Consumers Energy

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June 30, 2009

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

Re: Case No. U-15996: Electric Generation Alternatives Analysis for Proposed Permit to Install No. 341-07 for an Advanced Supercritical Pulverized Coal Boiler at the Karn-Weadock Generating Station

Dear Ms. Kunkle:

Enclosed for filing in this proceeding is supporting data used in the Electric Generation Alternatives Analysis previously submitted in this case. This information is being provided in response to the June 24, 2009 Technical Conference.

If there are any questions, please call either myself or Kristin VanReesema at (517) 788-2925.

Sincerely,

Digitally signed by Jon R. Robinson
Date: 2009.06.30 17:15:35 -04'00'

Jon R. Robinson

cc: G. Vinson Hellwig, MDEQ
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fl0609-3-224

Question:

1. What resource planning model and risk analyses did Consumers use in preparing the analyses presented in the BEI EGAA?

Response:

The EGAA order specified a bus-bar analysis. We have provided the back-up materials for this bus-bar analysis which was filed June 15, 2009.

Question:

2. Are the CO_2 costs shown in footnote 35 on page 27 of the EGAA in nominal or constant year dollars? If in constant year dollars, what year?

Response:

Nominal dollars.

MPSC Case No. U-15996 - Consumers Energy Answers to MPSC Staff Questions from June 24th, 2009 Technical Conference

Question:

3. What assumption does Consumers make in the analyses presented in the EGAA concerning the impact that carbon legislation will have on natural gas prices – in other words, does Consumers increase the cost of natural gas when it includes carbon prices? If so, by how much? And what are the analyses, studies and other evidence that form the basis for this assumption?

Response:

See Direct Testimony of David F. Ronk in Case No. U-15805 letter to MPSC Jan. 8, 2009 Exhibit: A-14 (DFR-7) pg. 1-4

Question:

4. Why does Consumers assume in its levelized cost analyses that each of the new units begins operations at the start of 2009? Isn't the proposed Karn-Weadock plant planned to enter service in 2017?

Response:

Each bus-bar calculation assumes that a project would be in-service today in order to develop a comparative analysis to all the alternative supply sources. See also Direct Testimony of David F. Ronk in Case No. U-15805 letter to MPSC Jan 21, 2009 Exhibit: A-14 (DFR-8) pg. 1-3 for details on the methodology of the bus-bar analysis.

<u>Question:</u>

5. What coal units retirements does Consumers assume in its BEI analyses and in what years? Is the company committing to retiring those plants? Has it prepared economic and engineering analyses showing that each of those retirements is either needed from an engineering perspective or is the lowest cost option?

Response:

The reductions in existing capacity are provided in our June 15, 2009 filing. We have not committed to retire these plants as this time. We have not prepared economic or engineering analyses for this purpose to show it is the lowest cost option. We can not predict what future environmental and regulatory compliance requirements that may in the future render our older plants uneconomical.

Question:

6. What would be the rate impact in 2017 of retiring the approximate 950 MW of existing coal plants mentioned in the EGAA and adding the proposed Karn-Weadock unit?

Response:

Rate impacts were not requested as part of this EGAA filing.

Question:

7. (reference the 44th page in Consumers' June 15, 2009 filing of supporting data for its EGAA) In its levelized cost calculations for the natural gas combined cycle and combustion turbine alternatives, Consumers assumes that natural gas prices are $7.72 per MMBTU in 2009, $8.40 per MMBTU in 2010, increasing each year thereafter. Are these really Consumers' projected natural gas prices in 2009 and 2010? Or do they represent what Consumers' projects will be natural gas prices in 2017 and subsequent years? Please explain how these natural gas prices were developed and on what they are based.

Response:

These are the projected natural gas prices in 2009 and 2010. They do not represent what Consumers' projects will be the natural gas prices in 2017 and subsequent years. See direct testimony of David F. Ronk in Case No. U-15805 letter to MPSC Jan. 8, 2009 Exhibit: A-14 (DFR-7) pg. 1-4 for how these gas prices were developed.

Question:

8. What are Consumers' most recent long-term natural gas price projections?

Response:

The Company's long-term natural gas price is reflected in the Direct testimony of David F. Ronk in Case No. U-15805 letter to the MPSC dated January 8, 2009 for Henry Hub prices. The gas price reflected in the bus-bar analysis includes delivery costs to a new gas combine cycle facility.

Question:

9. (Reference the 26th page in Consumers' June 15, 2009 filing of supporting data for its EGAA) Consumers assumes a $3276 per kW capital cost + AFUDC in its levelized cost calculations for an Advanced Supercritical Pulverized Coal Plant. Is this Consumers' new cost estimate for Karn-Weadock? How much of the $3276 per kW is capital cost and how much is AFUDC? What is the currently estimated construction cost for the plant (with and without AFUDC) both in EOY 2008 and in nominal dollars?

Response:

See direct testimony of David F. Ronk in Case No. U-15805 letter to MPSC Jan. 8, 2009 Exhibit: A-14 (DFR-7) pg. 5-6.

<u>Question:</u>

11. Please quantify the individual components of the capital fixed charge rates used to calculate the levelized costs for the Advanced Supercritical Pulverized Coal Plant, the natural gas combined cycle alternative, the natural gas combustion turbine alternative and the on-shore and off-shore wind alternatives.

Response:

See Attachments 1-4 .

CONSUMERS ENERGY COMPANY
FIXED CHARGE RATE FOR REGULATED ENVIRONMENT
ASCPC

1		0.026750	Depreciation
2	+	0.060158	Average Return On Investment
3	+	0.019840	Federal Income Tax
4	+	0.002300	Michigan Business Tax

5		0.109049	Fixed Charge Rate Narrowly-Defined
6	+	0.013727	Property Tax Rate
7	+	0.001031	Insurance Rate

8		0.123807	Fixed Charge Rate Broadly- Defined

CONSUMERS ENERGY COMPANY
FIXED CHARGE RATE FOR REGULATED ENVIRONMENT
Natural Gas CC

1		0.035667	Depreciation
2	+	0.058224	Average Return On Investment
3	+	0.019202	Federal Income Tax
4	+	0.002226	Michigan Business Tax

5		0.115319	Fixed Charge Rate Narrowly-Defined
6	+	0.013727	Property Tax Rate
7	+	0.001031	Insurance Rate

8		0.130077	Fixed Charge Rate Broadly- Defined

CONSUMERS ENERGY COMPANY
FIXED CHARGE RATE FOR REGULATED ENVIRONMENT
Natural Gas CT

1		0.052500	Depreciation
2	+	0.057773	Average Return On Investment
3	+	0.019053	Federal Income Tax
4	+	0.002209	Michigan Business Tax

5		0.131535	Fixed Charge Rate Narrowly-Defined
6	+	0.013727	Property Tax Rate
7	+	0.001031	Insurance Rate

8		0.146293	Fixed Charge Rate Broadly- Defined

CONSUMERS ENERGY COMPANY
FIXED CHARGE RATE FOR REGULATED ENVIRONMENT
Wind

1		0.050000	Depreciation
2	+	0.058761	Average Return On Investment
3	+	0.019379	Federal Income Tax
4	+	0.002247	Michigan Business Tax

5		0.130387	Fixed Charge Rate Narrowly-Defined
6	+	0.013727	Property Tax Rate
7	+	0.001031	Insurance Rate

8		0.145145	Fixed Charge Rate Broadly- Defined

<u>Question:</u>

12. (Reference 48th page in Consumers' June 15, 2009 filing of supporting data for its EGAA) What is the basis for the assumption that wind capital costs will increase over time to $4384 per kW?

Response:

The $4,384/kW is based on a capital cost escalation rate of 3% per year. See Direct Testimony of Tom W. Swartz in Case No. U-15805 pg. 8.

Question:

13. (reference footnote no. 11 on page 7 of the EGAA) Has Consumers' prepared new forecasts of peak demand, electric deliveries and generation requirements since testimony was filed in Case No. U-15645 in November 2008? If not, when are such new forecasts expected? If yes, what are the new forecasts, year by year.

Response:

The forecast utilized is our official forecast for long range planning. An updated forecast would be filed with the Company's Certificate on Necessity.

Question:

14. What was Consumers' actual 2008 peak load and what is its currently projected 2009 peak load?

Response:

Actual peak demand was 7705 MW, weather normalized 8716 MW. Our 2009 forecasted peak demand is 8578 MW.

Question:

15. Has Consumers prepared an assessment of the potential for energy efficiency in its service territory? If so, when? What were the results? Will you provide a copy?

Response:

See reference 15 on pg. 8 of the EGAA – January 2009 EPRI report.

Question:

16. (reference page 38 of the EGAA) What are the studies and other evidence that show that energy efficiency and demand response programs are included in the BEI at levels the Company believes are cost effective and realistically achievable.

Response:

The company does not have any additional materials beyond what was sited in the EGAA.

Question:

17. Other than the cited EPRI report, what is the basis for the Company's assumption that increment energy efficiency savings will increase at only 0.5% per year after 2015?

Response:

The company used the EPRI report to justify the amount of incremental energy efficiency savings beyond 2015.

Question:

18. Why are no additional renewable resources added in the BEI after 2017?

Response:

See page 9 of EGAA – Due to the high cost of this capacity, its intermittent and unpredictable operational nature, the company has not included additional renewable resources after 2017.

Question:

19. (reference Figure 4 on page 14) What are the GWh energy provided in the years 2017, 2021 and 2025 by fuel type, i.e., coal, gas, purchases, renewable, etc.?

Response:

See Attachment 1. Total GWh in the attachment matches column (n) Total Requirements GWh in Figure 4 of the June 15, 2009 filing.

Attachment 1 to Attachment 1 to 15996 - Tech Conf June 24 Question 19
EGAA Technical Conference
Question #19

	2017 GWh	2021 GWh	2025 GWh
Coal	15,608	13,047	12,529
New Coal	4,145	4,135	3,402
Gas	1,387	1,397	744
Oil	15	9	3
Nuclear	6,779	5,990	0
Pumped Storage	-463	-445	-446
Renewables	4,079	4,570	4,536
AMI - Demand Response	0.211	0.212	0.217
AMI - Load Management	0.276	0.360	0.372
Energy Efficiency	2,635	3,455	4,267
Purchases	8,200	10,738	18,280
Total	42,385	42,897	43,316

Question:

20. How much capacity from the Zeeland plant is included in the BEI? In other words, please reconcile the 868 MW for Zeeland included at page 5 of EGAA and included in Figure 2 of the EGAA and the 535 MW included in the workpaper for Figure 1?

Response:

868 MW was included in Figure 2. The 535 MW is the amount of the combine cycle capacity that is comparable to the 519 MW baseload coal facility.

<u>Question:</u>

21. Please reconcile the 912 MW of new renewable resources included in Figure 1 with the 125 MW of new renewable resources included in Figure 2.

Response:

900 MW of the 912 MW is nameplate wind capacity. We used the long-term average net capacity factor forecast of 12.5% of nameplate capacity for coincident peak capacity. This factor was provided in Michigan's 21st Century Energy Plan.

Question:

22. Figure 2 – Peak Load and Capacity in the EGAA reflects a 12.69% planning reserve margin. (p. 7 of the EGAA).

The workpaper for Figure 2 (provided on June 15, 2009) includes the Total Requirements (including Reserves) in MW shown in the second column of the table below. Reducing these Total Requirements by 12.69% should produce the projected peak loads as shown in the third column of the table below.

Footnote No. 11 on page 7 of the EGAA says that "Details associated with the company's forecasts of electric deliveries, generation requirements, and peak demand can be found in the direct testimony of Lincoln D. Warriner contained in the Company's November 2008 electric rate case filing with the MPSC (Case No. U-15645)"

The peak load forecasts from Mr. Warriner's Exhibit A-79, LDW-4 are presented in the fourth column of the table below.

Question: Please reconcile the differences between the projected peak loads used for the EGAA with the peak loads projected by the Company in its November 2008 rate case filing.

	From Workpaper for Figure 2 in EGAA		From Mr. Warriner's Exhibit A-79, LDW-4
	Total Loads (including reserves)	Total Loads (excluding reserves)	
2008	9,642	8,556	
2009	9,398	8,340	8,578
2010	9,513	8,442	8,665
2011	9,700	8,608	8,738
2012	9,783	8,681	8,667
2013	9,819	8,713	8,561
2014	9,889	8,775	8,487
2015	10,014	8,886	8,482
2016	10,076	8,941	8,433
2017	10,099	8,962	8,393
2018	10,123	8,983	8,356

Response:

See Attachment 1.

Attachment 1 to 15996 - Tech Conf June 24 Question 22 & 23

Reconciliation of EGAA loads (MW) to November 2008 rate case filing

	U-15645, Exhibit A-79(LDW-4) System Peak		U-15645, Exhibit A-81(LDW-6) ROA at System Peak		Energy Optimization Included in Ex. A-79(LDW-4)		Load Control and Demand Response Included in Ex. A-79(LDW-4)		Total Load (excluding reserves)
2009	8,578	-	256	+	18	+	0	=	8,340
2010	8,665	-	268	+	45	+	0	=	8,442
2011	8,738	-	263	+	87	+	46	=	8,608
2012	8,667	-	263	+	144	+	133	=	8,681
2013	8,561	-	267	+	202	+	217	=	8,713
2014	8,487	-	271	+	259	+	300	=	8,775
2015	8,482	-	271	+	296	+	379	=	8,886
2016	8,433	-	271	+	323	+	456	=	8,941
2017	8,393	-	271	+	350	+	489	=	8,961
2018	8,356	-	271	+	378	+	520	=	8,983

Reconciliation of EGAA requirements (GWH) to November 2008 rate case filing

	U-15645, Exhibit A-79(LDW-4) Generation Requirements		U-15645, Exhibit A-81(LDW-6) ROA Generation Requirements		Energy Optimization Included in Ex. A-79(LDW-4)		Load Control and Demand Response Included in Ex. A-79(LDW-4)		Generation Requirements
2009	39,389	-	1,864	+	122	+	0	=	37,647
2010	39,974	-	1,955	+	316	+	0	=	38,335
2011	40,637	-	1,955	+	611	+	0	=	39,294
2012	41,020	-	1,955	+	1,012	+	0	=	40,077
2013	40,976	-	1,955	+	1,416	+	0	=	40,437
2014	41,066	-	1,956	+	1,820	+	0	=	40,931
2015	41,502	-	1,954	+	2,224	+	0	=	41,773
2016	41,743	-	1,954	+	2,429	+	0	=	42,218
2017	41,699	-	1,954	+	2,635	+	0	=	42,381
2018	41,652	-	1,954	+	2,840	+	1	=	42,539

Question:

23. Please reconcile the total requirements (in GWh) between those shown in the workpaper for Figure 4 in the EGAA and the total generation requirements presented in Mr. Warriner's Exhibit A-79 (LDW-4) in Case No. U-15645, as presented in the following table:

	From Workpaper for Figure 4	From Exhibit A-79 in Case U-15645
2008		
2009	37,647	39,389
2010	38,335	39,974
2011	39,294	40,637
2012	40,077	41,020
2013	40,438	40,976
2014	40,932	41,066
2015	41,776	41,502
2016	42,218	41,743
2017	42,385	41,699
2018	42,545	41,652

Response:

See Attachment 1.

Attachment 1 to 15996 - Tech Conf June 24 Question 22 & 23

Reconciliation of EGAA loads (MW) to November 2008 rate case filing

	U-15645, Exhibit A-79(LDW-4) System Peak		U-15645, Exhibit A-81(LDW-6) ROA at System Peak		Energy Optimization Included in Ex. A-79(LDW-4)		Load Control and Demand Response Included in Ex. A-79(LDW-4)		Total Load (excluding reserves)
2009	8,578	-	256	+	18	+	0	=	8,340
2010	8,665	-	268	+	45	+	0	=	8,442
2011	8,738	-	263	+	87	+	46	=	8,608
2012	8,667	-	263	+	144	+	133	=	8,681
2013	8,561	-	267	+	202	+	217	=	8,713
2014	8,487	-	271	+	259	+	300	=	8,775
2015	8,482	-	271	+	296	+	379	=	8,886
2016	8,433	-	271	+	323	+	456	=	8,941
2017	8,393	-	271	+	350	+	489	=	8,961
2018	8,356	-	271	+	378	+	520	=	8,983

Reconciliation of EGAA requirements (GWH) to November 2008 rate case filing

	U-15645, Exhibit A-79(LDW-4) Generation Requirements		U-15645, Exhibit A-81(LDW-6) ROA Generation Requirements		Energy Optimization Included in Ex. A-79(LDW-4)		Load Control and Demand Response Included in Ex. A-79(LDW-4)		Generation Requirements
2009	39,389	-	1,864	+	122	+	0	=	37,647
2010	39,974	-	1,955	+	316	+	0	=	38,335
2011	40,637	-	1,955	+	611	+	0	=	39,294
2012	41,020	-	1,955	+	1,012	+	0	=	40,077
2013	40,976	-	1,955	+	1,416	+	0	=	40,437
2014	41,066	-	1,956	+	1,820	+	0	=	40,931
2015	41,502	-	1,954	+	2,224	+	0	=	41,773
2016	41,743	-	1,954	+	2,429	+	0	=	42,218
2017	41,699	-	1,954	+	2,635	+	0	=	42,381
2018	41,652	-	1,954	+	2,840	+	1	=	42,539

<u>Question:</u>

24. What is the fixed charge rate components for off-shore wind?

Response:

Same as for on-shore wind - See Question #11- Attachment 4.

MPSC Case No. U-15996 - Consumers Energy Answers to MPSC Staff Questions from June 24th, 2009 Technical Conference

Question:

25. Can you provide a copy of the Brattle Group report that is reference on page 8 of the EGAA filing?

Response:

Please see attached report (Attachment 1) from the Consumers Energy's A/C Load Management and Demand Response Program Proposals –A Review Essay, Ahmad Faruqui and Ryan Hledik dated May 22, 2009

Consumers Energy's
A/C Load Management and Demand Response Program Proposals –A Review Essay

Ahmad Faruqui and Ryan Hledik
May 22, 2009

This essay presents a review of Consumers Energy's proposals for carrying out an A/C load management program and a demand response program involving a dynamic pricing pilot. Overall, the two proposals address a key need that has been identified in Michigan's 21st Century Energy Plan: how to meet the state's peak demands in a cost effective manner?[1]

A review of Consumers Energy's load duration curves reveals that about 10 percent of the peak demand is concentrated in the top 100 hours of the year, or about one percent of the year's duration. Historically, peaking generation units have been used to meet this peak demand. But, in the wake of rising capacity and energy costs, it may be better to lower peak demand through programs such as those identified by Consumers Energy than to continue meeting these demands with expensive and peaking generation units.

In our opinion, the two programs are well designed and should go a long way in identifying the feasibility of meeting the future energy needs of Consumers Energy's customers. As in any pilot, there are sometimes gaps between the ideal pilot design and what can be achieved in practice, given time, budget and technological constraints. This document is designed to benchmark elements of Consumers Energy's proposed pilots against that ideal, which is sometimes called the gold standard, as well as against the "basic requirements" necessary for a successful pilot. Additionally, we provide an evaluation of the assumptions that are behind Consumers Energy's projected impacts of the proposed programs.

[1] http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/

1. LOAD MANAGEMENT PROGRAM

The proposed load management program is a residential air conditioning cycling program, with a pilot scheduled for 2010 and plans for a full scale launch upon completion of the pilot. Our review of this program is provided in the following sections.

1.1 Assumed Peak Reduction

Ideally, the projected reduction in residential peak demand would account for both naturally occurring and program induced increases in air conditioner energy efficiency over time. It is generally expected that A/C units will become more efficient over time. This could be due to natural improvements in efficiency, improvements triggered by federal and state codes, and standards and utility energy efficiency programs. As a result, the size of the peak demand reduction that will be achieved through the A/C load cycling program could potentially decrease over time.

Accounting for this effect, however, can be a challenge as projections of such increases in efficiency are region specific, uncertain, and often not readily available. Since Consumers Energy is being conservative in its choice of assumptions related to central air conditioning (CAC), such as holding the CAC saturation constant over the forecast horizon, it is unlikely that it is overstating the potential program impacts. Consumers Energy has qualitatively recognized the potential impact of this effect in its analysis.

The Company's program impact for the first year is similar to existing estimates. Typically, we have seen residential A/C load management impacts estimates that range between 0.9 kW and 1.1 kW based on a 50% cycling strategy. The Consumers Energy assumption of 1.39 kW appears to lie outside this range. However, Consumers Energy has assumed a 66% cycling strategy and the impact is documented through an engineering study. Further, the Consumers Energy impact is grossed up for a nine percent line loss factor, which is reasonable and is not represented in the range of impacts from other studies. With these adjustments, the Consumers Energy impact is similar to the other estimates. Ultimately, the pilot itself will provide a definitive answer as to the per-customer reduction impact from the program.

1.2 Program Participation

Compared to existing large scale A/C direct load control programs, Consumers Energy's assumed participation rate is aggressive but reasonable. Consumers Energy has assumed that 30 percent of eligible customers – or roughly 16 percent of all customers – will participate in the A/C load control program. The 30 percent participation rate (of eligible customers) is toward the high end of the range of established programs at some of the largest utilities in the country, but is not outside this range. Table 1 summarizes these participation rates.

Attachment 1 to 15996 - Tech Conf June 24 Question 25

Table 1: Participation Rates in Residential A/C Load Control Progams (Existing and Projected)

Utility	Existing or Projected?	Number of Customers Enrolled	Total Number of Customers	Total Participation Rate	CAC Saturation	Participation Rate of CAC Customers	Approximate Financial Incentive ($/year)
Xcel (Northern States Power)	Existing	250,000	1,000,000	25%	-	-	$40
Baltimore Gas and Electric	Projected (2012)	428,274	1,302,735	33%	78%	42%	$50 to $100
Consumers Energy	***Projected (2020)***	***245,544***	***1,574,000***	***16%***	***52%***	***30%***	***$7 to $18***
Southern California Edison	Projected (2013)	472,500	4,500,000	11%	42%	25%	$25 to $200
Pepco	Projected (2014)	128,500	748,095	17%	75%	23%	-
Florida Power and Light	Existing	650,000	4,200,000	15%	93%	17%	$40 to $60
Detroit Edison	Existing	280,000	2,200,000	13%	76%	17%	$17 to $37
Delmarva Power and Light	Projected (2014)	40,250	472,422	9%	53%	16%	$20
Atlantic City Electric	Projected (2014)	32,900	539,651	6%	55%	11%	-

Notes:
All figures are approximations.
CAC saturation data was not available for Xcel.
Planned incentive payments were not available for Pepco and Atlantic City Electric
Range of incentive for Detroit Edison and Consumers Energy is based on customers with average monthly consumption of 750 and 1,000 kWh.
Range of incentive for other utilities is based on various levels of cycling and frequency of interruption.

1.3 Customer Incentive

There are alternative ways to provide the financial incentive to participate in the program. Consumers Energy has proposed to reduce the second tier rate by 1.1 cents/kWh for all participating customers. However, this distorts the price signal that the customers are receiving and does not reflect the true cost of providing that electricity to the customer. Inadvertently, the Company is providing customers who are in the second tier an incentive to increase electricity consumption during all hours of the day including the peak hours. It may want to consider alternative options. One alternative method could be to reduce the customer charge rather than provide a discount in the second tier rate. This would have the benefit of removing the link between the payment and the customer's consumption and would still avoid paying a rebate to the customer. A second, less desirable approach would be to spread the discount over both tiers of the rate, thus providing a participation incentive to all customers, not just those in the second tier. The ideal approach would be to simply give the customers a credit on their monthly bill, which is the common practice in the industry. Ultimately, this issue will not have any impact on the validity of the pilot results, but if implemented as currently proposed, could run counter to the conservation objectives of the company's energy efficiency programs.

The overall amount of the credit is in the range of other A/C load control programs. If the average customer with CAC consumes between 750 kWh and 1,000 kWh per month, then her bill savings will be between $1.70/month and $4.55/month on this program, or $7 to $18 per year.[2] That is near the low end of many programs around the country. See Table 1 for a sample of financial incentives being offered through direct load control programs at other utilities. Given that Consumers Energy's projected participation rate is near the high end of these programs but that the financial incentive is near the low end, it would be useful to explain how Consumers hopes to achieve a higher participation rate with a lower financial incentive.

[2] The discount would apply June through September.

1.4 Customer Acquisition

Marketing/advertising efforts could be informed by conjoint analysis, a survey, or focus groups. Furthermore, such research could be valuable in determining how to market the load management program. For example, the fact that there are some limited environmental benefits associated with load management may be helpful in recruiting certain customer segments. However, even more significant are the customers' opportunity to save money on their electricity bills and the improved reliability (reduced chance of an outage) that will result from participating in this program. Ultimately, focus groups, surveys, and interviews will be helpful in determining the issues that are of most importance to the potential participants. Even if such studies cannot be carried out, it would appear to be useful to highlight these attributes of the program and tap customers' desire to "do the right thing" by improving system reliability.

1.5 Business Case Benefits

Avoided energy costs have been excluded from the benefits. While A/C load management programs only result in a small decrease in total consumption, it may be desirable to include avoided energy (fuel and variable O&M) costs as an additional benefit. However, these benefits are often very small and somewhat uncertain so by excluding them Consumers Energy is being conservative.

The avoided generating capacity costs should be derated to reflect wholesale energy market revenues that would have been realized by the avoided unit, if this is not being done already. In addition, it should be derated to account for (a) the uncertainty in the program's ability to coincide with peak demand and (b) to account for the limited number of times that the program can be called. At Southern California Edison, the full cost of a peaker is generally derated by 30 percent to account for the (a) and (b) factors. However, across the California investor-owned utilities there is no consensus regarding the appropriate de-rating method.

2. DYNAMIC PRICING PILOT

In addition to the load management program, Consumers Energy has also proposed a "Demand Response Program," or dynamic pricing pilot. The proposed pilot would test the impacts of different rate designs and technologies on customer consumption patterns. It will involve roughly 1,400 customers and be conducted during the summer of 2010. We provide our review of this program in the sections that follow.

2.1 Pilot Design

The pilot makes good use of multiple control groups to improve statistical validity of the results and account for the Hawthorne Effect. As far as we know, no other dynamic pricing pilot has explicitly included multiple control groups and Consumers Energy's efforts in this regarded should be lauded.

Gathering pre-treatment data is an important component of good pilot design. Pre-treatment data is valuable for measuring any pre-existing differences between the control and treatment groups before the pilot is conducted and for measuring any self-selection bias in the group of participants. Consumers Energy has indicated that pre-treatment data will be collected for the pilot participants during the summer of 2009. This data will be important in defending the validity of the results. To the extent that it is not possible to collect pre-treatment data during the summer of 2009, there are other options that will accomplish the same goal to a lesser extent:

1. Data could be collected during the winter months of 2009/2010. This would still provide some insight into self-selection bias but the information would be less valuable because Consumers Energy's winter rates are flat while summer rates are tiered. Further, most customers have significantly different consumption patters in the winter than in the summer.

2. Data could be collected for a subset of the summer months of 2009. While this would not cover the entire time period for which the pilot would be conducted the following summer, it would avoid some of the issues described above with winter data collection. Ultimately, Consumers Energy should try to collect at least two months of data.

3. Data could be collected for the entire summer of 2009 for a subset of the customers. If only a subset of the pilot participants is equipped with AMI by the beginning of 2009, pre-treatment data could be collected for that subset. While this would not provide data for every customer, if the subset represents a significant portion of the population of participants then it could still provide valuable insights.

There would be benefits to testing two price points within any given rate design. For econometric purposes, multiple rate configurations could be chosen within each rate design. This will allow the estimation of customer demand curves and price elasticities. Ideally, there should be a "high" and a "low" scenario for each rate design. The "high" rate will have a higher on-peak price and, as a result of the revenue neutrality constraint, a lower off-peak price. The "low" rate will have a lower on-peak price and higher off-peak price.

The purpose of these "high" and "low" rate scenarios is to produce sufficient variation in data for econometric analysis. With an estimation of customer response at more than one price level, it is possible to estimate the curvature of the customer's price elasticity, rather than simply assuming that customer response increases linearly with an increase in price at all price levels. In fact, the most thorough pricing experiments have suggested that peak reductions increases as the peak rate increases, but the reductions grow at a rate that gets incrementally smaller (i.e., there are diminishing returns to higher prices). This is illustrated in Figure 1 using simulations from the PRISM (Pricing Impact Simulation Model). PRISM was initially estimated using data from California's Statewide Pricing Pilot but in a project that we are currently performing for the Federal Energy Regulatory Commission, has been modified to include data from a number of other pricing pilots.

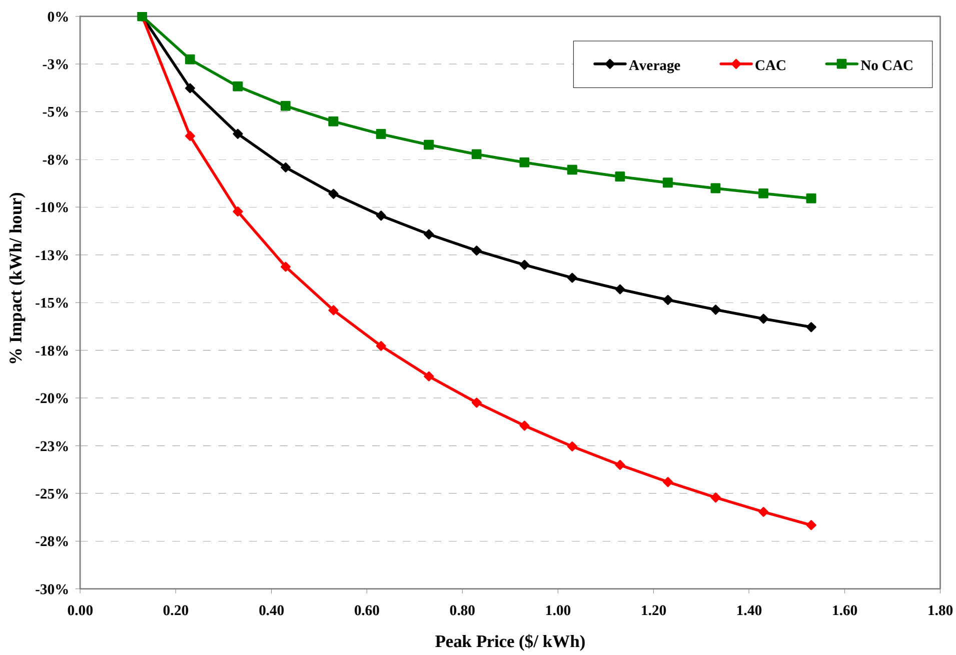

Figure 1: Illustrative Customer Response Curves to Critical Peak Prices

The number of customers in each treatment group can be reduced to accommodate multiple rate configurations without increasing the total number of participants. Our experience has suggested that a cell size of around 100 customers is sufficient to produce statistically valid pilot results.[3] Thus, it would be possible to maintain the aggregate sample size but subdivide each treatment group into two sub-treatment groups, one for each price level.

[3] See, for example, the summary of other recent experimental designs in Appendix A.

2.2 Customer Recruitment

Recruiting customers to participate in the pilot without informing them as to which rate they will be on could pose a challenge. This approach, while having considerable scientific appeal and a long and successful history in clinical testing of new drugs, is untested in the field of dynamic pricing pilots. Typically, customers are randomly selected, offered a given dynamic pricing rate and given the option of saying yes or no. With a full-scale opt-in offering of dynamic pricing, customers who voluntarily sign up on the rate would do so knowing what the rate looks like. In this sense, the pilot's customer recruitment process is inconsistent with what will happen on a large scale. Consumers Energy's proposed approach is actually more consistent with a full scale opt-out rate offering, in which customers would be placed on a rate without proactively choosing to enroll. Consumers Energy should consider providing the details of the rate to customers before they are signed up for the pilot.

2.3 Rate Design

Consumers Energy should consider testing a PTR that is simply layered on the existing rate. The PTR that has been proposed for the pilot is layered on a TOU rate. Such a rate design has not been tested in other pilots and is worth consider as an alternative means of eliciting demand response. However, in addition Consumers Energy should also consider testing a PTR that is simply layered on today's inclining block rate. In practice, that offers two benefits: (1) It is a simpler rate for customers to understand, and (2) it could seamlessly be offered as the default rate, as it would not require a change to the existing rate structure other than providing customers with the opportunity to save money by reducing demand. From the customer's perspective, in a worst case scenario she pays the same price for electricity that she would pay under the existing rate.

Of course, the PTR/TOU combination has the benefit of encouraging customers to reduce peak demand during non-critical event days through the TOU rate. It also does a better job of conveying the true cost of providing power during peak periods, and reduces the subsidization of customers with peakier-than-average load shapes by customers with flatter-than-average load shapes. Testing both variations of the PTR side-by-side would provide an interesting comparison for the pilot to explore.

Ideally, the critical peak pricing rate would be based on avoided costs. In our judgment, the number being proposed by Consumers, 50 cents/kWh, is low relative to the value that has been used in several other experimental pilots. Consumers Energy has provided an estimate of avoided peak costs that amounts to $102.85/kW-year. Dividing this by 32 critical peak hours leads to an hourly avoided cost of $3.21/kWh. This, plus the existing rate of roughly 9 cents/kWh would produce a cost-based critical peak rate of $3.30/kWh.

Of course, we are not recommending that a rate of this magnitude be offered. Generally, customers have been found to have a psychological aversion to critical peak rates that are higher than $2.00/kWh. This is likely to be particularly true in the current economic climate, in which customers around the country have shown a greater sensitivity to the cost of electricity and are scaling back consumption even in the absence of a price increase. Generally, the critical peak pricing rate is capped at an amount below $2.00/kWh. See Figure 2 for examples of critical peak pricing rates that have recently been tested or proposed in other dynamic pricing pilots.

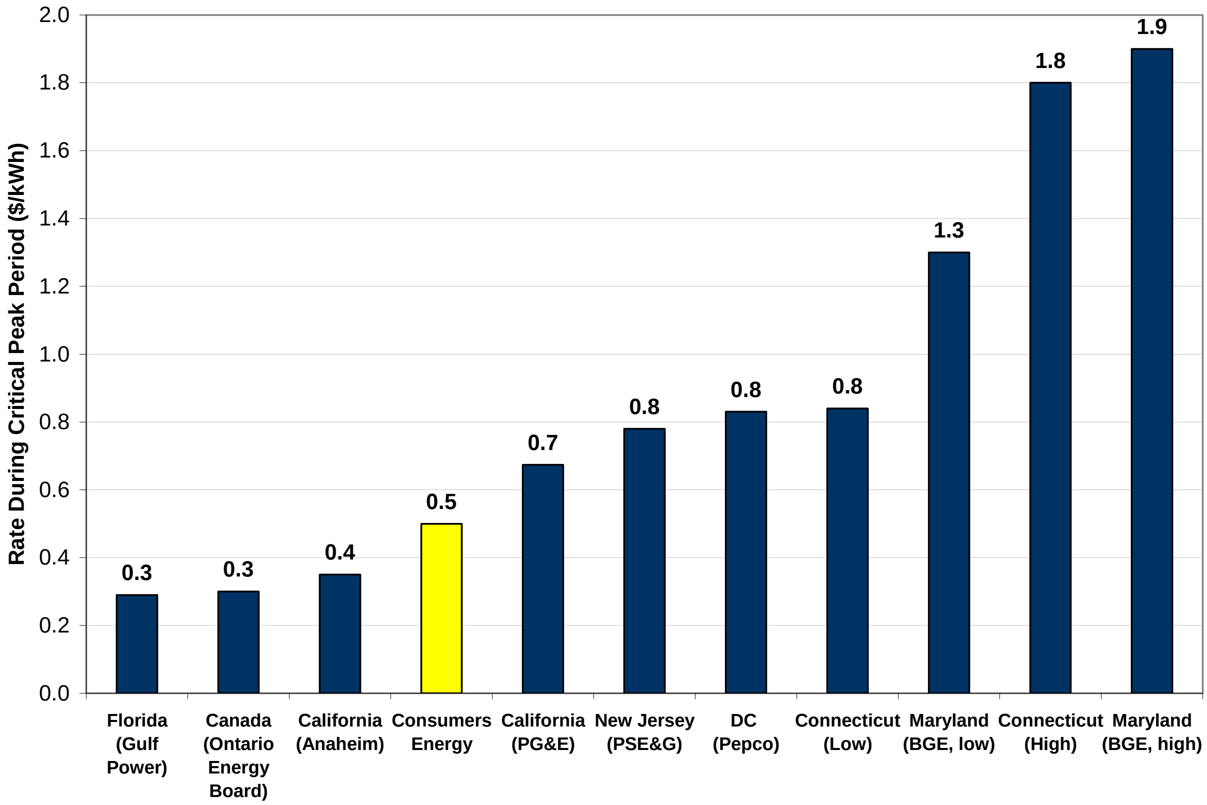

Figure 2: Comparison of Critical Peak Rates[4]

Consumers Energy should consider developing a second rate that is higher during critical peak times than the currently proposed rate, along the lines of the "high" and "low" scenarios discussed above. For example, CPP rates of $0.50/kWh and $1.00/kWh could be offered. Since these would be revenue neutral rates, customers paying the higher CPP rates would be offered lower rates during the non-critical hours. We recommend that Consumers Energy conduct focus groups to gauge customer reactions to these new rates. Other utilities have calculated a cost-based rate and then scaled it back to a level that they determined to be within their customers' tolerance threshold. It is important to convey to customers that they actually stand to save larger amounts with higher (rather than lower) critical peak pricing rates.

2.4 Participation Projection

The assumed price elasticity is based on data from a utility with a significantly different CAC saturation rate, and this could skew the projected impacts. The average price elasticity across a

[4] This figure illustrates rates that exist today, or have been tested pilots, or have been proposed in AMI business cases. Rate designs include CPP and PTR. For a discussion of the demand response impacts associated with these pilots, consult: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132.

population of customers will be influenced heavily by the CAC saturation for those customers. A major finding of the California Statewide Pricing Pilot was that customers with CAC are much more responsive to dynamic rates than customers without it. Consumers Energy has used ComEd's residential price elasticity of -0.047 in its analysis. However, ComEd's CAC saturation is 64 percent, while the CAC saturation of the participants in the Consumers Energy pilot is expected to be closer to 42 percent.[5] As a result, one might expect the average Consumers Energy customer to have a lower price elasticity and to display somewhat lower impacts. Using the relationship derived from the California Statewide Pricing Pilot to make this adjustment to the ComEd elasticity, we would expect the elasticity of participants in the Consumers Energy pilot to be closer to -0.035.[6] Of course, this is an approximate estimate with a significant amount of uncertainty. One of the main objectives of the proposed pricing pilot is to address issues such as these and reduce this uncertainty.

The assumed participation rate of 25 percent (of eligible customers) for an opt-in dynamic rate is aggressive. Even when taken as a percentage of the entire population of residential customers, the final opt-in participation rate is roughly 22 percent.[7] While there is little empirical evidence on the opt-in participation rate for a well-designed mass market dynamic pricing offering, the Company's assumption is toward the high end of the best available data.

2.5 Customer Acquisition

The same comments apply as identified in Load Management section of this memo.

[5] CAC saturation for the residential class has been estimated by Consumers Energy to be 52 percent. However, after removing from this population the customers who are assumed to be participating in the load management program, the CAC saturation of the remaining customers is closer to 42%. It is assumed that customers participating in the load management program would not also be enrolled in the dynamic rate to avoid double-counting of benefits.

[6] It is possible that the long-run price elasticity would be significantly higher. See for example, a recent RAND study on short- and long-run residential electricity price elasticities: Mark A. Bernstein and James Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," prepared for the National Renewable Energy Laboratory, The RAND Corp., Santa Monica, California, 2005.

[7] 212,000 kW reduction / 0.6 kW reduction per customer = 353,333 participating customers. 353,333 participants / 1,574,000 total customers = 22 percent.

References

Baltimore Gas and Electric, "Advanced Metering Infrastructure/Critical Peak Pricing Program: Supplement 392 to P.S.C. Md. E-6," filed June 25, 2007 with the Maryland Public Service Commission.

Bernstein. Mark A. and James Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," prepared for the National Renewable Energy Laboratory, The RAND Corp., Santa Monica, California, 2005.

CRA International, "Impact Evaluation of the California Statewide Pricing Pilot," March 2005.

Faruqui, Ahmad and Lisa Wood, "Quantifying the Benefits of Dynamic Pricing in the Mass Market," prepared for Edison Electric Institute, January 2008.

Pepco, "Business Case in Support of Blueprint for the Future Application," filed October 1, 2007 with the Public Service Commission of the District of Columbia.

PSE&G and Summit Blue Consulting, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments," 2007.

Attachment 1 to 15996 - Tech Conf June 24 Question 25

Appendix A: Experimental Designs from Recent Pricing Pilots

Table 2: Baltimore Gas and Electric (BGE) SEP Experimental Design

		Enabling Technology		No Enabling Technology	Control	TOTAL
		Orb Only	**Orb + A/C Switch**			
DPP	Normal Rate	-	111	148	-	259
PTR	Low Rate	141	113	126	-	380
	High Rate	137	118	127	-	382
TOTAL		278	342	401	354	1375

Table 3: California SPP Experimental Design (Ex-ante)

				Track A: Random Sampling With Opt Out Design			
Residential	**Control**	**CPP-F**	**CPP-F (info)**	**CPP-V (SDG&E)**	**Info Only**	**TOU**	**Total**
Zone 1	63	52	0	0	0	50	165
Zone 2	100	188	0	0	0	50	338
Zone 3	207	188	0	125	126	50	696
Zone 4	100	114	0	0	0	50	264
Total	**470**	**542**	**0**	**125**	**126**	**200**	**1,463**
Commercial			**CPP-V (SCE)**			**TOU (SCE)**	
SCE							
<20 kW	88	0	0	58	0	50	196
>20 kW	88	0	0	80	0	50	218
Total	**176**	**0**	**0**	**138**	**0**	**100**	**414**
All Sectors							
Total	**646**	**542**	**0**	**263**	**126**	**300**	**1,877**
				Track B: SF Cooperative			
Residential	**Control**	**CPP-F**	**CPP-F (Info)**	**CPP-V**	**Info Only**	**TOU**	**Total**
PG&E	63	64	126	0	0	0	253
Total	**63**	**64**	**126**	**0**	**0**	**0**	**253**
				Track C: AB 970 Sub-Sample			
Residential	**Control**	**CPP-F**	**CPP-F (info)**	**CPP-V (SDG&E)**	**Info Only**	**TOU**	**Total**
SDG&E	20	0	0	125	0	0	145
Total	**20**	**0**	**0**	**125**	**0**	**0**	**145**
Commercial		**CPP-F**	**CPP-F (Info)**	**CPP-V (SCE)**	**Info Only**	**TOU**	**Total**
SCE							
<20 kW	42	0	0	56	0	0	98
>20 kW	42	0	0	76	0	0	118
Total	**84**	**0**	**0**	**132**	**0**	**0**	**216**
All Sectors							
Total	**104**	**0**	**0**	**257**	**0**	**0**	**361**
				Summary			
	Control	**CPP-F**	**CPP-F (Info)**	**CPP-V**	**Info Only**	**TOU**	**Total**
Total Sample Size	**813**	**606**	**126**	**520**	**126**	**300**	**2,491**

Attachment 1 to 15996 - Tech Conf June 24 Question 25

Table 4: California SPP Experimental Design (Ex-post)

Number of Residential Customers in the Experiment and Estimating Sample									
Customer Segment	**Climate Zone**	**Track**	**Tariff**	**Load Data**			**Load & A/C Ownership Data**		
				Summer 2003	**Winter**	**Summer 2004**	**Summer 2003**	**Winter**	**Summer 2004**
R	1	A	Standard	68	62	64	51	47	48
R	2	A	Standard	106	107	108	90	92	90
R	3	A	Standard	105	108	108	89	88	81
R	4	A	Standard	106	109	105	87	83	81
R	1	A	CPP-F	59	59	61	54	54	56
R	2	A	CPP-F	212	214	217	205	206	202
R	3	A	CPP-F	214	215	219	200	201	203
R	4	A	CPP-F	129	128	136	121	120	124
R	2	A	CPP-V			58			53
R	3	A	CPP-V			41			40
R	2	A	Info Only (Standard)	70	64	68	65	60	64
R	3	A	Info Only (Standard)	68	68	69	63	62	63
R	1	A	TOU	57	57	58	55	55	56
R	2	A	TOU	56	56	57	54	54	55
R	3	A	TOU	58	57	63	54	53	58
R	4	A	TOU	55	55	56	53	53	53
R	2	A	Standard			26			21
R	3	A	Standard			17			16
R	1	B	Info Only (Standard)	71	53	52	48	34	33
R	1	B	CPP-F	135	133	133	104	102	102
R	1	B	CPP-F	78	78	78	71	71	71
R	2&3	C	Standard	20	21	20	18	19	19
R	2&3	C	CPP-V	131	142	135	121	127	124
R	2&3	C	Standard	94	97	87	80	80	77

MPSC Case No. U-15996 - Consumers Energy Answers to MPSC Staff Questions from June 24th, 2009 Technical Conference

Question:

26. Can you provide a copy of the C&B report that is reference in MPSC Case. No. U-15889 January 8, 2009 letter to the MPSC?

Response:

Please see attached (Attachment 1) HDR / C&B letter to Paul Proudfoot dated January 15, 2009 report regarding a Generic Coal-fired Power Plant 830 MW net Project Definition Document.

January 15, 2009

Michigan Public Service Commission
Attn: Paul Proudfoot, Director, Electric Reliability Division
6545 Mercantile Way
Lansing, MI 48909

Re: MPSC Case No. U-15800

Mr. Proudfoot:

Enclosed is the Generic Coal-fired Power Plant 830 MW net Project Definition Document in support of subject MPSC Case No. U-15800 per the direction HDR|Cummins & Barnard (HDR|CB) has received from Consumers Energy (CEC) and Detroit Edison (DTE). This document has been prepared to support development of the capital cost estimate and project definition document for a greenfield, generic, coal-fired 830 MW net, electric generating unit, with a commercial operating date of January 1, 2016.

Two cost estimates are presented both in January 2016 nominal dollars. One is for the total constructed cost by the Engineer, procurement and Construction Contractor (EpCM) and the second is for the total installation cost including Owner's costs and electrical interconnection costs, but not including allowance for funds used during construction (AFUDC). AFUDC is provided by CEC.

The attachments to the document include the Assumption Sheet of cost and operating parameters, and a cash flow percentage sheet for calculation of AFUDC.

If you have any questions, please call me at 734-332-6461.

Sincerely,

Steven P. Yambor

Steven P. Yambor, P.E.
Senior Project Manager - Major Projects

Enclosures (3)

cc: Kristin van Reesema – CEC
Irene M. Dimitry - DTE

GENERIC COAL-FIRED POWER PLANT
830 MW NET – MICHIGAN

Project Definition Document

1.0 INTRODUCTION

This document presents the project definition and engineering design basis for a generic, nominal 830 MW (net), coal-fired power plant to be located in Michigan on an undetermined greenfield site. This document forms the basis for the Generic Coal-fired Power Plant Cost Estimate-830 MW net.

The capital cost estimate for the project is $2.678 billion on an Engineer, procure, and Construction Management (EpCM) basis with a project delivery commercial operating date (COD) of January 1, 2016. The total capital EpCM cost includes escalation and contingency assumptions as defined in Section 4.0. The total installed cost including Owner's costs and interconnection costs totals $2.979 billion. The Capital Cost Estimate includes cash flows and is used to support escalation and allowance for funds used during construction (AFUDC) calculations. Attached are two tables, one showing the Generic Coal Plant Assumptions and a second Cost Percentage Table that shows project cash flows as a percentage that supports CEC provided AFUDC calculations.

HDR|CB has been involved with numerous assignments involving both new and retrofit projects for major coal plants throughout the United States. This experience encompasses Owner's Engineer services as well as detailed design assignments. Section 7.0 of this document contains a more detailed overview of HDR|CB's experience. Experience drawn from these recent and ongoing assignments, as well as HDR|CB's extensive staff experience, provides the basis for the project definition and resulting cost estimate.

2.0 PROJECT DESCRIPTION

We have assumed that the site will encompass approximately 1,200 continuous acres and will house the power block and solid waste disposal facilities for fly ash, bottom ash and gypsum, as well as an acreage allowance for fuel handling double loop rail tracks and future provisions for carbon dioxide capture. The power plant site is to be located in Michigan within 20 miles of a high voltage 345 kV to 765 kV power line and accessible by a new main line rail track. The plant will be a grass roots, greenfield plant. The site would allow for a future second unit, resulting in a 1600 MW (net) total site development.

The design and permitting of the plant are based on installation of a 830 MW net plant featuring an advanced supercritical pulverized coal (ASCPC) fired steam generator operating at supercritical pressures and advanced temperatures to support steam turbine maximum throttle conditions of 3800 psig at 1100°F (main steam) - 1100°F (reheat) and designed to start up and operate in a sliding pressure mode. The unit is to have a nominal 40 percent steam turbine bypass system.

The steam generator will be designed and permitted to fire Powder River Basin (PRB) coal. Pulverizers will support full load operation with one spare pulverizer out of service while burning the lowest BTU fuel. The combustion air and flue gas system will feature two axial flow forced draft (FD) fans, four axial flow induced draft (ID) fans, two centrifugal primary air (PA) fans, and two tri-sector air heaters with separate gas flow paths through two pulse jet baghouses to a single wet flue gas desulfurization (WFGD) system. The air quality control system components feature low NO_x burners, selective catalytic reduction (SCR) system, two pulse jet baghouse units, a single WFGD system and a 600-foot reinforced concrete stack with fiberglass liner. Activated carbon and hydrated lime will be injected before the fabric filter for control of mercury and acid mist, respectively.

The thermodynamic cycle will incorporate eight feedwater heaters including a heater above the reheat point (HARP) extraction. The steam turbine generator is a four flow, tandem compound unit with maximum 40-inch last stage blades (LSB), a single flow high pressure (HP) turbine and double flow intermediate pressure (IP) turbine with an electric generator rated for operation at approximately 1095 MVA with a 0.85 power factor.

Cycle equipment will feature two 50 percent capacity turbine driven boiler feedwater pumps (BFPs), two standby 25 percent motor driven start-up BFPs, three 50 percent condensate pumps, duplex low pressure feedwater heaters 1 & 2, single low pressure feedwater heaters 3 and 4, a deaerator, and two 60 percent high pressure feedwater streams for high pressure heaters 6, 7 and 8 (HARP) for a final feedwater temperature of 552°F. The design is based on closed cooling using a mechanical draft cooling tower.

Cycle makeup, cooling tower makeup and plant service water requirements will be obtained from water wells or a municipal source.

Coal will be supplied by rail and shall require unloading, stacking out and reclaiming facilities. Pulverized limestone will be delivered by truck.

It is anticipated that the predicted net capability of the unit will exceed 830 MW and the ECAR or system rating of the unit will be 830 MW net. The permitted heat input is 8190 MMBTU/kWhr. The expected average full load, long term heat rate using 100 percent PRB fuel is 9134 BTU/kWhr (annual average temperature) and auxiliary power consumption of 59 MW is assumed. The unit will be designed to operate with the top heater out of service at turbine maximum continuous rating (TMCR) throttle flow.

The coal handling system is designed for fugitive dust collection and includes an enclosed live storage coal barn. Coal trackage is arranged with a double loop track capable of receiving two to three trains per day. Coal is unloaded with a rotary car dumper. Dead storage emergency reclaim and stackout provisions are included using a radial stacker and two reclaim hoppers.

The site is designed for minimal liquid discharge and maximum reuse of wastewater and minimum use of well water with final disposal of the remaining wastewater assumed to discharge to an available municipal system.

Electrical facilities include 345 KVA single phase step-up transformers (plus one spare), two 100 percent nominal capacity auxiliary power transformers and generator breaker with dual feed 7 kV and 480 V electrical switchgear and motor control centers, respectively.

The plant control systems and equipment will provide centralized operation from distributive control system (DCS) operator stations located in the central control room (CCR).

Emissions will be controlled to comply with Federal Best Available Control Technology (BACT) requirements.

3.0 PROJECT SCOPE

The major process equipment and systems of the plant includes the following items, summarized below:

- Supercritical steam generator, PC-fired, balanced draft, with superheater, reheater, and economizer using low NO_x burners. The steam generator area will be enclosed.
- Steam turbine generator (STG), extraction, condensing, reheat type using eight stages of feedwater heating, including a deaerator. The steam turbine generator area will be enclosed.
- Heat exchangers with pumps to cool the auxiliary equipment using closed cooling water systems.
- Closed cooling circulating water systems consisting of condenser, circulating water pumps, and mechanical draft cooling tower for the turbine exhaust steam.
- Auxiliary boiler (with electric superheater) for steam seals, DA pegging, air preheating, and building heating.
- Coal conveying and associated mechanical equipment including rotary car dumper, double loop rail track for two trains before and after car dumper, 60,000-ton coal barn with stacker reclaimer, and radial stacker to 72,000-ton reserve stackout pile, and 1,000,000-ton reserve storage pile with two independent underground reclaimers, generally rated for 1300 ton/hour coal supply rate.
- Pneumatic fly ash handling system for each fabric filter with one fly ash storage silo to be removed by Owner’s truck to the onsite fly ash storage cells.
- Bottom ash drag chain conveyor, dumped into three-sided ground level bunker to be removed by Owner’s mobile equipment to an onsite ash storage area.
- Natural gas igniter system for start-up and flame stabilization.
- Cooling tower make-up water pretreatment system.
- Steam condensate cycle make-up water treatment system.
- Tie-in to site wells for all permanent plant potable water uses.
- Fire protection system with electric-motor-driven and diesel-engine-driven fire pumps.
- Soot blowing air compressors and a common compressed air system for instrument air and plant service air.

- Demineralized water storage tank and condensate storage tank.
- Condensate polishing system with external regeneration system.
- Water-steam-condensate quality monitoring system.
- Boiler feedwater chemical injection systems with chemical storage.
- Water treatment chemical storage and injection system.
- Wastewater treatment system, including sludge dewatering equipment.
- Wastewater collection sumps, treatment, and recycle system.
- Sanitary waste collection sewage system and sewage disposal system.
- Heating and ventilating system for the boiler, turbine and other miscellaneous enclosures.
- SCR systems.
- Wet scrubber (WFGD) system.
- Pulverized limestone delivery system for truck delivery capability.
- Gypsum removal conveyor system with truck removal capability.
- Pulse jet baghouses for flue gas particulate mercury and H_2SO_4 removal.
- Activated carbon and hydrated lime storage silos and injection systems (mercury and acid mist).
- Single flue stack with fiberglass flue.
- Distributed control system (DCS).
- Turbine room crane, nominal 100 tons with 30-ton small hook.
- Miscellaneous hoists and monorails.
- Heat tracing system for process requirements and freeze protection.
- Lighting, grounding and cathodic protection (if required) systems.
- Electric power distribution system.
- Radio based plant communications system.

The scope also includes an administrative building with mechanical and electrical shops and stores area. A warehouse and coal handling equipment maintenance facility are also provided onsite.

Owner-Supplied Equipment and Plant Services

The following items are in the Owner's scope of supply and Owner's cost as defined herein:

- Bottom ash and fly ash transport to disposal facilities
- Service gases (hydrogen, CO_2, oxygen, and nitrogen) stored in transportation containers
- Transmission lines
- Telephone communications and load dispatching facilities
- Mobile equipment for coal stacking and reclaim, ash removal, or other uses

- Rail cars
- Movable equipment and furniture for shops, offices, etc.
- All laboratory equipment (excludes cabinets, counter, and sink)
- Hazardous waste removal/remediation (other than that generated by the Contractor during the course of the project)
- Solids removal from water treatment and wastewater basins

4.0 MAJOR EQUIPMENT RATINGS, OPERATING MODE AND BASIC CONTROL PHILOSOPHY

The unit is expected to be operated in a base-load mode at the maximum output achievable with daily load cycling. The unit will be designed to operate continuously on coal from approximately 40 percent to full load.

To ensure adequate emission control is available, the air quality control system (AQCS) is designed to meet the emissions requirements at the BMCR conditions. The AQCS can maintain performance as long as it is operated and maintained in accordance with the manufacturer's recommendations.

All Balance of Plant (BOP) steam generator equipment is designed to support the BMCR conditions, and the equipment is margined from the BMCR heat balance.

5.0 SITE DESIGN CRITERIA ASSUMPTIONS

Temperatures

Basis for Plant Performance:

- Design Dry Bulb 46°F
- Design Mean Coincident Wet Bulb with Design Dry Bulb 40°F

Basis for Design of HVAC Equipment:

Summer conditions (design dry bulb and mean coincident wet bulb):

- Maximum dry bulb 100°F
- Mean coincident wet bulb at 21.4 percent RH 67°F

Winter Conditions:

- Normal winter dry bulb 15°F
- Extreme low dry bulb -33°F

Air Emission Limitations

The plant will be designed to meet the air emissions listed below when firing the range of coal as defined below:

Emission Limits by Pollutants

Pollutant	Emission Limit
SO_2	0.06 Lb/MMBtu
NO_x as NO_2	0.05 Lb/MMBtu
CO	0.12 Lb/MMBtu
VOC	0.0035 Lb/MMBtu
PM_{10}	0.011 Lb/MMBtu (Filterable only) 0.024 Lb/MMBtu (Filterable + Condensable)
H_2SO_4	0.004 Lb/MMBtu
Opacity	10%
Hg	64.4 lbs/yr

CO_2, though not a pollutant, will be emitted at an estimated rate of 206.30 Lb/MMBtu.

Geotechnical Data

Geotechnical information is currently not available. For this project, it was assumed that all deep excavation for the reclaim hoppers, rotary car dumper, and circulating water pipes and pump structure will be in soft earth or gravel.

Electrical Interconnection

The plant will be connected to the electric utility's system at an onsite 345/765 kV switchyard owned by MISO. The plant will have an interfacing switchyard ring buss configuration with two assumed outlets. During plant start-up and shut-down, the power required for the plant's electrical auxiliary systems will be backfed from the Utility's system through the main and auxiliary transformers.

Electrical Protection, Metering and Controls

Protective relays, meters and control instruments will be provided to properly interface, operate and monitor plant electrical equipment and systems. Protection and control interfaces with the Utility will meet the requirements identified by MISO.

Codes and Standards

The design will be in accordance with the applicable American codes and standards in effect on the effective date of the contract. Applicable codes, standards and regulations will be defined in the specification.

6.0 CAPITAL COST ESTIMATE

The format of the estimate is based on an Engineer, procure, and Construct Management (EpCM) approach with additional costs added for Owner's costs, electrical interconnection costs. Certain offsite costs are included in the EpCM cost estimate including extensive rail facilities ($127 million) and natural gas transportation ($40 million).

Major project milestone dates are as follows:

- Limited Notice to Proceed – May 1 2011
- Mobilize for Construction – August 15, 2011
- Commercial Operation – January 1, 2016

The costs presented in Section 1.0 are nominal dollars in January 2016.

Basis of Estimate

A cost estimate was developed that portrays as complete a picture of the total scope as possible with the information available. In developing the costs, bulk quantities were compared with known bulk quantities from other power plants of similar size and scope. This served as a check and helped to establish a baseline from which to factor quantities for this plant. Bulk commodities which were compared in this estimate included quantities for structural steel, piping, valves, hangers, concrete, power and control cable, and conduit.

Site development costs were based on past experience of other projects of similar size.

A cash flow table was developed based on past experience with other projects and with input from the schedule, which included milestone dates for notice to proceed, EpCM contract procurement, regulatory approvals, and commercial operation.

In addition to the scope assumptions discussed above, it is important to note that the final, agreed upon Terms and Conditions of the Contract will directly affect the cost of the project. These estimates are based on typical EpCM contract terms that would be expected for a project of this size and complexity. Although the estimate includes costs for items such as contractor contingency and profit margin based on past experience, it should be noted that market and competitive conditions at the time of contracting will determine the pricing for a specific project.

The estimate is based on the following major information sources:

- Conceptual site general arrangement
- Information from the HDR|CB power plant database for pulverized coal power plants including supporting typical heat balances, mass balances and drawings
- Wage rate information based on the Michigan Wage Determination

General Assumptions

The estimate was developed using the available project specific information noted above. The estimate was then checked on a "top-down" basis by factoring costs and quantities from detailed power plant information using a cost size scaling factor where applicable.

The following items define the general assumptions used to develop the estimate:

- All labor costs are based on working five, 10-hour days per week for a 50-hour workweek.
- Bulk material costs for items like concrete, reinforcing steel, structural steel, wire and cable, piping, etc. are based on current published information taken from industry sources like RS Means and current pricing from other projects where applicable.
- A labor productivity allowance has been conceptualized based on specific site related conditions and applied to the installation man-hours to allow for union shop, weather conditions, commuting times, and working five 10-hour days per week. The net effect balances out to a productivity factor of 1.10.
- Allowances are included for contractor overheads, indirect costs, statutory taxes and insurance, temporary site facilities, consumable materials, site laydown areas, and miscellaneous site services required during construction. (See Specific Assumptions – Indirect Costs section for further detail.)
- Major equipment pricing is based on factored costs from HDR|CB's power plant database for recent procurements with adjustments made for escalation and size.
- Quantities were developed various ways including factoring data from other power plants. In cases where a quantity was developed based on a general assumption, the calculation is included in the remarks column.
- The estimate includes costs associated with construction equipment, temporary facilities, field office staffing, project management, construction management, support craft and site services, testing and other construction related indirect costs. Much of this information was developed based on historical information and estimator judgment backed up by reviewing indirect costs from other power plant projects.

Specific Assumptions

<u>Direct Costs</u>

The following items define the major assumptions associated with specific items, systems or areas within the estimate at the direct cost level:

- Concrete foundations are calculated based on an assumed size and thickness, in some cases factored from other power plants. The costs include concrete, reinforcing steel, formwork, embedded metal, and finish work.
- Architectural features are based on similar-sized plant building estimates. Miscellaneous architectural features are estimated based on estimator experience and judgment. The building structural steel quantity is based on the building volume and recent bidding on similar projects.
- Major and auxiliary piping systems have been identified and quantities developed based on historical information from similar sized power plants. Critical systems, pipe quantities and unit costs are factored from other similar sized power plants.
- Piping systems estimates include an allowance for fittings. The estimate assumes that large bore piping will be shop fabricated and delivered to the site as spool pieces for field erection. Small bore piping will be field routed by the contractor.

- An allowance for cathodic protection is included for buried steel piping to protect against corrosion.
- The estimate includes allowances for the necessary pipe weld testing, stress relieving, hydrostatic testing, and steam blow.
- Quantities for valves, pipe hangers and supports and insulation are factored from other power plant total known quantities.
- The estimate includes an allowance for a pulverized limestone handling and storage system based on truck delivery to the site.
- The estimate includes gypsum handling and storage onsite.
- The air quality control system includes a selective catalytic reduction system with a liquid urea truck unloading facility, storage tanks and vaporizers, pulse jet fabric filters, and WFGD system along with associated ductwork, support steel, and ID fans.
- Storage silos and activated carbon injection equipment are included for mercury emissions.
- The fly ash system is based on pressurized systems to one onsite ash silo for onsite storage.
- A new bottom ash system is included based on constructing a bottom ash storage bunker.
- The estimate includes a coal handling barn and reclaiming system, with a rotary car dumper, thaw shed, train positioner, reclaim hoppers, conveyors, transfer towers, crushers, and coal storage barn with stacking and reclaiming equipment.
- The circulating water system is based on a closed loop system with intake and discharge piping fabricated from reinforced concrete pipe 96 inches in diameter. A mechanical draft cooling tower with 20 cells, basin and circulating water pump intake structure.
- Wastewater treatment system for maximum reuse of water and treatment of discharge for removal of contaminants including mercury.
- The estimate includes a demineralized water treatment system with dual trains. a deep bed condensate polishing system, cooling tower water treatment system, wastewater treatment system and a sanitary treatment system. The estimate also includes necessary piping and tanks for condensate, demineralized water, service water recycle basin and wastewater collection basin.
- A well water pretreatment system is included to reduce high levels of silica prior to pumping to the cooling tower make-up water system.
- Boiler and turbine generator equipment pricing and erection are based on costs factored from other power plants. Breeching and ductwork are based on estimated quantities and conceptual layouts from similar sized projects.
- The chimney cost is factored from another power plant project and is sized at 600 feet tall with a single fiberglass type flue liner.
- All balance of plant equipment including pumps, drives, compressors, heat exchangers and tanks are based on defined quantities and duty service and factored pricing from other power plants.

- Allowances are included for all necessary electrical and instrumentation and control equipment, cabling, grounding, terminations, raceway, devices, switches, breakers, motor control centers, bus duct, below ground duct banks, and transformers.

Indirect Costs

The following items define the major assumptions associated with specific items, systems, or areas within the estimate at the indirect cost level:

- EpCM construction indirect costs are included for construction field staff and expenses, construction equipment, small tools, consumable materials, field office expense, temporary facilities and utilities, site support craft and services, safety, permits, construction and performance testing, start-up supervision and pre-op start-up.
- EpCM project indirect costs are included for project management, construction management, procurement, home office overheads, design engineering, and start-up, and testing. All derivations to indirect costs were checked based on experience from other projects.
- Allowances have been included for escalation. Cash flows have been developed that allow for escalation calculation to January 1, 2016.
- The cost estimate includes contingency for the EpCM contract and EpCM contractor profit margin. Both are based on the total EpCM project cost including escalation of EpCM contractor costs where applicable.
- An estimate of typical Owner's costs is included. The estimate is based on input from other similar projects, except as noted below, and include:
  - Project management
  - Engineering support (Owner's Engineer)
  - Construction management
  - Owner's construction administrative and other costs
  - Plant operations
  - Construction utilities interconnection
  - Electricity usage, based on a 52-month construction schedule
  - Initial spare parts inventory
- No costs have been included for start-up fuel costs as it was assumed that the fuel cost will be offset by the sale of electricity generated during start-up.
- An allowance for escalation on Owner's costs is included.

7.0 HDR|CB EXPERIENCE SUMMARY

HDR|Cummins & Barnard (HDR|CB) has over seventy years of experience providing a full range of power generation engineering and consulting services. The firm offers a diverse array of services including traditional design and consulting, as well as troubleshooting, commissioning and Owner's Engineer, with a major focus on providing consulting and design services for power and electric generation and distribution. Highlights of HDR|CB's resume of strategic consulting and Owner's Engineer assignments for coal-fired facilities include:

- Current and recent involvement with Owner's Engineer assignments with EPC contract values from $100 million to $3 billion.
- Provided Owner's Engineer services for over 24,000 MW of generating facilities.
- Current Owner's Engineer services for Consumers Energy's Next Generation Program including 830 MW SCPC unit, E.ON's New Base Load Unit program (3x800 MW SCPC) and Trimble County Unit 2 (750 MW SCPC), and 650 MW SCPC Unit 2 for IPA Colletto Creek LLC.
- Recent solid fuel electric generation projects for coal-fired generating facilities including 500 MW development for Idaho Power, Twin Oaks Unit 3 (600 MW) and Idaho Valley Unit 1 (600 MW) for Sempra Generation, 600 MW Rockdale Power development for Constellation Energy, 900 MW project development for Intermountain Power Agency, and Elm Road (2x625 MW) SCPC unit additions for We Energies
- Current experience with major AQCS projects includes We Energies - Compliance Plan for all Coal-fired Facilities, FirstEnergy - 2400 MW AQCS retrofit; Consumers Energy's AQCS Compliance Program, We Energies - Pleasant Prairie Power AQCS Units 1-2, Valley Plant NOx reduction and Oak Creek Units 5-8 AQCS project, Constellation Energy's Brandon Shores Units 1-2, and Allegheny Power's Hatfield's Ferry and Fort Martin Power Stations FGD retrofits.
- Extensive resume of Owner's Engineer projects has fostered development of internal tools and procedures including up-to-date databases on equipment costs, allowing for peak productivity and efficiency. We have directly applicable cost estimating experience having recently completed detailed cost estimates for all major projects.

TABLE I - NEW CONVENTIONAL COAL PLANT ASSUMPTIONS

1	First Year Available (Jan 1)	-		2016
2	Winter Capacity	(MW)		830
3	Summer Capacity	(MW)		830
4	Summer Derate	(%)		0
5	Minimum Dispatch Capacity	(MW)		332
6				
7	Total EPC at COD	($/kW)		$3,227
8	Total Owners Cost at COD	($/kW)		$323
9	Total Interconnection Cost at COD	($/kW)		$39.4
10	Total AFUDC at COD	($/kW)		
11	Total Installed Cost at COD (7+8+9+10)	($/kW)		$3,589
12	Network Upgrade Cost	($/kW)		$29
13	Service Life	(Yrs)		
14	Fixed Charge Rate	(%)		
15	AFUDC Rate	(%)		
16	Discount Rate	(%)		
17	Capital Cost Escalation Rate	(%)		4.00
18	O&M Escalation Rate	(%)		
19				
20				
21	Fixed O&M (2007$)	($/kW-yr)		$33.41
22				
23	Variable O&M (2007$)	($/MWh)		$2.30
24	Annual EFOR	(%)		3.5%
25	Annual Maint. Rate	(%)		5.5%
26	Availability	(%)		91.0%
27				
28				
29	Max NDC Capacity	(MW)		830
30	75% Output	(MW)		623
31	50% Output	(MW)		415
32	25% Output	(MW)		208
33				
34	Full Load Heat Rate	(Btu/kWh)		9,134
35	75% Output	(Btu/kWh)		9,402
36	50% Output	(Btu/kWh)		9,868
37	25% Output	(Btu/kWh)		11,879
38				
39	SO2 Emission Rate	(lbs/MMBtu)		0.06
40	NOx Emission Rate	(lbs/MMBtu)		0.05
41	CO2 Emission Rate	(lbs/MMBtu)		206.30
42				
43	Start-up Cost	($/MW)		$497
44				
45	Fuel Type and Blends	-		100% Western
46	Cash flow / expenditure profile			% per year
47	Fuel Costs	$/ton		
49	Fuel Heat Content	(BTU/lb)		

	Provided by DTE/Consumers
	Provided by Independent Consultant

Table II - GENERIC COAL-FIRED POWER PLANT - 830 MW

Project Month		Key Milestone		Cumulative Percent
-5		LOI		0.0%
-4				0.0%
-3		LNTP		0.3%
-2				0.5%
-1				0.8%
0		NTP		1.6%
1				4.5%
2				6.7%
3				7.6%
4				8.8%
5				10.4%
6				11.8%
7				13.6%
8				15.4%
9				17.3%
10				18.7%
11				20.4%
12				22.4%
13				24.5%
14				26.7%
15				29.0%
16				31.6%
17				34.4%
18				36.8%
19				39.5%
20				41.7%
21				43.9%
22				46.4%
23				48.9%
24				51.4%
25				53.9%
26				56.4%
27				58.8%
28				60.4%
29				62.7%
30				65.3%
31				67.8%
32				70.2%
33				72.4%
34				74.5%
35				76.5%
36				78.3%
37				80.0%
38				81.6%
39				83.2%
40				84.4%
41		Gas Path		85.6%
42				86.7%
43		TG CMPLT		87.8%
44				88.8%
45				89.8%
46				90.6%
47		Turb Roll		91.6%
48				92.8%
49				94.1%
50				95.1%
51				96.4%
52		COD		98.0%
53				99.5%
54				99.9%
55				100.0%

KEY

LOI - Letter of Intent

LNTP - Limited Notice to Proceed

NTP - Notice to Proceed

TG CMPLT - Turbine Generator Complete

COD - Commercial Operation Date