Table 2 (Cont.)
Case 2 Description

Case 2		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500		500	500	500
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	500	500	500
Excess Capacity (MW)		0	95	60	20

Table 2 (Cont.)
Case 4 Description

Case 4		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4b Description

Case 4b		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 6 Description

Case 6		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 3
RealTime Modeling Results with Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generation Cost $	Total Expenses $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 368,912,026	-$244,181,124	$ 270,450,846	$ 415,261,748	6.4%	$ 26,084,747
	LS Power Unit 1 (Online 2001)	270	5,665,415	$ 172,351,827						
	LS Power Unit 2 (Online 2001)	270	3,215,447	$ 164,023,818						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	25	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,092,792						
	(Peaking Capacity)	25	10,849	$ 1,720,833						
	Unit-Contingent Purchase	55	12,626	$ 3,128,081						
	Sales		-4,636,473	-$244,181,124						
Case 2					$ 34,009,946	-$229,966,146	$ 585,146,241	$ 391,161,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 148,901,361						
	Utilicorp Unit 2 (Online 2001)	250	4,741,847	$ 124,812,148						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,999,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,644,199						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,183	$ 1,728,457						
	Unit-Contingent Purchase	55	12,721	$ 3,110,368						
	Sales		-8,354,721	-$229,966,146						
Case 3					$ 264,739,260	-$115,277,363	$ 292,881,747	$ 436,363,764	11.6%	$ 45,194,763
	CP&L	150	272,864	$ 35,010,850						
	Southern	100	2,344,776	$ 58,891,796						
	Aquila Option 3	100	128	$ 24,370,528						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	127	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,722,696	$ 87,764,815						
	(Peaking Capacity)	25	11,869	$ 1,738,086						
	Unit-Contingent Purchase	55	12,622	$ 3,122,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,887,863	-$115,277,363						
Case 4					$ 252,834,489	-$115,370,380	$ 292,791,358	$ 430,263,374	10.0%	$ 39,066,373
	CP&L	150	271,876	$ 33,819,200						
	Southern	100	2,805,807	$ 58,860,878						
	NP Energy	100	7,611	$ 14,826,889						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	166	$ 4,814,164						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,644,200						
	SPS Option A (Partial Requirement)	75/100	2,735,858	$ 87,822,864						
	(Peaking Capacity)	25	10,864	$ 1,726,183						
	Unit-Contingent Purchase	55	12,886	$ 3,123,740						
	Peaking Contract		0	$ 1,444,000						
	Sales		-4,689,357	-$115,370,380						
Case 4a					$ 207,834,375	-$76,733,810	$ 305,744,510	$ 436,644,085	11.6%	$ 45,381,084
	CP&L	150	286,523	$ 36,611,371						
	Southern	100	2,888,871	$ 60,366,896						
	NP Energy	100	18,366	$ 18,801,960						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,861,525						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Partial Requirement)	75	342,946	$ 16,860,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,766	$ 3,128,320						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,861,867	-$76,733,810						
Case 4b					$ 245,658,954	-$104,544,438	$ 299,063,964	$ 440,176,580	12.8%	$ 49,009,499
	CP&L	150	299,141	$ 35,880,521						
	Southern	100	2,095,140	$ 60,801,334						
	NP Energy	100	8,746	$ 19,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	25	$ 4,801,525						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NatAm	100	1,524,314	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,092,792						
	(Peaking Capacity)	25	10,849	$ 1,720,833						
	Unit-Contingent Purchase	55	12,626	$ 3,128,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,834	-$104,544,438						
Case 5					$ 327,585,083	-$79,905,446	$ 362,632,924	$ 450,522,569	15.2%	$ 59,335,564
	CP&L	150	284,307	$ 33,788,107						
	Aquila Option 3	100	109	$ 24,368,583						
	NP Energy	100	18,118	$ 18,864,609						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	186	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,866	$ 87,824,847						
	(Peaking Capacity)	25	10,904	$ 1,729,165						
	Unit-Contingent Purchase	55	12,886	$ 3,122,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,587,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,802,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,789,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,000	$ 16,873,962						
	Southern	100	2,835,887	$ 58,608,912						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	166	$ 4,819,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,859	$ 87,822,864						
	(Peaking Capacity)	25	10,904	$ 1,726,183						
	Unit-Contingent Purchase	55	12,886	$ 3,123,740						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,802,417						
Case 7					$ 297,872,015	-$140,445,134	$ 287,434,365	$ 444,863,186	13.7%	$ 53,396,183
	Southern	100	2,836,417	$ 58,954,686						
	Aquila Option 3	100	196	$ 24,377,367						
	NatAm	100	1,475,468	$ 71,147,064						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	20	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	3,138,170	$ 87,825,484						
	(Peaking Capacity)	25	10,873	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,120,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-5,553,100	-$140,445,134						

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/kW-mo. for all capacity delivered

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-607
SUPPLEMENTAL RESPONSE

DATE OF REQUEST: December 2, 2003

DATE RECEIVED: December 2, 2003

DATE DUE: December 22, 2003

REQUESTOR: Cary Featherstone

BRIEF DESCRIPTION: Support for the EWG Build Option

QUESTION:

With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.

RESPONSE:

1. Analyses relating to the need for additional power supply resources for Missouri Public Service was communicated to Staff and OPC through the following:
   Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
   Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998
2. Any notes taken at the referenced meeting are no longer available.
3. Any letters, e-mail, correspondence, and other communication are no longer available.

ATTACHMENT:
Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998

ANSWERED BY: Frank DeBacker

SIGNATURE OF RESPONDENT

Supplemental Response: See attached "Report on the Evaluation of Power Supply Proposals" dated 8/28/98. Missing page 2 was found and included in this complete copy of the report. Also included is the 2/1/99 update on "Report on the Evaluation of Power Supply Proposals".

Supplemental Attachments: Hard copy of "Report on the Evaluation of Power Supply Proposals" dated 8/21/98 and update to "Report on the Evaluation of Power Supply Proposals" dated 2/1/99.

Supplemental Response ANSWERED BY: Frank DeBacker

RECEIVED
DEC 30 2003
UTILITY SERVICES DIV.
PUBLIC SERVICE COMMISSION

Burns & McDonnell 100 1898-1998

February 1, 1999

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals. UtiliCorp United (UCU) provided the proposals and updated offers from Houston Industries (HI) and Merchant Energy Partners (MEP).

The objective of the evaluation was to verify that the information from the proposals had been accurately input into the model. The evaluation was also performed to determine the power supply option which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2005. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU.

Burns & McDonnell verified that the information provided by UCU had been correctly input into the model. Assumptions made in the evaluation of the offers were provided by UCU and included the natural gas price forecasts, spot energy market price forecasts, and energy sales price forecasts. Burns & McDonnell has reviewed these assumptions and determined that they are reasonable.

The results of the RealTime modeling are shown on the attached tables. Both proposals were modeled under a base, low, and high gas price forecast and a base, low, and high energy market price forecast. All cases were run with and without the sale of energy not required by UCU. The energy to be sold could be provided by any available resources in each case modeled.

As shown in the tables, the total expenses of the two proposals were very similar across all of the cases run. The NPV of total costs for the MEP option is slightly less than the HI option in all but one case. The HI proposal was less expensive in the case involving the base gas price forecast, low market energy prices, and no off-system sales.

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We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

Missouri Power Supply
Bid Comparison
6/1/2000 - 5/31/2005
$x1,000

	Annual Cost $x1,000					NPV
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-00
To>	May-01	May-02	May-03	May-04	May-05	May-05
Without Off System Sales						
Base Gas & Mkt						
Merchant Energy Partners	108,388	130,053	135,381	143,852	154,103	530,017
Houston Industries	108,388	129,074	136,181	145,432	156,081	532,248
Low Gas & Mkt						
Merchant Energy Partners	107,201	128,131	133,679	141,514	150,536	521,700
Houston Industries	107,201	127,071	133,707	142,439	152,179	522,611
High Gas & Mkt						
Merchant Energy Partners	109,286	131,741	136,817	145,969	157,239	537,054
Houston Industries	109,287	130,352	138,055	147,781	159,531	539,738
Base Gas & High Mkt						
Merchant Energy Partners	109,286	131,611	136,202	144,902	155,416	534,428
Houston Industries	109,287	130,372	137,863	147,227	158,542	538,522
Base Gas & Low Mkt						
Merchant Energy Partners	107,201	128,216	134,081	142,533	152,026	523,854
Houston Industries	107,201	127,093	133,884	142,788	152,650	523,348
With Off System Sales						
Base Gas & Mkt						
Merchant Energy Partners	104,398	124,280	125,783	135,176	145,695	501,582
Houston Industries	104,496	123,971	132,218	141,965	152,742	516,301
Low Gas & Mkt						
Merchant Energy Partners	104,900	124,198	127,032	135,426	144,548	502,371
Houston Industries	105,051	123,833	131,134	140,080	149,887	512,508
High Gas & Mkt						
Merchant Energy Partners	103,334	123,486	123,798	134,399	146,379	498,234
Houston Industries	103,366	122,870	132,193	143,092	155,022	516,671
Base Gas & High Mkt						
Merchant Energy Partners	103,334	123,245	122,774	132,659	143,683	494,100
Houston Industries	103,366	122,768	131,681	142,090	153,522	514,421
Base Gas & Low Mkt						
Merchant Energy Partners	104,900	124,319	127,710	136,885	146,458	505,385
Houston Industries	105,051	123,918	131,452	140,701	150,685	513,833

Merchant Energy Partners
Annual Ownership and Operating Cost
$x1,000

	Annual Fixed Cost				
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Aquila Capacity Payment	4,866				
MEP Capacity Payment		17,696	27,660	27,660	27,660
SEC Capacity Payment	7,566	6,693			
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		6,890	6,890	6,890	6,890
Total Fixed Costs	19,608	31,279	34,550	37,387	40,947

	Total Annual Supply Cost				
Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,779	98,774	100,831	106,565	113,157
Total Cost	108,388	130,053	135,381	143,952	154,103
MWh $ w/Low Gas & Mkt	87,592	96,852	99,129	104,127	109,589
Total Cost	107,201	128,131	133,679	141,514	150,536
MWh $ w/ High Gas & Mkt	89,678	100,462	102,267	108,582	116,293
Total Cost	109,286	131,741	136,817	145,969	157,239
MWh $ w/Base Gas & High Mkt	89,678	100,332	101,652	107,515	114,469
Total Cost	109,286	131,611	136,202	144,902	155,416
MWh $ w/Base Gas & Low Mkt	87,592	96,937	99,531	105,146	111,079
Total Cost	107,201	128,216	134,081	142,533	152,026
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,789	93,001	91,233	97,790	104,748
Total Cost	104,398	124,280	125,783	135,176	145,695
MWh $ w/Low Gas & Mkt	85,292	92,919	92,482	98,040	103,601
Total Cost	104,900	124,198	127,032	135,426	144,548
MWh $ w/ High Gas & Mkt	83,725	92,207	89,248	97,012	105,433
Total Cost	103,334	123,486	123,798	134,399	146,379
MWh $ w/Base Gas & High Mkt	83,725	91,966	88,224	95,272	102,736
Total Cost	103,334	123,245	122,774	132,659	143,683
MWh $ w/Base Gas & Low Mkt	85,292	93,040	93,160	99,498	105,511
Total Cost	104,900	124,319	127,710	136,885	146,458

Houston Industries
Annual Ownership and Operating Cost
$x1,000

Annual Fixed Cost

From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Houston Capacity Payment		23,576	23,576	23,576	23,576
Aquila Capacity Payment	4,866				
SEC Capacity Payment	7,566				
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		8,755	8,755	8,755	8,755
Total Fixed Costs	19,608	32,331	32,331	35,168	38,728

Total Annual Supply Cost

	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,780	96,743	103,850	110,264	117,353
Total Cost	108,388	129,074	136,181	145,432	156,081
MWh $ w/Low Gas & Mkt	87,592	94,740	101,375	107,271	113,451
Total Cost	107,201	127,071	133,707	142,439	152,179
MWh $ w/ High Gas & Mkt	89,678	98,021	105,724	112,613	120,803
Total Cost	109,287	130,352	138,055	147,781	159,531
MWh $ w/Base Gas & High Mkt	89,678	98,041	105,531	112,059	119,814
Total Cost	109,287	130,372	137,863	147,227	158,542
MWh $ w/Base Gas & Low Mkt	87,592	94,761	101,553	107,620	113,922
Total Cost	107,201	127,093	133,884	142,788	152,650
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,888	91,639	99,886	106,797	114,014
Total Cost	104,496	123,971	132,218	141,965	152,742
MWh $ w/Low Gas & Mkt	85,442	91,501	98,802	104,912	111,159
Total Cost	105,051	123,833	131,134	140,080	149,887
MWh $ w/ High Gas & Mkt	83,757	90,539	99,861	107,924	116,293
Total Cost	103,366	122,870	132,193	143,092	155,022
MWh $ w/Base Gas & High Mkt	83,757	90,437	99,349	106,922	114,794
Total Cost	103,366	122,768	131,681	142,090	153,522
MWh $ w/Base Gas & Low Mkt	85,442	91,587	99,120	105,533	111,957
Total Cost	105,051	123,918	131,452	140,701	150,685

August 21, 1998

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals made in response to the request for proposals (RFP) issued by Utilicorp United (UCU). The proposals were opened on July 6, 1998 with representatives of UCU and Burns & McDonnell in attendance. Proposals were received from the following companies in alphabetical order:

- Aquila Power Corporation (Aquila)
- Basin Electric Power Cooperative (Basin)
- Carolina Power & Light Company (CP&L)
- LS Power, LLC (LS Power)
- NorAm Energy Services (NorAm)
- NP Energy, Inc. (NP Energy)
- Southern Company Energy Marketing (Southern)
- Southwestern Public Service Company (SPS)

The objective of the evaluation was to determine the power supply option or combination of power supply options which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2004. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU. Assumptions made in the evaluation of the offers are listed in Table 1. This list of assumptions includes all information used in the modeling that was not specifically provided in the offers.

Combinations of the power supply options were made as necessary to minimize total expenses and meet the capacity requirements of UCU in the evaluation period. The timing and combinations of offers for the lowest cost cases are shown in Table 2 at the end of the report. Each case was run under two different scenarios. The first scenario allowed the energy not required by UCU to be sold. The sale price used in the model for

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this surplus energy was the spot market price of energy less $2.00/MWh. The spot market energy price forecast and the adjustment for the energy sales prices were provided by UCU. The energy to be sold could be provided by any available resources in each case modeled. The second scenario did not take into account the sale of surplus energy.

Table 3 shows the results of the RealTime modeling for the scenario with energy sales. The cases shown in the table represent the lowest cost cases developed by Burns & McDonnell. The lowest cost option includes a combination of purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the study period and the addition of 500 MW of combined cycle capacity by UCU on June 1, 2001. This combination of resources results in total expenses of $391,167,001, approximately $25 million less than the next least expensive case which includes the same purchases and combined cycle units offered by LS Power.

The relative cost rankings change considerably if sales are not taken into consideration as shown in Table 4. The lowest cost case without sales of excess energy includes purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the evaluation period and purchases from CP&L, Southern, NP Energy, and Aquila over the remaining three years. The case including the addition of combined cycle units by UCU has total expenses of approximately $7 million more than the least cost case over the evaluation period.

We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

Daniel A. Froelich

Daniel A. Froelich, P.E.
Vice President

James M. Flucke

James M. Flucke, P.E.
Project Manager

Table 1
Assumptions Made for RealTime Modeling

Evaluation period - June 1, 2000 to May 31, 2004.
Capacity and demand forecasts for 2001-2004 provided by Utilicorp.
Spot market energy price forecast provided by Utilicorp.
MPS internal wheeling charges are assumed to the same for both generation built internal to the MPS transmission system and power delivered from outside the MPS transmission system.
MPS natural gas price forecast provided by MPS equals Henry Hub Index price forecast minus $0.09/mmBtu plus $0.35/mmBtu in transmission charges.
At the direction of Utilicorp, peaking capacity assumed to be available for $4.00/kW-mo.
Sales of excess energy were made at the spot market energy price less $2.00/MWh.
Information on 55 MW unit-contingent purchase provided by Utilicorp.

Aquila
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

Basin Electric Power Cooperative

Carolina Power & Light
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed contract could start on June 1, 2001.

LS Power
The effect of the 10-year contract beyond the evaluation period has not been taken into consideration.
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed Availability Adjustment Factor equal to one for the second and third years of the contract.
Gross Domestic Price Deflator assumed to equal three percent.

NorAm
Transmission charge of $998/MW-mo. based on present Ameren transmission charges and $1.37/MWh provided by NorAm. .

NP Energy
Market based hourly energy price forecast provided by Utilicorp.
Transmission charge of $2,497/MW-mo. provided by Utilicorp.
Assumed losses of 4.2% for both capacity and energy price provided by Utilicorp.
Energy price equals market based price forecast plus $3.40/MWh in transmission charges plus 4.2% losses.

Southern Company
Cost of natural gas assumed to be equal to Henry Hub Index price forecast provided by Utilicorp.
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

SPS
Option A assumed to be available for a one-year term based on discussions with Utilicorp.
Assumed transmission charges equal to $4,033/MW-mo. provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.
Assumed losses of 8.05% for both capacity and energy provided by Utilicorp.

Utilicorp United
Fuel costs based on heat rate curves and natural gas price forecasts provided by Utilicorp.
Combined-cycle capacity addition of 500 MW on June 1, 2001.
Capacity charge of $5.50/kW-mo with no escalation assumed for CC units based on discussions with Utilicorp.
Operation & Maintenance cost forecast provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.

Table 2
Case 1 Description

Case 1		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
		Evaluation Period			
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540		540	540	540
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	540	540	540
Excess Capacity (MW)		0	135	100	60

Table 2 (Cont.)
Case 2 Description

Case 2		Evaluation Period			
		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500		500	500	500
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	500	500	500
Excess Capacity (MW)		0	95	60	20

Table 2 (Cont.)
Case 3 Description

Case 3		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
GP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4 Description

Case 4		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		***Capacity Utilized (MW)***			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4a Description

Case 4a		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4b Description

Case 4b		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 5 Description

Case 5		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100				
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 6 Description

Case 6		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
		Evaluation Period			
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 2 (Cont.)
Case 7 Description

Case 7		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
CP&L	150				
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 3
RealTime Modeling Results with Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generation Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,826	-$244,101,124	$ 270,450,846	$ 416,261,346	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,563,419	$ 172,351,827						
	LS Power Unit 2 (Online 2001)	270	5,218,847	$ 166,023,918						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,881,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,702						
	(Peaking Capacity)	25	10,848	$ 1,720,933						
	Unit-Contingent Purchase	55	12,626	$ 3,126,061						
	Sales		-4,838,472	-$244,101,124						
Case 2					$ 96,009,986	-$229,989,148	$ 365,146,241	$ 391,167,081	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 148,501,581						
	Utilicorp Unit 2 (Online 2001)	250	4,741,547	$ 134,812,146						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	6	$ 1,648,189						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,726,497						
	Unit-Contingent Purchase	55	12,220	$ 3,110,388						
	Sales		-4,294,721	-$229,989,148						
Case 3					$ 280,719,200	-$115,277,263	$ 272,981,747	$ 438,363,784	11.6%	$ 45,196,701
	CP&L	150	272,884	$ 35,003,880						
	Southern	100	2,040,278	$ 58,884,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,732,885	$ 97,748,915						
	(Peaking Capacity)	25	11,089	$ 1,730,065						
	Unit-Contingent Purchase	55	12,822	$ 3,129,822						
	Peaking Contract		0	$ 1,440,000						
	Sales		-2,607,303	-$115,277,263						
Case 4					$ 253,834,498	-$115,373,380	$ 292,798,355	$ 430,283,374	10.0%	$ 39,096,373
	CP&L	150	271,870	$ 35,071,240						
	Southern	100	2,035,807	$ 59,800,870						
	NP Energy	100	7,811	$ 18,821,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,818,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,864						
	(Peaking Capacity)	25	10,904	$ 1,726,183						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-1,808,397	-$113,176,398						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,341,904
	CP&L	150	290,890	$ 35,871,171						
	Southern	100	2,090,811	$ 60,981,896						
	NP Energy	100	19,360	$ 18,901,369						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,645						
	SPS Option A (Partial Requirement)	75	347,040	$ 18,850,715						
	(Peaking Capacity)	25	10,823	$ 1,721,204						
	Unit-Contingent Purchase	55	12,706	$ 3,128,353						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,001,867	-$76,232,010						
Case 4b					$ 245,856,964	-$104,544,438	$ 298,063,884	$ 448,176,900	12.5%	$ 49,309,459
	CP&L	150	268,141	$ 38,900,829						
	Southern	100	2,095,140	$ 60,001,226						
	NP Energy	100	6,740	$ 18,663,173						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,579						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Nathan	100	1,524,516	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,782						
	(Peaking Capacity)	25	10,848	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,871,933	-$104,544,438						
Case 5					$ 227,195,689	-$75,905,446	$ 302,832,926	$ 450,522,568	15.2%	$ 59,356,564
	CP&L	150	294,207	$ 35,784,707						
	Aquila Option 3	100	109	$ 24,366,566						
	NP Energy	100	10,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,818,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,856	$ 97,834,847						
	(Peaking Capacity)	25	10,904	$ 1,726,183						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$75,905,446						
Case 6					$ 249,212,528	-$107,863,417	$ 292,856,510	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	108	$ 24,374,734						
	NP Energy	100	13,600	$ 18,873,562						
	Southern	100	2,035,607	$ 39,980,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,818,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,864						
	(Peaking Capacity)	25	10,904	$ 1,726,183						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,863,417						
Case 7					$ 257,378,013	-$140,445,134	$ 287,934,305	$ 444,963,186	13.7%	$ 53,388,105
	Southern	100	2,038,417	$ 58,654,506						
	Aquila Option 3	100	108	$ 24,377,567						
	Nathan	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,881,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,423	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-3,533,100	-$140,445,134						

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/kW-mo. for all capacity deficits

Table 4
RealTime Modeling Results without Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 247,482,085	$ 228,719,801	$ 476,201,886	4.9%	$ 22,182,486
	LS Power Unit 1 (Online 2001)	270	3,450,651	$ 128,875,814					
	LS Power Unit 2 (Online 2001)	270	1,159,977	$ 79,414,823					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,018,014					
Case 2					$ 44,330,926	$ 423,308,758	$ 467,639,684	3.0%	$ 13,620,284
	Utilicorp Unit 1 (Online 2001)	250	3,380,441	$ 120,708,610					
	Utilicorp Unit 2 (Online 2001)	250	1,379,094	$ 77,768,906					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	147	$ 4,814,017					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199					
	SPS Option A (Partial Requirement)	75	174,554	$ 12,397,030					
	(Peaking Capacity)	25	11,078	$ 1,731,887					
	Unit-Contingent Purchase	55	9,350	$ 3,018,199					
Case 3					$ 196,163,051	$ 264,990,950	$ 461,154,001	1.6%	$ 7,134,601
	CP&L	150	88,983	$ 28,773,230					
	Southern	100	940,495	$ 38,572,089					
	Aquila Option 3	100	153	$ 24,373,182					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75/100	1,422,437	$ 71,756,138					
	(Peaking Capacity)	25	10,905	$ 1,723,749					
	Unit-Contingent Purchase	55	9,891	$ 3,019,883					
	Peaking Contract		0	$ 1,440,000					
Case 4					$ 190,167,020	$ 264,956,444	$ 455,123,464	0.2%	$ 1,104,064
	CP&L	150	67,346	$ 28,669,735					
	Southern	100	835,112	$ 36,457,450					
	NP Energy	100	4,090	$ 18,644,079					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,528					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75/100	1,423,251	$ 71,770,826					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4a					$ 173,655,923	$ 280,363,477	$ 454,019,400	0.0%	$ -
	CP&L	150	128,230	$ 30,895,167					
	Southern	100	1,272,189	$ 43,749,960					
	NP Energy	100	19,468	$ 19,007,529					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	Aquila 3	100	131	$ 24,370,845					
	SPS Option A (Partial Requirement)	75	173,579	$ 12,375,423					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4b					$ 190,348,728	$ 270,494,040	$ 460,842,768	1.5%	$ 6,823,368
	CP&L	150	45,557	$ 28,633,893					
	Southern	100	1,279,851	$ 43,918,072					
	NP Energy	100	6,758	$ 18,593,725					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	NorAm	100	647,710	$ 51,208,572					
	SPS Option A (Partial Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,018,014					
	Peaking Contract		0	$ 1,440,000					
Case 5					$ 191,200,852	$ 278,177,382	$ 469,378,234	3.4%	$ 15,358,834
	CP&L	150	125,345	$ 30,504,382					
	Aquila Option 3	100	131	$ 24,370,845					
	NP Energy	100	18,890	$ 18,991,817					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75/100	1,525,643	$ 73,874,603					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 6					$ 192,908,455	$ 265,188,518	$ 458,096,973	0.9%	$ 4,077,573
	Aquila Option 3	100	196	$ 24,377,567					
	NP Energy	100	14,527	$ 18,899,818					
	Southern	100	835,112	$ 36,457,442					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75/100	1,423,244	$ 71,770,683					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					
Case 7					$ 214,582,569	$ 257,622,027	$ 472,204,596	4.0%	$ 18,185,196
	Southern	100	941,572	$ 36,595,807					
	Aquila Option 3	100	196	$ 24,377,567					
	NorAm	100	390,664	$ 44,985,611					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Partial Requirement)	75/100	1,426,397	$ 71,834,585					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

Highly Confidential

Interview of UtiliCorp

Regulated Utility Operations Personnel

Frank DeBacker

Robert Holzwarth

Dated: October 28, 2003

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-548

DATE OF REQUEST: November 17, 2003

DATE RECEIVED: November 17, 2003

DATE DUE: December 7, 2003

REQUESTOR: Mark Oligschlaeger

BRIEF DESCRIPTION: Aries Power Plant

QUESTION:

Please review the attached set of notes taken by Staff of Aquila representations made at the meeting between Staff and Aquila representatives on Oct. 28, 2003, concerning the Aries power plant. Please make any revisions or additions necessary to accurately convey what Mr. DeBacker and Mr. Holzwarth stated during this meeting.

RESPONSE:

Attached is a revised set of notes.

ATTACHMENT:

MEETING NOTES of interview of Missouri Public Service personnel – revised Nov. 20, 2003.

ANSWERED BY: Frank DeBacker

____

SIGNATURE OF RESPONDENT

AQUILA INC
Case No. ER-2004-0034
HIGHLY CONFIDENTIAL

MEETING NOTES of interview of Missouri Public Service personnel

Attending from Missouri Commission Staff: Cary Featherstone, Mark Oligschlaeger
Attending from Aquila: Frank DeBacker, Robert Holzwarth, Denny Williams

Location: Aquila Headquarters—20~~0~~ West 9th, downtown Kansas City, Mo.

Date: October 28, 2003

Time: 9:45 am to 1:30 pm

(Note: References to "Aquila" generically refer to both the current organization and the organization known as "UtiliCorp United" prior to the name change to Aquila in 2002. References to the merchant operations of Aquila will be specifically referred to as "Aquila Merchant.")

Frank DeBacker retired from Aquila on June 30, 2001. Since then, he has worked part-time with Burns & McDonnell. He is currently working part-time for Aquila as a consultant in relation to the current Missouri rate case (Case No. ER-2004-0034). He was brought back as a contractor to specifically respond to the Staff's inquiry into the purchased power capacity contract with the Aries Partners. In 1998-99, Mr. DeBacker held the position of Vice-President – Fuel and Purchased Power on Aquila's regulated side. He reported then to Robert Holzwarth. Mr. DeBacker had coal, freight and purchased power under his authority. He did not have natural gas, which was done in Omaha, NE. Phil Rogers worked with Mr. DeBacker on the acquisition of coal supply for the regulated generating units.

Mr. DeBacker originally came to Aquila (Utilicorp) when the Company acquired the electric properties of Centel in early 1990s. He came from Colorado to ~~Missouri in mid-1990s (~~to Kansas City in June 1995~~)~~. He was in charge of power supply resources for Missouri, Kansas and Colorado from1996 through June 2001.

The electric regulated operations of Aquila consist of Missouri Public Service (MPS) (and as of January 2002, St. Joseph Light & Power) operating in state of Missouri, West Plains of Kansas (WPK) operating in state of Kansas and West Plains of Colorado (WPC) operating in eastern side of Colorado.

Mr. Holzwarth is still employed full-time with Aquila, and is currently between assignments; he recently returned from Australia as where he was CEO of United Energy. In 1998-99, Mr. Holzwarth was Vice-President/General Manager – Power Services (UPS) on Aquila's regulated side. He reported to Harvey Padawer, who was a Senior Vice-President with Aquila (UtiliCorp). Mr. Padawer reported to Bob Green, UtiliCorp President. Mr. Padawer is no longer with Aquila or any its affiliates. Mr. Featherstone stated that Mr. Green is still on the Aquila payroll. Mr.

Holzwarth left Missouri in 2000 to take a position with Aquila's Canadian operation in Calgary. He left Canada for Australia in ~~2000~~ 2002 and became the Chief Executive Officer of United Energy. The Australian operation ~~company~~ was sold by Aquila and closed as of July 24, 2003.

As Vice President of UPS, Mr. Holzwarth was over all three of Aquila's states that had electric operations and had four direct reports:

--Mike Appril- Wholesale
--John Browning—Dispatch and off-system sales
--Glenn Keefe—Generation (operations of power plants)
--Frank DeBacker—Fuel & Purchased Power

Mr. Keith Stamm, currently Aquila's Chief Operating Officer, was head of Aquila's (UtiliCorp) Australia operations but left to head up Aquila Merchant. Mr. Stamm started out at Missouri Public Service Company as an engineer, the predecessor company to Aquila (UtiliCorp). Mr. Stamm left for Australia from MPS in 1997.

As VP-Fuel, Mr. DeBacker was responsible for issuing Request For Proposals (RFPs) for purchased power, and negotiating with the bidders. MPS' need for power starting in 2001 led to the issuing of an RFP in 1998, which was largely caused by the expiration of major long-term capacity power contracts MPS had with Union Electric (UE) and Associated Electric Cooperative (AEC) for 150/180 megawatts, as well as the expiration of a smaller three-year contract with Kansas City Power & Light (KCPL). Load growth also contributed to MPS'need for power in the 2001-2005 timeframe UtiliCorp had problems with UE on this power contract and UE ultimately terminated the agreement. They are not sure why UE was not interested in renewing its contract. With the AEC contract, there were generation and transmission difficulties in receiving the power from that company – consequently Aquila did not want to renew that contract. The AEC agreement provided energy at ~~market price~~ the marginal cost of AEC's system energy plus 10% which was trending towards the regional market price due to the above mentioned difficulties. Both of these capacity agreements ended in 2000/2001 time period.

The KCPL capacity agreement was for summer peaking (3 months or 6 months) contract for 3 years. Had marginal costs increase.

Neither UE, AEC nor KCPL submitted bids in response to the 1998 RFP.

There was a significant power price "spike" in summer of 1998. The price of power was well known when the media reported power costs as high as $5,000 per megawatt hour. After summer of 1998, every one had "big interest" in building generation. The market price of power for 1999 looking to 2000 was very volatile. MPS did not want to rely on the wholesale spot market for power – they wanted to have a fixed price contract with a specific resource(s). Mr. DeBacker said they "needed resource that you could count on what the price would be." The 1998 RFP called from bids related to specific generating resources, as MPS did not want to rely upon a "system energy" purchase.

In 1998, and for some time before that, Aquila was concerned with the uncertainty of the future direction of the electric industry: the possibility of restructuring, retail access, etc. The possibility of these events occurring were demonstrated by the March 1998 Missouri Commission-sponsored Electric Restructuring Task Force Report. In recognition of this environment, Aquila (UtiliCorp), the Commission Staff and the Office of Public Counsel entered into a Joint Agreement that was approved by the Missouri Commission in an Order dated June 1998. The Joint Agreement provided for modifications to the Commission's Integrated Resource Planning process as it applied to Aquila, and also laid out Aquila's strategy to meet its immediate power needs through an RFP for purchased power, due to the current electric industry environment. MPS did not intend to build and include in rate base generating units to supply its power needs. Thus, Aquila (UtiliCorp) through its regulated MPS division never considered building generating capacity as a "regulated" unit. The five-year period covered by this RFP was chosen because any longer period might have exposed Aquila to the risk of losing customers through retail access; some at Aquila thought five years was too long for a power solicitation. The 5-year period would serve the regulated needs through May 31, 2005.

The philosophy of "buy/not build" in regard to power supply, taken in response to perceived electric industry uncertainty, was an Aquila (UtiliCorp) corporate strategy in place by 1998; it wasn't just Mr. DeBacker's and Mr. Holzwarth's belief at that time. The Aquila (UtiliCorp) philosophy was consistent with MPS' strategy in 1998. MPS took the position to depend on purchased power for short-term power needs, no construction of regulated power plants. The Aquila (UtiliCorp) divisions in Colorado and Kansas followed this same approach. Bob Green, Jim Miller and Harvey Padawer communicated the "buy/not build" strategy for the regulated entities. This strategy is not set down in writing, to DeBacker's and Holzwarth's knowledge, but was no secret within Aquila. Mr. Holzwarth was present at one meeting where Bob Green expressed the "buy/not build" philosophy. Among the senior officers still with Aquila, Rick Green, currently Chairman, President and Chief Executive Officer could address this philosophy if necessary.

Both Mr. DeBacker and Mr. Holzwarth indicated that UtiliCorp was concerned about the future of retail competition / retail access and was concerned about the "stranded costs" relating to loss of customers to competition from "customer choice". The Company wanted to "stay short in the market" (stay in market 3 to 5 years only). The decision to "stay short" in the market was made by UtiliCorp in 1996/ 1997 time frame. Mr. Holzwarth said, "what would happen if you build big units (generating units) and half your customers went away?" When asked if either of them knew of any system (electric system) where half the customers "went away" neither Mr. DeBacker nor Mr. Holzwarth knew where this had occurred. Mr. Holzwarth cited the competition that was occurring in other states such as Pennsylvania, New Jersey, New York and Illinois.

In 1998, the only economic analysis performed to assess MPS' power options for the first years of the next century were for a three-to-five year period only. Building plants for MPS' rate base was not considered as an option, but Holzwarth's group did consider building a generating plant as an unregulated Exempt Wholesale Generator (EWG) within MPS. Building a unit as part of an EWG was viewed as superior to including a regulated unit in rate base because there was less risk to Aquila of stranded costs if retail access was allowed in Missouri. Plus, the EWG proposal allowed MPS to better control costs and to "control its own destiny" in regard to power supply, and also allowed MPS the opportunity to profit on a non-regulated basis in the wholesale marketplace through the sale of energy as off-system sales. The analysis performed by UtiliCorp for the EWG never assumed MPS to be a customer of the MPS EWG unit beyond the original five-year power supply proposal in the RFP. Mr. Holzwarth stated that the MPS EWG option was presented at a meeting attended by Bob Green, then UtiliCorp President, and Harvey Padawer (maybe Jim Miller as well). The MPS EWG option was rejected because of questions raised at the meeting the risk of a massive EWG operating failure when taking into consideration MPS' relatively small size; how to obtain generating economies of scale, since a separate organization within MPS would have to be responsible for the EWG unit; MPS' lack of familiarity with the combined-cycle technology; and regulatory scrutiny of possible cross-subsidies between MPS' regulated and non-regulated sides. Mr. Holzwarth said some of the questions posed at this meeting where he recommended that MPS (through UPS) build non-regulated EWG generating unit were: How can MPS operating people manage the EWG also? What would be the "risk" to cash? Where would you get economies of scale from a regulated operation running a non-regulated EWG operations? Mr. Holzwarth stated he did not have answers to these questions.

So, the decision was made to obtain power from other sources. They are not aware of any records documenting the reasons for the MPS EWG option rejection by Aquila senior management. ~~Mr. Holzwarth stated Bob Green made the decision not to build regulated generating units and maybe Mr. Padawer was also involved.~~ Mr Holzwarth stated that the ultimate decision would have been made by Bob Green and/or Harvey Padawer; however, the consensus opinion of senior management was that a regulated power plant with its potential stranded cost issues was not desirable. Mr. Holzwarth indicated he did not make the decision, he only made the presentation recommending that his group UtiliCorp Power Supply build a generating unit as a non-regulated EWG.

If the MPS EWG option had been picked to supply power for MPS' regulated customers, MPS would still have only entered into a 3 to 5 year capacity purchased power contract with the EWG, in accord with the Aquila "buy/not build" corporate philosophy in effect at that time.

Were Bob Green, Harvey Padawer and Jim Miller involved in meetings dealing with Aquila Merchant matters? DeBacker and Holzwarth said Padawer would have been; he was head of Aquila Merchant at the time and reported to Mr. Green. They supposed Bob Green would have met with Aquila Merchant people; Bob Green as President of Aquila (UtiliCorp) was over Aquila Merchant as well as the regulated utility operations. Mr. DeBacker and Mr. Holzwarth were not sure about Mr. Miller, Senior Vice President of UtiliCorp Energy Delivery (UED) which was responsible for the transmission and distributions system (pipes and wires) of the regulated utilities.

Mr. DeBacker and Mr. Holzwarth did not know how purchased price forecasts would affect the generating resource planning process for MPS. They did have access to forecasts of fuel prices for coal, natural gas prices, "market-clearing prices" (purchased power prices), etc, as produced by various models. RDI and Hill & Associates were involved in this forecasting process.

The RFP for MPS power in 1998 was only issued once, but all of the bidders were asked to re-bid after the MPS EWG option was rejected. In the initial round of bidding, the MPS EWG was the low-cost option. Aquila Merchant's bid was second lowest, and at that time was based on supplying MPS power from its Batesville, Mississippi unit. All bidders were expected to supply firm transmission service to get the power to MPS. The bid price was expected to include getting the power to MPS service territory. Once the RFP was re-bid, the new bids came in with lower prices. MEPPH was formed in September 1998. Aquila Merchant/MEPPH' new bid was now based on the Aries unit proposal, a two on one combined cycle unit (two combustion turbines on one steam turbine generator with two heat recovery steam generators). Aquila Merchant/MEPPH and NorAm/Houston Industries (now Reliant) were the two finalists from the re-bid process. Houston Industries bid was for three simple cycle combustion turbines. After the re-bids came in, MPS negotiated with both parties to obtain lower prices and more favorable contract conditions. Aquila Merchant/MEPPH ultimately was selected after Houston refused to lower its bid price in order to remain competitive with the most recent ~~meet~~ Aquila Merchant/MEPPH's bid price. Once Aquila Merchant/MEPPH was selected from the RFP process, a contract was negotiated, it was submitted to the Missouri Commission for approval, and was filed with and accepted by FERC.

The present site of the Aries unit in Pleasant Hill would have been the site of the new unit whether Aquila Merchant/MEPPH or Houston had built it. MPS had already selected that site for the new unit, based upon analysis of a number of injection (interconnection) points into the MPS system. That site adjoined the location of an already existing MPS substation. The land was previously owned by MPS many years ago but had been sold to a couple for farmland. MPS inquired through their search for land to build the EWG option that the couple would sell the land. MPS told Aquila Merchant, the bidders of capacity to MPS, that they thought the owners of the land would sell the property because of a divorce situation. MPS would not get the land from the owners, Aquila Merchant had do all the negotiations on their own. With this land adjacent to MPS' substation, there were no interconnection problems in transporting large amount of electricity to MPS system.

Burns & McDonnell were hired to analyze the first set of RFP responses in 1998. MPS did its own in-house analysis for the "re-bids," but Burns & McDonnell also reviewed MPS' work in that regard. In reference to materials Mr. DeBacker has on the 1998 RFP process, he has the materials included in the response to Staff Data Request No. 302 in this case, the 1998 Missouri Commission Order accepting the Joint Recommendation, and the FERC orders on Aries matters. Holzwarth has nothing. There is a policy at Aquila to "wipe out" your data from the system three months after you walk out the door. The underlying support for the analysis and the actual models can not be located by either of them. They contacted Aquila's current Information Systems group to retrieve electronic files and were told they no longer existed. Mr. DeBacker attempted to locate his files but he believes they no longer exist.

Regarding the Greenwood unit, Holzwarth's group was involved with the negotiations with the former owner as the lease was expiring. Neither Holzwarth nor DeBacker was involved in the decision to create a separate subsidiary for the Greenwood unit after Aquila became the owner; Glenn Keefe would be the person to ask about that.

Highly Confidential

Merchant Energy Partners – Missouri Combined Cycle Development Project

Dated January 5, 1999

Merchant Energy Partners℠

Missouri Combined Cycle Development Project

January 5, 1999

AQUILA ENERGY

Meeting Purpose

- Inform and update UCU on proposed EWG transaction parameters;
- Seek approval of proposed capital budget for development of 500 MW CCGT;
- Proceed with operating, legal and finance activities related to formation of project team and project development;
- Determine Executive Review Team and establish key communication elements and timeline for project execution.

Outline

I. Project Summary
- Description and Economics

II. Project Risks and Assessment
- A . Market Assessment
- B . Contract Structure
- C . Development Risks and Requirements
- D . Regulatory/Legal
- E . Finance Risks

III. Project Economics
- A . Commodity Assumptions
- B . Unit Assumptions
- C . Financial Sensitivities

IV. Timeline

I. Project Summary

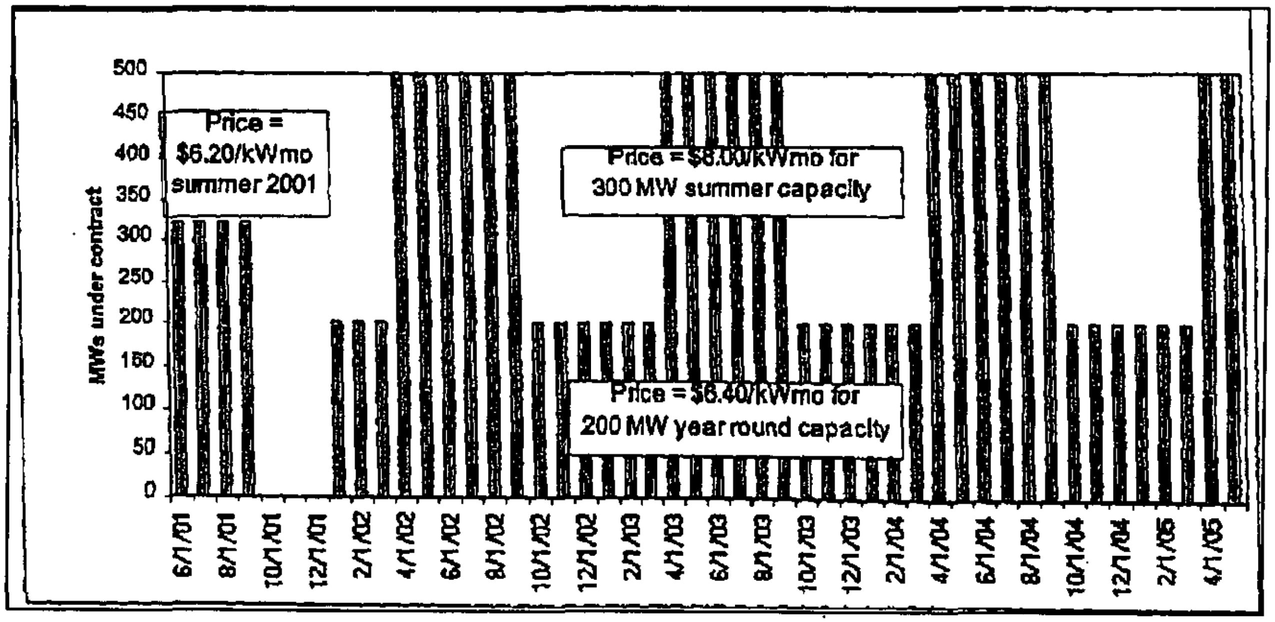
Project Description

Size:	500 MW
Ownership:	MEP; equity sale at time of project financing
Technology:	Combined cycle "F" class gas turbines plant
Location:	Pleasant Hill, Missouri
Estimated Cost:	$224 million (excluding reserve funding)
Heat Rate:	7,000 Btu/kWh
Build Method:	EPC contract, completed December 2001
Operational:	June 2001 (Simple Cycle): 320 MW January 2002 (Combined Cycle): 500 MW
Transmission:	Direct interconnection to MPS (Northern SPP) Option to tie into 345 kV KCPL line to be investigated
Gas Transportation:	Panhandle Eastern, Williams or KN

Contract Description

Contract between EWG and Missouri Public Service:

- Project Company (EWG) sells capacity and energy to MPS under tolling agreement
- Sales unit contingent, guaranteed at 94% availability
- MPS responsible to purchase its own firm gas transportation
- Simple cycle summer 2001, combined cycle starting January 2002



Project Economics

Major Capital Assumptions

- 100% debt financing during construction, 80% at start of full operations
- MEP owns 50% of project company
- All-in cost to build, approximately $450/kW (excluding pre-funding reserves)
- MEP capital invested at end of construction totals approximately $24 million
- Project Company is 100% merchant after expiration of MPS and MEP contract (years 16+)
- All revenue and expenditures capitalized through construction ending December 2001
  - Thus, no incremental income or EPS impact until 2002

Major Operating Assumptions

- Forced outage rate of 3% per year
- Scheduled maintenance 20 days per year (in April or October)
- Heat rate 7,000 Btu/kWhr
- Turbine maintenance NPV (15% discount) = $38 million
- Firm gas transportation NPV (15% discount) = $32 million
- 22 full time equivalent employees at site

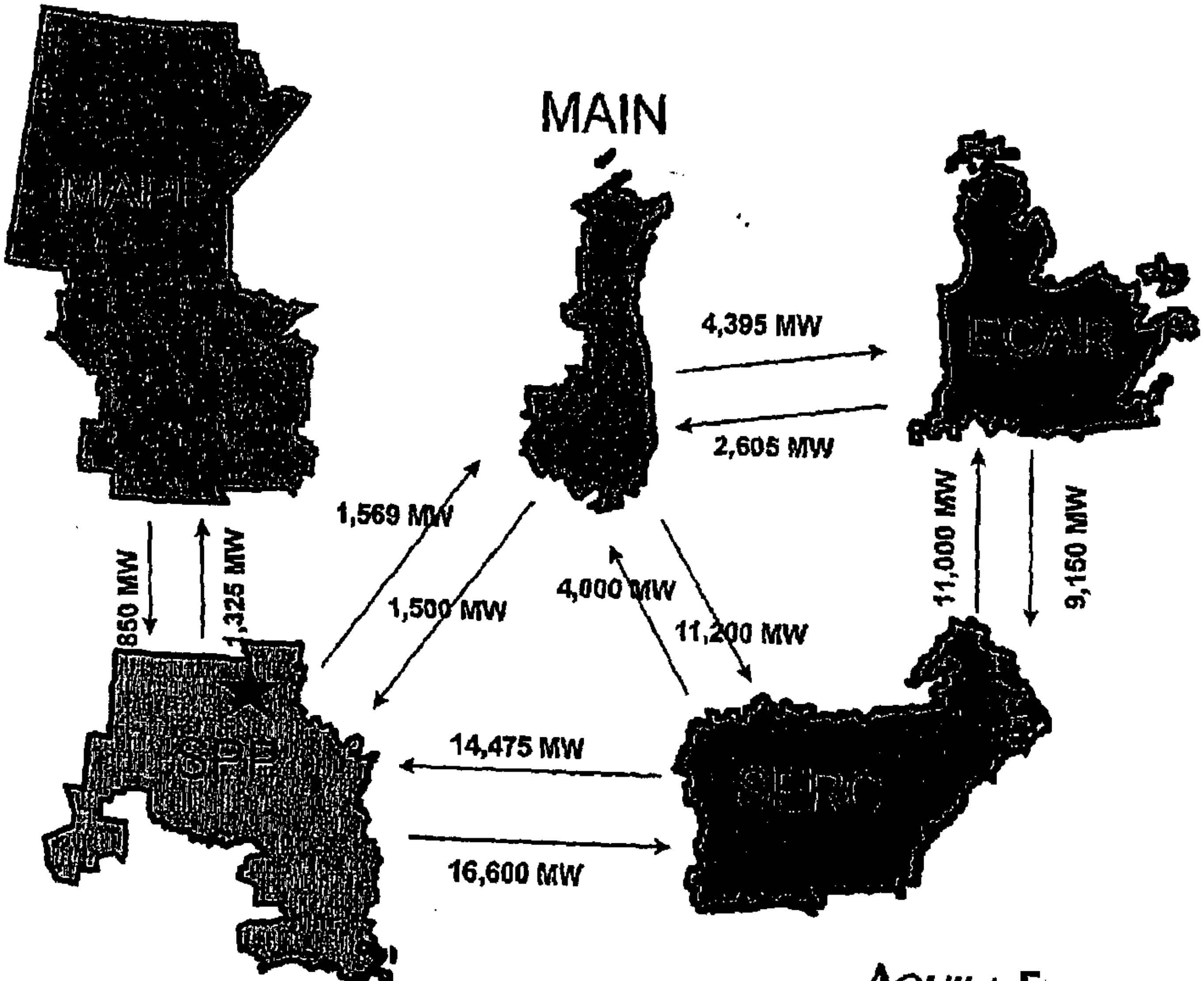
Results

- 15% after-tax IRR to UCU over 30 years based on MEP contribution
- Incremental EPS ranges from less than $0.005 loss per share to $0.02 gain per share over the first three years, increasing to a gain above $0.02 per share for all years thereafter

II. Project Risk Assessment

A. Market Assessment

Total Inter-Regional Transfer Capability



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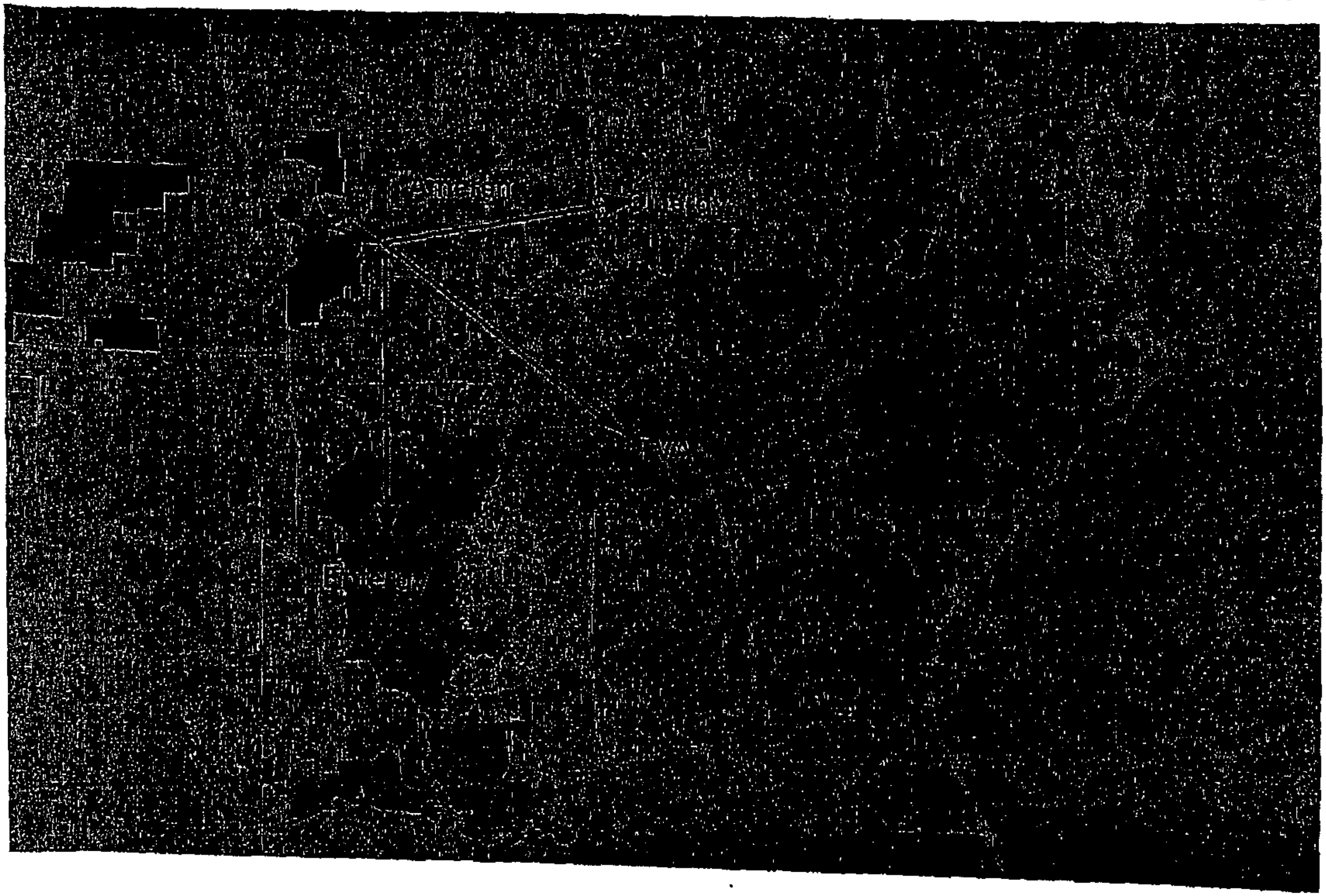
Energy Markets - Liquid Trading Hubs

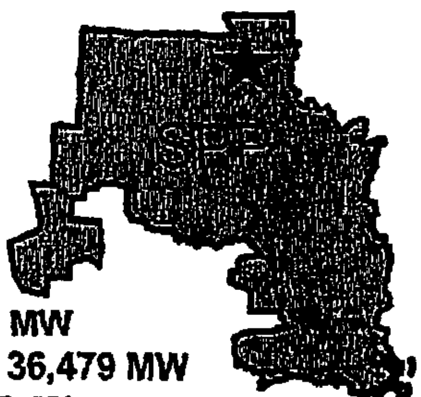


1997 Regional Supply & Demand

Supply 39,552 MW
Peak Demand 34,891 MW
Rsv. Margin 11.8%

Supply 51,961 MW
Peak Demand 45,887 MW
Rsv. Margin 11.7%

Supply 104,212 MW
Peak Demand 93,492 MW
Rsv. Margin 10.3%



Supply 41,845 MW
Peak Demand 36,479 MW
Rsv. Margin 12.8%

Supply 152,402 MW
Peak Demand 137,382 MW
Rsv. Margin 9.9%

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HC Schedule 3-13

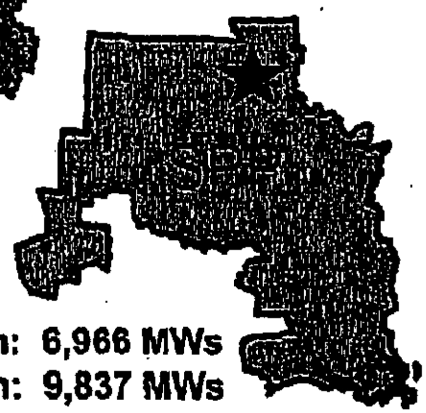
2005: New Capacity Requirements

New capacity required by NERC Region by 2005 to Maintain Reserve Margin

10% Reserve Margin: 6,704 MWs
15% Reserve Margin: 8,949 MWs

10% Reserve Margin: 6,955 MWs
15% Reserve Margin: 10,420 MWs

10% Reserve Margin: 14,364 MWs
15% Reserve Margin: 21,339 MWs



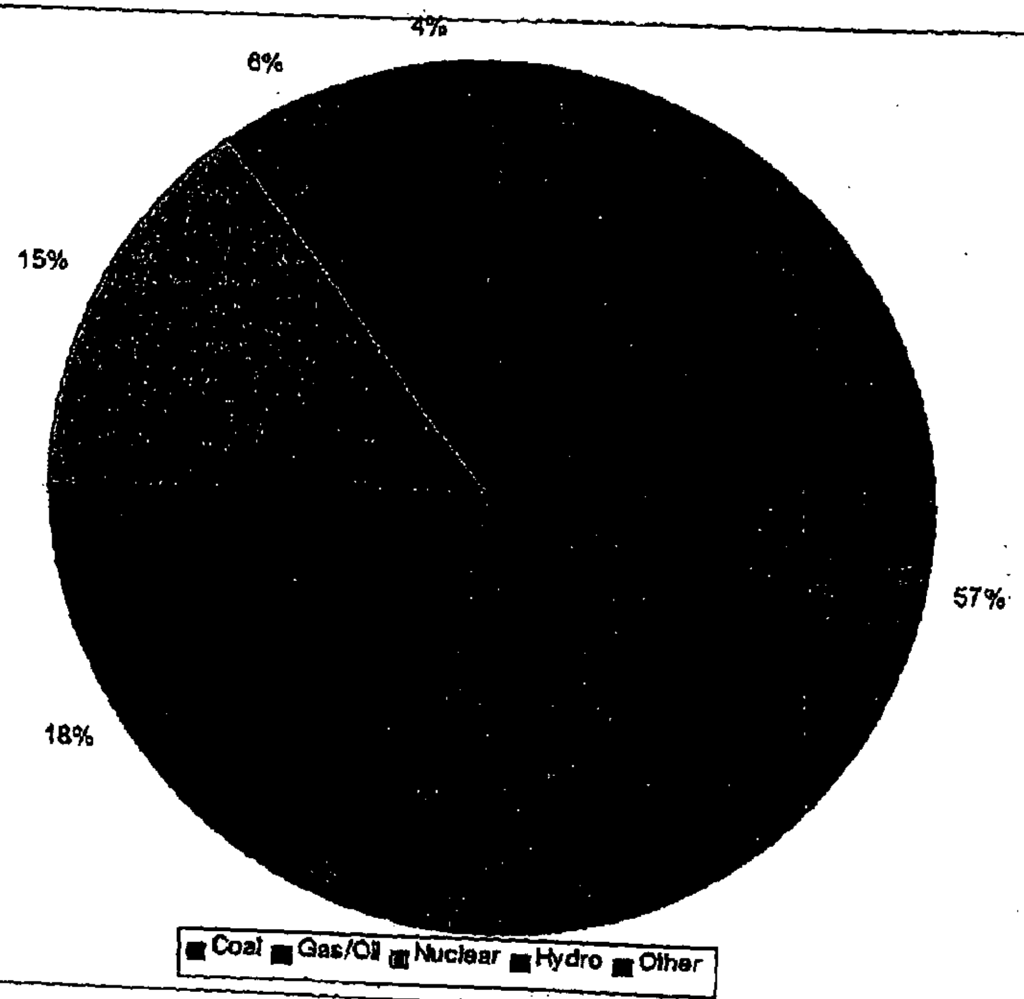
10% Reserve Margin: 6,966 MWs
15% Reserve Margin: 9,837 MWs

10% Reserve Margin: 30,287 MWs
15% Reserve Margin: 41,033 MWs

HC Schedule 3-14

Capacity by Fuel

Collective for SPP, MAPP, MAIN, ECAR, SERC



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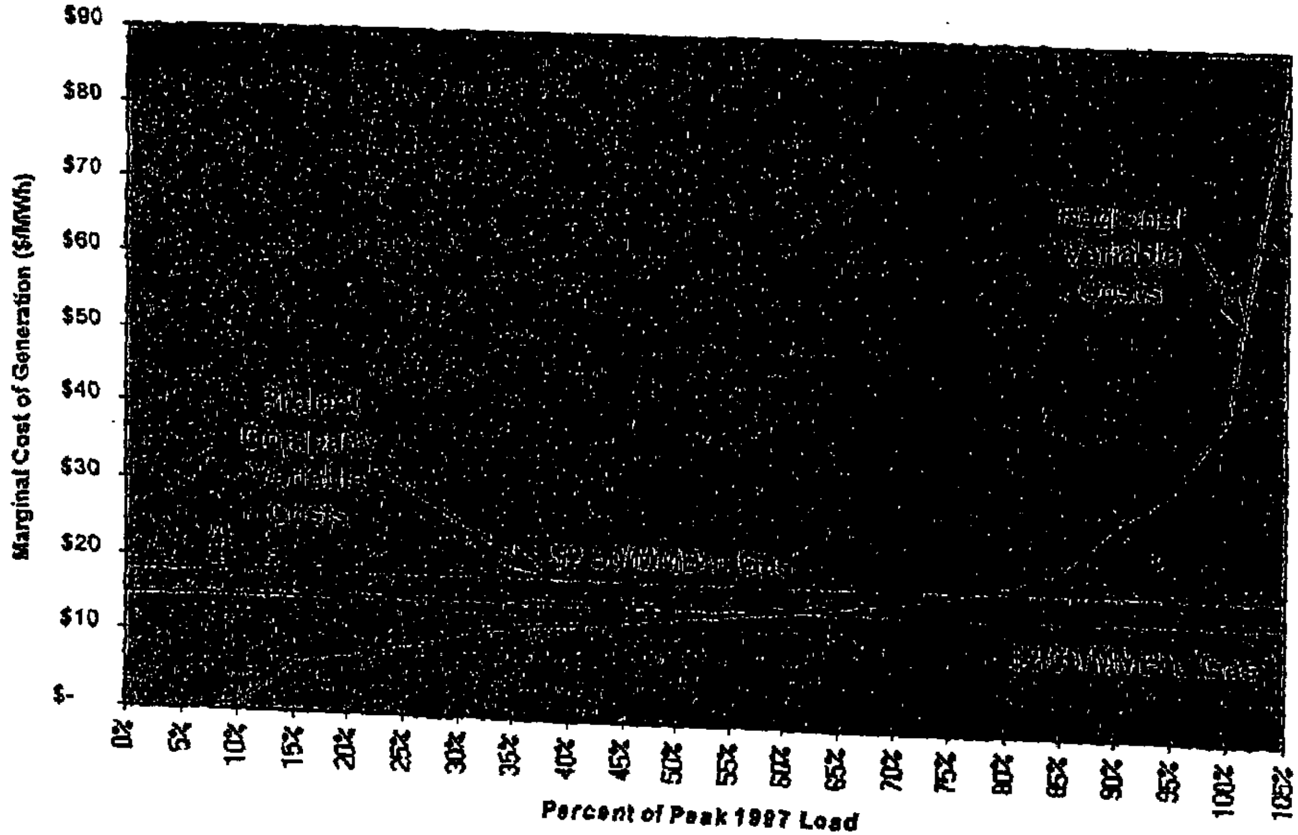
Unit Ranking in Supply Curve

Collective for SPP, MAPP, MAIN, ECAR, SERC



B. Contract Structure of Project Company