0	$361	($6,353)
Renewable Certificates ($KWH)	**$0.0000**	2023	15	$372.20	$0	$0	$0	$372	($5,981)
Results		2024	16	$383.37	$0	$0	$0	$383	($5,598)
Loan Payments		2025	17	$394.87	$0	$0	$0	$395	($5,203)
Monthly Payment ($):	$0	2026	18	$406.71	$0	$0	$0	$407	($4,796)
Value of Interest Deduction ($):	$0	2027	19	$418.92	$0	$0	$0	$419	($4,377)
Net Monthly Payment ($):	$0	2028	20	$431.48	$0	$0	$0	$431	($3,946)
		2029	21	$444.43	$0	$0	$0	$444	($3,501)
Ave. Monthly Savings on Bill		2030	22	$457.76	$0	$0	$0	$458	($3,043)
Year 1 ($):	$4	2031	23	$471.49	$0	$0	$0	$471	($2,572)
Year 10 ($):	$16	2032	24	$485.64	$0	$0	$0	$486	($2,086)
Year 20 ($):	$69	2033	25	$500.21	$0	$0	$0	$500	($1,586)
Year 30 ($):	$306	2034	26	$515.21	$0	$0	$0	$515	($1,071)
		2035	27	$530.67	$0	$0	$0	$531	($540)
Internal Rate of Return		2036	28	$546.59	$0	$0	$0	$547	$6
Years 1 - 30:	0.6%	2037	29	$562.99	$0	$0	$0	$563	$569
		2038	30	$579.88	$0	$0	$0	$580	$1,149

11 Wind Turbine Analysis 6KW System Northeast of Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

11.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **10,155 KWH**
- First year value of the power produced by the system for consumer **$731.64**
- Cash purchase system install price **$45,000.00** does not include tax;
- Federal Investment Tax Credit value **$13,500**;
- Adjusted system cost basis **$31,500**;
- **IRR 1.6 % Simple Payback 25 years**

11.2 System Report - KCPLProvenNE.hmr

11.2.1 Sensitivity case

Primary Load 1 Scaled Average: 31.2 kWh/d

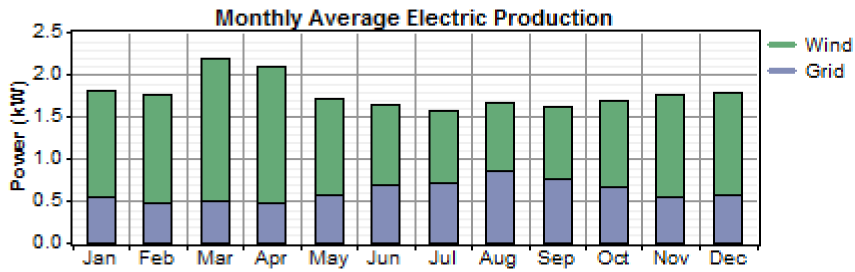
11.2.2 System architecture

Wind turbine	Proven WT6000
Grid	1,000,000 kW
Inverter	6 kW

Rectifier	6 kW

11.2.3 Electrical

Component	Production	Fraction
	(kWh/yr)	
Wind turbine	10,155	65%
Grid purchases	5,389	35%
Total	15,544	100%



Load	Consumption	Fraction
	(kWh/yr)	
AC primary load	11,388	73%
Grid sales	4,156	27%
Total	15,544	100%

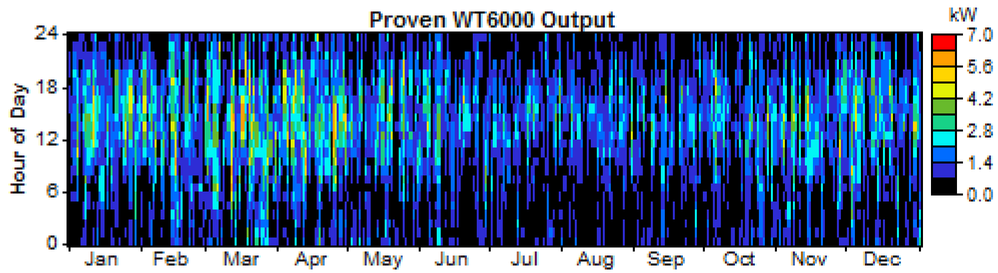
Quantity	Value	Units
Excess electricity	0.0000310	kWh/yr

Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr
Renewable fraction	0.653	

11.2.4 AC Wind Turbine: Proven WT6000

Variable	Value	Units
Total rated capacity	6.30	kW
Mean output	1.16	kW
Capacity factor	18.4	%
Total production	10,155	kWh/yr

Variable	Value	Units
Minimum output	0.0192	kW
Maximum output	6.01	kW
Wind penetration	89.2	%
Hours of operation	8,760	hr/yr
Levelized cost	0.116	$/kWh



11.2.5 Energy Produced

Month	Energy Produced	Energy Value
	(kWh)	($)
Jan	948	-60
Feb	856	-54
Mar	1,256	-79
Apr	1,165	-73
May	853	-54
Jun	696	-69
Jul	636	-63
Aug	597	-59
Sep	616	-61
Oct	762	-48
Nov	870	-55

Dec	900	-57
Annual	10,155	-732

11.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	405	402	3	7	0	0
Feb	325	365	-39	5	-2	0
Mar	371	620	-249	7	-16	0
Apr	336	553	-217	5	-14	0
May	418	364	54	6	3	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	490	276	214	7	13	0
Nov	398	380	18	7	1	0
Dec	429	381	48	7	3	0

Annual	3,172	3,340	-169	7	-11	0

Rate: Summer Rate

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Purchases (kWh)	Peak Demand (kW)	Energy Charge ($)	Demand Charge ($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	494	239	255	7	25	0
Jul	536	210	326	7	32	0
Aug	644	165	479	8	48	0
Sep	544	202	341	8	34	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,217	815	1,401	8	139	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	405	402	3	7	0	0
Feb	325	365	-39	5	-2	0
Mar	371	620	-249	7	-16	0
Apr	336	553	-217	5	-14	0
May	418	364	54	6	3	0
Jun	494	239	255	7	25	0
Jul	536	210	326	7	32	0
Aug	644	165	479	8	48	0
Sep	544	202	341	8	34	0
Oct	490	276	214	7	13	0
Nov	398	380	18	7	1	0
Dec	429	381	48	7	3	0
Annual	5,389	4,156	1,233	8	129	0

11.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	779
Carbon monoxide	0
Unburned hydocarbons	0

Particulate matter	0
Sulfur dioxide	3.38
Nitrogen oxides	1.65

11.3 Financial Analysis

Proven Analysis 6.0 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$45,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**7,610**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**2,545**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($31,500)**	**($31,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$731.64**	**$0**	**$0**	**$0**	**$732**	**($30,768)**
Down Payment ($):	**$45,000**	**2010**	**2**	**$848.70**	**$0**	**$0**	**$0**	**$849**	**($29,920)**

Amount of Loan ($):	$0	2011	3	$933.58	$0	$0	$0	$934	($28,986)
Interest Rate (%):	7	2012	4	$961.58	$0	$0	$0	$962	($28,024)
Loan Term (Years):	10	2013	5	$990.43	$0	$0	$0	$990	($27,034)
Month Installed:	0	2014	6	$1,020.14	$0	$0	$0	$1,020	($26,014)
Net Federal Tax Rate (%):	28	2015	7	$1,050.75	$0	$0	$0	$1,051	($24,963)
Net State Tax Rate (%):	8	2016	8	$1,082.27	$0	$0	$0	$1,082	($23,881)
O & M Cost ($/kWh):	$0.000	2017	9	$1,114.74	$0	$0	$0	$1,115	($22,766)
O & M Inflation Rate (%):	0	2018	10	$1,148.18	$0	$0	$0	$1,148	($21,618)
State Rebate (%):	0	2019	11	$1,182.63	$0	$0	$0	$1,183	($20,435)
State Tax Credit (%):	0	2020	12	$1,218.10	$0	$0	$0	$1,218	($19,217)
Federal Tax Credit (%):	30	2021	13	$1,254.65	$0	$0	$0	$1,255	($17,963)
Less KCPL Incentive	$0	2022	14	$1,292.29	$0	$0	$0	$1,292	($16,670)
Renewable Certificates ($KWH)	$0.0000	2023	15	$1,331.05	$0	$0	$0	$1,331	($15,339)
Results		2024	16	$1,370.99	$0	$0	$0	$1,371	($13,968)
Loan Payments		2025	17	$1,412.12	$0	$0	$0	$1,412	($12,556)
Monthly Payment ($):	$0	2026	18	$1,454.48	$0	$0	$0	$1,454	($11,102)
Value of Interest Deduction ($):	$0	2027	19	$1,498.11	$0	$0	$0	$1,498	($9,604)
Net Monthly Payment ($):	$0	2028	20	$1,543.06	$0	$0	$0	$1,543	($8,061)
		2029	21	$1,589.35	$0	$0	$0	$1,589	($6,471)
Ave. Monthly Savings on Bill		2030	22	$1,637.03	$0	$0	$0	$1,637	($4,834)
Year 1 ($):	$13	2031	23	$1,686.14	$0	$0	$0	$1,686	($3,148)
Year 10 ($):	$59	2032	24	$1,736.72	$0	$0	$0	$1,737	($1,411)
Year 20 ($):	$260	2033	25	$1,788.83	$0	$0	$0	$1,789	$378
Year 30 ($):	$1,145	2034	26	$1,842.49	$0	$0	$0	$1,842	$2,220
		2035	27	$1,897.77	$0	$0	$0	$1,898	$4,118

Internal Rate of Return		**2036**	**28**	**$1,954.70**	**$0**	**$0**	**$0**	**$1,955**	**$6,073**
Years 1 - 30:	**1.6%**	**2037**	**29**	**$2,013.34**	**$0**	**$0**	**$0**	**$2,013**	**$8,086**
		2038	**30**	**$2,073.74**	**$0**	**$0**	**$0**	**$2,074**	**$10,160**

12 Wind Turbine Analysis 2.4 KW System Southwest

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

12.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **3,009 KWH**
- First year value of the power produced by the system for consumer **$213.36**
- Cash purchase system install price **$15,000.00** does not include tax;
- Federal Investment Tax Credit value **$4,500**;
- Adjusted system cost basis **$10,500**;
- **IRR .8 % Simple Payback 28 years**

12.2 System Report - KCPLSkystreamSW.hmr

12.2.1 Sensitivity case

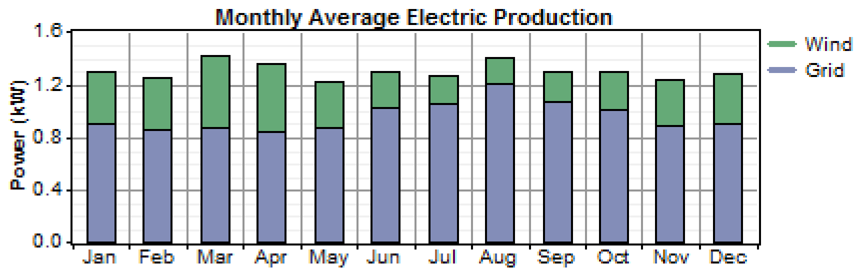
Primary Load 1 Scaled Average: 30 kWh/d

12.2.2 System architecture

Wind turbine	1 SW Skystream 3.7
Grid	1,000,000 kW

12.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	3,008	26%
Grid purchases	8,394	74%
Total	11,403	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	10,950	96%
Grid sales	453	4%
Total	11,403	100%

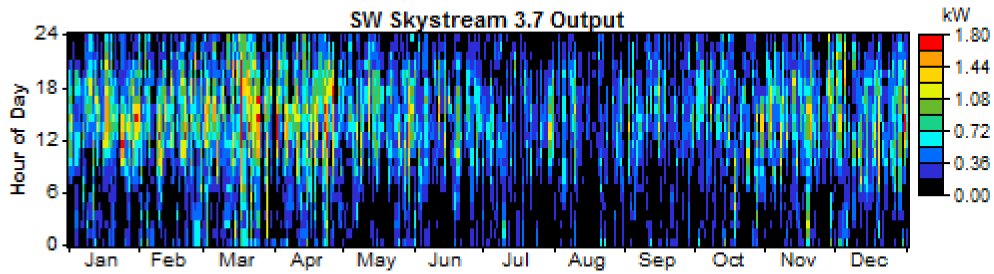
Quantity	Value	Units
Excess electricity	0.0000307	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.264	

12.2.4 AC Wind Turbine: SW Skystream 3.7

Variable	Value	Units
Total rated capacity	1.82	kW
Mean output	0.343	kW
Capacity factor	18.9	%
Total production	3,008	kWh/yr

Variable	Value	Units
Minimum output	0.00	kW
Maximum output	1.76	kW
Wind penetration	27.5	%
Hours of operation	7,470	hr/yr
Levelized cost	0.595	$/kWh



12.2.5 Energy Produced

Month	Energy Produced	Energy Value
	(kWh)	($)
Jan	296	-19
Feb	267	-17
Mar	404	-25
Apr	373	-23
May	262	-16
Jun	193	-19
Jul	157	-16
Aug	144	-14
Sep	165	-16
Oct	214	-13
Nov	253	-16
Dec	279	-18
Annual	3,008	-213

12.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	671	53	619	7	39	0
Feb	570	52	518	6	33	0
Mar	652	87	564	7	35	0
Apr	605	66	538	8	34	0
May	648	38	610	6	38	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	747	23	724	7	46	0
Nov	638	37	601	7	38	0
Dec	674	41	633	8	40	0
Annual	5,205	398	4,807	8	302	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	739	18	721	8	72	0
Jul	781	13	768	7	76	0
Aug	901	10	891	8	89	0
Sep	768	14	755	7	75	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,190	55	3,135	8	312	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	671	53	619	7	39	0
Feb	570	52	518	6	33	0
Mar	652	87	564	7	35	0
Apr	605	66	538	8	34	0

May	648	38	610	6	38	0
Jun	739	18	721	8	72	0
Jul	781	13	768	7	76	0
Aug	901	10	891	8	89	0
Sep	768	14	755	7	75	0
Oct	747	23	724	7	46	0
Nov	638	37	601	7	38	0
Dec	674	41	633	8	40	0
Annual	8,394	453	7,942	8	614	0

12.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,019
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	21.8
Nitrogen oxides	10.6

12.3 Financial Analysis

Skystream Analysis 2.4 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,349**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual**	**Total**
Summer Energy Usage (kWh):	**660**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Cash Flow**	**Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,500)**	**($10,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$213.36**	**$0**	**$0**	**$0**	**$213**	**($10,287)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$247.49**	**$0**	**$0**	**$0**	**$247**	**($10,039)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$272.24**	**$0**	**$0**	**$0**	**$272**	**($9,767)**
Interest Rate (%):	**7**	**2012**	**4**	**$280.41**	**$0**	**$0**	**$0**	**$280**	**($9,486)**
Loan Term (Years):	**10**	**2013**	**5**	**$288.82**	**$0**	**$0**	**$0**	**$289**	**($9,198)**
Month Installed:	**0**	**2014**	**6**	**$297.49**	**$0**	**$0**	**$0**	**$297**	**($8,900)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$306.41**	**$0**	**$0**	**$0**	**$306**	**($8,594)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$315.60**	**$0**	**$0**	**$0**	**$316**	**($8,278)**

O & M Cost ($/kWh):	$0.000	2017	9	$325.07	$0	$0	$0	$325	($7,953)
O & M Inflation Rate (%):	0	2018	10	$334.82	$0	$0	$0	$335	($7,618)
State Rebate (%):	0	2019	11	$344.87	$0	$0	$0	$345	($7,273)
State Tax Credit (%):	0	2020	12	$355.21	$0	$0	$0	$355	($6,918)
Federal Tax Credit (%):	30	2021	13	$365.87	$0	$0	$0	$366	($6,552)
Less KCPL Incentive	$0	2022	14	$376.85	$0	$0	$0	$377	($6,175)
Renewable Certificates ($KWH)	$0.0000	2023	15	$388.15	$0	$0	$0	$388	($5,787)
Results		2024	16	$399.80	$0	$0	$0	$400	($5,388)
Loan Payments		2025	17	$411.79	$0	$0	$0	$412	($4,976)
Monthly Payment ($):	$0	2026	18	$424.14	$0	$0	$0	$424	($4,552)
Value of Interest Deduction ($):	$0	2027	19	$436.87	$0	$0	$0	$437	($4,115)
Net Monthly Payment ($):	$0	2028	20	$449.98	$0	$0	$0	$450	($3,665)
		2029	21	$463.47	$0	$0	$0	$463	($3,201)
Ave. Monthly Savings on Bill		2030	22	$477.38	$0	$0	$0	$477	($2,724)
Year 1 ($):	$3	2031	23	$491.70	$0	$0	$0	$492	($2,232)
Year 10 ($):	$15	2032	24	$506.45	$0	$0	$0	$506	($1,726)
Year 20 ($):	$67	2033	25	$521.64	$0	$0	$0	$522	($1,204)
Year 30 ($):	$297	2034	26	$537.29	$0	$0	$0	$537	($667)
		2035	27	$553.41	$0	$0	$0	$553	($113)
Internal Rate of Return		2036	28	$570.02	$0	$0	$0	$570	$457
Years 1 - 30:	0.8%	2037	29	$587.12	$0	$0	$0	$587	$1,044
		2038	30	$604.73	$0	$0	$0	$605	$1,648

13 Wind Turbine Analysis 6KW System Southwest of Kansas City

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

13.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **10,618 KWH**
- First year value of the power produced by the system for consumer **$758.43**
- Cash purchase system install price **$45,000.00** does not include tax;
- Federal Investment Tax Credit value **$13,500**;
- Adjusted system cost basis **$31,500**;
- **IRR 1.9 % Simple Payback 24 years**

13.2 System Report - KCPLProvenSW.hmr

13.2.1 Sensitivity case

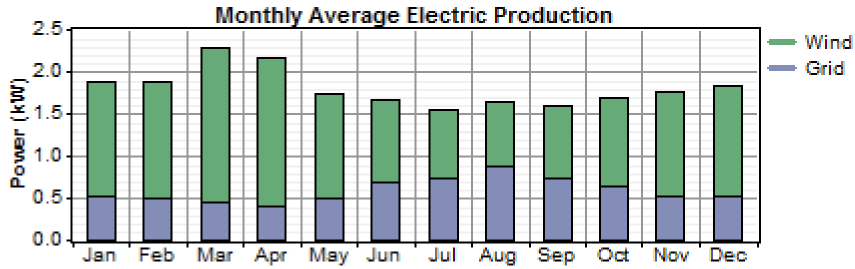
Primary Load 1 Scaled Average: 31.2 kWh/d

13.2.2 System architecture

Wind turbine	1 Proven WT6000
Grid	1,000,000 kW

13.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	10,618	67%
Grid purchases	5,226	33%
Total	15,844	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	72%
Grid sales	4,456	28%
Total	15,844	100%

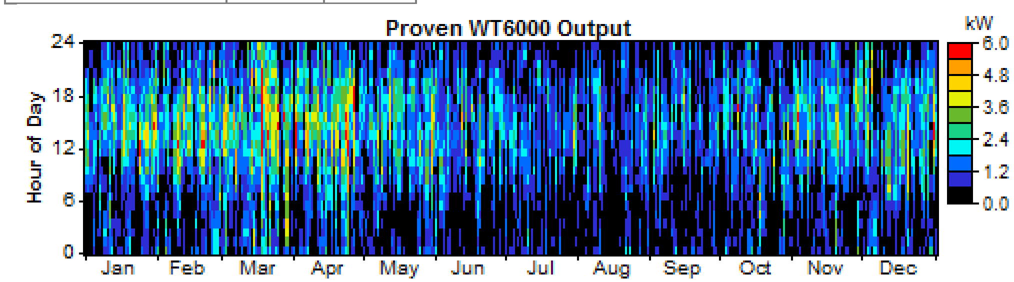
Quantity	Value	Units
Excess electricity	0.0000278	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.670	

13.2.4 AC Wind Turbine: Proven WT6000

Variable	Value	Units
Total rated capacity	6.30	kW
Mean output	1.21	kW
Capacity factor	19.2	%
Total production	10,618	kWh/yr

Variable	Value	Units
Minimum output	0.0145	kW
Maximum output	5.81	kW
Wind penetration	93.2	%
Hours of operation	8,760	hr/yr
Levelized cost	0.169	$/kWh



13.2.5 Energy Produced

Month	Energy Produced	Energy Value	Demand Charge
	(kWh)	($)	($)
Jan	1,025	-64	0
Feb	926	-58	0
Mar	1,363	-86	0
Apr	1,263	-79	0
May	922	-58	0
Jun	705	-70	0
Jul	599	-59	0
Aug	558	-55	0
Sep	620	-62	0
Oct	775	-49	0
Nov	891	-56	0
Dec	972	-61	0
Annual	10,618	-758	0

13.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	382	457	-74	7	-5	0
Feb	334	444	-110	6	-7	0
Mar	343	698	-356	7	-22	0
Apr	298	613	-315	6	-20	0
May	378	392	-15	6	-1	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	483	282	201	6	13	0
Nov	371	374	-3	6	0	0
Dec	393	417	-24	7	-2	0
Annual	2,982	3,678	-696	7	-44	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	493	247	246	8	24	0
Jul	557	193	364	7	36	0
Aug	660	141	518	7	52	0
Sep	534	197	337	7	33	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,244	778	1,465	8	146	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	382	457	-74	7	-5	0
Feb	334	444	-110	6	-7	0
Mar	343	698	-356	7	-22	0
Apr	298	613	-315	6	-20	0

May	378	392	-15	6	-1	0
Jun	493	247	246	8	24	0
Jul	557	193	364	7	36	0
Aug	660	141	518	7	52	0
Sep	534	197	337	7	33	0
Oct	483	282	201	6	13	0
Nov	371	374	-3	6	0	0
Dec	393	417	-24	7	-2	0
Annual	5,226	4,456	770	8	102	0

13.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	486
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	2.11
Nitrogen oxides	1.03

13.3 Financial Analysis

Proven Analysis 6.0 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) | **Annual Cash Flow Model**

Assumptions (Inputs)			Year	Net Energy	O&M Costs	Net Deprec.	Net Loan Payments	Annual Cash Flow	Total Cash Flow
Total Installed Cost ($):	$45,000								
Allocation to Business (%):	0								
Winter Energy Usage (kWh)	8,137								
Summer Energy Usage (kWh):	2,481								
2009 Winter Electricity Cost ($/kWh):	$0.0629		0					($31,500)	($31,500)
2009 Summer Electric Cost ($/kWh):	$0.0994								
2010 Electric Rate Increase (%):	16								
2011 Electric Rate Increase (%):	10								
2012 - 2038 Electric Rate Increase (%):	3								
Loan Down payment (%):	100	2009	1	$758.43	$0	$0	$0	$758	($30,742)
Down Payment ($):	$45,000	2010	2	$879.78	$0	$0	$0	$880	($29,862)
Amount of Loan ($):	$0	2011	3	$967.76	$0	$0	$0	$968	($28,894)
Interest Rate (%):	7	2012	4	$996.79	$0	$0	$0	$997	($27,897)
Loan Term (Years):	10	2013	5	$1,026.69	$0	$0	$0	$1,027	($26,871)
Month Installed:	0	2014	6	$1,057.49	$0	$0	$0	$1,057	($25,813)
Net Federal Tax Rate (%):	28	2015	7	$1,089.22	$0	$0	$0	$1,089	($24,724)
Net State Tax Rate (%):	8	2016	8	$1,121.89	$0	$0	$0	$1,122	($23,602)
O & M Cost ($/kWh):	$0.000	2017	9	$1,155.55	$0	$0	$0	$1,156	($22,446)

O & M Inflation Rate (%):	0	2018	10	$1,190.22	$0	$0	$0	$1,190	($21,256)
State Rebate (%):	0	2019	11	$1,225.92	$0	$0	$0	$1,226	($20,030)
State Tax Credit (%):	0	2020	12	$1,262.70	$0	$0	$0	$1,263	($18,768)
Federal Tax Credit (%):	30	2021	13	$1,300.58	$0	$0	$0	$1,301	($17,467)
Less KCPL Incentive	$0	2022	14	$1,339.60	$0	$0	$0	$1,340	($16,127)
Renewable Certificates ($KWH)	$0.0000	2023	15	$1,379.79	$0	$0	$0	$1,380	($14,748)
Results		2024	16	$1,421.18	$0	$0	$0	$1,421	($13,326)
Loan Payments		2025	17	$1,463.82	$0	$0	$0	$1,464	($11,863)
Monthly Payment ($):	$0	2026	18	$1,507.73	$0	$0	$0	$1,508	($10,355)
Value of Interest Deduction ($):	$0	2027	19	$1,552.96	$0	$0	$0	$1,553	($8,802)
Net Monthly Payment ($):	$0	2028	20	$1,599.55	$0	$0	$0	$1,600	($7,202)
		2029	21	$1,647.54	$0	$0	$0	$1,648	($5,555)
Ave. Monthly Savings on Bill		2030	22	$1,696.96	$0	$0	$0	$1,697	($3,858)
Year 1 ($):	$13	2031	23	$1,747.87	$0	$0	$0	$1,748	($2,110)
Year 10 ($):	$57	2032	24	$1,800.31	$0	$0	$0	$1,800	($310)
Year 20 ($):	$253	2033	25	$1,854.32	$0	$0	$0	$1,854	$1,545
Year 30 ($):	$1,116	2034	26	$1,909.95	$0	$0	$0	$1,910	$3,455
		2035	27	$1,967.25	$0	$0	$0	$1,967	$5,422
Internal Rate of Return		2036	28	$2,026.26	$0	$0	$0	$2,026	$7,448
Years 1 - 30:	1.9%	2037	29	$2,087.05	$0	$0	$0	$2,087	$9,535
		2038	30	$2,149.66	$0	$0	$0	$2,150	$11,685

14 Wind Turbine Analysis 2.4 KW System Sedalia

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

14.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,588 KWH**
- First year value of the power produced by the system for consumer **$182.39**
- Cash purchase system install price **$15,000.00** does not include tax;
- Federal Investment Tax Credit value **$4,500**;
- Adjusted system cost basis **$10,500**;
- **IRR 0 % Simple Payback 30 years**

14.2 System Report - KCPLSkystreamSedalia.hmr

14.2.1 Sensitivity case

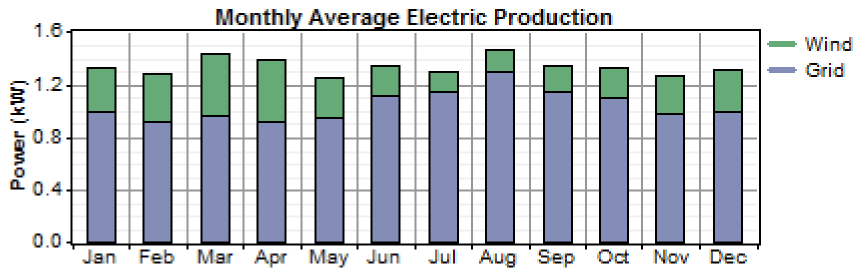
Primary Load 1 Scaled Average: 31.2 kWh/d

14.2.2 System architecture

Wind turbine	1 SW Skystream 3.7
Grid	1,000,000 kW

14.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	2,588	22%
Grid purchases	9,117	78%
Total	11,704	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	97%
Grid sales	316	3%
Total	11,704	100%

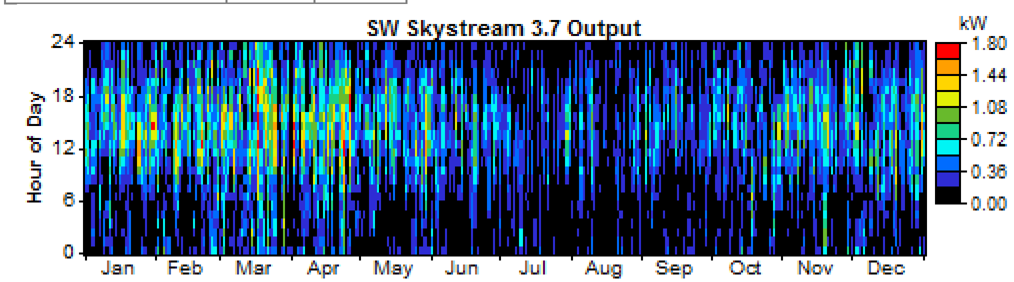
Quantity	Value	Units
Excess electricity	0.0000352	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.221	

14.2.4 AC Wind Turbine: SW Skystream 3.7

Variable	Value	Units
Total rated capacity	1.82	kW
Mean output	0.295	kW
Capacity factor	16.2	%
Total production	2,588	kWh/yr

Variable	Value	Units
Minimum output	0.00	kW
Maximum output	1.76	kW
Wind penetration	22.7	%
Hours of operation	7,264	hr/yr
Levelized cost	0.692	$/kWh



14.2.5 Energy Produced

Rate: All

Month	Energy Produce (kWh)	Energy Charge ($)
Jan	252	-16
Feb	242	-15
Mar	350	-22
Apr	339	-21
May	237	-15
Jun	162	-16
Jul	119	-12
Aug	119	-12
Sep	137	-14
Oct	180	-11
Nov	215	-14
Dec	237	-15
Annual	2,588	-182

14.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	734	36	699	8	44	0
Feb	615	40	574	7	36	0
Mar	720	63	657	7	41	0
Apr	661	52	609	8	38	0
May	698	28	670	7	42	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	811	15	796	7	50	0
Nov	698	25	674	7	42	0
Dec	739	27	711	8	45	0
Annual	5,675	285	5,391	8	339	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge

	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	800	11	789	9	78	0
Jul	850	6	844	7	84	0
Aug	964	7	957	8	95	0
Sep	827	8	819	8	81	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,441	32	3,410	9	339	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	734	36	699	8	44	0
Feb	615	40	574	7	36	0

Mar	720	63	657	7	41	0
Apr	661	52	609	8	38	0
May	698	28	670	7	42	0
Jun	800	11	789	9	78	0
Jul	850	6	844	7	84	0
Aug	964	7	957	8	95	0
Sep	827	8	819	8	81	0
Oct	811	15	796	7	50	0
Nov	698	25	674	7	42	0
Dec	739	27	711	8	45	0
Annual	9,117	316	8,800	9	678	0

14.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,562
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	24.1
Nitrogen oxides	11.8

14.3 Financial Analysis

Skystream Analysis 2.4 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) — **Annual Cash Flow Model**

Assumptions (Inputs)			Year	Net Energy	O&M Costs	Net Deprec.	Net Loan Payments	Annual Cash Flow	Total Cash Flow
Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,051**								
Summer Energy Usage (kWh):	**537**								
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,500)**	**($10,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$182.39**	**$0**	**$0**	**$0**	**$182**	**($10,318)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$211.57**	**$0**	**$0**	**$0**	**$212**	**($10,106)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$232.72**	**$0**	**$0**	**$0**	**$233**	**($9,873)**
Interest Rate (%):	**7**	**2012**	**4**	**$239.71**	**$0**	**$0**	**$0**	**$240**	**($9,634)**
Loan Term (Years):	**10**	**2013**	**5**	**$246.90**	**$0**	**$0**	**$0**	**$247**	**($9,387)**
Month Installed:	**0**	**2014**	**6**	**$254.30**	**$0**	**$0**	**$0**	**$254**	**($9,132)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$261.93**	**$0**	**$0**	**$0**	**$262**	**($8,870)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$269.79**	**$0**	**$0**	**$0**	**$270**	**($8,601)**
O & M Cost ($/kWh):	**$0.000**	**2017**	**9**	**$277.88**	**$0**	**$0**	**$0**	**$278**	**($8,323)**

O & M Inflation Rate (%):	0	2018	10	$286.22	$0	$0	$0	$286	($8,037)
State Rebate (%):	0	2019	11	$294.81	$0	$0	$0	$295	($7,742)
State Tax Credit (%):	0	2020	12	$303.65	$0	$0	$0	$304	($7,438)
Federal Tax Credit (%):	30	2021	13	$312.76	$0	$0	$0	$313	($7,125)
Less KCPL Incentive	$0	2022	14	$322.14	$0	$0	$0	$322	($6,803)
Renewable Certificates ($KWH)	$0.0000	2023	15	$331.81	$0	$0	$0	$332	($6,471)
Results		2024	16	$341.76	$0	$0	$0	$342	($6,130)
Loan Payments		2025	17	$352.02	$0	$0	$0	$352	($5,778)
Monthly Payment ($):	$0	2026	18	$362.58	$0	$0	$0	$363	($5,415)
Value of Interest Deduction ($):	$0	2027	19	$373.45	$0	$0	$0	$373	($5,042)
Net Monthly Payment ($):	$0	2028	20	$384.66	$0	$0	$0	$385	($4,657)
		2029	21	$396.20	$0	$0	$0	$396	($4,261)
Ave. Monthly Savings on Bill		2030	22	$408.08	$0	$0	$0	$408	($3,853)
Year 1 ($):	$3	2031	23	$420.33	$0	$0	$0	$420	($3,432)
Year 10 ($):	$12	2032	24	$432.94	$0	$0	$0	$433	($2,999)
Year 20 ($):	$55	2033	25	$445.92	$0	$0	$0	$446	($2,553)
Year 30 ($):	$242	2034	26	$459.30	$0	$0	$0	$459	($2,094)
		2035	27	$473.08	$0	$0	$0	$473	($1,621)
Internal Rate of Return		2036	28	$487.27	$0	$0	$0	$487	($1,134)
Years 1 - 30:	-0.1%	2037	29	$501.89	$0	$0	$0	$502	($632)
		2038	30	$516.95	$0	$0	$0	$517	($115)

15 Wind Turbine Analysis 6KW System Sedalia

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

15.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **9,317 KWH**
- First year value of the power produced by the system for consumer **$662.69**
- Cash purchase system install price **$45,000.00** does not include tax;
- Federal Investment Tax Credit value **$13,500**;
- Adjusted system cost basis **$31,500**;
- **IRR 1.0 % Simple Payback 27 years**

15.2 KCPLProvenSedalia.hmr

15.2.1 Sensitivity case

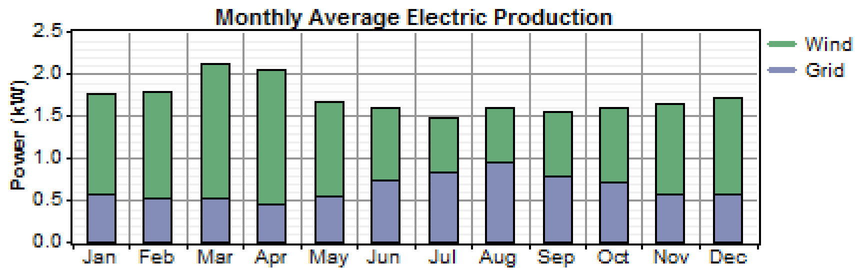
Primary Load 1 Scaled Average: 31.2 kWh/d

15.2.2 System architecture

Wind turbine	1 Proven WT6000
Grid	1,000,000 kW

15.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	9,317	62%
Grid purchases	5,680	38%
Total	14,997	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	76%
Grid sales	3,609	24%
Total	14,997	100%

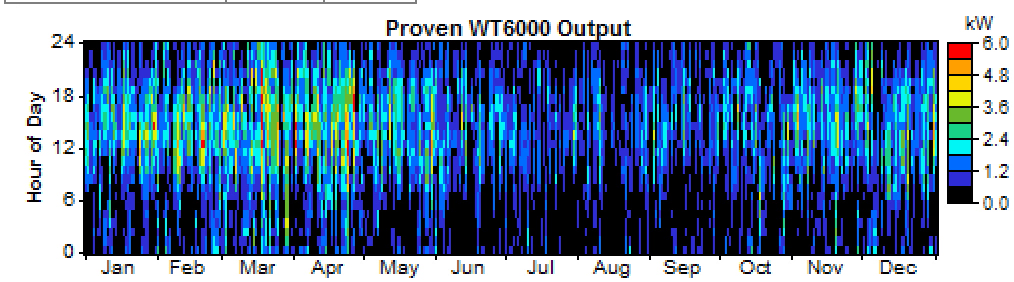
Quantity	Value	Units
Excess electricity	0.0000246	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.621	

15.2.4 AC Wind Turbine: Proven WT6000

Variable	Value	Units
Total rated capacity	6.30	kW
Mean output	1.06	kW
Capacity factor	16.9	%
Total production	9,317	kWh/yr

Variable	Value	Units
Minimum output	0.0165	kW
Maximum output	5.81	kW
Wind penetration	81.8	%
Hours of operation	8,760	hr/yr
Levelized cost	0.192	$/kWh



15.2.5 Energy Produced

Month	Energy Sold	Energy Charge
	(kWh)	($)
Jan	891	-56
Feb	848	-53
Mar	1,194	-75
Apr	1,155	-73
May	844	-53
Jun	609	-61
Jul	479	-48
Aug	479	-48
Sep	533	-53
Oct	669	-42
Nov	772	-49
Dec	844	-53
Annual	9,317	-663

15.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	428	368	60	7	4	0
Feb	355	387	-32	6	-2	0
Mar	384	571	-187	7	-12	0
Apr	326	533	-207	6	-13	0
May	401	338	63	6	4	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	523	216	307	7	19	0
Nov	410	294	116	6	7	0
Dec	434	329	104	7	7	0
Annual	3,261	3,036	225	7	14	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	533	191	342	8	34	0
Jul	612	128	483	7	48	0
Aug	702	104	597	8	59	0
Sep	573	150	423	7	42	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,419	573	1,846	8	184	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	428	368	60	7	4	0
Feb	355	387	-32	6	-2	0
Mar	384	571	-187	7	-12	0
Apr	326	533	-207	6	-13	0

May	401	338	63	6	4	0
Jun	533	191	342	8	34	0
Jul	612	128	483	7	48	0
Aug	702	104	597	8	59	0
Sep	573	150	423	7	42	0
Oct	523	216	307	7	19	0
Nov	410	294	116	6	7	0
Dec	434	329	104	7	7	0
Annual	5,680	3,609	2,071	8	198	0

15.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	1,309
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	5.67
Nitrogen oxides	2.78

15.3 Financial Analysis

Proven Analysis 6.0 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$45,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**7,217**								
Summer Energy Usage (kWh):	**2,100**		**Year**	**Net Energy**	**O&M Costs**	**Net Deprec.**	**Net Loan Payments**	**Annual Cash Flow**	**Total Cash Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($31,500)**	**($31,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	1	**$662.69**	**$0**	**$0**	**$0**	**$663**	**($30,837)**
Down Payment ($):	**$45,000**	**2010**	2	**$768.72**	**$0**	**$0**	**$0**	**$769**	**($30,069)**
Amount of Loan ($):	**$0**	**2011**	3	**$845.59**	**$0**	**$0**	**$0**	**$846**	**($29,223)**
Interest Rate (%):	**7**	**2012**	4	**$870.96**	**$0**	**$0**	**$0**	**$871**	**($28,352)**
Loan Term (Years):	**10**	**2013**	5	**$897.09**	**$0**	**$0**	**$0**	**$897**	**($27,455)**
Month Installed:	**0**	**2014**	6	**$924.00**	**$0**	**$0**	**$0**	**$924**	**($26,531)**
Net Federal Tax Rate (%):	**28**	**2015**	7	**$951.72**	**$0**	**$0**	**$0**	**$952**	**($25,579)**
Net State Tax Rate (%):	**8**	**2016**	8	**$980.27**	**$0**	**$0**	**$0**	**$980**	**($24,599)**
O & M Cost ($/kWh):	**$0.000**	**2017**	9	**$1,009.68**	**$0**	**$0**	**$0**	**$1,010**	**($23,589)**

O & M Inflation Rate (%):	0	2018	10	$1,039.97	$0	$0	$0	$1,040	($22,549)
State Rebate (%):	0	2019	11	$1,071.17	$0	$0	$0	$1,071	($21,478)
State Tax Credit (%):	0	2020	12	$1,103.31	$0	$0	$0	$1,103	($20,375)
Federal Tax Credit (%):	30	2021	13	$1,136.40	$0	$0	$0	$1,136	($19,238)
Less KCPL Incentive	$0	2022	14	$1,170.50	$0	$0	$0	$1,170	($18,068)
Renewable Certificates ($KWH)	$0.0000	2023	15	$1,205.61	$0	$0	$0	$1,206	($16,862)
Results		2024	16	$1,241.78	$0	$0	$0	$1,242	($15,621)
Loan Payments		2025	17	$1,279.03	$0	$0	$0	$1,279	($14,342)
Monthly Payment ($):	$0	2026	18	$1,317.40	$0	$0	$0	$1,317	($13,024)
Value of Interest Deduction ($):	$0	2027	19	$1,356.93	$0	$0	$0	$1,357	($11,667)
Net Monthly Payment ($):	$0	2028	20	$1,397.63	$0	$0	$0	$1,398	($10,270)
		2029	21	$1,439.56	$0	$0	$0	$1,440	($8,830)
Ave. Monthly Savings on Bill		2030	22	$1,482.75	$0	$0	$0	$1,483	($7,347)
Year 1 ($):	$11	2031	23	$1,527.23	$0	$0	$0	$1,527	($5,820)
Year 10 ($):	$49	2032	24	$1,573.05	$0	$0	$0	$1,573	($4,247)
Year 20 ($):	$214	2033	25	$1,620.24	$0	$0	$0	$1,620	($2,627)
Year 30 ($):	$945	2034	26	$1,668.85	$0	$0	$0	$1,669	($958)
		2035	27	$1,718.91	$0	$0	$0	$1,719	$761
Internal Rate of Return		2036	28	$1,770.48	$0	$0	$0	$1,770	$2,532
Years 1 - 30:	1.0%	2037	29	$1,823.60	$0	$0	$0	$1,824	$4,355
		2038	30	$1,878.30	$0	$0	$0	$1,878	$6,233

16 Wind Turbine Analysis 2.4 KW System St. Joseph

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

16.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **3,014 KWH**
- First year value of the power produced by the system for consumer **$213.09**
- Cash purchase system install price **$15,000.00** does not include tax;
- Federal Investment Tax Credit value **$4,500**;
- Adjusted system cost basis **$10,500**;
- **IRR .8 % Simple Payback 28 years**

16.2 KCPLSkystream St. Joseph.hmr

16.2.1 Sensitivity case

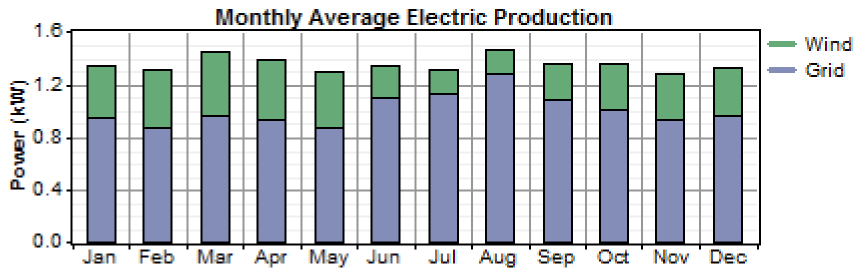
Primary Load 1 Scaled Average: 31.2 kWh/d

16.2.2 System architecture

Wind turbine	1 SW Skystream 3.7
Grid	1,000,000 kW

16.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	3,014	25%
Grid purchases	8,808	75%
Total	11,821	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	96%
Grid sales	433	4%
Total	11,821	100%

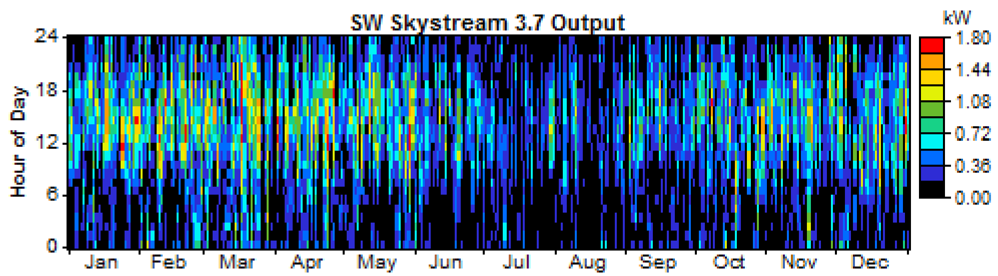
Quantity	Value	Units
Excess electricity	0.0000303	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.255	

16.2.4 AC Wind Turbine: SW Skystream 3.7

Variable	Value	Units
Total rated capacity	1.82	kW
Mean output	0.344	kW
Capacity factor	18.9	%
Total production	3,014	kWh/yr

Variable	Value	Units
Minimum output	0.00	kW
Maximum output	1.76	kW
Wind penetration	26.5	%
Hours of operation	7,457	hr/yr
Levelized cost	0.594	$/kWh



Schedule JMO-4

16.2.5 Energy Produced

Month	Energy Produced	Energy Charge
	(kWh)	($)
Jan	292	-18
Feb	293	-18
Mar	359	-23
Apr	331	-21
May	308	-19
Jun	180	-18
Jul	135	-13
Aug	135	-13
Sep	194	-19
Oct	260	-16
Nov	251	-16
Dec	275	-17
Annual	3,014	-213

16.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	708	49	659	8	41	0
Feb	583	60	523	6	33	0
Mar	715	67	648	7	41	0
Apr	667	50	617	8	39	0
May	650	51	599	6	38	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	749	33	716	7	45	0
Nov	672	35	637	7	40	0
Dec	711	38	673	8	42	0
Annual	5,455	383	5,072	8	319	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	785	14	771	9	77	0
Jul	836	8	828	7	82	0
Aug	950	9	941	8	94	0
Sep	782	19	763	7	76	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	3,353	50	3,303	9	328	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	708	49	659	8	41	0
Feb	583	60	523	6	33	0
Mar	715	67	648	7	41	0
Apr	667	50	617	8	39	0

May	650	51	599	6	38	0
Jun	785	14	771	9	77	0
Jul	836	8	828	7	82	0
Aug	950	9	941	8	94	0
Sep	782	19	763	7	76	0
Oct	749	33	716	7	45	0
Nov	672	35	637	7	40	0
Dec	711	38	673	8	42	0
Annual	8,808	433	8,374	9	647	0

16.2.7 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	5,292
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	22.9
Nitrogen oxides	11.2

16.3 Financial Analysis

Skystream Analysis 2.4 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) | **Annual Cash Flow Model**

Total Installed Cost ($):	**$15,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,370**			**Net**	**O&M**	**Net**	**Net Loan**	**Annual Cash**	**Total Cash**
Summer Energy Usage (kWh):	**644**		**Year**	**Energy**	**Costs**	**Deprec.**	**Payments**	**Flow**	**Flow**
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($10,500)**	**($10,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$213.09**	**$0**	**$0**	**$0**	**$213**	**($10,287)**
Down Payment ($):	**$15,000**	**2010**	**2**	**$247.18**	**$0**	**$0**	**$0**	**$247**	**($10,040)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$271.90**	**$0**	**$0**	**$0**	**$272**	**($9,768)**
Interest Rate (%):	**7**	**2012**	**4**	**$280.06**	**$0**	**$0**	**$0**	**$280**	**($9,488)**
Loan Term (Years):	**10**	**2013**	**5**	**$288.46**	**$0**	**$0**	**$0**	**$288**	**($9,199)**
Month Installed:	**0**	**2014**	**6**	**$297.11**	**$0**	**$0**	**$0**	**$297**	**($8,902)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$306.02**	**$0**	**$0**	**$0**	**$306**	**($8,596)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$315.20**	**$0**	**$0**	**$0**	**$315**	**($8,281)**

O & M Cost ($/kWh):	$0.000	2017	9	$324.66	$0	$0	$0	$325	($7,956)
O & M Inflation Rate (%):	0	2018	10	$334.40	$0	$0	$0	$334	($7,622)
State Rebate (%):	0	2019	11	$344.43	$0	$0	$0	$344	($7,277)
State Tax Credit (%):	0	2020	12	$354.77	$0	$0	$0	$355	($6,923)
Federal Tax Credit (%):	30	2021	13	$365.41	$0	$0	$0	$365	($6,557)
Less KCPL Incentive	$0	2022	14	$376.37	$0	$0	$0	$376	($6,181)
Renewable Certificates ($KWH)	$0.0000	2023	15	$387.66	$0	$0	$0	$388	($5,793)
Results		2024	16	$399.29	$0	$0	$0	$399	($5,394)
Loan Payments		2025	17	$411.27	$0	$0	$0	$411	($4,983)
Monthly Payment ($):	$0	2026	18	$423.61	$0	$0	$0	$424	($4,559)
Value of Interest Deduction ($):	$0	2027	19	$436.32	$0	$0	$0	$436	($4,123)
Net Monthly Payment ($):	$0	2028	20	$449.41	$0	$0	$0	$449	($3,673)
		2029	21	$462.89	$0	$0	$0	$463	($3,210)
Ave. Monthly Savings on Bill		2030	22	$476.78	$0	$0	$0	$477	($2,734)
Year 1 ($):	$3	2031	23	$491.08	$0	$0	$0	$491	($2,243)
Year 10 ($):	$15	2032	24	$505.81	$0	$0	$0	$506	($1,737)
Year 20 ($):	$66	2033	25	$520.99	$0	$0	$0	$521	($1,216)
Year 30 ($):	$290	2034	26	$536.62	$0	$0	$0	$537	($679)
		2035	27	$552.71	$0	$0	$0	$553	($127)
Internal Rate of Return		2036	28	$569.30	$0	$0	$0	$569	$443
Years 1 - 30:	0.8%	2037	29	$586.37	$0	$0	$0	$586	$1,029
		2038	30	$603.97	$0	$0	$0	$604	$1,633

17 Wind Turbine Analysis 6KW System St. Joseph

The following assumptions were used in preparing this system performance with **HOMER:**

- Primary Load **31.2 KWH/Day** and a daily **9.1 KW** Peak;

17.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **10,631 KWH**
- First year value of the power produced by the system for consumer **$757.42**
- Cash purchase system install price **$45,000.00** does not include tax;
- Federal Investment Tax Credit value **$13,500**;
- Adjusted system cost basis **$31,500**;
- **IRR 1.9 % Simple Payback 27 years**

17.2 System Report - KCPLProven St. Joseph .hmr

17.2.1 Sensitivity case

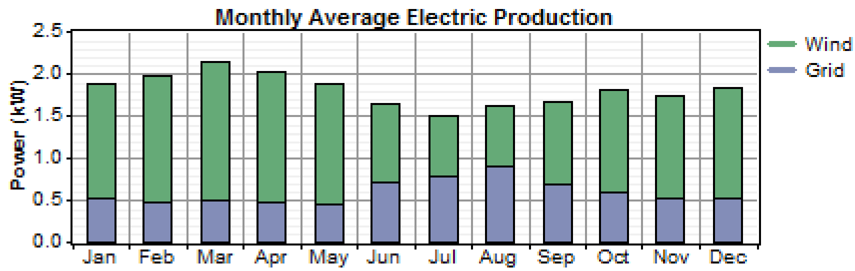
Primary Load 1 Scaled Average: 31.2 kWh/d

17.2.2 System architecture

Wind turbine	1 Proven WT6000
Grid	1,000,000 kW

17.2.3 Electrical

Component	Production (kWh/yr)	Fraction
Wind turbine	10,631	67%
Grid purchases	5,229	33%
Total	15,860	100%



Load	Consumption (kWh/yr)	Fraction
AC primary load	11,388	72%
Grid sales	4,472	28%
Total	15,860	100%

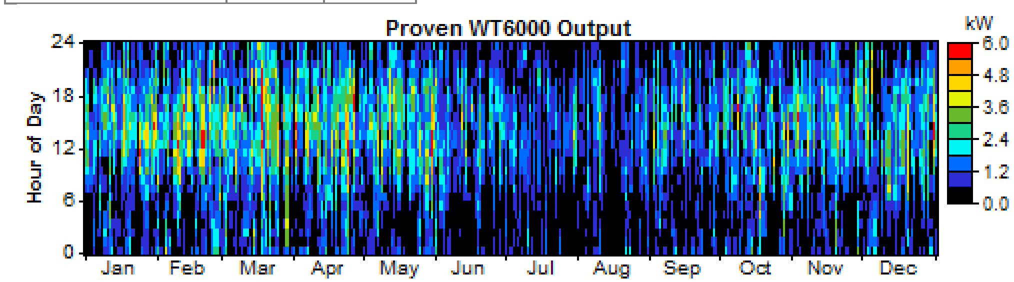
Quantity	Value	Units
Excess electricity	0.0000244	kWh/yr
Unmet load	0.00	kWh/yr
Capacity shortage	0.00	kWh/yr

Renewable fraction	0.670	

17.2.4 AC Wind Turbine: Proven WT6000

Variable	Value	Units
Total rated capacity	6.30	kW
Mean output	1.21	kW
Capacity factor	19.3	%
Total production	10,631	kWh/yr

Variable	Value	Units
Minimum output	0.0226	kW
Maximum output	5.81	kW
Wind penetration	93.4	%
Hours of operation	8,760	hr/yr
Levelized cost	0.169	$/kWh



17.2.5 Energy Produced

Month	Energy Sold	Energy Charge
	(kWh)	($)
Jan	1,013	-64
Feb	1,008	-63
Mar	1,222	-77
Apr	1,131	-71
May	1,064	-67
Jun	665	-66
Jul	530	-53
Aug	530	-53
Sep	707	-70
Oct	914	-57
Nov	885	-56
Dec	963	-61
Annual	10,631	-757

17.2.6 Net Metering

Rate: Non Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	387	450	-62	7	-4	0
Feb	313	505	-191	6	-12	0
Mar	379	595	-216	7	-14	0
Apr	334	518	-183	7	-12	0
May	338	495	-157	6	-10	0
Jun	0	0	0	0	0	0
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	0	0	0	0	0	0
Oct	436	374	62	6	4	0
Nov	374	370	4	6	0	0
Dec	396	411	-14	7	-1	0
Annual	2,959	3,717	-758	7	-48	0

Rate: Summer Rate

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	0	0	0	0	0	0

Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	510	224	286	8	28	0
Jul	588	155	433	7	43	0
Aug	675	128	547	7	54	0
Sep	497	247	250	7	25	0
Oct	0	0	0	0	0	0
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Annual	2,270	755	1,515	8	151	0

Rate: All

Month	Energy Purchased	Energy Sold	Net Purchases	Peak Demand	Energy Charge	Demand Charge
	(kWh)	(kWh)	(kWh)	(kW)	($)	($)
Jan	387	450	-62	7	-4	0
Feb	313	505	-191	6	-12	0
Mar	379	595	-216	7	-14	0
Apr	334	518	-183	7	-12	0

May	338	495	-157	6	-10	0
Jun	510	224	286	8	28	0
Jul	588	155	433	7	43	0
Aug	675	128	547	7	54	0
Sep	497	247	250	7	25	0
Oct	436	374	62	6	4	0
Nov	374	370	4	6	0	0
Dec	396	411	-14	7	-1	0
Annual	5,229	4,472	757	8	103	0

17.3 Emissions

Pollutant	Emissions (kg/yr)
Carbon dioxide	478
Carbon monoxide	0
Unburned hydocarbons	0
Particulate matter	0
Sulfur dioxide	2.07
Nitrogen oxides	1.01

17.4 Financial Analysis

Proven Analysis 6.0 KW

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs) **Annual Cash Flow Model**

Total Installed Cost ($):	**$45,000**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**8,200**		**Year**	**Net Energy**	**O&M Costs**	**Net Deprec.**	**Net Loan Payments**	**Annual Cash Flow**	**Total Cash Flow**
Summer Energy Usage (kWh):	**2,431**								
2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($31,500)**	**($31,500)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	1	**$757.42**	**$0**	**$0**	**$0**	**$757**	**($30,743)**
Down Payment ($):	**$45,000**	**2010**	2	**$878.61**	**$0**	**$0**	**$0**	**$879**	**($29,864)**
Amount of Loan ($):	**$0**	**2011**	3	**$966.47**	**$0**	**$0**	**$0**	**$966**	**($28,898)**
Interest Rate (%):	**7**	**2012**	4	**$995.46**	**$0**	**$0**	**$0**	**$995**	**($27,902)**
Loan Term (Years):	**10**	**2013**	5	**$1,025.33**	**$0**	**$0**	**$0**	**$1,025**	**($26,877)**
Month Installed:	**0**	**2014**	6	**$1,056.09**	**$0**	**$0**	**$0**	**$1,056**	**($25,821)**
Net Federal Tax Rate (%):	**28**	**2015**	7	**$1,087.77**	**$0**	**$0**	**$0**	**$1,088**	**($24,733)**
Net State Tax Rate (%):	**8**	**2016**	8	**$1,120.40**	**$0**	**$0**	**$0**	**$1,120**	**($23,612)**
O & M Cost ($/kWh):	**$0.000**	**2017**	9	**$1,154.02**	**$0**	**$0**	**$0**	**$1,154**	**($22,458)**

O & M Inflation Rate (%):	0	2018	10	$1,188.64	$0	$0	$0	$1,189	($21,270)
State Rebate (%):	0	2019	11	$1,224.29	$0	$0	$0	$1,224	($20,046)
State Tax Credit (%):	0	2020	12	$1,261.02	$0	$0	$0	$1,261	($18,784)
Federal Tax Credit (%):	30	2021	13	$1,298.85	$0	$0	$0	$1,299	($17,486)
Less KCPL Incentive	$0	2022	14	$1,337.82	$0	$0	$0	$1,338	($16,148)
Renewable Certificates ($KWH)	$0.0000	2023	15	$1,377.95	$0	$0	$0	$1,378	($14,770)
Results		2024	16	$1,419.29	$0	$0	$0	$1,419	($13,351)
Loan Payments		2025	17	$1,461.87	$0	$0	$0	$1,462	($11,889)
Monthly Payment ($):	$0	2026	18	$1,505.73	$0	$0	$0	$1,506	($10,383)
Value of Interest Deduction ($):	$0	2027	19	$1,550.90	$0	$0	$0	$1,551	($8,832)
Net Monthly Payment ($):	$0	2028	20	$1,597.43	$0	$0	$0	$1,597	($7,235)
		2029	21	$1,645.35	$0	$0	$0	$1,645	($5,589)
Ave. Monthly Savings on Bill		2030	22	$1,694.71	$0	$0	$0	$1,695	($3,895)
Year 1 ($):	$13	2031	23	$1,745.55	$0	$0	$0	$1,746	($2,149)
Year 10 ($):	$56	2032	24	$1,797.92	$0	$0	$0	$1,798	($351)
Year 20 ($):	$248	2033	25	$1,851.86	$0	$0	$0	$1,852	$1,501
Year 30 ($):	$1,094	2034	26	$1,907.41	$0	$0	$0	$1,907	$3,408
		2035	27	$1,964.63	$0	$0	$0	$1,965	$5,373
Internal Rate of Return		2036	28	$2,023.57	$0	$0	$0	$2,024	$7,396
Years 1 - 30:	1.9%	2037	29	$2,084.28	$0	$0	$0	$2,084	$9,481
		2038	30	$2,146.81	$0	$0	$0	$2,147	$11,627

18 Solar Hot Water System Analysis All Areas

The following assumptions were used in preparing this system performance with RETScreen:

- System comprised of 2 Heliodyne Gobi 410s Solar Hot Water Collectors, 80 Gallon Hot Water Tank;

18.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **4,393 KWH**
- First year value of the power produced by the system for consumer **$316.43**
- Cash purchase system install price **$9,500** does not include tax;
- Federal Investment Tax Credit value **$2,850**;
- Adjusted system cost basis **$6,650**;
- **IRR 6.7 % Simple Payback 15 years**

RETScreen® Energy Model - Solar Water Heating Project

Training & Support

Site Conditions		Estimate	Notes/Range
Project name		**Residential North East**	*See Online Manual*
Project location		**Kansas City, MO**	
Nearest location for weather data		Kansas City, MO	*Complete SR&HL sheet*
Annual solar radiation (tilted surface)	MWh/m²	1.75	
Annual average temperature	°C	12.6	-20.0 to 30.0

Annual average wind speed	m/s	4.6	
Desired load temperature	°C	60	
Hot water use	L/d	302	
Number of months analysed	month	12.00	
Energy demand for months analysed	MWh	6.10	

System Characteristics		**Estimate**	**Notes/Range**
Application type		Service hot water (with storage)	
Base Case Water Heating System			
Heating fuel type	-	**Electricity**	
Water heating system seasonal efficiency	%	190%	50% to 190%
Solar Collector			
Collector type	-	Glazed	*See Technical Note 1*
Solar water heating collector manufacturer		Heliodyne	*See Product Database*
Solar water heating collector model		Heliodyne Gobi 410	
Gross area of one collector	m^2	3.74	1.00 to 5.00
Aperture area of one collector	m^2	3.56	1.00 to 5.00
Fr (tau alpha) coefficient	-	0.74	0.50 to 0.90
Fr UL coefficient	$(W/m^2)/°C$	4.57	1.50 to 8.00
Temperature coefficient for Fr UL	$(W/(m \cdot °C)^2)$	0.00	0.000 to 0.010
Suggested number of collectors		2	
Number of collectors		2	
Total gross collector area	m^2	7.5	
Storage			
Ratio of storage capacity to coll. area	L/m^2	45.9	37.5 to 100.0
Storage capacity	L	327	
Balance of System			
Heat exchanger/antifreeze protection	yes/no	No	
Suggested pipe diameter	mm	10	8 to 25 or PVC 35 to 50
Pipe diameter	mm	38	8 to 25 or PVC 35 to 50
Pumping power per collector area	W/m^2	22	3 to 22, or 0
Piping and solar tank losses	%	1%	1% to 10%

Losses due to snow and/or dirt	%	3%	2% to 10%
Horz. dist. from mech. room to collector	m	5	5 to 20
# of floors from mech. room to collector	-	2	0 to 20

Annual Energy Production (12.00 months analysed)		Estimate	Notes/Range
SWH system capacity	kW_{th}	5	
	MWth	0.005	
Pumping energy (electricity)	MWh	**0.27**	
Specific yield	kWh/m²	587	
System efficiency	%	34%	
Solar fraction	%	72%	
Renewable energy delivered	MWh	**4.39**	
	kWh	4,393	
			Complete Cost Analysis sheet

Version 3.1

NRCan/CETC - Varennes

18.2 Financial Analysis

Solar Hot Water Heating System All Areas

Prepared for: **Grid Tied Application**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$9,500**									
Allocation to Business (%):	**0**									

Winter Energy Usage (kWh)	3,294		Year	Net Energy	O&M Costs	Net Deprec.	Net Loan Payments	Annual Cash Flow	Total Cash Flow
Summer Energy Usage (kWh):	1,099								
2009 Winter Electricity Cost ($/kWh):	$0.0629		0					($6,650)	($6,650)
2009 Summer Electric Cost ($/kWh):	$0.0994								
2010 Electric Rate Increase (%):	16								
2011 Electric Rate Increase (%):	10								
2012 - 2038 Electric Rate Increase (%):	3								
Loan Down payment (%):	100	2009	1	$316.43	$0	$0	$0	$316	($6,334)
Down Payment ($):	$9,500	2010	2	$367.06	$0	$0	$0	$367	($5,967)
Amount of Loan ($):	$0	2011	3	$403.77	$0	$0	$0	$404	($5,563)
Interest Rate (%):	7	2012	4	$415.88	$0	$0	$0	$416	($5,147)
Loan Term (Years):	10	2013	5	$428.36	$0	$0	$0	$428	($4,718)
Month Installed:	0	2014	6	$441.21	$0	$0	$0	$441	($4,277)
Net Federal Tax Rate (%):	28	2015	7	$454.45	$0	$0	$0	$454	($3,823)
Net State Tax Rate (%):	8	2016	8	$468.08	$0	$0	$0	$468	($3,355)
O & M Cost ($/kWh):	$0.000	2017	9	$482.12	$0	$0	$0	$482	($2,873)
O & M Inflation Rate (%):	0	2018	10	$496.58	$0	$0	$0	$497	($2,376)
State Rebate (%):	0	2019	11	$511.48	$0	$0	$0	$511	($1,865)
State Tax Credit (%):	0	2020	12	$526.83	$0	$0	$0	$527	($1,338)
Federal Tax Credit (%):	30	2021	13	$542.63	$0	$0	$0	$543	($795)
Less KCPL Incentive	$0	2022	14	$558.91	$0	$0	$0	$559	($236)
Renewable Certificates ($KWH)	$0.0000	2023	15	$575.68	$0	$0	$0	$576	$339
Results		2024	16	$592.95	$0	$0	$0	$593	$932
Loan Payments		2025	17	$610.74	$0	$0	$0	$611	$1,543

Schedule JMO-4

Monthly Payment ($):	$0	2026	18	$629.06	$0	$0	$0	$629	$2,172
Value of Interest Deduction ($):	$0	2027	19	$647.93	$0	$0	$0	$648	$2,820
Net Monthly Payment ($):	$0	2028	20	$667.37	$0	$0	$0	$667	$3,488
		2029	21	$687.39	$0	$0	$0	$687	$4,175
Ave. Monthly Savings on Bill		2030	22	$708.01	$0	$0	$0	$708	$4,883
Year 1 ($):	$6	2031	23	$729.25	$0	$0	$0	$729	$5,612
Year 10 ($):	$25	2032	24	$751.13	$0	$0	$0	$751	$6,363
Year 20 ($):	$112	2033	25	$773.66	$0	$0	$0	$774	$7,137
Year 30 ($):	$495	2034	26	$796.87	$0	$0	$0	$797	$7,934
		2035	27	$820.78	$0	$0	$0	$821	$8,755
Internal Rate of Return		2036	28	$845.40	$0	$0	$0	$845	$9,600
Years 1 - 30:	6.7%	2037	29	$870.76	$0	$0	$0	$871	$10,471
		2038	30	$896.89	$0	$0	$0	$897	$11,368

19 Solar Air Heating System Analysis All Areas

The following assumptions were used in preparing this system performance with RETScreen:

- System comprised of 2 SolarSheats

19.1 Summary of Results

The following summarizes the results of this analysis. All the detail is provided in the system production report section below.

- Annual power production from system **2,807 KWH**
- First year value of the power produced by the system for consumer **$176.56**
- Cash purchase system install price **$4,900** does not include tax;
- **IRR 4.6% Simple Payback 18 years**

RETScreen® Energy Model - Solar Air Heating Project

Training & Support

Units: Imperial

Site Conditions		Estimate	Notes/Range
Project name		**Residential Northeast**	See Online Manual
Project location		**Kansas City, MO**	
Nearest location for weather data		Kansas City, MO	Complete SR sheet
Annual solar radiation (tilted surface)	kWh/ft²	143.22	

Annual average temperature	ºF	12.6	
Annual average wind speed	mph	4.6	

System Characteristics		Estimate	Notes/Range
Heating application type	-	Ventilation air	
Base Case Heating System			
Heating fuel type	-	**Electricity**	
Heating system seasonal efficiency	%	100%	0% to 350%
Building			
Building type	-	Residential	
Indoor temperature	ºF	70.0	68.0 to 77.0
Maximum delivered air temperature	ºF	105.0	
R-value of building wall	ft² - ºF/(Btu/h)	19.0	0.6 to 56.8
Airflow Requirements			
Design airflow rate	cfm	6,200	29 to 588,578
Operating days per week (weekday)	d/w	5.0	0.0 to 5.0
Operating hours per day (weekday)	h/d	5.0	5.0 to 24.0
Operating days per week (weekend)	d/w	2.0	0.0 to 2.0
Operating hours per day (weekend)	h/d	5.0	5.0 to 24.0
Solar Collector			
Design objective	-	High temperature rise	
Collector colour	-	Black	*See Product Database*
Solar absorptivity	-	0.94	0.20 to 0.99
Suggested solar collector area	ft²	3,150	
Solar collector area	ft²	80	
Percent shading during season of use	%	0%	0% to 50%
SAH fan flow rate	cfm/ft²	78	
Average air temperature rise	ºF	1.5	
Incremental fan power	W/ft²	0.0	0.0 to 0.7

Annual Energy Production (6.0 months analysed)		Estimate		Notes/Range
Incremental fan energy	MWh	**0.0**		
Specific yield	kWh/ft²	35		
Collector efficiency	%	95%		
Solar availability while operating	%	25%		
Renewable energy collected	million Btu	9.2		
Building heat loss recaptured	million Btu	0.4		
Renewable energy delivered	MWh	**2.8**		
	kWh	2,807		
				Complete Cost Analysis sheet

Version 3.1

NRCan/CETC - Varennes

19.2 Financial Analysis

Solar Air Heating System All Areas

Prepared for: **KCPL**
Date: **June 1, 2009**

Cash Purchase

Assumptions (Inputs)

Annual Cash Flow Model

Total Installed Cost ($):	**$4,900**								
Allocation to Business (%):	**0**								
Winter Energy Usage (kWh)	**2,807**		**Year**	**Net Energy**	**O&M Costs**	**Net Deprec.**	**Net Loan Payments**	**Annual Cash Flow**	**Total Cash Flow**
Summer Energy Usage (kWh):	**0**								

Schedule JMO-4

2009 Winter Electricity Cost ($/kWh):	**$0.0629**		**0**					**($4,900)**	**($4,900)**
2009 Summer Electric Cost ($/kWh):	**$0.0994**								
2010 Electric Rate Increase (%):	**16**								
2011 Electric Rate Increase (%):	**10**								
2012 - 2038 Electric Rate Increase (%):	**3**								
Loan Down payment (%):	**100**	**2009**	**1**	**$176.56**	**$0**	**$0**	**$0**	**$177**	**($4,723)**
Down Payment ($):	**$4,900**	**2010**	**2**	**$204.81**	**$0**	**$0**	**$0**	**$205**	**($4,519)**
Amount of Loan ($):	**$0**	**2011**	**3**	**$225.29**	**$0**	**$0**	**$0**	**$225**	**($4,293)**
Interest Rate (%):	**7**	**2012**	**4**	**$232.05**	**$0**	**$0**	**$0**	**$232**	**($4,061)**
Loan Term (Years):	**10**	**2013**	**5**	**$239.01**	**$0**	**$0**	**$0**	**$239**	**($3,822)**
Month Installed:	**0**	**2014**	**6**	**$246.18**	**$0**	**$0**	**$0**	**$246**	**($3,576)**
Net Federal Tax Rate (%):	**28**	**2015**	**7**	**$253.57**	**$0**	**$0**	**$0**	**$254**	**($3,323)**
Net State Tax Rate (%):	**8**	**2016**	**8**	**$261.17**	**$0**	**$0**	**$0**	**$261**	**($3,061)**
O & M Cost ($/kWh):	**$0.000**	**2017**	**9**	**$269.01**	**$0**	**$0**	**$0**	**$269**	**($2,792)**
O & M Inflation Rate (%):	**0**	**2018**	**10**	**$277.08**	**$0**	**$0**	**$0**	**$277**	**($2,515)**
State Rebate (%):	**0**	**2019**	**11**	**$285.39**	**$0**	**$0**	**$0**	**$285**	**($2,230)**
State Tax Credit (%):	**0**	**2020**	**12**	**$293.95**	**$0**	**$0**	**$0**	**$294**	**($1,936)**
Federal Tax Credit (%):	**0**	**2021**	**13**	**$302.77**	**$0**	**$0**	**$0**	**$303**	**($1,633)**
Less KCPL Incentive	**$0**	**2022**	**14**	**$311.86**	**$0**	**$0**	**$0**	**$312**	**($1,321)**
Renewable Certificates ($KWH)	**$0.0000**	**2023**	**15**	**$321.21**	**$0**	**$0**	**$0**	**$321**	**($1,000)**
Results		**2024**	**16**	**$330.85**	**$0**	**$0**	**$0**	**$331**	**($669)**
Loan Payments		**2025**	**17**	**$340.77**	**$0**	**$0**	**$0**	**$341**	**($328)**
Monthly Payment ($):	**$0**	**2026**	**18**	**$351.00**	**$0**	**$0**	**$0**	**$351**	**$23**
Value of Interest Deduction ($):	**$0**	**2027**	**19**	**$361.53**	**$0**	**$0**	**$0**	**$362**	**$384**
Net Monthly Payment ($):	**$0**	**2028**	**20**	**$372.37**	**$0**	**$0**	**$0**	**$372**	**$756**

		2029	21	$383.54	$0	$0	$0	$384	$1,140
Ave. Monthly Savings on Bill		2030	22	$395.05	$0	$0	$0	$395	$1,535
Year 1 ($):	$0	2031	23	$406.90	$0	$0	$0	$407	$1,942
Year 10 ($):	$0	2032	24	$419.11	$0	$0	$0	$419	$2,361
Year 20 ($):	$0	2033	25	$431.68	$0	$0	$0	$432	$2,793
Year 30 ($):	$0	2034	26	$444.63	$0	$0	$0	$445	$3,237
		2035	27	$457.97	$0	$0	$0	$458	$3,695
Internal Rate of Return		2036	28	$471.71	$0	$0	$0	$472	$4,167
Years 1 - 30:	4.6%	2037	29	$485.86	$0	$0	$0	$486	$4,653
		2038	30	$500.44	$0	$0	$0	$500	$5,153

20 Appendix A Product Information

This section contains the product information used in the preparation of this analysis report.

CALIFORNIA STANDARD PRACTICE MANUAL:
ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

July 2002

Gray Davis, Governor

Table of Contents

Page

Chapter 1

Basic Methodology

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives-participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the “Non-Participant Test” to the “Ratepayer Impact Test“; (2) renaming the All-Ratepayer Test” to the “Total Resource Cost Test.”; (3) treating the “Societal Test” as a variant of the “Total Resource Cost Test;” and, (4) an expanded explanation of “demand-side” activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for “cost effective conservation and energy efficiency” for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency — the Consumer Power and Conservation Financing Authority — was created. This agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand-Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I
Cost-Effectiveness Tests

Primary	Secondary
Participant	
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. 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.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in **Table 1** is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used.

Externality Values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

Participant Test

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the societal test should also be performed.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

How the Results can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

[2] It should be noted that if a demand-side program is beneficial to its participants (NPVp ≥ 0 and BCRp ≥ 1.0) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

NPV_P	=	Bp - Cp
NPVavp	=	(Bp - Cp) / P
BCRp	=	Bp / Cp
DPp	=	Min j such that Bj > Cj

Where:

NPVp	=	Net present value to all participants
NPVavp	=	Net present value to the average participant
BCRp	=	Benefit-cost ratio to participants
DPp	=	Discounted payback in years
Bp	=	NPV of benefit to participants
Cp	=	NPV of costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
J	=	First year in which cumulative benefits are cumulative costs.
d	=	Interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Where:

BRt	=	Bill reductions in year t

Bit	=	Bill increases in year t
TCt	=	Tax credits in year t
INCt	=	Incentives paid to the participant by the sponsoring utility in year t[3]
PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax[4] • Ongoing operation and maintenance costs include fuel cost • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PACat	=	Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)
Abat	=	Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times (K_{it} - 1)) + OBI_t$$

Where:

ΔEG_{it} = Reduction in gross energy use in costing period i in year t

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

ΔDG_{it}	=	Reduction in gross billing demand in costing period i in year t
$AC{:}E_{it}$	=	Rate charged for energy in costing period i in year t
$AC{:}D_{it}$	=	Rate charged for demand in costing period i in year t
K_{it}	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (e.g.,, customer charges, standby rates).
OBI_t	=	Other bill increases (i.e. customer charges, standby rates).
I	=	Number of periods of participant's participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

Chapter 3

The Ratepayer Impact Measure Test[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or 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 or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

How the Results can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue

[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g.,, funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements.

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = I
ARIRIMt	=	FRIRIM	for t = I
	=	(CRIMt - BRIMt)/Et	for t=2, ………….., N
NPVRIM	=	BRIM-CRIM	

BCRRIM` = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')
NPVRIM	=	Net present value levels
BCRRIM	=	Benefit-cost ratio for rate levels
BRIM	=	Benefits to rate levels or customer bills
CRIM	=	Costs to rate levels or customer bills
E	=	Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRIRIM test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where:

UACt	=	Utility avoided supply costs in year t
UICt	=	Utility increased supply costs in year t
RGt	=	Revenue gain from increased sales in year t
RLt	=	Revenue loss from reduced sales in year t
PRCt	=	Program Administrator program costs in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
UACat	=	Utility avoided supply costs for the alternate fuel in year t

Rlat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D \times (K_{it} - 1))$$

<u>Where</u>:

[Only terms not previously defined are included here.]

ΔENit	=	Reduction in net energy use in costing period i in year t
ΔDNit	=	Reduction in net demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
MC:Dit	=	Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RGt	=	BIt	* (net-to-gross ratio)
RLt	=	BRt	* (net-to-gross ratio)
Rlat	=	Abat	* (net-to-gross ratio)

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

[6] This test was previously called the All Ratepayers Test

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test expressed in terms of net present value, a benefit-cost ratio, or levelized costs is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g.,, kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPVTRC) is the discounted value of the net benefits to this test over a specified period of time. NPVTRC is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCRTRC) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit-cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain

7 Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make.

externality costs of power generation not captured by the market system. An illustrative and by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
    a. Avoided costs of supply disruptions
    b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
    c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
    d. Benefits to customers and the public of avoiding blackouts.

5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.

6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test'. This test and the sepcific benefits associated with this test are outside the scope of this manual.

7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management.

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

NPVTRC = BTRC - CTRC
BCRTRC = BTRC /CTRC
LCTRC = LCRC / IMP

Where:

NPVTRC	=	Net present value of total costs of the resource
BCRTRC	=	Benefit-cost ratio of total costs of the resource
LCTRC	=	Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)
BTRC	=	Benefits of the program
CTRC	=	Costs of the program
LCRC	=	Total resource costs used for levelizing
IMP	=	Total discounted load impacts of the program
PCN	=	Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \;\; where \; I = peak \;\; period) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

Program Administrator Cost Test

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator’s overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPVpa) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCRpa) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

NPVpa = Bpa - Cpa
BCRpa = Bpa/Cpa
LCpa = LCpa/IMP

Where:

NPVpa	Net present value of Program Administrator costs
BCRpa	Benefit-cost ratio of Program Administrator costs

LCpa	Levelized cost per unit of Program Administrator cost of the resource
Bpa	Benefits of the program
Cpa	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the Bpa equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A

Inputs to Equations and Documentation

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.

2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.

3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.

4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.

6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.

7. The development and treatment of load impact estimates should distinguish between gross (i.e., impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.

8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g.,, termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP	=	BP - CP
NPVavp	=	(BP - CP) / P
BCRP	=	BP/CP
DPP	=	min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = 1
ARIRIMt	=	FRIRIM	for t = 1
	=	(CRIMt- BRIMt)/Et	for t=2,... ,N
NPVRIM	=	BRIM — CRIM	
BCRRIM	=	BRIM /CRIM	

Total Resource Cost Test

NPVTRC	=	BTRC - CTRC
BCRTRC	=	BTRC / CTRC
LCTRC	=	LCRC / IMP

Program Administrator Cost Test

NPVpa	=	Bpa - Cpa
BCRpa	=	Bpa / Cpa
LCpa	=	LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n}\left[(\sum_{i=1}^{n} \Delta EN_{it}) \; or \; (\Delta DN_{it} \; where \; I = peak \; period) \right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat = Avoided bill reductions on bill from alternate fuel in year t
AC:Dit = Rate charged for demand in costing period i in year t
AC:Eit = Rate charged for energy in costing period i in year t
ARIRIM = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp = Benefit-cost ratio to participants
BCRRIM = Benefit-cost ratio for rate levels
BCRTRC = Benefit-cost ratio of total costs of the resource
BCRpa = Benefit-cost ratio of program administrator and utility costs
BIt = Bill increases in year t
Bj = Cumulative benefits to participants in year j
Bp = Benefit to participants
BRIM = Benefits to rate levels or customer bills
BRt = Bill reductions in year t
BTRC = Benefits of the program
Bpa = Benefits of the program
Cj = Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Appendix C.

Derivation of Rim Lifecycle Revenue Impact Formula

Most of the formulas in the manual are either self-explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRIRIM) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPVRIM The amount which present valued revenues are below present valued revenue requirements equals NPVRIM

The LRIRIM is the change in rates that creates a change in the revenue stream that, when present valued, equals the NPVRIM* If the utility raises (or lowers) its rates in the base year by the amount of the LRIRIM' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRIRIM is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the NPVRIM or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times E_t}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Bigg/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

SCHEDULE JMO-6

THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC ORIGINAL FILED UNDER SEAL

An Independent Review of DSMore

An Examination of the Structure, Function and Operations of the DSMore Software

Prepared for Duke Energy

139 East Forth Street
Cincinnati, OH 45202

January 24, 2007

Submitted by

Mr. Nick Hall

TecMarket Works
165 West Netherwood Road
2nd Floor, Suite A
Oregon, Wisconsin 53575

Dr. Michael Ozog

Summit Blue Consulting
1722 14th Street
Suite 230
Boulder, Colorado 80302

Purpose of The Review

In order to understand the strengths and weaknesses of the DSMore software and obtain user feedback, Duke Energy contracted with TecMarket Works and Summit Blue Consulting to conduct an independent review of the software.

What Is DSMore

DSMore is a software package designed to help energy professionals more fully understand the potential impacts of different types of various energy demand options including energy efficiency, demand reduction, and load control programs. The software allows for the direct comparison of the resource potential of these programs compared to other typical types of approaches and technologies. The software is designed to provide information to resources planners, evaluation experts and policy development professionals regarding the energy and load impacts of energy programs under a wide range of load, weather and energy pricing scenarios. The software is developed and supported by Integral Analytics.

Integral analytics (IA) is located at 312 Walnut Street, Suite 1600, Cincinnati, Ohio, 45202. Integral Analytics can be contacted by telephone at 513 762-7621, or by e-mail at Kenneth.Skinner@IntegralAnalytics.com.

Review Approach

The review consisted of a three-phase assessment followed by the development of this document presenting the result of the review. First, the software was provided to Nick Hall of TecMarket Works and Michael Ozog of Summit Blue. This purpose of this distribution was to allow both reviewers time to become familiar with the software prior to attendance at a user's workshop. This allowed both reviewers time to load the software and begin to become familiar with the layout, screens, screen functions and operating environment. However, prior to this distribution both assessors had seen the software and had experimented with the beta test version to a limited degree. Dr. Ozog had also ran a number of test simulations though the beta version and had begun to conduct capability tests. Next, both assessors attended a one day workshop provided by IA. During the workshop the software was presented and discussed and demonstration runs were provided. During these runs there was considerable back-and-forth discussions of the program, the software's capability and the operational processes. After the workshop both assessors independently tested the software and ran assessments of fictional programs and examined the results. The two reviewers then collaborated on the development of this document to present the results of the review.

Executive Summary

We found DSMore to be a powerful new tool for energy professionals. It allows us to document and understand the impacts of energy efficiency and demand response programs and different supply side options at market based values rather than at a constant value (embedded cost based) that is not reflective of how forward or future energy markets are likely to operate. The program allows us to easily estimate likely program impacts within different weather zones and to use a range of weather conditions to quickly value the differences in energy saving impacts across these regional weather zones. The software also incorporates the "Standard Practice" cost effectiveness tests and allows these tests to be valued at the market price of energy specifically at the hour the energy is saved. We like the fact that we now have a tool that provides market based "weather normal" energy efficiency impact results. For demand response programs DSMore allows the assessment to be based on the value of the energy at the hour the relief is provided under the weather conditions occurring at that time. This is because the DSMore model is based on real weather (not predicted, modeled or averaged) over a 30-plus year period, and has the ability to select the best fitting non-linear regression model for each hour that best matches the weather, or use other user-selected input variables that best explain the energy and load impacts for that hour, month and type of day. This makes our job a lot easier and we can have more confidence in our analysis.

The software also incorporates a risk assessment tool that allows the user to specify the degree of risk associated with the input parameters (energy and load) and uses those parameters to estimate energy impact distributions and market values. The user can pick @Risk or CrystalBall for this effort. In our work for California we are using CrystalBall for our risk analysis efforts, so this means that we do not have to learn a different risk assessment package for DSMore. Likewise, if you are used to @Risk, this software can be used. The software also provides energy savings impacts associated with the type of fuel that is being saved (gas or electricity) so combined programs (such as weatherization programs) are well suited for this software.

Overview of DSMore

DSMore represents a significant leap forward in our ability to understand energy and load impacts from energy efficiency, demand reduction, load control, and renewable energy demand programs. This program, in the hands of competent user, can revolutionize what we are doing and help us understand the impacts we are having on the energy markets. The program is not one that should be considered a self-taught program. You will not find a *DSMore for Dummies* instruction manual at the local Barns & Nobel. It is a complex modeling program that requires an understanding of different energy supply and demand options and their influence on price and supply in order to set up the software and make it ready for analysis runs. However, once the weather, energy, load and market price and supply conditions are entered into the analysis database, individuals trained in DSMore scenario testing can conduct the program runs. Part of the package is that this information is loaded into the software by IA while working with their customers. We found that we could use the software shortly after taking advantage of the DSMore Training Workshop.

> DSMore represents a significant leap forward in our ability to understand energy and load impacts from energy efficiency, demand reduction, load control, renewable energy and other more traditional demand options.

DSMore is built to assess demand options and values in a market in which price and demand are not constant values, but vary depending upon weather and use conditions. Specifically, hourly customer future load is modeled based upon historical regression equations that relate load to temperature, humidity, year, wind, and interaction effects. Future weather conditions and their probability of occurrence are forecasted based on past weather (with the ability to modify this distribution within the software). The resulting future weather is then used to forecast future load distributions based upon the estimated hourly regression equations.

The hourly future market price forecasts to go along with the future loads are based upon weather conditional GARCH models[1]. The distribution of future energy prices are then generated based upon the estimated model and the distribution of future weather conditions.

By correlating future prices and future load through weather, DSMore insures that extreme weather conditions, which will lead to high demand, will also lead to high market prices. Therefore, DSMORE is the only tool currently available that correctly values demand resources under extreme market conditions.

New users who must learn the software need to plan for a one-day workshop (included in the price of the software) to learn the software and begin to become familiar with it. However, we recommend negotiating with IA to arrange for a two or perhaps a three-day workshop. It is not the software or how to use it that is difficult to learn, but rather the many and varied concepts that are integrated into DSMore, and gaining an understanding of how these concepts relate to the source tables and output values. Because energy price changes relate to a range of market conditions, including structured market deals and price volatility and capacity vs. energy values, the new user will find it useful to fully understand these concepts and how they function within the software. This will take more than a single day. In addition, we suggest that the new user plan for a week or two practicing with the software. To be most effective, the user-leads should at least have a theoretical foundation of energy markets and understand how different supply and demand conditions impact markets. Users who need to run scenarios once the software is fully configured can use the model effectively after a day or two workshop and a few days practicing with different scenarios.

One of the most important conditions of using DSMore is to be sure to group your analysis so that the load profiles are representative of the groups that are being assessed. The assessments and outputs will be in error if the program impacts or supply options do not link with the associated load profiles. This means that the user may have to segment a complex customer targeted program into multiple runs. For example, for a small industrial-commercial program offered in different weather zones covering several different measures that impact a load in different ways, the user will need to segment the analysis into measure groupings. We suggest that the segmentation approach be based on load profile groups in order to move the r-square values up to where the user is confident that the load profile matches the customer groupings.

[1] GARCH stands for Generalized Autoregressive Conditional Heteroskedastic, and refers to a special type of regression model which is used extensively in financial modeling.

In assessing DSMore we found it a bit more complicated that other software programs we have used, such as the E3-Calculator. However, we find that this program represents a quantum leap beyond the power of the software we have used in the past. In cases where the price of electricity is not a fixed value (such as in market based acquisition), DSMore provides a much better handle on the real value of a program or supply option. The simple TRCs that we have used in the past are based on a fixed price for energy or load impacts and do not provide an accurate picture of a program's benefits. DSMore provides estimates of the actual price/cost benefits that are avoided rather than an artificial policy-driven value for a program. Moreover, DSMore values energy efficiency and demand impact programs in a manner akin to the way that supply-side planners value assets. In this respect it places our programs on the same playing field with more traditional supply options. The two become directly comparable and operate on the same playing field, allowing us to see the real comparative value between our programs and traditional supply. DSMore goes beyond the traditional supply side valuations and factors in weather extremes. We can compare and value supply and demand side resources under both normal and extreme weather conditions. We no longer have to guess at how these compare. In the end, we see that we may be substantially undervaluing our programs using traditional DSM valuation tools because we historically have set the value of the avoided costs at price levels that are not reflected in hourly markets. The use of average pricing in our analyses of energy programs occurs at the detriment of understanding the true value of energy efficiency programs.

This program represents a quantum leap beyond the power of the software we have used in the past.

Strengths of DSMore

During the review efforts we identified a number of strengths of the software. These strengths are discussed below.

Savings are Valued At Market Price

DSMore allows for a more robust analysis of the value of energy efficiency or demand reduction programs. While DSMore can be set to value energy at a constant price (i.e., a traditional avoided cost) similar to other avoided capacity approaches. The software's advantage is that it is designed to value energy at forward market prices. The price of energy acquired in the market (such as in a purchased power agreement) is dependant on the availability and demand for the energy. As a result, the actual value of energy efficiency, and its avoided cost, change hour-by-hour, year-by-year, and are typically contingent on future weather conditions. DSMore allows the user to observe the avoided cost of energy across thousands of market, demand, weather and supply conditions. Then, the software allows the user to conduct probability analysis and risk analysis to predict the value of energy savings at any specific period based on the probability assignments associated with that supply. Rather that reporting the savings values at

DSMore allows for a more accurate analysis of the value of the energy saved or the load reduced.

arbitrary policy-based price, the software allows the user to see the value of the program at the price and supply conditions likely to be experienced in the market, and over the expected future weather conditions, including extreme weather. In short, DSMore allows for a much more accurate analysis of the value of the energy saved or the load reduced.

Cost Effectiveness Tests

DSMore incorporates the cost effectiveness tests using the general formulas from the California Standard Practice Manual, however the value of the energy can be optionally valued either at the forward-market price or at the current embedded cost of energy ("system lambda"). In either case, the user need not simply assume that a single avoided cost be used, or that a policy-assigned price be evaluated to the exclusion of other valuation perspectives. This option allows program mangers, evaluators and policy managers to test the cost effectiveness of a program or portfolio using actual, historic or forward market price conditions. Using market price conditions that are structured off the load profiles and market price conditions entered into DSMore provides a more accurate estimate of the true range of values of an energy program. A review of the formulas used in the software indicates that the cost effectiveness tests are consistent with the California Standard Practice Manual. However the formula for the TRC test needs to be updated so that it does not count the incremental cost of the freerider participant costs, if the user needs to be consistent with a recent California order to adjust the formula for the TRC. However, not all evaluation professionals agree with the need to change the formula in this way. This condition does not matter to the DSMore TRC test, as the users must input the costs, and California users can simply omit the cost where needed. The user can elect to deduct the freerider incremental costs or not, depending on the inputs used to adjust the formula as appropriate for the requirements in the jurisdiction in which the software is used. The cost effectiveness tests included in DSMore include the following Standard Practice Tests.

> DSMore offers the user a full set of cost effectiveness tests that incorporate the market values for the energy impacts associated with market conditions in which the savings occur.

Utility Test = Avoided Costs / Utility Costs

Where avoided cost (electricity and gas) includes avoided societal arrearage.

TRC Test = (Avoided Costs + Tax Saved) / (Utility Costs + Net Participant Costs)

Where avoided cost (electricity and gas) includes avoided societal arrearage and Participant Costs are net of incentives.

RIM Test = Avoided Costs / (Utility Costs + Lost Revenue)

Where avoided cost (electricity and gas) includes avoided societal arrearage.

RIM (Net Fuel) Test = Avoided Costs / (Utility Costs + Lost Revenue)

Where avoided cost (electricity and gas) includes avoided societal arrearage and Lost Revenues are net fuel.

Societal Test = (Avoided Costs + Participant Tax Savings + Environmental + Other) / (Utility Costs + Net Participant Costs)
Where avoided cost (electricity and gas) includes avoided societal arrearage, environmental, and other benefits and participant tax savings. Participant Costs are net of incentives.

Participant Test = (Lost Revenue + Incentives + Participant Tax Savings) / Participant Costs

Provides More Accurate Cost Effectiveness Test

DSMore represents a quantum leap in our ability to understand the cost effectiveness of energy efficiency programs. The software automatically leverages the analysis of somewhere between 2,000 and 5,000 different hourly-based load forecasts to optimally forecast hourly load and load shape profiles for a given customer class (for a single customer if needed). This helps assure that the best load and market price relationships are utilized in the "mark-to-market" valuations of future avoided costs for energy efficiency programs. The user can specify the load and market price conditions most likely to occur.

DSMore represents a quantum leap in our ability to understand the cost effectiveness of our programs.

Because DSMore provides a wide spectrum of future avoided cost values for the energy saved or the demand reduced, we obtain a more reliable cost effectiveness test because the weather normal cost effectiveness impacts are valued at the expected forward market price rather than a designated avoided cost. DSMore directly computes the value of demand resources under varied market prices and weather scenarios rather than just the cost-effectiveness under a single market scenario. DSMore may be the only tool that can provide rapid insight into the value of a program under different market conditions without having to run repeated and potentially unrelated model runs that neither account for variances or covariances between future market prices and expected load reductions. This is strength of the DSMore approach.

We Can Value The Broader Market Price Effects of Programs

One of the most troubling aspects of our standard cost effectiveness tests is that there is no value provided to a program because it helps reduce extreme demand or energy savings during extreme weather events. Under these conditions energy programs are able to lower the market price for all customers (participants and non-participants). When an energy efficiency program portfolio reduces system demand, especially during extreme weather or demand events, the overall price of energy falls. This is one of the primary values of much of our industry's energy efficiency and demand response efforts. Our standard approaches to cost effectiveness have not allowed us to identify the full value for energy efficiency and demand response benefits. Our industry's previous software have not provided the computational or the methodological power to assess the energy savings and weather sensitive impacts on the

With DSMore we have the availability to value the economic benefits of our programs on both participants and non-participants.

price or avoided cost of energy in the market. It is nice to have a tool with this power in our toolbox. DSMore is specifically designed to identify and quantify the value of the reduced demand across the hours that experience the reduced demand, and on the system as a whole. This economic effect is captured and reported in DSMore within the almost 700 avoided cost simulations. However, one of the aspects that we think would be beneficial are graphical outputs of the results of all of these simulations rather than only nine of the best-fit outcomes. This should be considered in future versions. Nevertheless, with DSMore we now have the ability to value the system-wide economic benefits of our programs over many market price and weather scenarios than was previously possible with our current tools.

Uses Real Weather Data Rather than Modeled or Predicted Data

The approach DSMore uses for correlating weather data moves away from using modeled or predicted weather. The software is built to use 30+ years of actual weather data to support the analysis efforts. Thirty or more years of weather became the platform following tests indicating that additional years beyond 30 did not add accuracy or reliability to the results, but reductions below 30 began to erode expected reliability and the ability to pin down weather normal cost effectiveness results. The software allows the user to select actual weather data for the analysis, or select different weather profiles from which the analysis can be conducted. For example, the user can identify the type of weather that they think most represents what can be expected, or use the historic weather data. So, if you prefer the Global Warming scenarios, simply simulate weather based on the past 10 years. Or, if 30 years is not enough, IA indicated to us that they can add more years to meet a specific user need if requested. The model is also fast enough (on a relatively new computer with 2 gigs of RAM) to run through 30 years of weather for an efficiency program in about 5 seconds, or through 6 strategies of demand response in about 30 to 40 seconds. The weather data can be easily up-dated to any location for which the weather data is available. If you don’t have weather data, you can also use existing DSMore weather functions that best fit the weather for the program in the area being assessed. This will give the users close estimates of what they would get if they used actual weather. These functions allow the user to use DSMore's weather and load response functions if the user does not have the weather or the load response data. However, IA suggests that it is always better to use actual data (customer class or customer) if available. We agree. IA reports that they have found that even within a single utility service territory load reductions, and hence avoided costs, can vary significantly.

> DSMore uses actual weather data for the areas in which the analysis is being conducted.

Supports Climate Zone Impact Distributions

DSMore allows the user to set different energy savings and load impacts for any or all climate zones involved in an analysis. However, DSMore suggests using the most appropriate set of weather based load shapes each time the user selects a given customer class. These customer class load shapes are established by IA as part of the software license agreement. These load classes can be as small as a single customer or zone, or as large as a country. The user should

> Once we enter the actual weather and the savings/demand impacts, DSMore allows us to see how the impacts change within each climate zone.

group together hourly customer data in customer classes that are homogenous, such as gas-heated homes or large commercial buildings. The energy and load impact assignments, and their derived weather response functions, can be different for the same measure or supply condition across regions, and are valued within the climate zone(s) or the area in which the measure is installed or the supply is planned to be placed or acquired. For energy efficiency and demand reduction programs, this means that the software can be used to distribute impacts for statewide or local programs that cover different climate zones, with different impacts and avoided costs. The users can then examine the impacts for the program as a whole or for any specific climate zone. However, the user must specify up front to IA the specific weather zones and load shapes that are to be evaluated uniquely. This allows DSMore to provide energy savings and load impacts for any climate area, with a forecast of avoided costs per region and per customer class. We no longer have to separately recalculate the expected impacts as we move from climate zone to climate zone. This ability can be tailored to match the reporting requirement for climate-specific impacts such as those required in the California Evaluation Protocols.

Use-Defined or Model-Defined Outputs

DSMore can be set up to provide model assessment in two ways. That is, the user can define the energy and load conditions for any given program or supply option, or the user can use one of the available load profiles in the software. If the user defines the profiles it must be entered into the software and selected. If one of the profiles in the software is used, the user selects that profile for the analysis needed. There is no restriction on the number of profiles used for any given analysis. It is possible to use over 100 different load profiles to assess any given program or supply option. This option allows people familiar with the energy and load impacts to build their own profiles, or select a DSMore suggested load profile and use that profile to have DSMore automatically distribute the impacts. In this sense, DSMore is able to perform much like the older DSManager with pre and post load shapes, except that DSMore focuses on the "load shape savings" rather than on a pre load shape and a post load shape separately. Additionally, DSMore reports the mean or average load shape and the savings, along with the standard deviation of the pre load shape, whereas DSManager simply assumed 4 daytype shapes for peak, off peak, medium and low shapes without consideration of the weather that might have caused those shapes. Instead DSMore retains in its data matrices (several thousands of load shapes), for the 30+ years of weather, at the hourly level. This effort is represented by a single average, or mean, load shape and the standard deviation of all load shapes over the 30+ years of weather, by month, weekend and weekday.

> The user can build their own load impact profiles or use one of the profiles available in the software.

For program evaluation analysis we suggest that the user input actual load savings, whenever possible, and real weather in order to obtain the most accurate results. When the user allows IA to model the load research data by classes, load savings will automatically be estimated at normal weather levels. Many end use or load research programs have acquired metered load and impact data for groups of customers and for types of measures. These data should be used in preference to selecting one of DSMore's default load impact profiles.

Readily Handles Demand Response Programs

DSMore is one of the few cost effectiveness calculations programs that can easily handle demand response and time-of-use (TOU) programs, at the hourly level (using 30+ years of weather). The program allows the user to input various demand response parameters including hourly load reductions, hourly price responses, TOU prices, etc. This flexibility in modeling load impacts is unmatched by other programs. There are 3 different types of load reduction or demand response strategies and two different sets of avoided market price scenarios that are calculated each time a demand response evaluation is conducted. The advantage is that the user obtains significantly more useful information about the value of a demand response program and this supports the program design efforts. The disadvantage is that the additional detail and strategies that must be calculated slow the calculation time to about 30 to 45 seconds. Nevertheless, this is still quicker than other programs, and provides the valuations that occur at GARCH-based market price forecasts, which other energy efficiency and demand response software, or the more expensive and slower IRP valuation models do not provide. It is important to note that more representative valuations of demand response effects are conducted using market prices when a utility is short of power. This is when GARCH price forecasts provide the better estimate of program value. As part of the up front license fee DSMore (beta test version) provides 21 GARCH price forecasts customized to the user's region. However, it is not clear if this aspect will be continued as an incorporated component or priced separately.

Analyzing Multiple Runs

DSMore is already set up to accumulate multiple assessments into a portfolio file.

DSMore is already set up for portfolio analysis. DSMore contains a portfolio folder in which the outputs from several related assessments (essentially saved Excel files which can be shared) can be accumulated within a folder, and maintained, and/or aggregated as a portfolio with portfolio test results and impacts, using a "one click" batch processing approach. This allows the user to assess the combined impacts of multiple programs or supply options and aggregate them into a single file for summary assessments. There is no need to maintain a different database for accumulating the results from multiple runs. One of the surprises we found is that these Excel based roll-up files can be e-mailed so that multiple roll-ups from different users can be grouped. This is a valuable tool if several utilities were running this software and wanted to do a statewide, regional or territory roll-ups. The roll-up files are not large, because they reflect the inputs and the outputs of the analysis.

Probability & Risk Assessment

DSMore is built to deal with uncertainty and risk. There is always a level of uncertainty associated with predicting load impacts, energy savings, or supply conditions. This has always been true on the supply side, and now can be explicitly valued on the demand side using DSMore. One of the key strengths of the software is that it is built with a risk assessment accessory. The users can use either Crystal Ball or @Risk software. The experienced user, using either package, can assign levels of probability to load shapes and market conditions, program costs, free ridership, etc. and let the software conduct Monte Carlo probability distributions around the assignments based on the level of assigned risk. Crystal Ball is the risk analysis software used by the California Public Utilities Commission, however, @Risk performs the same type of analyses. DSMore allows the user to distribute probability profiles across the impact programs or supply options and let the software provide the expected results based on the risk distributions. Likewise, the software can be used to assess measure-level impact uncertainty and allocate energy and load impacts based on the probability distributions. However, the user does not need to assign uncertainty or risk distributions around the weather impacts, market price forecasts or covariances between prices and loads because DSMore is already programmed to value these uncertainties implicitly. Moreover, since these uncertainties and risks are non-linear, it is likely that many users would be unable to specify the appropriate non-linear risks and covariances on their own. With DSMore the user can program the variability of the average, weather normal, load reduction expected from a measure or a program, and DSMore will apply the appropriate load forecast variances and price-load covariances around the average load reduction uncertainty.

> The software is built with a risk assessment accessory that allows the user to incorporate probability analysis into the projections.

Values Impacts and Supply Options

One of the key strengths of the DSMore software is that it can provide a range of values for the program impact or supply scenarios examined. Because DSMore is built around impact and supply options at different market conditions, and because you can select the supply and price scenarios you want to use, DSMore can provide the high values, the low values and the expected (weather normal) values based on the market conditions specified by the users. Likewise, the user can see the market and supply conditions that are associated with the value of a program or supply option. These options allow the user to see the real value of measures, programs, and portfolios or supply options. The user can examine the program impacts and values for each of the market conditions and impact profiles needed. This ability also allows the program or supply planner or regulator to explicitly see the market conditions under which a program is cost effective and when it is not cost effective.

> The user can see the market conditions that are needed to make the program cost effective and see what conditions are needed before it becomes non-cost effective.

Selects The Best Regression Function

The DSMore software has the power to automatically select the best non-linear regression function that best matches the load research data associated with the analysis being performed for a given customer class. For example, an HVAC program often has consumption and load impacts that correlate well with outside temperature only after a threshold condition has been met. HVAC programs typically do not show reliable temperature-related impacts until after 80 degrees. Likewise these programs can show deteriorating relationships after 90 to 95 degrees because units cannot operate more than 100% once they are fully dispatched. DSMore will search a large inventory of regression equations to find the best match to the physical conditions specified in the measure, program, portfolio or supply inputs. This searching is constructed to select the regression equations that provides the best fit. These searches are done across different times and day-types. For example, it will do a weekday search, and a weekend search. DSMore has over 3,000 different regression equations that are tested for the best adjusted R-square fit between weather, load and energy and the regression model. Typically, a non-linear function changes at or near the thermostat set point for a home (say, 80 degrees) and again at its full duty cycle (100% run time). DSMore automatically searches for, and calculates, these thresholds and uses them in the DSMore load forecasts and simulations over 30+ years of weather. In this manner, the most accurate and precise forecast of the likely load reduction is obtained for each hour over the 30+ year analysis period.

DSMore can search over 3,000 regression equations to find the best r-square fit between weather, load and energy and use that equation in the regression model.

Flexibility for the User

DSMore allows the user substantial flexibility in altering most aspects of the program. For example, the user can easily adjust the baseline load shape, either inflating or deflating each hour of the year to allow customization of the load shape to address a given circumstance. Other examples include adjusting the probabilities of each weather event, the probability of each market price, and the values of various unbundled structured contract market adders. There is no variable within the model over which the user does not have control. The simplest case is a lighting program, where the energy savings is arguably constant over each of a set of specified hours. The user can easily set the lighting savings to be constant in every hour used, and eliminate any weather sensitivity or weather variance to obtain a fixed load reduction and accurate test result for a non-weather sensitive load reduction. Where weather sensitivity matters, DSMore's default modes automatically assesses thousands of load shapes to forecast the appropriate load reductions across all 30+ years of weather.

DSMore offers full customization of all variables and distributions used in the model.

DSMore Gives Energy Supply Impacts At The Fuel-Type Level

One of the values of DSMore that stood out during our assessment is that DSMore's dispatch valuation module can be setup to represent the type of fuel supply that is saved at a given hour. When the software is set up with this option, the user can input the magnitude and availability of the program's resource, and obtain a reasonable forecast of the fuel type and supply distribution that is avoided. If this step is taken then the impact results and values can be provided by fuel type, and the resulting emissions reductions can be valued. This is a powerful and needed capability that is lacking in our industry. Because the industry is turning to emissions reduction tracking, it is important to know not just the energy and demand reductions achieved, but also if that reduction is likely to be from coal fired

DSMore can provide outputs identifying if the energy impacts are coming from coal, nuclear, renewable energy, or other types of production. The next logical step is greenhouse gas accounting.

plants, natural gas or combined cycle plants. DSMore moves to the head of the pack because it can provide this information once the distributions and supply side resources are input into the energy supply tables. Because we can now estimate greenhouse gas production by fuel type, it is a simple effort to build greenhouse emissions accounting into the package to allow us to document the reduction in greenhouse gas emissions. Although it is clear that the capability exists within DSMore this emissions savings output is not currently provided. We hope to see this in a future version.

Identifies Price Impacts for Any Supply Option

Although not currently available in the commercially available version that we directly evaluated, demonstrations of the soon to be released version of DSMore were provide in the training session held prior to this assessment. These presentations showed that the new (soon to be released) version will be able to evaluate specific combinations of supply options on an hour-by-hour basis, given the specific availability of program impacts relative to its comparable supply side option. For example, if an energy program resource provides an 8760 profiled load reduction, then DSMore will show how a coal or nuclear supply side facility can be avoided. This will be a powerful new tool. If the energy program resource is a more typical demand response program, then the appropriate blend of capacity and energy will be valued for the period in question. While energy efficiency and demand reduction programs are the key focus of many energy efficiency planners, it is also important to be able to value specific avoided cost options on the supply side to better interface with the IRP and asset planners. If the current version of DSMore is supplemented with this new supply side dispatch valuation module, we will be able to directly value and assess changes in the appropriate type of supply, regardless if that supply is from a program, a new wind turbine, a new peaker, a coal plant, or a purchased power agreement. In this sense, DSMore will be able to closely approximate the valuation that is likely to be embedded within a more data-intensive IRP model, but should not suffer from the sluggish run times or modeling complexities that have historically slowed IRP program effects modeling. The basic engine of DSMore is a market-conditions-based supply and demand model compiled within a set of "C++" programs that run behind the scenes. The benefit of this approach is that it works off a more simplified Excel interface. We found this Excel interface easy to use after a couple of days practice. Essentially, DSMore is an add-in to the more familiar Excel software, with two DSMore functions (Evaluate and Print). In our opinion experienced Excel users will be able to effectively run DSMore. However, new users must take the training and devote a few days to "play" with the package to become familiar with its operations and capabilities. As with any software package the phrase "Garbage In Garbage Out" applies to DSMore. Nevertheless, DSMore seems to provide the user with the ability to assess a wide variety of price and supply related impacts for any type of energy efficiency or demand response programs. DSMore allows the user to compare any combination of supply options and identify the cost and price impacts associated with those supply scenarios.

> DSMore allows the user to compare any combination of demand options and identify the cost and price impacts associated with those demand scenarios.

Suggested Improvements

During the review we identified several improvements we would like to see made to the program in the next version. These are discussed below.

Input Table Can Be Improved

There is a need to reduce potential confusion associated with the different input tables. Many of the input tables look alike. The new user needs to carefully examine which tables are associated with which information. These tables can be structured using linked color-coding systems or other similar approaches so that the input tables are more easily identified.

Reset Button Needed

In the version examined in this review the tables needed to be cleared manually when they needed to be repopulated. This process would benefit from a “reset” button with a warning flag that would allow the input field for a given table to be cleared.

Field Definitions Needed on Some Fields

The developers of the software have done a good job of defining many fields in a way that the user knows what the fields are for or what needs to go into them. However, several of the fields lack full definitions. While most experienced evaluation professionals or supply analysts will know what these fields mean, a new user may have some difficultly understanding the field definitions. For this reason the developers may wish to have pop-up definitions that allow the new user to better understand the fields.

Needs a kWh Output Table

While the software provides the demand impact tables and the demand savings are easy to identify, the software needs to have a summary output table of the energy savings. As it is now the user needs to calculate the energy savings from the load impact reduction tables.

More Error Messages Needed

At the current time the software does not identify when a missing input is stopping a calculation from proceeding. We would like to see error messages that tell what fields need data in order for the calculation to continue.

Greenhouse Gas Reduction Table Needed

While the program is not designed to provide reductions in greenhouse gas emissions, it has all the processing capability to do so. The only metric that is missing is a user input field that identifies the amount of greenhouse gas produced from each type of generation source. We would like to see a greenhouse gas reduction table built into the program as an output table.

Need For Graphical Presentation of the Avoided Cost Simulations

DSMore provides the nine best outputs of the more than 700 avoided cost simulations run by the program. This allow the users to examine these nine outputs, but the software restricts users from seeing the results of all 700 runs. We agree that it is not is not necessary to have 900 outputs from the runs, but it would benefit the user to be able to see a graphic presentation of the 700 runs.

Most Aspects of the Model are Hidden

The interface with DSMore is through Excel spreadsheets. These spreadsheets are inputs into the actual DSMore engine. IA indicated that they have benchmarked and validated many of the calculations and have found no issues or errors.

The DSMore user has no contact with the DSMore engine and, as a result, the calculations cannot be easily examined or tested. This provides both a benefit and a concern, depending on one's perspective. The advantage of this "black box" software is that the results are 1) easily replicated by other users with the same inputs, 2) not easily manipulated or altered by "unscrupulous" users, and 3) the compiled C++ code running behind the scenes allows for fast, comprehensive evaluations. The disadvantage is that more advanced users cannot explicitly observe and confirm the calculations embedded in the source code. Because of the complexity of the computations and the need to safeguard the computations from accidental or deliberate changes, having the calculations locked in a unavailable source code may be preferable once test scenarios have been conducted to compare to the DSMore outputs.

SCHEDULE JMO-8

THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC ORIGINAL FILED UNDER SEAL