VOLUME 1-S:

SUPPLEMENTAL FILING

2008 KCP&L

INTEGRATED RESOURCE PLAN

CASE NO. EE-2008-0034

4 CSR 240-22

** PUBLIC **

KCP&L
energizing life

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

TABLE OF APPENDICES

VOLUME 1-S:

SUPPLEMENTAL FILING FOR KANSAS CITY POWER & LIGHT'S (KCP&L) INTEGRATED RESOURCE PLAN (IRP) FILING

CASE NO. EE-2008-0034

SECTION 1: INTRODUCTION

1.1 OBJECTIVE

This report addresses specific issues raised and information requested by the Parties during IRP-review meetings held in Jefferson City, Missouri. This supplemental filing provides additional details regarding the processes and evaluations included in KCP&L's 2008 IRP filing.

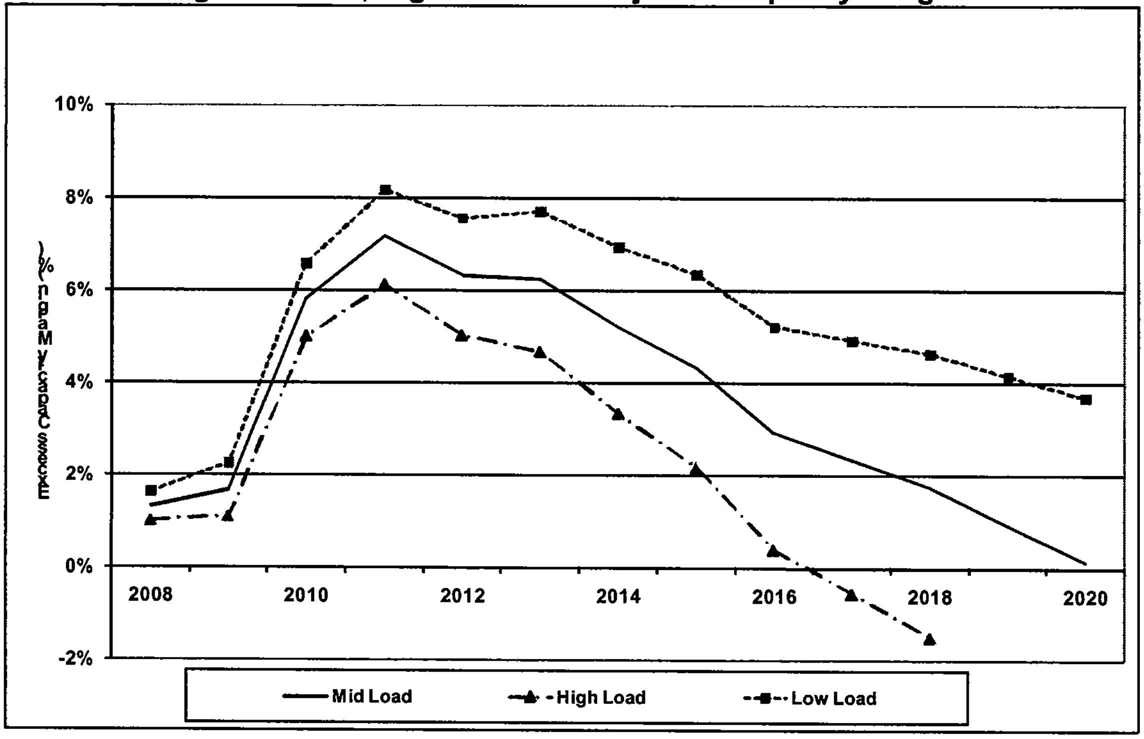
The primary issues raised focused on implementation planning, contingency planning and identification of critical uncertainties. Additional details regarding specific evaluation processes were also requested. The contingency plans detailed in the IRP indicated reliance on the proposed Sustainable Resource Strategy (SRS) process to refine and expand on the findings of the IRP.

This report will address the above issues.

1.2 IRP BACKGROUND

It is important to note that under the base case load forecast, KCP&L will not require additional capacity to meet current Southwest Power Pool (SPP) generation reliability standards (12% capacity margin) until 2020. Projected capacity margins above the required minimum are shown for the base, low and high load forecast in Figure 1, below:

Figure 1: Mid, High and Low Projected Capacity Margins



The detailed capacity and load forecast is shown in Appendix 1-S.2.

1.3 IMPACT OF PROBABLE ENVIRONMENTAL COSTS

Based on the above referenced forecast, new resource additions would not normally be expected over the short-term. However, the uncertainty created by potential environmental regulations indicated a need to consider early adoption of alternatives to mitigate the risk exposure associated with possible carbon dioxide (CO_2) emission limits. Based on this uncertainty, alternative resource plans were developed to include near-term additions of wind generation and expanded efforts to increase Demand-Side Management (DSM) programs. For purposes of this supplemental filing and future IRP-related documentation, DSM includes both Demand Response (DR) and end-use Energy Efficiency (EE) measures or programs. The results of integrated analysis indicated that inclusion of these two near-term resources lowered the expected Net Present Value of Revenue Requirements (NPVRR) compared to resource plans without these near term additions when probable environmental costs were considered.

1.4 PREFERRED PLAN

KCP&L evaluated 26 alternative resource plans that included various combinations of supply-side and demand-side resources with varied implementation timelines. Resource Plan 19 was selected as the Preferred Plan and is outlined in Table 1: Preferred Resource Plan shown below:

Table 1: Preferred Resource Plan

BASE CASE	Plan 19: Install Wind with PTC, Residential and Aggressive C&I EE and CT's					
	Sell PPA (MW)	Buy PPA (MW)	Install CT's (MW)	Install Wind (MW)		Install Residential and Aggressive C&I EE (MW)
2008	50	0	0			0
2009	75	0	0	100		0
2010	200	0	0	100		17
2011	200	0	0	100		40
2012	200	0	0	100		66
2013	200	0	0			89
2014	200	0	0			114
2015	200	0	0			109
2016	200	0	0			103
2017	200	0	0			95
2018	200	0	0			94
2019	175	0	0			92
2020	150	0	0			90
2021	125	0	0			89
2022	100	0	0			90
2023	75	0	0			90
2024	25	0	0			90
2025	0	25	0			89
2026	0	50	0			90
2027	0	100	0			90
2028	0	150	0			90
2029	0	50	154			89
2030	0	75	0			89
2031	0	100	0			89
2032	0	150	0			89

Attached in Appendix 1-S.1 are the twenty-six alternative resource plans. These tables provide the timing, capacity amount, and generation resource type for each of the twenty-six plans.

1.5 REPORT ORGANIZATION

The Supplemental filing is presented in the order shown below.

1.5.1 SPECIFIC ISSUES

Section 1: Introduction

Section 2: Critical Uncertainties, Subjective Probabilities

Section 3: Implementation Planning

Section 4: Contingency Planning

1.5.2 ADDITIONAL REQUESTED DELIVERABLES

Section 5: Load Forecasting and Analysis

Section 6: Supply-Side Analysis

Section 7: Demand-Side Analysis

Section 9: Sustainable Resource Strategy (SRS)

SECTION 2: CRITICAL UNCERTAINTIES, SUBJECTIVE PROBABILITIES

2.1 CRITICAL UNCERTAINTIES IDENTIFIED IN THE IRP

The critical uncertainties identified in the IRP filing were:

1. Natural Gas Prices
2. Environmental Allowance Prices
3. Coal Prices
4. CO_2 Allowance Prices
5. Load Growth

With the exception of load growth, all the listed uncertainties were evaluated using forecast averaging, which provides the average price forecast based on several different sources of price forecasts. In the KCP&L IRP submittal, Appendix 4.C.1 discusses this process in more detail and explains why forecast averaging yields better results than relying on one forecast. Applying the forecast average assumes the results yield a normal probability distribution curve. Similarly, the Load Forecast is assumed to result in a normal distribution curve.

2.1.1 SUBJECTIVE PROBABILITIES

The subjective probabilities applied to the 5 key uncertainties were 25%, 50% and 25% for the low, base and high forecasts, respectively. These probabilities capture the 10th and 90th percentile of expected results under the assumed normal distribution of results. The subject matter experts providing the 4 "price" uncertainty probabilities, Items 1-4 above, were Mr. Ed Blunk and Mr. Gary Halbert in KCP&L's Fuels Department. Mr. George McCollister, in KCPL's Business Planning Department provided the load forecasts including uncertainties and probabilities.

In 1978, Mr. Blunk was awarded the degree of Bachelor of Science in Agriculture Cum Laude, Honors Scholar in Agricultural Economics by the University of Missouri at Columbia. The University of Missouri awarded him the Master of Business Administration degree in 1980. He has completed additional graduate coursework in forecasting theory and applications. In 1981, Mr. Blunk joined KCP&L as Transportation/Special Projects Analyst. Since that time, his responsibilities have included fuel price forecasting, market analysis, fuel risk analysis and other analyses relevant to fuel procurement strategy, negotiation and/or litigation with railroads and coal companies. In 1984 Mr. Blunk was promoted to the position of Supervisor, Fuel Planning. In 2007, his position was upgraded to Manager, Fuel Planning.

In 1993 Mr. Halbert was awarded the degree of Bachelor of Science in Geology and Geophysics Magna Cum Laude Honors, by the University of Missouri-Rolla. In 1993 Gary joined ASARCO as an Exploration Geologist and Analyst for development of international resource projects with responsibilities that included feasibility studies, reserve estimation, resource modeling, budgeting, database design and forecasting. Gary was awarded the degree of Master of Business Administration by the University of Missouri-Columbia in 2000. In 2001 Mr. Halbert joined Trigen Energy of White Plains, NY as Business Development Analyst with responsibilities covering project finance and advisory for the development and construction of power generation facilities for industrial and governmental clients; responsibilities included market analysis, risk analysis, proforma projections and forecasting. In 2004 Mr. Halbert joined KCP&L as Fuel Analyst. Responsibilities have included fuel price forecasting, market analysis, fuel risk analysis and other analyses relevant to transportation and fuel procurement strategy. In 2008 Gary was promoted to Senior Fuel Planning Analyst.

George McCollister earned three degrees from the University of California at San Diego including a Bachelor of Arts degree in mathematics and chemistry, a Master of Arts degree in mathematics, and a Ph.D. in economics. Specialties in the economics program were microeconomics and econometrics. Prior to joining KCP&L in 2005, he had previously been employed at three electric and natural gas utilities. At Pacific

Gas and Electric Company as an Energy Economist responsible for developing end-use models of electric and natural gas sales and for analyzing responses to energy-use surveys of customers. At San Diego Gas and Electric Company as a Senior Forecast Analyst responsible for developing models of customer choice, energy sales and system reliability. At UtiliCorp United, Inc. as the Forecast Leader responsible for end-use forecasting in integrated resource plans; budget forecasts; weather normalization; variance analysis; and for statistical analysis. Prior work experience also includes employment with several consulting firms including Resource Management International and Spectrum Economics, Inc. that specialized in regulated industries where the majority of projects focused on energy forecasting issues and modeling for electric and natural gas utilities.

2.1.2 APPROVAL OF FORECASTS

Results of the forecasts including the subjective probabilities were reviewed with a core team of key executives and subject matter experts. That core team is referred to as the Sustainable Resource Strategy Core Team (SRS Core Team). Members of the Core team are shown in Table 2 below.

Table 2: SRS Core Team

Sustainable Resource Strategy (SRS) Core Team Members	
Member	**Position**
Terry Bassham	Executive VP-Finance & Strategy
Kevin Bryant	VP-Energy Solutions
Chuck Caisley	Senior Director-Public Affairs
Michael Cline	VP-Investor Relations & Treasurer
Chris Giles	VP-Regulatory
John Grimwade	Senior Director-Strategic Planning & Development
Bill Riggins	General Coucil & Chief Legal Officer
John Wallis	Director-Business Planning
John Marshall	Executive VP-Utility Operations
Todd Kobayashi	VP-Strategy & Risk Management
Mike Deggendorf	Senior VP-Delivery

During the review meetings, the primary concern raised focused on the natural gas price forecast. At the time of these reviews, natural gas was considerably higher than the base forecast proposed for the IRP. The 2009 price of natural gas included in the IRP forecasts was in the range of $8/mmbtu. Natural gas prices were in the $10-$12/mmbtu range when reviews were conducted. After discussing the long-term planning horizon of the IRP, approval was granted to move forward with the forecasts as developed for the IRP.

2.2 ADDITIONAL CRITICAL UNCERTAINTIES

Three additional critical uncertainties are identified in this supplemental filing:

1. Financial markets
2. Stakeholder support for the Preferred Plan
3. DSM cost recovery

1) At the time of the IRP filing, the recent economic turmoil and the extent of its impact on financial markets was not contemplated as a likely or critical concern. Today, the ability to finance projects has developed into a new critical uncertainty that could impact the implementation and acquisition strategies for the Preferred Plan.

2) The need for stakeholder support for the Preferred Plan is also identified as a new critical uncertainty. With today's uncertainty concerning the potential for future greenhouse gas emission limitations, stakeholder support is viewed as a critical requirement for new investment. The results of the Ventyx capacity expansion modeling demonstrate a wide range of potentially economic alternative resource plans based on the uncertain value of greenhouse gas emissions. Economic plans range from minimal resource additions to significant coal retirements in conjunction with nuclear additions. This significant range of alternatives drives the need for obtaining stakeholder buy-in. The Ventyx modeling results are reviewed below in Section 2.2.1.

3) KCP&L's Preferred Plan includes aggressive pursuit of DSM programs. Adequate cost recovery including recovery of lost margins is required for KCP&L to implement the proposed DSM programs.

2.2.1 VENTYX MODELING REVIEW

Ten planning scenarios were developed based on the five critical uncertainties listed in Section 2.1. The ten plans were developed with varied critical uncertainties associated with each plan. ** [redacted].** The ten plans with their associated critical uncertainties are shown in Figure 2 below:

Figure 2: Ventyx Planning Scenarios and Plans ** Highly Confidential **

Ventyx Capacity Expansion Model (CEM) Plans					
Natural Gas Prices	Enviromental Allowance Prices	Load Growth	Coal Prices	CO_2 Allowance Prices	Plan Number
[redacted]					

The resulting resource alternatives developed from these ten plans are shown in Figure 3 and Figure 4 below. ** [redacted] **

HC

Figure 3: Resource Scenarios for Plans V-1 through V-5 <u>**** Highly Confidential ****</u>

Plan V-1	Plan V-2	Plan V-3	Plan V-4	Plan V-5
[redacted]				

Figure 4: Resource Scenarios for Plans V-6 through V-10 <u>**** Highly Confidential ****</u>

Plan V-6	Plan V-7	Plan V-8	Plan V-9	Plan V-10
[redacted]				

** [redacted] **

HC

Because of this wide range of uncertainty, stakeholder buy-in is a necessary requirement prior to committing significant funding for new resources. Additional discussions around the need for stakeholder support are included below in Section 9: Sustainable Resource Strategy (SRS).

SECTION 3: IMPLEMENTATION PLANNING

3.1 CAPACITY AND LOAD FORECAST

A request was made to document the annual resource additions under the Preferred Plan and the resulting impacts on capacity and loads forecasts. Table 3 shows Year's 2008 through 2014 for the existing forecast, prior to adding Preferred Plan resources. The entire existing forecast for Year's 2008 through 2032 is attached in Appendix 1-S.2.

Table 3: Existing Capacity and Load Forecast

Existing Capacity and Load Forecast	2008	2009	2010	2011	2012	2013	2014
LOADS							
Projected Internal Demand	3,759	3,803	3,837	3,870	3,907	3,947	3,995
On-Going Demand Response	140	158	158	158	158	158	158
On-Going Energy Efficiency	8	15	23	29	33	33	33
Peak Responsibility	3,612	3,630	3,657	3,683	3,716	3,756	3,803
Capacity Responsibility	4,104	4,125	4,155	4,185	4,223	4,268	4,322
CAPACITY							
Total Existing Generating Capacity	4,051	4,089	4,089	4,107	4,101	4,094	4,094
Total Capacity Purchases	257	257	36	36	35	35	35
Total Capacity Sales	(141)	(141)	(141)	(51)	(51)	0	0
Total Accredited Capacity (Existing Resources)	4,167	4,205	3,984	4,092	4,085	4,129	4,129
Iatan 2			465	465	465	465	465
Total Accredited Capacity (With Planned Additions)	4,167	4,205	4,449	4,557	4,550	4,594	4,594
Capacity Balance	63	80	294	372	328	326	272
Capacity Margin	13.3%	13.7%	17.8%	19.2%	18.3%	18.3%	17.2%

Table 4 shows Year's 2008 through 2014 for the forecast that includes the Preferred Resource Plan. The entire forecast including the Preferred Resource Plan for Year's 2008 through 2032 is attached in Appendix 1-S.2.

Table 4: Capacity and Load Forecast with Preferred Plan

Capacity and Load Forecast with Preferred Plan	2008	2009	2010	2011	2012	2013	2014
LOADS							
Projected Internal Demand	3,759	3,803	3,837	3,870	3,907	3,947	3,995
On-Going Demand Response	140	158	158	158	158	158	158
On-Going Energy Efficiency	8	15	23	29	33	33	33
Cool Homes			1	5	9	12	16
Blue Line			2	5	7	7	7
Home Performance with Energy Star			2	6	11	16	20
On-Line Energy Audit with Energy Kits			2	3	5	7	8
Appliance Turn-In			3	5	8	9	10
Prescriptive Lighting			4	8	13	18	25
Prescriptive Motors			0	0	0	0	0
Prescriptive Refrigeration			0	0	0	0	0
Prescriptive HVAC			1	2	3	4	5
Prescriptive Process			0	0	0	0	0
Prescriptive Washer			0	0	0	0	0
Prescriptive Computer			2	3	5	7	7
Custom Incentives, RFP, & New Construction			1	2	5	10	16
Peak Responsibility	3,612	3,630	3,639	3,642	3,649	3,665	3,688
Capacity Responsibility	4,104	4,125	4,135	4,139	4,147	4,165	4,191
CAPACITY							
Total Existing Generating Capacity	4,051	4,089	4,089	4,107	4,101	4,094	4,094
Total Capacity Purchases	257	257	36	36	35	35	35
Total Capacity Sales	(50)	(75)	(200)	(200)	(200)	(200)	(200)
Total Accredited Capacity (Existing Resources)	4,258	4,271	3,925	3,943	3,936	3,929	3,929
Iatan 2			465	465	465	465	465
Wind (15% accreditation adding 100 MW per year for 4 years)		100	200	300	400	400	400
Combustion Turbines							
Total Accredited Capacity (With Planned Additions)	4,258	4,286	4,420	4,453	4,461	4,454	4,454
Capacity Balance	154	161	285	314	314	289	263
Capacity Margin	15.2%	15.3%	17.7%	18.2%	18.2%	17.7%	17.2%

3.2 DEMAND-SIDE IMPLEMENTATION: 050 (11) (H), 070 (9)

A listing of the annual penetrations and annual spending for each program was requested for the first 3-years of the Preferred Plan. Additional details responding to Rule 22.050 (11) (H) were also requested. Rule 22.050 (11) (H) requests incremental and cumulative participants, load impacts and costs. In response to these requests, annual spending and annual penetration details are provided in the following subsections.

3.2.1 DEMAND-SIDE BUDGETING

3.2.1.1 Existing Demand-Side Programs

KCP&L had developed demand-side programs as part of its Comprehensive Energy Plan (CEP). These programs are on-going. The costs of each existing program are shown in Table 5 through Table 7 below:

Table 5: Existing Affordability Program Spending ** Highly Confidential **

On-Going Spending Levels - Affordability	
	[redacted]
Affordable New Homes	
Weatherization	
Total	

Table 6: Existing Energy Efficiency Program Spending ** Highly Confidential **

On-Going Spending Levels - Energy Efficiency						
	2008	2009	2010	2011	2012	2013
Change A Light	[redacted]					
Cool Homes Program						
Energy Star Homes						
New and Retrofit Audits, Incentives, and Rebates						
Building Operator Certification						
Total						

Table 7: Existing Demand Response Program Spending ** Highly Confidential **

On-Going Spending Levels - Demand Response	
	[redacted]
Air Conditioning Cycling - Energy Optimizer	
Mpower	
Total	

The affordability and energy efficiency programs were assumed to be funded as shown above for all twenty-six alternative resource plans evaluated. Demand response programs were assumed to be funded as shown above in all but two alternative resource plans. In Plan 22, demand response was assumed to grow (increased funding and penetration). In Plan 24, demand response was curtailed (decreased funding and penetration). Projected spending includes both Kansas and Missouri program roll-outs.

3.2.1.2 Proposed Demand-Side Programs

Proposed demand-side programs include both enhancements to existing programs as well as new programs. There are five proposed Residential Energy Efficiency programs: Cool Homes, Home Performance with Energy Star, Home Energy Analyzer Plus, Energy Use Monitor – Blue Line, and Appliance Turn-In. There was one spending level assumed for the residential programs as show below in Table 8:

HC

Table 8: Proposed Residential Energy Efficiency Program Spending <u> Highly Confidential **</u>**

Projected Spending Levels - Residential					
	Year 1	Year 2	Year 3	Year 4	Year 5
Cool Homes Program	[redacted]				
Blue Line - Energy Monitor					
Home Performance with Energy Star					
On-Line Energy Audit with Energy Kits					
Appliance Turn-In					
Total					

There are four proposed C&I Energy Efficiency programs: Custom Incentives, Request For Proposal (RFP), New Construction, and Prescriptive. There were two spending levels developed for these programs as shown in Table 9 and Table 10:

Table 9: Proposed "Normal" C&I Energy Efficiency Program Spending <u> Highly Confidential **</u>**

Projected Spending Levels - Normal C&I					
	Year 1	Year 2	Year 3	Year 4	Year 5
Prescriptive Lighting	[redacted]				
Prescriptive Motors, Pumps & VFDs					
Prescriptive Food Service & Refrigeration					
Prescriptive HVAC					
Prescriptive Process					
Prescriptive Commerical Appliances					
Prescriptive Computers					
Custom, RFP, & Construction					
Total					

Table 10: Proposed "Aggressive" C&I Energy Efficiency Program Spending <u> Highly Confidential **</u>**

Projected Spending Levels - Aggressive C&I					
	Year 1	Year 2	Year 3	Year 4	Year 5
Prescriptive Lighting	[redacted]				
Prescriptive Motors, Pumps & VFDs					
Prescriptive Food Service & Refrigeration					
Prescriptive HVAC					
Prescriptive Process					
Prescriptive Commerical Appliances					
Prescriptive Computers					
Custom, RFP, & Construction					
Total					

Note that for the twenty-six alternative resource plans modeled, start dates for beginning these proposed programs were varied. Plans 1, 2, 10, 12-16, and 19-26 initiate new programs in 2010. Plans 3-9, and 11 initiate new programs in 2012. Plans 17 and 18 do not include new energy efficiency programs. Residential Energy Efficiency and Normal C&I Energy Efficiency penetration and spending levels were included in Plans 1, 2, and 16. Residential Energy Efficiency and Aggressive C&I Energy Efficiency penetration and spending levels were included in Plans 3-11, 15,

HC

16, and Plans 19-26. Plan 12 includes Residential Energy Efficiency only. Plan 13 includes Normal C&I Energy Efficiency only. Plan 14 includes Aggressive C&I Energy Efficiency only. For detailed views of each of the twenty-six plans, see Appendix 1-S.1.

3.2.2 DEMAND-SIDE PROGRAM CAPACITY AND ENERGY IMPACTS

3.2.2.1 Existing Programs

Expected demand and energy reductions from the on-going demand-side programs are shown in Table 11. These programs were included as part of the Stipulation and Agreement tied to the Comprehensive Energy Plan (Case Number EO-2005-0329). Energy impacts are shown through 2012, although life-cycle impacts of some programs extend beyond this timeframe.

Table 11: Existing Energy Affordability, Efficiency, and Demand Response Program Demand and Energy Reductions

Projected Demand and Energy Reductions					
ENERGY (MWh)	**2008**	**2009**	**2010**	**2011**	**2012**
Affordable New Homes	25	76	127	178	228
Weatherization	391	827	1,310	1,837	2,410
Change a Light	1,274	2,547	3,821	5,095	6,368
Cool Homes Program	1,948	4,855	7,762	10,669	13,576
Energy Star Homes	0	1,304	3,911	6,518	9,125
New and Retrofit Audits, Incentives, and Rebates	8,800	15,980	23,160	30,340	30,340
Building Operator Certification	0	1,250	2,500	3,750	5,000
Mpower	0	0	0	0	0
Energy Optimizer	0	0	0	0	0
Total	**12,438**	**26,839**	**42,590**	**58,386**	**67,047**
PEAK (MW)	**2008**	**2009**	**2010**	**2011**	**2012**
Affordable New Homes	0.0	0.0	0.1	0.1	0.1
Weatherization	0.1	0.2	0.3	0.4	0.5
Change a Light	3.4	4.5	5.6	5.6	5.6
Cool Homes Program	1.7	4.2	6.6	9.1	11.6
Energy Star Homes	0.0	0.5	1.4	2.3	3.3
New and Retrofit Audits, Incentives, and Rebates	2.9	5.2	7.6	9.9	9.9
Building Operator Certification	0.0	0.5	1.0	1.5	2.0
Mpower	54.0	66.0	66.0	66.0	66.0
Energy Optimizer	20.0	26.0	26.0	26.0	26.0
Total	**82.0**	**107.1**	**114.6**	**121.0**	**125.1**

3.2.2.2 Proposed Demand-Side Programs

Projections for demand and energy reductions for the five proposed residential programs are shown in Table 12 below. The two levels of penetrations for the proposed C&I programs are shown in Table 13 and Table 14. Note that only the first five years of data are provided in this report.

Table 12: Proposed Residential Energy Efficiency Program Demand and Energy Reductions

Projected Demand and Energy Reductions - Residential					
ENERGY (MWh)	**2010**	**2011**	**2012**	**2013**	**2014**
Cool Homes Program	2,342	8,420	14,498	20,577	26,655
Energy Use Monitor - Blue Line	9,505	19,010	28,514	28,514	28,514
Home Performance with Energy Star	9,672	24,180	43,524	62,868	82,212
Home Energy Analyzer Plus (HEAP)	6,356	12,712	19,067	25,423	31,779
Appliance Turn-In	8,008	16,816	26,505	29,156	32,071
Total	**35,882**	**81,138**	**132,109**	**166,538**	**201,231**
PEAK (MW)	**2010**	**2011**	**2012**	**2013**	**2014**
Cool Homes Program	1	5	9	12	16
Energy Use Monitor - Blue Line	2	5	7	7	7
Home Performance with Energy Star	2	6	11	16	20
Home Energy Analyzer Plus (HEAP)	2	3	5	7	8
Appliance Turn-In	3	5	8	9	10
Total	**10**	**25**	**40**	**51**	**62**

Table 13: Proposed C&I "Normal" Energy Efficiency Program Demand and Energy Reductions

Projected Demand and Energy Reductions - C&I					
ENERGY (MWh)	**2010**	**2011**	**2012**	**2013**	**2014**
Prescriptive Lighting	11,207	22,736	32,230	41,924	51,782
Prescriptive Motors	320	646	979	1,315	1,652
Prescriptive Refrigeration	319	645	977	1,313	1,650
Prescriptive HVAC	1,833	3,728	5,710	7,795	9,915
Prescriptive Process	135	272	413	554	697
Prescriptive Washer	7	14	21	28	36
Prescriptive Computer	3,776	7,627	11,554	15,518	15,765
Custom Incentives, RFP, & New Construction	3,595	8,988	17,077	29,211	47,412
Total	**21,192**	**44,657**	**68,961**	**97,658**	**128,907**
PEAK (MW)	**2010**	**2011**	**2012**	**2013**	**2014**
Prescriptive Lighting	3	6	8	11	15
Prescriptive Motors	0	0	0	0	0
Prescriptive Refrigeration	0	0	0	0	0
Prescriptive HVAC	1	1	2	2	3
Prescriptive Process	0	0	0	0	0
Prescriptive Washer	0	0	0	0	0
Prescriptive Computer	1	2	3	4	4
Custom Incentives, RFP, & New Construction	1	2	3	6	9
Total	**5**	**11**	**17**	**24**	**32**

Table 14: Proposed C&I "Aggressive" Energy Efficiency Program Demand and Energy Reductions

Projected Demand and Energy Reductions - C&I					
ENERGY (MWh)	**2010**	**2011**	**2012**	**2013**	**2014**
Prescriptive Lighting	14,048	30,715	47,554	67,552	91,330
Prescriptive Motors	400	820	1,261	1,723	2,210
Prescriptive Refrigeration	399	818	1,259	1,721	2,206
Prescriptive HVAC	2,400	4,920	7,565	10,343	13,260
Prescriptive Process	169	346	531	727	932
Prescriptive Washer	9	18	27	37	48
Prescriptive Computer	7,157	14,672	22,563	30,849	32,440
Custom Incentives, RFP, & New Construction	3,595	10,786	25,166	46,738	73,702
Total	**28,176**	**63,094**	**105,928**	**159,690**	**216,126**
PEAK (MW)	**2010**	**2011**	**2012**	**2013**	**2014**
Prescriptive Lighting	4	8	13	18	25
Prescriptive Motors	0	0	0	0	0
Prescriptive Refrigeration	0	0	0	0	0
Prescriptive HVAC	1	2	3	4	5
Prescriptive Process	0	0	0	0	0
Prescriptive Washer	0	0	0	0	0
Prescriptive Computer	2	3	5	7	7
Custom Incentives, RFP, & New Construction	1	2	5	10	16
Total	**7**	**16**	**26**	**39**	**53**

3.2.3 DSM DEPLOYMENT PLANS

The Energy Solutions Department is charged with development and roll-out of DSM program implementation. A narrative Implementation Plan for Energy Solutions is attached as Appendix 1-S.6. The Implementation Plan summarizes Energy Solutions activities and initiatives required for DSM program implementation.

3.3 SUPPLY-SIDE IMPLEMENTATION

Supply-side additions in the preferred strategy include wind and combustion turbine (CT) additions. Wind is added in four (4) separate annual increments of 100 MW in 2009-2012. CT's are not required until 2029 with the Preferred Plan adding two GE 7EA's for 154 MW of capacity. The annual supply-side installations for the Preferred Plan are shown in Table 1 of Section 1.4 for years 2008-2032. The capacity balance impacts of these supply-side additions are shown in Table 34 of Section 3.1 above for years 2008 through 2014. The entire forecast that includes the Preferred Resource Plan for Year's 2008 through 2032 is attached in Appendix 1-S.2.

3.3.1 WIND IMPLEMENTATION

The implementation of wind will follow the timeline and processes pursued to complete the Spearville-1 wind farm. The anticipated schedule and key milestones are described below. Progress toward completion of the proposed 2009 wind farm is in Step 4 of the schedule. Due to existing capital market conditions and the rising cost of capital, consideration of a PPA alternative to ownership is currently under consideration.

Table 15: Wind Implementation Milestones & Schedule

Process/Step Number	Year-1 of Project Development
1	1st Quarter – Assemble Wind Resource Team
2	2nd Quarter – Develop and issue an RFP for a nominal 100 MW or greater, as determined by a supply side analysis, of wind generation resources
3	3rd Quarter – Receive proposals, screen proposals, select finalists for contract negotiations, exercise due diligence, seek regulatory approval, begin engineering and procurement activities, begin Firm Transmission Service request process, begin contract negotiations
4	4th Quarter –Negotiate contract terms with developer - PPA or Build Transfer. Finalize and sign contract with developer, complete engineering and procurement for substation construction, community outreach, develop Operations and Maintenance plan – in-house or external contractor secured, project transferred from Wind Resource Team to Construction Management Team
	Year-2 of Project Development
6	1st Quarter – Equipment delivery begins, contractor mobilization
7	2nd Quarter – Construction begins on wind farm, substation and interconnection, begin commissioning of wind turbines
8	3rd Quarter – Last wind turbine commissioned, begin demobilization
9	4th Quarter – Final clean-up and land restoration as required, Contractor demobilized

3.3.2 COMBUSTION TURBINE IMPLEMENTATION

Implementation details were not completed for the proposed 2029 installation of CT's due to the long lead time prior to the required in-service date and the expected filing of future IRP's prior to the need for implementation.

SECTION 4: CONTINGENCY PLANNING

Section 2.1 above lists the 5 critical uncertainties originally identified in KCP&L's 2008 IRP filing. Section 2.2 above added 3 additional critical uncertainties, for a total of 8 critical uncertainties as listed below:

1. Natural Gas Prices
2. Environmental Allowance Prices
3. Coal Prices
4. CO_2 Allowance Prices
5. Load Growth
6. Financial Markets and the ability to finance the preferred plan
7. Stakeholder support for the preferred plan
8. DSM cost recovery

Contingencies are required to address potential changes in critical uncertainties. Because KCP&L is not projected to require new resource additions until the 2020 timeframe, the first contingency to consider is to delay implementation of the near-term resources included in the Preferred Plan. Changes in the key uncertainties listed above might lead to the preference to delay implementation of the Preferred Plan or to adjust the Preferred Plan as described in KCP&L's 2008 IRP filing. Key uncertainties and their potential impacts on the Preferred Plan are discussed below for the proposed DSM and Supply-Side resources.

4.1 DSM CONTINGENCIES

Five of the eight critical uncertainties identified above in Sections 2.1 and 2.2, have the greatest potential impact on DSM program implementation:

1. CO_2 allowance prices
2. Load growth
3. Financial markets
4. Stakeholder support
5. DSM cost recovery

1) The value associated with greenhouse gas emissions will have a significant impact of the benefits associated with DSM programs. Subsequently, the level of incentive payments, consumer pay-back and utility value will be impacted by CO_2 values. The resulting impact on the Preferred Plan could be an increase or a decrease in proposed spending and penetration levels. Future program measurement and verification evaluations will consider greenhouse gas values and potential adjustments to the DSM included in the Preferred Plan.

2) Load growth can impact the level of DSM implementation. Economic growth and new construction provide additional opportunities to promote many of the DSM programs. A slowing economy with reduced new construction and lower load growth may reduce the opportunities for promoting DSM programs. Again, the impact on the Preferred Plan may be an increase or decrease in spending and penetration rates. The expected range of impacts on future resource needs is assumed to be captured in the high-low range of load forecasts utilized in the IRP.

3) The ability to obtain economic financing will play a key role in DSM program implementation. If adequate financing is not available, the scope, spending and penetration rates proposed for the Preferred Plan will not be achieved. For this contingency, program roll-out would be delayed and budgeted spending levels would be reduced. It is anticipated that the lack of adequate financing would be economy-wide, resulting in low load growth and no significant change in the Preferred Plan for DSM other than delaying implementation and reducing budgeted spending levels.

4) Stakeholder buy-in is required for successful implementation of the DSM programs. Without agreement from key stakeholders including consumers, it is

unlikely that adequate cost recovery or adequate participation in DSM programs can be achieved. Lacking stakeholder buy-in, the proposed DSM programs would be delayed and budgeted spending would be reduced. The primary impact on the Preferred Plan would be a reduction in DSM penetration and the subsequent earlier need for the addition of Combustion Turbines (CT's), currently planned for 2029. The CT's would not be required prior to KCP&L's next IRP filing date.

5) Adequate cost recovery for DSM programs is necessary to meet the proposed spending and penetration rates. Without the necessary cost recovery, DSM programs would be delayed and spending curtailed. Results would be similar to Item 4) above. Additional discussion of the required cost recovery is included in Section 7.4, Request for Non-Traditional Ratemaking, of this report.

4.1.1 OTHER POTENTIAL CONTINGENCIES

Further contingencies are likely to include changes in program incentives as well as development of new marketing plans and/or new DSM program offerings. Measurement and Verification (M&V) of program success may lead to the application of such contingencies. Plans for M&V are included in Section 9 of Volume 5 of the original IRP submittal.

4.2 SUPPLY-SIDE CONTINGENCIES

4.2.1 COMBUSTION TURBINE INSTALLATIONS

Due to their late installation dates, no contingency plans were developed for the addition of CT's in 2029. The likely contingencies include earlier or later installation of the proposed CT's. Timing is expected to be driven by load forecasts and market conditions during the later years of the planning horizon.

4.2.2 WIND INSTALLATIONS

Four critical uncertainties may impact the wind installations included in the Preferred Plan:

1. The availability of Production Tax Credits (PTC) or similar incentives for renewable generation
2. Imposition of Renewable Portfolio Standards (RPS)
3. Availability of adequate and economic financing
4. Stakeholder buy-in

1) The PTC, currently at over $30/MWh, plays a key role in the economics of this resource. If the PTC is not available for one or more of the proposed 100 MW installations, KCP&L will need to reevaluate the economics of the current preferred plan.

2) The existence of a Federal or State RPS may drive additional wind installations. It is assume that any potential RPS requirements will provide the needed timeline to implement required installations and will be evaluated if and when an RPS is in place. The wind resources included in the Preferred Plan meet the requirements of the Missouri RPS ballot initiative recently approved by voters; however, the addition of solar generation will be also be necessary to meet this new requirement.

3) Maintaining adequate credit ratings is considered a requirement for implementing the Preferred Plan. The availability and cost of capital will be assessed prior to executing contracts for future wind installations to balance the interests of both shareholders and customers.

4) Stakeholder buy-in and agreement is also necessary to move forward with the proposed wind implementation. The Stipulation and Agreement approved by the MPSC in Case Number EO-2005-0329 requires on-going reporting and discussion regarding the Company's Comprehensive Energy Plan (CEP) including the timing and magnitude of additional wind resources. These on-going discussions are included as a portion of KCP&L contingency plans around the proposed wind resources shown in the Preferred Plan. Subsequent discussions with key

stakeholders is anticipated for wind installations that may occur after the timelines of the CEP Stipulation and Agreement.

ADDITIONAL REQUESTED DELIVERABLES

SECTION 5: LOAD FORECASTING AND ANALYSIS DELIVERABLES

Additional inputs regarding economic drivers and price elasticity were requested during the November 18th review of the Load Forecasting and Analysis efforts submitted in KCP&L's 2008 IRP filing. An email from George McCollister to David Roos, MPSC Staff member, was sent on October 8th to provide the requested data. Two items were attached:

1. An assessment of the Kansas City metro area economy outlook provided by Moody's Economy.Com (attached in Appendix 1-S.3) and
2. A spreadsheet containing energy price elasticity tables used in the load forecast (attached in Appendix 1-S.4).

SECTION 6: SUPPLY-SIDE ANALYSIS DELIVERABLES

6.1 FUEL & EMISSIONS FORECASTS

The sources of various fuel price forecasts were provided in Section 6 of Volume 4, Supply-Side Analysis in KCP&L's 2008 IRP filing. Sources of forecasts for emission allowance pricing were provided in Section 7 of Volume 4 in KCP&L's 2008 IRP filing. Due to the confidentiality and copyright protections of certain forecast sources utilized by KCP&L, these data will only be available for viewing at KCP&L's Headquarters in Kansas City. Requests for viewing these data should be coordinated through Lois Liechti, KCP&L's Regulatory Affairs Department.

6.2 BIOMASS BACKGROUND INFORMATION

Plan 25 of the alternative resource plans included converting Montrose Station to 10% biomass usage. Cost estimates for biomass and changes in unit operating parameters were obtained from a 2006 study performed by Black & Veatch for KCP&L. Note that the scope of work for this study was to explore several potential options for Montrose Station. Case M5 was the study of utilizing 10% biomass fuel, which begins on Page 4-34 of the Black & Veatch report. Appendix 1-S.5 contains the entire study.

6.3 ENVIRONMENTAL RETROFIT ESTIMATED COSTS

Environmental retrofits were included in the base case capital budgets utilized in the IRP. Table 16 provides the projected costs of these retrofits.

Table 16: Capital Budget Environmental Retrofits ** Highly Confidential **

	Capital Budget Environmental Retrofits				
	2008	2009	2010	2011	2012
Iatan-1 Environmental Retrofit	[redacted]				
LaCygne-1 Environmental Retrofit					
LaCygne-2 Environmental Retrofit					
Montrose-1 Environmental Retrofit					
Montrose-2 Environmental Retrofit					
Montrose-3 Environmental Retrofit					
Total					

HC

The environmental retrofit costs listed in the capital budget for Montrose Station were for Low NO_x burners only. Because no corporate-level decisions had been made regarding any additional environmental retrofits at Montrose Station, no additional retrofit-related capital was attributed to the continued operation of the Station.

Current projections indicate that Montrose Station may require environmental upgrades by January, 2015. Project cost estimates for SO_2, particulate, NO_x and Mercury reducing technologies were developed from pricing supplied by equipment suppliers. It is currently assumed that the budgeted Low NO_x burners will meet NO_x requirements until Phase III of BART, which is projected to impact Montrose in January 2023. Phase III of BART would require the installation of Selective Catalytic Reduction (SCR) equipment for additional NO_x removal. Current cost and emission rates for the complete retrofit of Montrose Station are shown below in Table 17:

Table 17: Estimated Cost of Environmental Retrofit Equipment <u> Highly Confidential **</u>**

Technology	Total Capital Cost (2008 $)	SO_2 Emissions Rate (lbs/mmBtu)	NO_x Emissions Rate (lbs/mmBtu)	Hg Emissions Reduction
SCR/Spray Dryer Absorber/Activated Carbon Injection/Baghouses/Burner Management System/Digital Control System	[redacted]			

The Net Present Value (NPV) of future spending for the Montrose environmental retrofits is $218 million. Table 18 shows the results included in Volume 7 of the IRP filing. Table 19 shows the results of the 26 plans after adding the NPV of the Montrose retrofits to plans that did not include coal retirement. Comparing the two tables shows that the ranking of the top three plans does not change based on this adjustment. Therefore the recommendation of the Preferred Plan does not change.

HC

Table 18: Original NPVRR of 26 Alternative Plans

NPVRR of 26 Alternative Plans as Modeled							
Coal Retirement	**Plan #**	**NPVRR ($'s x Millions)**	**Delta NPVRR**	**Coal Retirement**	**Plan #**	**NPVRR ($'s x Millions)**	**Delta NPVRR**
No	Plan26	21,006	-	Yes	Plan11	21,271	265
No	Plan19	21,019	13	No	Plan22	21,289	283
No	Plan21	21,021	15	No	Plan23	21,290	284
No	Plan15	21,071	65	No	Plan17	21,334	328
No	Plan20	21,072	66	No	Plan18	21,340	334
No	Plan24	21,126	120	Yes	Plan4	21,360	354
No	Plan2	21,137	131	Yes	Plan9	21,442	436
No	Plan14	21,168	162	Yes	Plan8	21,525	518
No	Plan25	21,215	209	Yes	Plan10	21,539	533
No	Plan13	21,221	215	No	Plan3	21,554	548
No	Plan12	21,239	233	Yes	Plan6	21,722	716
No	Plan1	21,240	234	Yes	Plan5	22,022	1,016
No	Plan16	21,244	238	No	Plan7	22,089	1,083

Table 19: NPVRR of 26 Alternative Plans Adjusted for Environmental Retrofits

NPVRR Adjusted for Coal Unit Retrofits							
Coal Retirement	Plan #	NPVRR ($'s x Millions)	Delta NPVRR	Coal Retirement	Plan #	NPVRR ($'s x Millions)	Delta NPVRR
No	Plan26	21,224		No	Plan12	21,457	233
No	Plan19	21,237	13	No	Plan1	21,458	234
No	Plan21	21,239	15	No	Plan16	21,462	238
Yes	Plan11	21,271	47	No	Plan22	21,507	283
No	Plan15	21,290	65	No	Plan23	21,508	284
No	Plan20	21,290	66	Yes	Plan8	21,525	300
No	Plan24	21,344	120	Yes	Plan10	21,539	315
No	Plan2	21,356	131	No	Plan17	21,552	328
No	Plan4	21,360	136	No	Plan3	21,554	330
No	Plan14	21,386	162	No	Plan18	21,558	334
No	Plan25	21,433	209	Yes	Plan6	21,722	498
No	Plan13	21,439	215	Yes	Plan5	22,022	798
Yes	Plan9	21,442	218	No	Plan7	22,307	1,083

6.4 ADDITIONAL DATA REGARDING WIND ALTERNATIVES

Responses received from the August 17, 2007 general RFP and the April 16, 2007 wind-specific RFP have were supplied as work papers on Thursday November 6, 2008.

SECTION 7: DEMAND-SIDE ANALYSIS DELIVERABLES

7.1 AVOIDED ENERGY COSTS

The Parties requested additional information regarding the application of market pricing for calculating avoided energy costs. Annual MIDAS hourly market price forecasts were used to develop the required market price inputs for the DSMore model. The Parties wanted to know the impact of using the DSMore calculations rather than a direct application of the MIDAS hourly prices. To answer this question, KCP&L reviewed one end-use program to compare key benefit test results using the MIDAS hourly prices Vs test results form the DSMore model. According to rule 4 CSR 240-22.050 (7) (F), DSM programs passing the Total Resource Cost Test (TRC) must be included in at least one alternative resource plan developed pursuant to 4 CSR 240-22.060 (3). Therefore, the TRC is the critical test for screening DSM programs.

Based on the evaluation of the replacement of a T-12 fluorescent lamp fixture (4'x4 lamps) with a T-8 fixture, the DSMore program returned higher TRC test results than the direct application of hourly MIDAS market prices as shown in Table 20 below. The conclusion is that no programs were excluded based on the application of hourly prices as modeled in DSMore. Alternative resource plans and their associated NPVRR results were calculated in MIDAS under rule 4 CSR 240-22.060. It can therefore be assumed that the NPVRR results of alternative resource plans were not impacted by the use of the DSMore hourly prices.

Table 20: MIDAS Vs DSMore Test Results

	DSMore Cost Based Results, normal year	DSMore, Market Price (Today's)	MIDAS Hourly Prices
Utility Test	2.86	2.14	2.00
TRC Test	1.48	1.11	1.03
RIM Test	1.00	0.74	0.77
Societal Test	1.77	1.39	1.28
Participant Test	N/A	1.53	1.72

7.2 END-USE MEASURES REJECTED

A list of the end-use measures rejected is in Volume 5, Section 2.2.2 page 23 of the IRP filing. Results are summarized below.

Residential end-use measures rejected:

- Adding two more inches of attic duct insulation
- Add insulation to floor
- Purchase an Energy Star dishwasher or clothes washer
- Insulate hot water pipes
- Replacing a SEER 13 air-conditioner with a 14, 15 or 16 SEER unit.

End-use renewable generation rejected:

- Solar PV
- Small scale wind turbines
- Solar air heat
- Solar hot water

7.3 DECISION-MAKER MEETING ATTENDANCE

Pages 11-12 of Volume 5 of the IRP filing lists numerous meetings with several customer groups. Additional information about these meetings was requested by parties regarding the purpose of key meetings with decision-makers as well as a listing of attendees. A summary of available meeting data is shown below.

7.3.1 MEETING DATE JAN 24, 2007 ~ KCP&L LOAD CURTAILMENT SEMINAR

Twenty-four people from 15 different companies attended this meeting which was conducted at KCP&L offices at 1201 Walnut Street, KC MO. The industries represented were plastics manufacturing, metal products manufacturing, food additives manufacturing, printing, educational sector, retail, hospitals and real estate services.

The purpose of the meeting was to review KCP&L's load curtailment programs and to discuss features and benefits of the program with potential participants. The following is a list of customers that attended:

Table 21: Jan 24, 2007 Meeting ** Highly Confidential **

[redacted]

HC

KCP&L Attendees	
Jason Jones	Emily Wagner
George Phillips	Dave Sutphin
Allen Dennis	Natalie Klass
Joe O'Donnell	Alan Kean
Scott Jones	Michelle McConnelle
Regina Hogan	Tim Bergerhoefer
Jon Carlson	Beth List
Craig Burgett	Kevin Bryant
Jan Harrison	Sue Nathan
Dave Wagner	

7.3.2 MEETING DATE MARCH 6, 2007:

KCP&L conducted a customer seminar to discuss and review our Comprehensive Energy Plan and demand-side management programs which was attended by 47 C&I firms. KCP&L senior management included Chris Giles, KCP&L's Vice President, Regulatory Affairs, Kevin Bryant, Vice President, Energy Solutions, and John Marshall Senior Vice President, Delivery. These senior managers made presentations to participants from a diverse group of industries. The participants are listed below:

Table 22: March 6, 2007 Meeting ** Highly Confidential **

[redacted]

HC

[redacted]

7.3.3 MEETING DATE JULY 18, 2007:

KCP&L conducted a customer lighting seminar to review current standards and review the benefits of more efficient technology. Dennis Spaulding with Sylvania presented on the benefits of energy efficient lighting and available technology. George Phillips, formerly manager of energy efficiency programs, for KCP&L discussed our custom rebate program. Mr. Phillips has since retired. The agenda is listed below:

9:00	Introductions	Allen Dennis – KCP&L
9:15	Lighting Presentation	Dennis Spaulding - Sylvania
10:15	Break	
10:45	KCP&L's C& I Rebate Program	George Phillips – KCP&L
11:05	AccountLink Advantage	Randy Vance - KCP&L
11:30	Wrap up	Regina Hogan - KCP&L

Table 23: July 18, 2007 Meeting ** Highly Confidential **

NAME	COMPANY	NAME	COMPANY
[redacted]			

HC

[redacted]

KCP&L EMPLOYEES	
Regina Hogan	Mike Schfman
Robin Burch	Joe Odonnell
Scott Jones	John Carlson
Jan Harrison	Michelle McConnell
George Phillips	Randy Vance
Allen Dennis	Elizabeth Golston
Doris Abernathy	Tim Bergenhofer
Jason Jones	

HC

7.3.4 MEETING DATE : AUG 29, 2007

KCP&L conducted a customer seminar to review industry best practices as related to building design features, thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock. Opportunities for benchmarking customer usage against regional and national standards were also discussed.

Table 24: Aug 29, 2007 Meeting ** Highly Confidential **

NAME	ORGANIZATION	NAME	ORGANIZATION
[redacted]			

HC

KCP&L EMPLOYEE	
Tim Bergerhofer	Robin Burch
Craig Burgett	Jan Harrison
Randy Vance	Regina Hogan
Joe O'Donnell	Scott Jones
Randy Vance	John Carlson
Brandon Whitaker	

7.3.5 SEPTEMBER 14, 2007 ~ KANSAS CITY ENERGY EFFICIENCY FORUM

KCP&L participated in the Kansas City Energy Efficiency Forum which was held at Bartle Hall in Kansas City, MO on September 14, 2007. This event was sponsored by Aquila, the Kansas City Chamber, KCP&L, the Kansas Energy Council, Mid-America Regional Council (MARC), Missouri Energy Development Association (MEDA) and the Sierra Club.

Presenters at this meeting included U.S Senator Claire McCaskill (D-MO), Kansas Governor Kathleen Sebelius, MO Governor Matt Blunt, KCP&L CEO Mike Chesser. More information about this meeting can be found on the website: http://www.kcenergyfuture.com/

KCP&L does not have an attendee list.

7.4 REQUEST FOR NON-TRADITIONAL RATE MAKING (RULE 22.080 (2))

7.4.1 INTRODUCTION AND STATEMENT OF PURPOSE

In 2005, KCP&L launched its Comprehensive Energy Plan which included, among other components, a portfolio of energy efficiency, demand response, and affordability programs classified as demand-side management ("DSM") programs. The DSM programs were filed as pilot programs to run for a period of time, subject to continuing Commission review and were part of a portfolio to meet the growing demand for electricity and address environmental concerns.

KCP&L supports the development of comprehensive DSM programs for its customers and a regulatory environment in which energy efficiency resources are considered a preferred resource option. KCP&L believes that DSM programs are greatly in the public interest as important and necessary resources, that should be a key component of any comprehensive energy plan designed to meet the future energy needs of Missouri customers for adequate, safe, efficient, and reliable electric service. KCP&L sees a unique opportunity to develop DSM programs in a way that benefits customers, the environment, the state economy, and the Company.

Two of KCP&L's key core principles related to the advancement of energy efficiency are:

1) To the customer, energy efficiency programs should demonstrate significant economic and societal benefits. Customers desire more influence and control over their own energy and demand usage through greater access to information that enables them to make informed decisions related to energy usage. The utility should be allowed to ensure those benefits are promoted to the customer and allow the customer a solid rationale for participation in these programs.

2) To the utility, energy efficiency should be treated as a preferred resource option, or at minimum on a level playing field with supply-side generation. As such, investments in energy efficiency should receive regulatory treatment so as not to discourage utilities from investing in energy efficiency programs.

DSM programs by their very nature pose financial challenges to utilities. The goal of such programs is to reduce customer usage and demand. By lowering customer usage and demand, the billing determinants are lowered on which the utility's charges are assessed. Each kWh and kW reduction leads to less revenue for the utility. While the utility can avoid the variable costs of providing the additional service, the net impact is almost always a reduction in net revenue and earnings -- often referred to as "lost margins." While the impact from the reduction of sales attributable to DSM can usually be re-established in the next rate case, there is still a net loss of allowed revenue between rate cases. KCP&L will experience this revenue, earnings and cash flow loss if it continues the current regulatory model, which includes a historical test year as the basis for establishing rates and recovery of and on the investment in energy efficiency, because the historical test year sets the sales levels of customers at a level that DSM programs are reducing. The current model for KCP&L's investment in DSM programs results in a disincentive to the development and implementation of energy efficiency programs as a more sustainable resource due to the detrimental shareholder impact that such investments currently have on KCP&L.

Given its positive experience with the Experimental Regulatory Plan in Missouri (CEP) related programs, KCP&L seeks to continue its commitment to DSM programs beyond the CEP in 2010. In order to aggressively pursue this commitment, the financial disincentives highlighted above need to be eliminated and DSM investments treated on at least an equal playing field to investments in traditional supply resources.

Rule 22.080 (2) (B) 1 requires an explanation of the specific form and mechanics of implementing the proposed accounting procedure and any associated ratemaking treatment to be sought. The following explanation meets this rule:

Specifically, KCP&L seeks Commission approval of non-traditional rate making associated with expenditures for the proposed DSM programs included in the 2008 IRP Preferred Plan. In order to continue offering DSM programs to customers, KCP&L proposes the following components for cost recovery:

1) Return of and on DSM investments;

2) Recovery of lost margins; and

3) Performance mechanism for meeting or exceeding DSM program energy savings goals.

The following is a discussion of each of the three components listed above:

7.4.2 RETURN OF AND ON DSM INVESTMENTS

KCP&L proposes to defer the costs of DSM programs in Account 186 and calculate allowance for funds used during construction (AFUDC) monthly. When new rates go into effect reflecting amortization recovery as a result of future general rate proceedings, KCP&L will transfer the prudently-incurred costs included in the Account 186 balance to Account 182.3 and include such costs in rate base; stop accruing AFUDC on the amount included in rate base; and begin amortizing the balance over a ten (10) year period. Additional DSM program costs incurred after the effective date of a final Report and Order recognizing these costs will be treated in the same manner, but will be deferred in a different sub-account by vintage. DSM program costs are defined as those costs, both capital and expense, incurred incrementally above existing costs in rates.

7.4.3 RECOVERY OF LOST MARGINS

KCP&L proposes to recover lost margins through an annual energy efficiency rider that is intended to reduce regulatory lag and mitigate the earnings erosion that historically has been associated with KCP&L's DSM initiatives. The Company proposes to establish the rider at the time the Commission approves tariffs required to implement DSM initiatives. At the time the Company applies for approval of the various tariffs, the Company will submit an analysis estimating the cost and impact of the initiatives. When the tariff is approved, the rider will be established to recover the projected lost margin over the following 12 months. In the ninth month of the rider, the Company will file an updated analysis projecting the lost margin for the next twelve months. Six months after the first 12 months, The Company will make a true-up filing to either return over recovery or collect under recovery of lost margin, based on the success of the implementation of the initiative. At the time new rates are established as a result of a general rate case, the rider would be set at zero, as the rates will reflect lost margins at that time.

Any changes to the initiatives that result in impacts that differ from those in the general rate case would necessitate another rider based on the next 12 months.

7.4.4 PERFORMANCE MECHANISM FOR MEETING OR EXCEEDING DSM PROGRAM ENERGY SAVINGS GOALS

KCP&L is proposing to determine the net economic benefits of the energy efficiency programs for purposes of developing an annual performance plan. Specifically, KCP&L requests the Commission to authorize a performance mechanism that allows the utility to retain for its shareholders a portion of the net economic benefits associated with DSM programs for performance that meets or exceeds agreed upon energy savings goals.

Estimated net benefits are equal to the sum of each program's total avoided cost minus program costs. Avoided costs are the cost that would otherwise be incurred by a utility to serve the load that is avoided due to an energy efficiency program.

KCP&L proposes a performance plan based on a sliding scale on the energy savings achieved as a percentage of the energy savings goal for each year of the program. If KCP&L achieves less than 50 percent of its Commission-approved energy savings goal for the year, it will earn no incentive. If KCP&L achieves energy savings equal to or greater than 50 percent, but less than 75 percent of its approved energy savings goal for the year, KCP&L will retain 10 percent of the net economic benefits. If KCP&L achieves 75 percent but less than 100 percent of its approved energy savings goal, KCP&L will retain 15 percent of the net economic benefits. If KCP&L achieves 100 percent or greater of its approved savings goals, KCP&L will retain 20 percent of the net economic benefits. A chart showing the proposed incentive percentages is provided below:

ANNUAL SAVINGS AS A PERCENTAGE OF SAVINGS GOAL	PERFORMANCE PAYOUT %
0 – 50%	0 %
51 – 74%	10 %
75 - 99%	15 %
> 99%	20 %

This mechanism meets KCP&L's goal of tying performance to the effectiveness of its DSM initiatives. Linking financial benefits of the programs to the actual net benefits generated and achievement of savings goals is preferable to tying an incentive to program costs or similar variable that simply captures the utility's effort. The litmus test of a DSM program's effectiveness is the net benefits created and the achievement of planned savings goals, not the dollars committed. KCP&L believes its proposed performance plan better aligns traditional public-policy goals with KCP&L's financial requirements.

7.4.5 SUMMARIZED PROPOSED COST RECOVERY RATIONALE

The proposed cost-recovery mechanism and financial incentive would, as a package, allow KCP&L to increase its commitment to DSM without suffering significant financial harm. In other words, DSM initiatives would have earnings impacts similar to or better than those of supply-side investments, depending on performance, and would meet the Commission's objective to develop DSM programs as a more sustainable resource. KCP&L may at some point seek additional or modified measures to further prevent revenue and earnings erosion, but this initial proposal would at least address the most detrimental financial impacts of DSM programs. This explanation of how this specific proposal meets the need for nontraditional treatment meets the requirements of Rule 22.080 (2) (B) 3.

7.4.6 KCP&L'S PREFERRED PLAN

Rule 22.080 (2) (B) 2 requires a discussion of the rationale and justification of the need for a nontraditional treatment of these costs. The following discussion satisfies this rule:

The analysis done to arrive at the Preferred Plan is an outcome of MIDAS, an hourly load dispatching software package that provides the Net Present Value of Revenue of Requirements (NPVRR) over a period of time under specific conditions and circumstances. The annual revenue requirement used in the NPVRR calculation are converted into annual average rates. In other words the MIDAS model assumes perfect ratemaking, both in terms of time and amount. It is this analysis from which the Preferred Plan was chosen.

This "perfect ratemaking" never occurs in actuality, due to the nature of Regulatory ratemaking. KCP&L believes nontraditional DSM ratemaking is necessary due to this mismatch.

Rule 22.080 (2) (B) 4 requires a qualitative comparison of the utility's estimated earnings over the three year implementation period with and without the proposed nontraditional accounting procedures and any associated ratemaking treatment to be sought. The following discussion satisfies this rule:

During the first five years of KCP&L's Preferred Plan, the major investment identified is DSM. DSM included in the Preferred Plan includes an initial three year estimated DSM investment of **[redacted]**. This investment is estimated to net an energy reduction over the three year period in the amount of 446,328,000 kWh. It should be noted that the DSM investment and energy reductions listed are for the proposed Residential and Aggressive Energy Efficiency programs. The ongoing Energy Efficiency programs developed under the CEP are not included in this qualitative analysis. The overall details of the actual calculation will be done specific to each program on a rate class basis.

HC

A simplistic estimation of the lost margin over the first three years of the implementation of the proposed DSM programs included in the Preferred Plan has been developed. This lost margin estimation was derived by subtracting the average marginal costs per kWh from average marginal revenue per kWh with the difference multiplied by the energy reduction estimated from the proposed DSM programs. The estimated 2008 average marginal retail revenue per kWh is 5.519 cents per kWh. For the first 11 months of 2008, the average marginal cost (fuel and purchased power) to serve native load was **[redacted]** cents per kWh. Therefore, lost margin is estimated as follows:

(Average Marginal Revenue per kWh – Average Marginal Cost per kWh) * DSM Energy Reduction

(5.519 cents per kWh – [redacted] cents per kWh) * 446,328,000 kWh

= **[redacted]**

This averages to **[redacted]** per year on a pre-tax basis. This has an annual earnings impact of **[redacted]**, based on 2008 3rd Quarter average shares outstanding.

This analysis is for illustrative purposes. The overall impact of the programs on shareholders would be done on a detail basis for each program on a rate class basis.

Rule 22.080 (2) (A) requires that the request for initial authorization of nontraditional accounting procedures must be limited to specific demand-side programs that are included in the utility's implementation plan. This Rule has been met as the DSM-related information provided in the IRP and Supplemental Filing submittal refer to proposed DSM programs defined as part of the Preferred Plan.

HC

7.4.7 SUMMARY

KCP&L recognizes that the proposed cost recovery articulated herein represents a significant departure from the traditional treatment of DSM investments and that such traditional treatment makes significant advancement of DSM resources extremely difficult from both a shareholder and credit perspective. Nonetheless, KCP&L believes that DSM programs are greatly in the public interest as important and necessary resources, that should be a key component of any comprehensive energy plan designed to meet the future energy needs of Missouri customers for adequate, safe, efficient, and reliable electricity.

Implementing the DSM portion of the Preferred Plan does more than create shareholder earnings risk, it virtually guarantees shareholder earnings loss and credit deterioration absent non-traditional ratemaking. For this reason, KCP&L believes it is necessary to request non-traditional ratemaking that includes return on and of the DSM investment, the recovery of lost margins, and the opportunity to share in benefits. This ratemaking treatment ensures DSM investments are made on an equivalent basis with supply-side resources.

7.5 OTHER REQUESTED INFORMATION

7.5.1 DSM PROGRAM PENETRATIONS BY STATE

KCP&L did not segment residential or customer potential analysis by State, Missouri and Kansas. KCP&L does not segment its supply requirement by State and we followed the same principle in our demand analysis.

7.5.2 GAS TO ELECTRIC WATER HEATERS

KCP&L monitors natural gas prices as compared to electric tariff rates and is of the opinion that it would not be economical for most residential customers to switch given the current natural gas price environment. KCP&L will continue to monitor energy prices and could potentially recommend switching, if economics would be beneficial to the customer.

7.5.3 EMS SYSTEMS

Building EMS systems were not evaluated. Building EMS systems could qualify through our custom rebate program and would be evaluated on a case by case basis. KCP&L did evaluate building lighting control systems such as central lighting controls, switching controls for multilevel lighting and daylight sensor controls.

7.5.4 HOME ENERGY ANALYZER PLUS (HEAP)

Parties requested information regarding the contents of the Home Energy Analyzer Kits offered through the Home Energy Analyzer Plus (HEAP) program. Home Energy Analyzer Plus ("HEAP") is KCP&L's enhanced energy efficiency web site. It provides KCP&L customers with the most advanced programs, tools, and measures available to manage their energy usage and achieve load reduction. The website features a multi-tiered design providing the customer the opportunity to receive quick customized energy tips and, if they choose, the ability to complete an online audit. Customers can also elect to receive an energy efficiency self-install starter kit. The Energy Efficiency Starter Kit provides the customer with the following measures:

- Six CFL Light Bulbs
- One LimeLite LED Night Light
- Two Switch/Outlet Draft Stoppers

The marketing of this energy efficiency website through the HEAP program is an initiative meant to diversify and increase the reach of KCP&L's DSM programs.

7.5.5 SEER 13 TO SEER 14, 15, OR 16

The conversion of SEER 13 HVAC units to SEER 14-16 units did not pass the screening tests. The cost to purchase the higher SEER units relative to a SEER 13 unit is high relative to energy savings. The annual energy savings are not large enough to justify the higher purchase cost.

7.5.6 ENERGY USE MONITORS

Parties questioned how distribution of the monitors in the proposed Energy Use Monitor – Blue Line program would be determined. KCP&L is recommending that the program initially run for three years and has projected a participation rate of 20,000 units per year. The program would be budgeted for this participation. All KCP&L residential customers would be eligible to participate. The program would be halted when participation rates have been reached.

7.5.7 APPLIANCE TURN-IN PROGRAM

Parties questioned how the turn-in program would be handled. KCP&L plans to partner with an entity that has experience and has success in running appliance turn-in programs. KCP&L is in discussion with entities that have had success in running turn-in programs in other areas of the country. A meeting with one of these entities, JACO Environmental, Inc. (JACO), is scheduled for early December. JACO has considerable experience and has had success in running turn-in programs for other utilities in the U.S.

7.5.8 ONE LEVEL OF RESIDENTIAL DSM PROGRAMS EVALUATED

Parties questioned why only one level of residential DSM programs was included in the alternatives. KCP&L relied on the expertise and advice of Morgan Marketing Partners to develop the proposed residential programs. After discussion with Morgan Marketing Partners, it was agreed that the C&I segment would need additional levels of scenario analysis due to the diversity of end-use measures and industry segments. There is more uncertainty around potential spending and penetration rates in the C&I segment than in the Residential segment. For Residential programs, the cost per participant and the resulting energy impacts are fairly well defined. Most program spending was capped at a certain level of penetration and the resulting energy impacts were believed to be fairly well defined.

For Residential programs, KCP&L's Preferred Plan included enhances for three existing programs:

1. Cool Homes

2. Home Performance with Energy Star®

3. Home Energy Analyzer Plus (Online Energy Information And Analysis Program Using Aclara® Residential Suite)

The enhanced programs are identified in the IRP document Volume 5; Demand-Side Resource Analysis, page 37. Descriptions of these programs with discussion of the proposed enhancements can be found in Appendix 5.O pages 18-27.

These enhancements build on the basic programs that were included in KCP&L's Comprehensive Energy Plan (CEP) and are described in the Stipulation and Agreement document, Missouri Report Order-EO-2005-0329 APPENDIX C-1. These enhanced programs essentially constitute a second level of program scenario analysis both in terms of program energy savings and participation rates.

KCP&L also proposes to have two new residential programs included in the Preferred Plan:

1. Energy Use Monitor – Blue Line

2. Appliance Turn-In

The proposed new programs are identified in the IRP document Volume 5; Demand-Side Resource Analysis, page 37-38. Descriptions of these programs with discussion of the proposed enhancements can be found in Appendix 5.O pages 28-32. The residential energy use monitor program is budgeted to a predetermined level of participation and savings and a second level of spending was not considered.

7.5.9 ALTERNATIVE RATE STRUCTURES

Parties asked if alternative rate structures were considered as DSM programs. KCP&L did not evaluate alternative rate structures in conjunction with DSM planning.

SECTION 8: CORRECTIONS FROM THE IRP SUBMITTAL

8.1 VOLUME 3: LOAD ANALYSIS AND FORECASTING

There was a formatting error on Page 73. The paragraph should read: Charts 31 and 32 show the resulting seasonal Missouri residential and commercial hourly end-use class load forecast.. Hourly end-end-use class load forecast for Missouri can be found in Appendix 3.F **Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.**and Kansas in Appendix 3.G.

8.2 APPENDIX 1.C DSM EE IMPLEMENTATION

There was a typo identified on Page 9. The paragraph should read: The marketing strategy for C&I will be stratified with segmentation and a more direct approach based on actual energy needs, usage trends, LEED certification requirements, new and retrofit construction, and incentive requirements. Company account managers will work closely with facility managers to identify opportunities and engage appropriate third parties, industry experts, etc to deliver energy saving solutions on an on-going basis. Marketing materials and presentations will be created to feature C&I products and services that can be distributed at trade shows, meetings, and presentations.

8.3 VOLUME 6: INTEGRATED ANALYSIS

Plan V-4, listed in Table 3, Page 9 incorrectly included CT's in this resource plan. The corrected table is shown below.

Table 25: Correction on Table 3, Volume 6, Page 9 ** Highly Confidential **

	Plan V-1	Plan V-2	Plan V-3	Plan V-4	Plan V-5
EE N= Normal C&I A = Aggressive C&I R= Residential	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PTC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combustion Turbines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Combined Cycle	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IGCC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coal Retirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

HC

Plan 16, outlined in Table 8, Page 13, incorrectly omitted adding solar in the year 2030. The corrected table is shown below:

Table 26: Correction on Table 8, Volume 6, Page 13

	Plan 15	Plan 16	Plan 17	Plan 18	Plan 19	Plan 20	Plan 21
EE N= Normal C&I A = Aggressive C&I R= Residential	A + R (2010)	N (2010)			A + R (2010)	A + R (2010)	A + R (2010)
DSM (CEP-1, Growth, Curtail)	CEP-1	CEP-1	Growth	Curtail	CEP-1	Growth	Growth
Wind		2014, 2018, 2121, 2023			400 MW (2009-2012)		400 MW (2009-2012)
PTC	N.A.	Yes	N.A.	N.A.	Yes	N.A.	Yes
Solar		2011, 2014, 2018, 2021, 2030					
SCPC							
Combustion Turbines	154 MW (2027 & 2031)	154 MW (2028 & 2032)	154 MW (2026 & 2029)	154 MW (2023, 2027, 2031)	154 MW (2029)	154 MW (2028 & 2032)	154 MW (2029)
Combined Cycle							
Nuclear							
IGCC							
Coal Retirement							

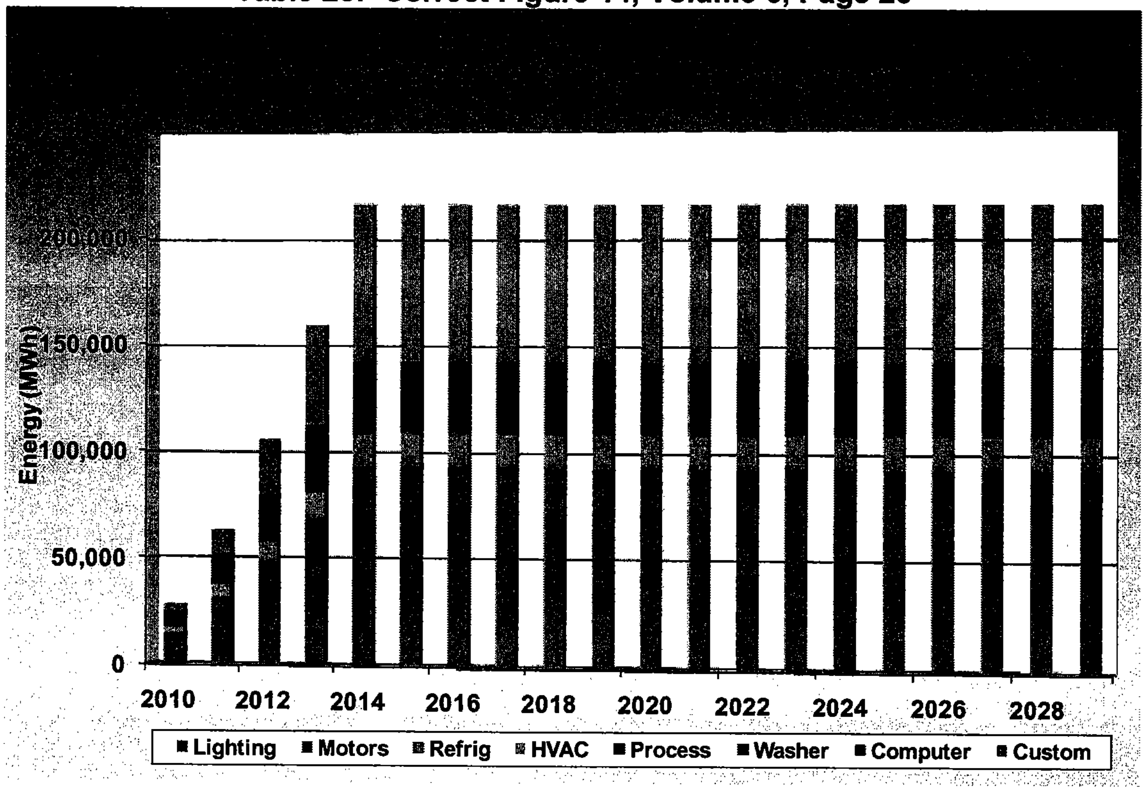
Plan 22, outlined in Table 9, Page 14, incorrectly omitted a CT addition in the year 2029. Plan 25, incorrectly omitted 10% biomass in this resource plan. The corrected table is shown below:

Table 27: Corrections on Table 9, Volume 6, Page 14

	Plan 22	Plan 23	Plan 24	Plan 25	Plan 26
EE N= Normal C&I A = Aggressive C&I R= Residential	A + R (2010)	A + R (2010)	A + R (2010)	A + R (2010)	A + R (2010)
DSM (CEP-1, Growth, Curtail)	Growth	CEP-1	Curtail	CEP-1	CEP-1
Wind	400 MW (2009-2012)	400 MW (2009-2012)	400 MW (2009-2012)	400 MW (2009-2012)	400 MW (2012-2015)
PTC	No	No	Yes	Yes	Yes
SCPC					
Combustion Turbines	154 MW (2029)	154 MW (2029)	154 MW (2027 & 2031)	154 MW (2029)	154 MW (2029)
Combined Cycle					
Nuclear					
IGCC					
Coal Retirement				10% Biomass (Montrose)	

Aggressive C&I EE Energy By Program, Figure 14, Page 26, incorrectly provided demand values. The figure was intended to provide energy values. The correct table is shown below:

Table 28: Correct Figure 14, Volume 6, Page 26



SECTION 9: SUSTAINABLE RESOURCE STRATEGY (SRS)

Parties asked for clarification of the SRS collaborative process that was referred to in KCP&L's IRP submittal. This section of the report further defines the need for the SRS as additional contingency planning beyond the findings included in the IRP filing.

The need for a collaborative process is driven by the significance of the critical uncertainties identified in the IRP. Concern over the contributions of man-made CO_2 emissions on global warming may lead to restrictions on the use of fossil fuels. The range of potential restrictions can drastically change the value of the Preferred Plan.

As demonstrated by the Ventyx modeling results, the range of impacts from this one critical uncertainty is too wide to be adequately evaluated based on the subjective probabilities and expected values. The risks of selecting a future resource plan based on expected values are well beyond the scope of risks commonly tied to fuel price uncertainty or other uncertainties historically identified in an integrated resource planning process. The risks apply to all stakeholders and could be created or mitigated through actions of public policy as opposed to utility decision making.

Under this wide range of risks, utilities cannot afford to move forward with significant investments without inputs and buy-in from critical stakeholders. Similarly, utility regulators should not want utility decision making to proceed without sharing their own concerns and issues and working collaboratively to establish future plans that fully account for the significant risks faced by the industry. The proposed SRS process is a mechanism to obtain this dialogue and stakeholder input.