BEFORE THE

KANSAS CITY BOARD OF PUBLIC UTILITIES

2023 RATE HEARING

LIST OF EXHIBITS

TO THE DIRECT TESTIMONY OF SARAH SHENSTONE-HARRIS
ON BEHALF OF SIERRA CLUB

Exhibit No.	Description of Exhibit
SSH-1	Resume of Sarah Shenstone-Harris
SSH-2	BPU responses to Sierra Club data requests

EXHIBIT SSH-1

Resume of Sarah Shenstone-Harris

Sarah Shenstone-Harris, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-245-8222
sshenstone-harris@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, October 2022 – Present.

- Provides research, analysis, and consulting services on various energy-sector issues, including integrated resource planning, rate design, electric vehicles and electrification, and clean energy
- Evaluates utility rate designs and their impacts on electric vehicles
- Forecasts load changes and their impacts on rates from future electric vehicle adoption
- Assesses the economic viability of generation resources (legacy coal plants, new solar projects) as opposed to alternative resources and market purchases

Reading Municipal Light Department (RMLD), Reading, MA. *Integrated Resource Analyst I,* January – September 2022; *Integrated Resource Specialist,* October 2020 – December 2021.

Integrated Resource Analyst I:

- Planned the Department's wholesale power supply strategy, including developing and running economic models to evaluate power supply decisions. Consistently working to achieve RMLD's goals of delivering reliable, low-cost, and emission-free power
- Led the rate increase process and the design of new rate structures, such as a residential electric vehicle time-of-use rate.
- Managed the retirement and sales of RMLD's Renewable Energy Certificates (RECs) and Emission-Free Certificates (EFECs) to ensure compliance with MA Climate Law and the achievement of RMLD's grid decarbonization goals, while keeping rates affordable for all classes
- Developed and maintained forecasting tools of retail load, energy purchases and hedging, power supply costs (energy, transmission, and capacity), and RECS/EFECs
- Prepared annual and monthly power supply budgets for energy, transmission, and capacity costs
- Adjusted monthly rates for all classes, based on expected costs and revenues
- Designed and implemented significant process improvements to track budgeted and actual costs, and manage the $65 million power supply budget

Integrated Resource Specialist:

- Administered, promoted, coordinated, and reported on utility energy efficiency and electrification programs, including Air Source Heat Pumps, Electric Vehicle Chargers, Commercial Lighting, Solar and Distributed Generation, Energy Audits, Appliance Rebates, and other energy management programs
- Designed and developed economic and analytical tools to help achieve RMLD's power supply and retail goals and objectives, such as a rate analysis models

- Developed and expanded utility load forecasts, to inform both power supply strategy and program management
- Implemented significant program process improvements, resulting in a >50% reduction in customer rebate application turnaround time
- Established systems to track program performance, including measure adoption, cost-effectiveness, energy savings, and environmental impacts
- Responsible for reporting to external agencies, such as the ISO-NE and US Energy Information Administration (EIA), as well as to board members and key stakeholders on all retail program activities
- Provided technical support to the Customer Service team, including administering training on new programs, a customer portal for rebate applications, and new program processes
- Coordinated with other RMLD departments, vendors, program partners, and other utilities to support RMLD programs and goals

ICLEI Canada – Local Governments for Sustainability, Toronto, Ontario, Canada. *Climate & Energy Planner Project Assistant*, October 2018 – March 2020; *Climate & Energy Project Assistant*, October 2017 – October 2018.

- Coordinated ICLEI's climate and energy consulting work for municipalities, including:
  - Stakeholder engagement (stakeholder identification, establishment of working groups, facilitating dialogue, collecting feedback and incorporating stakeholder input)
  - Identifying and developing programs and policies to improve environmental sustainability across multiple sectors (buildings, transportation, waste, land use, resource use, etc.)
  - Quantifying environmental and financial impacts of emission and energy reduction measures, identifying and collecting data sources, modelling energy and emissions with different policy options
  - Clearly and succinctly summarizing technical concepts to clients and stakeholders
  - Presenting recommendations and final plans to City Councils
- Coordinated and delivered capacity-building programs that support Canadian municipalities in greenhouse gas emissions mitigation activities and community energy planning
- Created resources and tools for climate action plan development and implementation (best practice guidelines, communication materials, emission measurement tools, decision-support tools, etc.)
- Developed and delivered workshops, webinars and training services to local governments participating in ICLEI programs and projects

Sustainable Development Technology Canada, Ottawa, Ontario, Canada. *Research and Technology Analyst* (8-month Co-op position), September 2016 – April 2017.

- Wrote and prepared briefing packages for the Board of Director's Investment Committee, detailing the technological, business, intellectual property, and financial merits of clean tech projects seeking funding

- Conducted research to assess and inform SDTC's clean tech investment priorities

EDUCATION

University of Ottawa, Ontario, Canada
Master of Science in Environmental Sustainability (focus on policy and economics), Institute of the Environment, 2017.
Masters Project: *Have we reached peak driving?: A 25-year decomposition of vehicle trends in Canada*

Queen's University, Kingston, Ontario, Canada
Bachelor of Science in Biology, 2013.
Graduated with Distinction and Dean's List Honors

PUBLICATIONS & TESTIMONY

Public Service Commission for the Commonwealth of Kentucky (Case No. 2022-00372): Direct Testimony of Sarah Shenstone-Harris in the matter of Electronic Application of Duke Energy Kentucky, Inc. for an adjustment of electric rates, approval of new tariffs and approval of accounting practices to establish regulatory assets, liabilities and all-over required approvals and relief. On behalf of Sierra Club. March 10, 2023.

Whited, M., S. Shenstone-Harris, A. Lawton, O. Griot, J. Frost. 2023. *Maximizing the Benefits of Transportation Electrification in Pennsylvania.* Synapse Energy Economics for Pennsylvania Department of Environmental Protection.

Public Service Commission of the State of Missouri (File No. EA 2022-0245): Surrebuttal testimony of Sarah Shenstone-Harris regarding Ameren Missouri's Application for a Certificate of Convenience and Necessity of a Solar Facility. January 18, 2023.

ICLEI Canada and Wood PLC. 2021. *Town of Aurora (Ontario) Community Energy Plan.*

ICLEI Canada and Wood PLC. 2020. *Township of Huron-Kinloss (Ontario) Climate Change and Energy Plan.*

LURA Consulting and ICLEI Canada. 2019. City of Kawartha Lakes (Ontario), Healthy Environment Plan.

ICLEI Canada and the Federation of Canadian Municipalities. 2020. *Guidebook on Quantifying Greenhouse Gas Reductions at the Project Level.*

Shenstone-Harris, S., Cai, Y., and Dean, M. 2019. *On the Money: Financing Tools for Local Climate Action, 2019*. Prepared for Partners for Climate Protection.

ICLEI Canada and the Federation of Canadian Municipalities. 2018 and 2019. *Partners for Climate Protection National Measures Report 2018, Partners for Climate Protection National Measures Report 2019*.

Rivers, N., S. Shenstone-Harris, N. Young. 2017. *Using nudges to reduce waste? The case of Toronto's plastic bag levy*. Journal of Environmental Management, Volume 188. ISSN 0301-4797. ZURA Consulting.

Resume updated May 2023

EXHIBIT SSH-2

BPU Responses to Sierra Club Data Requests

Data Requests

BPU Response to Sierra Club Request 1-3
BPU Response to Sierra Club Request 1-5
BPU Response to Sierra Club Request 1-6, and Attachments
BPU Response to Sierra Club Request 1-7, and Attachments
BPU Response to Sierra Club Request 1-8
BPU Response to Sierra Club Request 1-9
BPU Response to Sierra Club Request 1-10
BPU Response to Sierra Club Request 1-15
BPU Response to Sierra Club Request 1-17, and Attachments
BPU Response to Sierra Club Request 1-18
BPU Response to Sierra Club Request 1-19
BPU Response to Sierra Club Request 1-22

BPU Response to Sierra Club Request 2-1, and Attachments
BPU Response to Sierra Club Request 2-2
BPU Response to Sierra Club Request 2-3

BPU Response to Sierra Club Request 3-1
BPU Response to Sierra Club Request 3-3, and Attachment
BPU Response to Sierra Club Request 3-4

BPU Response to Sierra Club Request 4-3

 Exhibit SSH-2

Via: E-Mail

April 5, 2023

M E M O R A N D U M

From: Sierra Club

Teresa A. Woody
Kansas Appleseed
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Re: Discovery for the Board of Public Utilities ("BPU")

Sierra Club respectfully requests that BPU provide responses to these data requests.

1-1. Please provide the undepreciated plant balance for the Nearman Creek Power Station coal unit ("Nearman") as of January 1, 2023 (or closest date available).

As of December 31, 2022, the Net Book Value (NBV) for Nearman Creek Power Station coal unit was $305,224,524

1-2. Please provide BPU plant in service amounts from 2018 through the present for Nearman on a monthly basis. For each month, include plant balance as of the first day of the month, addition, transfers, retirements, and plant balance at the end of the month.

Below are the annual Plant in Service numbers for Nearman:

	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
Plant End Balance	**390,774,015**	**390,811,149**	**391,621,886**	**391,636,540**	**391,921,954**
Additions	38,976,413	37,134	810,737	14,654	285,414
Transfers	-	-	-	-	-
Retirements	-	-	-	-	-

1-3. Please provide Nearman's operations and maintenance costs that BPU is asking to include in rates for the years 2023 and 2024.

Exhibit SSH-2

		FY 2023	FY2024
Dept 1400	Nearman Common	774,300	789,786
Dept 1401	Nearman Maintenance	9,675,906	9,858,765
Dept 1402	Nearman Operations	9,881,045	10,062,967
Dept 1403	Nearman - Engineering	3,851,500	3,928,430
Dept 1491	Nearman - Fuel	27,700,000	27,700,000
	Total	51,882,751	52,339,948

1-4. Please provide Nearman's capital expenditure that BPU is requesting to include in rates for the years 2023 and 2024.

	2023	2024
Nearman Power Plant Unit 1	$ 6,788,000	$ 6,010,000
Nearman Power Plant Common	$ 125,000	$ 150,000

1-5. Please provide BPU's weighted average cost of capital.

6.7%

1-6. Please provide the following historical annual data from 2018 through 2022 for Nearman:

a. Installed Capacity
b. Unforced Capacity
c. Capacity Factor
d. Equivalent Availability Factor (EAF)
e. Heat Rate
f. Forced or random outage rate
g. Effective forced outage rate (EFORd)
h. Fixed O&M costs
i. Non-Fuel Variable O&M costs
j. Fuel Costs (by fuel type)

1-6 See Spreadsheet – Tabs 1-6 and 1-6 Actuals

1-7. For each of the years 2023 through 2032, please identify BPU's projection of Nearman's:

a. Installed Capacity
b. Unforced Capacity
c. Capacity factor
d. Availability
e. Heat rate
f. Effective forced outage rate (EFORd)
g. Fixed O&M cost
h. Non-Fuel Variable O&M cost
i. Fuel cost (by fuel type)

1-7 See Spreadsheet – Tabs 1-7 and 1-7 Budget

1-8. Please provide annual SPP energy and (if any) ancillary service market revenues for Nearman for the period 2018–2022.

1.8		2018	2019	2020	2021	2022
	Nearman SPP Revenue	$ 28,825,552.42	$ 26,150,785.51	$ 24,937,103.72	$ 113,092,926.87	$ 61,968,570.65

1-9. Please provide total projected SPP energy and (if any) ancillary service market revenues for Nearman for the period 2023–2034.

Yr	AMT
2023	$ 26,491,276
2024	$ 29,414,399
2025	$ 31,829,622
2026	$ 34,372,527
2027	$ 37,048,112
2028	$ 39,861,540
2029	$ 42,193,064
2030	$ 44,601,904
2031	$ 45,493,942
2032	$ 46,403,821

1-10. Please provide the following for Nearman:

a. Historical capital expenditures since 2018 and through 2022.

	2018	2019	2020	2021	2022
N1 Common	$ 1,214,295	$ 5,559,079	$ 1,375,190	$ 2,279,021	$ 2,531,236
NI Plant	$ 19,268,548	$ 4,674,215	$ 7,596,076	$ 797,239	$ 2,078,195
	$ 20,482,843	$ 10,233,294	$ 8,971,266	$ 3,076,260	$ 4,609,431

b. Projected capital expenditures from 2023 through 2032.

**Only have capital project projections through 2027

	2023	2024	2025	2026	2027
N1 Common	$ 125,000	$ 150,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
NI Plant	$ 6,788,000	$ 6,010,000	$ 5,300,000	$ 5,600,000	$ 5,600,000
	$ 6,913,000	$ 6,160,000	$ 6,300,000	$ 6,600,000	$ 6,600,000

c. Provide a specific accounting of all projects and capital expenditures already scheduled or planned at each unit over the next ten years.

PDF of BPU Provided Excel File:
Sheet "1-6" in "DR #1 Sierra Club Final.xlxs."

1.6

	2018	2019	2020	2021	2022
Installed Capacity	245	245	245	245	245
Unforced Capacity	151.9	193.55	196	213.15	208.25
Capacity Factor	45%	49%	50%	59%	55%
Equivalent Availability Factor				89%	84%
Heat Rate	11,001	11,385	11,118	11,134	11,369
Forced or Random Outage	16.5%	17.6%	11.5%	1.5%	5.3%
Effective Forced Outage Rate				1.5%	8.1%
Fixed O&M Costs	See Other Tab				
Non-Fuel Variable O&M Costs	See Other Tab				
Coal Cost	$ 17,998,559	$ 20,591,584	$ 19,989,152	$ 23,667,414	$ 25,545,947
Fuel Oil Cost	$ 704,869	$ 798,987	$ 576,385	$ 1,107,305	$ 1,865,718

PDF of BPU Provided Excel File:
Sheet "1-6 Actuals" in "DR #1 Sierra Club Final.xlxs."

Unit	Dept	Class_Type	Class	FY18	FY19	FY20	FY21	FY22
Production	1400	Material and Supplies	4000				356	
Production	1400	Material and Supplies	4010	31,535	35,051	11,531	12,111	7,904
Production	1400	Material and Supplies	4040	1,437		228	2,100	309
Production	1400	Material and Supplies	4050	485	533			
Production	1400	Material and Supplies	4100	655		7		311
Production	1400	Material and Supplies	4130				4	
Production	1400	Material and Supplies	4140	129,978	112,218	105,063	112,486	180,396
Production	1400	Material and Supplies	4150				12	
Production	1400	Material and Supplies	4160	3,050	434	596	2,019	1,529
Production	1400	Material and Supplies	4170	1,895	676	677	4,831	9,701
Production	1400	Material and Supplies	4180	123,002	324,898	260,257	156,335	570,746
Production	1400	Material and Supplies	4251			8		
Production	1400	Material and Supplies	4270				15	
Production	1400	Material and Supplies	4300	6				
Production	1400	Material and Supplies	4302	55				3
Production	1400	Material and Supplies	4323			940		
Production	1400	Material and Supplies	4990	4,316	44	878		
Production	1400	Services	2000		223			
Production	1400	Services	2200	8,685	9,238	7,169	10,509	9,634
Production	1400	Services	2243		157			
Production	1400	Services	2244			19		
Production	1400	Services	2250		10			
Production	**1400 Total**			**305,099**	**483,482**	**387,373**	**300,778**	**780,533**
Production	1401	Personnel Costs	1010	1,792,145	2,344,808	2,364,449	2,783,844	2,937,061
Production	1401	Personnel Costs	1020	348,214	386,626	309,951	212,830	290,223
Production	1401	Personnel Costs	1030	412,084	597,689	576,555	658,765	685,181
Production	1401	Personnel Costs	1040	185,442	286,833	115,628	104,827	50,120
Production	1401	Personnel Costs	1050	182,537	232,344	232,957	266,576	279,403
Production	1401	Personnel Costs	1070	26,896	40,795	41,861	46,979	49,035
Production	1401	Personnel Costs	1080	2,155	2,746	2,755	3,153	3,304
Production	1401	Personnel Costs	1090	164,445	208,849	209,736	240,894	252,173
Production	1401	Personnel Costs	1100	(6,125)	60,182	18,855	91,124	94,677
Production	1401	Personnel Costs	1110	84,182	81,374	99,401	101,219	95,868
Production	1401	Personnel Costs	1130	27,499	36,830	37,621	43,009	46,745
Production	1401	Personnel Costs	1180	2,352	2,615	2,724	3,353	3,619
Production	1401	Personnel Costs	1990	630		57,448	24,937	
Production	1401	Material and Supplies	4000	10,126	292			
Production	1401	Material and Supplies	4010	3,636	33	2,708		
Production	1401	Material and Supplies	4050	16,534	16,988	31,124	34,876	38,747
Production	1401	Material and Supplies	4060		5			
Production	1401	Material and Supplies	4100		15			
Production	1401	Material and Supplies	4120					(624)
Production	1401	Material and Supplies	4130	88,113	50,011	103,394	200,131	215,486
Production	1401	Material and Supplies	4131		95,688		52,770	6,170
Production	1401	Material and Supplies	4132	52,674	56,070	106,838	145,334	1,288
Production	1401	Material and Supplies	4133	18,292	19,787	27,542	32,960	9,080
Production	1401	Material and Supplies	4140	2,997	16,678	67,486	35,034	1,334
Production	1401	Material and Supplies	4190	138,456	131,798	18,488	79,493	209,867
Production	1401	Material and Supplies	4195			30,607	128,257	345,350
Production	1401	Material and Supplies	4210	239	780	571	9,267	11,857
Production	1401	Material and Supplies	4250	822	275	127	1,021	418
Production	1401	Material and Supplies	4251	106,360	669,224	479,803	112,831	357,527
Production	1401	Material and Supplies	4252	1,975		154	760	2,331
Production	1401	Material and Supplies	4253		699	782	12,387	11,134
Production	1401	Material and Supplies	4270		213	61	864	109
Production	1401	Material and Supplies	4300	340,608	596,267	468,590	403,049	804,282
Production	1401	Material and Supplies	4301	188,892	119,744	362,486	314,001	112,259
Production	1401	Material and Supplies	4302	616,744	991,145	1,050,537	515,202	390,956
Production	1401	Material and Supplies	4303	10,710	365	104,394	525	(32,930)
Production	1401	Material and Supplies	4304	2,280	4,603	165,570	85,561	39,337
Production	1401	Material and Supplies	4305	411,137	489,475	568,435	603,914	1,195,974
Production	1401	Material and Supplies	4306	651,552	249,591	136,560	79,002	77,324
Production	1401	Material and Supplies	4307	653,674	249,575	185,088	219,874	207,001
Production	1401	Material and Supplies	4308	887,494	75,128	593,720	198,516	458,630
Production	1401	Material and Supplies	4309					220
Production	1401	Material and Supplies	4310	2,262	2,611	7,650		2,013

Production	1401 Material and Supplies	4320	420,092	257,698	810,671	321,822	335,818
Production	1401 Material and Supplies	4321	8,441	14,279	272	19,117	(4,635)
Production	1401 Material and Supplies	4322	32,858	1,870	64,389	752	36,366
Production	1401 Material and Supplies	4323	415	173	497	36,541	2,305
Production	1401 Material and Supplies	4324	133	1,865		2,859	28,991
Production	1401 Material and Supplies	4326			42	164	2,941
Production	1401 Material and Supplies	4330			2,632	1,953	1,058
Production	1401 Material and Supplies	4990					70
Production	1401 Services	2030			(419)		
Production	1401 Services	2060			49		
Production	1401 Services	2110	20			139	
Production	1401 Services	2151				275	
Production	1401 Services	2160	14,991	13,301	4,097	4,523	14,529
Production	1401 Services	2240	104,368	309,109	207,895	114,506	52,939
Production	1401 Services	2241	57,327	59,262	43,624	44,892	213,326
Production	1401 Services	2242	56,287	104,593	52,433	80,728	114,815
Production	1401 Services	2243			3		
Production	1401 Services	2244	182,090	208,206	252,409	39,905	14,407
Production	1401 Services	2300	564		144,983	142,059	164,669
Production	1401 Services	2340	80			16,181	16,839
Production	1401 Services	2360	34,647	38,278	9,899	7,335	
Production	1401 Other Operating Expenses	5200					1,811
Production	**1401 Total**		**8,340,346**	**9,127,385**	**10,176,132**	**8,680,890**	**10,248,798**
Production	1402 Personnel Costs	1010	2,826,158	2,995,755	3,583,394	3,628,296	3,535,400
Production	1402 Personnel Costs	1020	323,088	288,669	315,109	366,140	431,552
Production	1402 Personnel Costs	1030	682,822	799,511	929,211	869,839	806,138
Production	1402 Personnel Costs	1040	267,860	424,937	191,384	166,277	66,288
Production	1402 Personnel Costs	1050	269,616	280,735	338,379	356,924	354,174
Production	1402 Personnel Costs	1070	45,999	48,899	60,006	62,404	60,484
Production	1402 Personnel Costs	1080	3,184	3,317	4,001	4,222	4,188
Production	1402 Personnel Costs	1090	243,603	253,755	305,814	320,663	317,853
Production	1402 Personnel Costs	1100	1,888	78,249	55,557	162,254	127,746
Production	1402 Personnel Costs	1110	121,596	120,554	163,770	218,988	127,677
Production	1402 Personnel Costs	1130	40,596	43,872	52,510	49,865	49,086
Production	1402 Personnel Costs	1180	7,116	7,220	7,498	9,436	8,912
Production	1402 Personnel Costs	1990	1,726	104	50,189	30,158	
Production	1402 Material and Supplies	4010	787	825	287	2,161	1,881
Production	1402 Material and Supplies	4050			93		
Production	1402 Material and Supplies	4100	58,144	118,113	37,349	74,885	62,451
Production	1402 Material and Supplies	4133	8,089				
Production	1402 Material and Supplies	4140	11,995	41	466		472
Production	1402 Material and Supplies	4160			778	703	3,055
Production	1402 Material and Supplies	4210	5,236	1,012	1,034	40,464	18,255
Production	1402 Material and Supplies	4250	13,531	571	1,731	1,876	798
Production	1402 Material and Supplies	4270			358	45	
Production	1402 Material and Supplies	4305				200	
Production	1402 Material and Supplies	4309	41,458	38,648	32,446	50,160	345,937
Production	1402 Material and Supplies	4320	(5,177)	200,715	132,025	32,471	342,270
Production	1402 Material and Supplies	4330	73,560	92,691	84,871	98,399	171,613
Production	1402 Services	2100			49		
Production	1402 Services	2150	373,169	255,305	253,272	136,401	248,839
Production	1402 Services	2151	5,238	15,100	16,884	13,128	16,372
Production	1402 Services	2160	15,910	5,210	982	332	276
Production	1402 Services	2200	1,811	2,310	1,901	2,136	2,084
Production	1402 Services	2240		454			
Production	1402 Ash Handling	3030	892,532	1,055,073	1,096,216	1,632,926	1,719,626
Production	1402 Off Road Fuel	3110	78,049	74,251	78,977	129,636	161,685
Production	1402 AQC Reagents	3025	882,420	965,232	1,054,251	1,741,084	2,177,436
Production	**1402 Total**		**7,292,004**	**8,171,128**	**8,850,792**	**10,202,473**	**11,162,548**
Production	1403 Personnel Costs	1010	69,329	100,028			
Production	1403 Personnel Costs	1030	9,128	19,094	(161)		
Production	1403 Personnel Costs	1040	13,736	9,844			
Production	1403 Personnel Costs	1050	5,996	8,686			
Production	1403 Personnel Costs	1070	1,078	1,510			
Production	1403 Personnel Costs	1080	71	103			
Production	1403 Personnel Costs	1090	5,428	7,590			
Production	1403 Personnel Costs	1100	(1,406)	1,146	161		

Production	1403 Personnel Costs	1110	5,319	2,248	161		
Production	1403 Personnel Costs	1130	416	737			
Production	1403 Personnel Costs	1180	28	188			
Production	1403 Personnel Costs	1990	35				
Production	1403 Material and Supplies	4010		38	260	4	
Production	1403 Material and Supplies	4195				24,000	
Production	1403 Material and Supplies	4301			15,471		
Production	1403 Material and Supplies	4302			16		
Production	1403 Material and Supplies	4305			436		
Production	1403 Material and Supplies	4310	(18,241)	211,630	1,297,152	96,249	484,068
Production	1403 Material and Supplies	4990	361				
Production	1403 Services	2000					22
Production	1403 Services	2030	252,480	156,502	483,573	316,071	546,467
Production	1403 Services	2160	21,889	18,143	6,381	198	2,582
Production	1403 Services	2190	310	102	50	72	36
Production	1403 Services	2210	23,506	7,405	22,205	6,615	14,769
Production	1403 Services	2240	111				
Production	1403 Services	2351	63,262	316,904	45,185	146,869	146,664
Production	1403 Other Operating Expenses	5200	12,426	32,252		8,130	
Production	**1403 Total**		**465,262**	**894,150**	**1,870,890**	**598,208**	**1,194,608**
Grand Total			**$ 16,402,711**	**$ 18,676,145**	**$ 21,285,187**	**$ 19,782,349**	**$ 23,386,487**

PDF of BPU Provided Excel File:
Sheet "1-7" in "DR #1 Sierra Club Final.xlxs."

1.7	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Installed Capacity	245	245	245	245	245	245	245	245	245	245
Unforced Capacity	196	208	208	203	208	208	196	208	208	203
Capacity Factor	42%	45%	47%	49%	51%	53%	55%	57%	57%	57%
Availability	80%	85%	85%	83%	85%	85%	80%	85%	85%	83%
Heat Rate	1150	1150	1150	1150	1150	1150	1150	1150	1150	1150
Effective forced outage Rate	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Fixed O&M cost	See Other Tab									
Non-Fuel Variable O&M cost	See Other Tab									
Coal Cost	$ 19,750,562	$ 21,584,543	$ 22,994,733	$ 24,452,697	$ 25,959,781	$ 27,517,368	$ 29,126,875	$ 30,789,754	$ 31,405,549	$ 32,033,660
Fuel Oil Cost	$ 1,442,459	$ 1,576,402	$ 1,679,393	$ 1,785,874	$ 1,895,942	$ 2,009,698	$ 2,127,247	$ 2,248,693	$ 2,293,667	$ 2,339,540

PDF of BPU Provided Excel File:
Sheet "1-7 Budget" in "DR #1 Sierra Club Final.xlxs."

	Dept	Class_Type	Class	2023	2024	2025	2026	2027	2028
Production	1400	Material and Supplies	4010	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520
Production	1400	Material and Supplies	4040	1,000	1,020	1,040	1,061	1,082	1,104
Production	1400	Material and Supplies	4140	150,000	153,000	156,060	159,181	162,365	165,612
Production	1400	Material and Supplies	4160	2,000	2,040	2,081	2,123	2,165	2,208
Production	1400	Material and Supplies	4170	5,000	5,100	5,202	5,306	5,412	5,520
Production	1400	Material and Supplies	4180	600,000	612,000	624,240	636,725	649,460	662,449
Production	1400	Material and Supplies	4990	1,000	1,020	1,040	1,061	1,082	1,104
Production	1400	Services	2200	10,000	10,200	10,404	10,612	10,824	11,040
Production	1400	Services	2243	200	204	208	212	216	220
Production	1400	Services	2250	100	102	104	106	108	110
Production	**1400 Total**			**774,300**	**789,786**	**805,581**	**821,693**	**838,126**	**854,887**
Production	1401	Personnel Costs	1010	3,029,939	3,105,687	3,183,329	3,262,912	3,344,485	3,428,097
Production	1401	Personnel Costs	1020	320,000	328,000	336,200	344,605	353,220	362,051
Production	1401	Personnel Costs	1030	752,637	771,453	790,739	810,507	830,770	851,539
Production	1401	Personnel Costs	1040	199,067	204,044	209,145	214,374	219,733	225,226
Production	1401	Personnel Costs	1050	284,745	291,864	299,161	306,640	314,306	322,164
Production	1401	Personnel Costs	1070	49,994	51,244	52,525	53,838	55,184	56,564
Production	1401	Personnel Costs	1080	3,350	3,434	3,520	3,608	3,698	3,790
Production	1401	Personnel Costs	1090	256,270	262,677	269,244	275,975	282,874	289,946
Production	1401	Personnel Costs	1100	35,450	36,336	37,244	38,175	39,129	40,107
Production	1401	Personnel Costs	1110	56,054	57,455	58,891	60,363	61,872	63,419
Production	1401	Personnel Costs	1130	39,389	40,374	41,383	42,418	43,478	44,565
Production	1401	Personnel Costs	1180	11,211	11,491	11,778	12,072	12,374	12,683
Production	1401	Material and Supplies	4050	20,000	20,400	20,808	21,224	21,648	22,081
Production	1401	Material and Supplies	4130	102,500	104,550	106,641	108,774	110,949	113,168
Production	1401	Material and Supplies	4131	50,000	51,000	52,020	53,060	54,121	55,203
Production	1401	Material and Supplies	4132	70,000	71,400	72,828	74,285	75,771	77,286
Production	1401	Material and Supplies	4133	20,000	20,400	20,808	21,224	21,648	22,081
Production	1401	Material and Supplies	4190	16,000	16,320	16,646	16,979	17,318	17,665
Production	1401	Material and Supplies	4195	325,000	331,500	338,130	344,893	351,791	358,827
Production	1401	Material and Supplies	4210	20,000	20,400	20,808	21,224	21,648	22,081
Production	1401	Material and Supplies	4251	504,300	514,386	524,674	535,167	545,870	556,787
Production	1401	Material and Supplies	4252	6,000	6,120	6,242	6,367	6,494	6,624
Production	1401	Material and Supplies	4253	4,000	4,080	4,162	4,245	4,330	4,417
Production	1401	Material and Supplies	4300	445,000	453,900	462,978	472,238	481,683	491,317
Production	1401	Material and Supplies	4301	87,000	88,740	90,515	92,325	94,172	96,055
Production	1401	Material and Supplies	4302	505,000	515,100	525,402	535,910	546,628	557,561
Production	1401	Material and Supplies	4303	60,000	61,200	62,424	63,672	64,945	66,244
Production	1401	Material and Supplies	4304	450,000	459,000	468,180	477,544	487,095	496,837
Production	1401	Material and Supplies	4305	545,000	555,900	567,018	578,358	589,925	601,724
Production	1401	Material and Supplies	4306	200,000	204,000	208,080	212,242	216,487	220,817
Production	1401	Material and Supplies	4307	200,000	204,000	208,080	212,242	216,487	220,817
Production	1401	Material and Supplies	4308	200,000	204,000	208,080	212,242	216,487	220,817
Production	1401	Material and Supplies	4320	87,000	88,740	90,515	92,325	94,171	96,054
Production	1401	Material and Supplies	4321	15,000	15,300	15,606	15,918	16,236	16,561
Production	1401	Material and Supplies	4322	15,000	15,300	15,606	15,918	16,236	16,561
Production	1401	Material and Supplies	4323	12,000	12,240	12,485	12,735	12,990	13,250
Production	1401	Material and Supplies	4324	17,000	17,340	17,687	18,041	18,402	18,770
Production	1401	Services	2160	107,500	109,650	111,843	114,080	116,361	118,688
Production	1401	Services	2240	88,000	89,760	91,555	93,386	95,254	97,159
Production	1401	Services	2241	274,000	279,480	285,070	290,771	296,586	302,518
Production	1401	Services	2242	100,000	102,000	104,040	106,121	108,243	110,408
Production	1401	Services	2244	30,000	30,600	31,212	31,836	32,473	33,122
Production	1401	Services	2340	12,500	12,750	13,005	13,265	13,530	13,801
Production	1401	Other Operating Expenses	5200	15,000	15,150	15,302	15,302	15,302	15,302
Production	**1401 Total**			**9,640,906**	**9,858,765**	**10,081,609**	**10,309,400**	**10,542,404**	**10,780,754**
Production	1402	Personnel Costs	1010	3,402,383	3,487,443	3,574,629	3,663,995	3,755,595	3,849,485
Production	1402	Personnel Costs	1020	250,000	256,250	262,656	269,222	275,953	282,852
Production	1402	Personnel Costs	1030	845,152	866,281	887,938	910,136	932,889	956,211
Production	1402	Personnel Costs	1040	223,537	229,125	234,853	240,724	246,742	252,911
Production	1402	Personnel Costs	1050	310,453	318,214	326,169	334,323	342,681	351,248
Production	1402	Personnel Costs	1070	56,139	57,542	58,981	60,456	61,967	63,516
Production	1402	Personnel Costs	1080	3,652	3,743	3,837	3,933	4,031	4,132
Production	1402	Personnel Costs	1090	279,407	286,392	293,552	300,891	308,413	316,123
Production	1402	Personnel Costs	1100	39,808	40,803	41,823	42,869	43,941	45,040
Production	1402	Personnel Costs	1110	62,944	64,518	66,131	67,784	69,479	71,216
Production	1402	Personnel Costs	1130	44,231	45,337	46,470	47,632	48,823	50,044
Production	1402	Personnel Costs	1180	12,589	12,904	13,227	13,558	13,897	14,244
Production	1402	Material and Supplies	4010	500	510	520	530	541	552
Production	1402	Material and Supplies	4100	62,500	63,750	65,025	66,326	67,653	69,006
Production	1402	Material and Supplies	4160	5,000	5,100	5,202	5,306	5,412	5,520
Production	1402	Material and Supplies	4210	25,000	25,500	26,010	26,530	27,061	27,602

Production	1402	Material and Supplies	4250	10,000	10,200	10,404	10,612	10,824	11,040
Production	1402	Material and Supplies	4309	71,900	73,338	74,805	76,301	77,827	79,384
Production	1402	Material and Supplies	4320	357,600	364,752	372,047	379,488	387,078	394,820
Production	1402	Material and Supplies	4330	120,000	122,400	124,848	127,345	129,892	132,490
Production	1402	Services	2150	282,000	287,640	293,393	299,261	305,246	311,351
Production	1402	Services	2151	16,250	16,575	16,907	17,245	17,590	17,942
Production	1402	Services	2160	10,000	10,200	10,404	10,612	10,824	11,040
Production	1402	Ash Handling	3030	1,530,000	1,552,950	1,545,185	1,529,733	1,514,436	1,514,436
Production	1402	Off Road Fuel	3110	100,000	101,500	100,993	99,983	98,983	98,983
Production	1402	AQC Reagents	3025	1,760,000	1,760,000	1,760,000	1,760,000	1,760,000	1,760,000
Production	**1402 Total**			**8,121,045**	**8,302,967**	**8,456,009**	**8,604,795**	**8,757,778**	**8,931,188**
Production	1403	Material and Supplies	4310	3,150,000	3,213,000	3,277,260	3,342,805	3,409,661	3,477,854
Production	1403	Services	2030	540,000	550,800	561,816	573,053	584,514	596,204
Production	1403	Services	2160	11,000	11,220	11,444	11,673	11,906	12,144
Production	1403	Services	2190	500	510	520	530	541	552
Production	1403	Services	2351	140,000	142,800	145,656	148,569	151,540	154,571
Production	1403	Other Operating Expenses	5200	10,000	10,100	10,201	10,201	10,201	10,201
Production	**1403 Total**			**3,851,500**	**3,928,430**	**4,006,897**	**4,086,831**	**4,168,363**	**4,251,526**
Production Total				**22,387,751**	**22,879,948**	**23,350,096**	**23,822,719**	**24,306,671**	**24,818,355**
Grand Total				**$ 24,147,751**	**$ 24,639,948**	**$ 25,110,096**	**$ 25,582,719**	**$ 26,066,671**	**$ 26,578,355**

1-7 See Spreadsheet – Tabs 1-7 and 1-7 Budget

1-8. Please provide annual SPP energy and (if any) ancillary service market revenues for Nearman for the period 2018–2022.

1.8		2018	2019	2020	2021	2022
	Nearman SPP Revenue	$ 28,825,552.42	$ 26,150,785.51	$ 24,937,103.72	$ 113,092,926.87	$ 61,968,570.65

1-9. Please provide total projected SPP energy and (if any) ancillary service market revenues for Nearman for the period 2023–2034.

Yr	AMT
2023	$ 26,491,276
2024	$ 29,414,399
2025	$ 31,829,622
2026	$ 34,372,527
2027	$ 37,048,112
2028	$ 39,861,540
2029	$ 42,193,064
2030	$ 44,601,904
2031	$ 45,493,942
2032	$ 46,403,821

1-10. Please provide the following for Nearman:

a. Historical capital expenditures since 2018 and through 2022.

	2018	2019	2020	2021	2022
N1 Common	$ 1,214,295	$ 5,559,079	$ 1,375,190	$ 2,279,021	$ 2,531,236
NI Plant	$ 19,268,548	$ 4,674,215	$ 7,596,076	$ 797,239	$ 2,078,195
	$ 20,482,843	$ 10,233,294	$ 8,971,266	$ 3,076,260	$ 4,609,431

b. Projected capital expenditures from 2023 through 2032.

**Only have capital project projections through 2027

	2023	2024	2025	2026	2027
N1 Common	$ 125,000	$ 150,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
NI Plant	$ 6,788,000	$ 6,010,000	$ 5,300,000	$ 5,600,000	$ 5,600,000
	$ 6,913,000	$ 6,160,000	$ 6,300,000	$ 6,600,000	$ 6,600,000

c. Provide a specific accounting of all projects and capital expenditures already scheduled or planned at each unit over the next ten years.

Exhibit SSH-2

Specific projects are listed below. **Only have capital project projections through 2027.

Description	Capital Expenditures by Year					
	2023 Budget	2024 Budget	2025 Budget	2026 Budget	2027 Budget	Total CIP Projects
Nearman Plant Unit 1						
100542 - N1 Boiler Future Projects	-	-	1,000,000	1,000,000	1,500,000	3,500,000
100543 - N1 Future Projects	-	-	2,500,000	2,500,000	2,500,000	7,500,000
100545 - N1 Turbine Future Projects	-	-	1,000,000	1,500,000	1,000,000	3,500,000
101188 - N1 No 5 FWH Replacement	350,000	550,000	-	-	-	900,000
101201 - N1 5KV Cables Replacement	220,000	200,000	-	-	-	420,000
101210 - N1 Drum & Heater Inst Upgrade	155,000	-	-	-	-	155,000
101213 - N1 MCC/Load Center Replace	250,000	575,000	200,000	-	-	1,025,000
102012 - N1 Volt Reg Conversion	160,000	-	-	-	-	160,000
103004 - N1 BOP PLC to DCS Upgrade	550,000	400,000	-	-	-	950,000
103006 - N1 SCR Doors	300,000	-	200,000	-	200,000	700,000
104020 - N1 SCR Catalyst Layer	550,000	600,000	400,000	600,000	400,000	2,550,000
104050 - N1 AQC Air Slide Blowers	300,000	-	-	-	-	300,000
104051 - N1 Automation of SH Spray Iso Vlvs	100,000	-	-	-	-	100,000
104052 - N1 Brnr Coal Nozzles and Heads Replacments	2,140,000	-	-	-	-	2,140,000
104054 - N1 Crusher/Dryer Replacement	100,000	385,000	-	-	-	485,000
104055 - N1 Demineralizer Rental Conversion	150,000	-	-	-	-	150,000
104056 - N1 Startup Transformer Rebuild	125,000	-	-	-	-	125,000
104089 - EP N1 Simulator WS to Ovation Upgrade	-	800,000	-	-	-	800,000
104091 - EP N1 ID Fan VFD Chillers	-	500,000	-	-	-	500,000
104104 - EP N1 PJFF Bags / Cages Replacement	500,000	2,000,000	-	-	-	2,500,000
104120 - EP N1 CT Acid Pumps Reconfiguration	150,000	-	-	-	-	150,000
104121 - EP N1 Gen Rewedge/RHSV Seat Restore	688,000	-	-	-	-	688,000
Total Nearman Plant Unit 1	**6,788,000**	**6,010,000**	**5,300,000**	**5,600,000**	**5,600,000**	**29,298,000**
Nearman Plant Common						
100549 - NC Coal Conveyor Belt - Replacement	75,000	-	-	-	-	75,000
100563 - NC Future Projects	-	-	1,000,000	1,000,000	1,000,000	3,000,000
104023 - NC Fire Protection System Upgrade	50,000	-	-	-	-	50,000
104059 - NC Mechanic Shop Roof Replacement	-	150,000	-	-	-	150,000
Total Nearman Plant Common	**125,000**	**150,000**	**1,000,000**	**1,000,000**	**1,000,000**	**3,275,000**

1-11. Please state whether BPU has any firm capacity contracts, wholesale energy contracts, and/or power purchase agreements. If yes, please provide these contracts.

BPU does not have any firm capacity contracts or wholesale energy contracts. In regards to the power purchase agreements, we are in the process of reviewing these documents for confidentiality obligation. Where appropriate, we will forward to you as soon as possible.

Annual Forecast (Sept 2021)

	Natural Gas (per mmBtu)	Coal (per mmBtu)	SPP Market Price (per Mwh on Peak)	SPP Market Price (per Mwh Off Peak)
January-22	$ 4.25	$ 2.01	$ 40.00	$ 21.00
February-22	$ 4.15	$ 2.03	$ 38.00	$ 19.00
March-22	$ 3.95	$ 2.04	$ 32.00	$ 14.00
April-22	$ 3.30	$ 2.06	$ 28.00	$ 14.00
May-22	$ 3.25	$ 2.03	$ 29.00	$ 14.00
June-22	$ 3.30	$ 1.99	$ 36.00	$ 16.00
July-22	$ 3.31	$ 2.00	$ 43.00	$ 21.00
August-22	$ 3.31	$ 1.98	$ 43.00	$ 21.00
September-22	$ 3.15	$ 2.00	$ 36.00	$ 18.00
October-22	$ 3.16	$ 1.95	$ 28.00	$ 12.00
November-22	$ 3.20	$ 1.97	$ 28.00	$ 12.00
December-22	$ 3.27	$ 1.96	$ 30.00	$ 14.00

Annual Forecast (Sept 2022)

	Natural Gas (per mmBtu)	Coal (per mmBtu)	SPP Market Price (per Mwh on Peak)	SPP Market Price (per Mwh Off Peak)
January-23	$ 9.46	$ 2.30	$ 62.00	$ 31.00
February-23	$ 8.59	$ 2.29	$ 58.00	$ 29.00
March-23	$ 7.31	$ 2.29	$ 44.00	$ 22.00
April-23	$ 5.43	$ 2.29	$ 36.00	$ 16.00
May-23	$ 5.39	$ 2.29	$ 36.00	$ 16.00
June-23	$ 5.46	$ 2.26	$ 44.00	$ 21.00
July-23	$ 5.51	$ 2.26	$ 55.00	$ 27.00
August-23	$ 5.52	$ 2.26	$ 55.00	$ 27.00
September-23	$ 5.43	$ 2.25	$ 44.00	$ 21.00
October-23	$ 5.46	$ 2.22	$ 36.00	$ 16.00
November-23	$ 5.59	$ 2.23	$ 36.00	$ 16.00
December-23	$ 5.74	$ 2.23	$ 40.00	$ 20.00

1-15. Please state whether BPU has had any challenges or disruptions in the delivery of coal since 2020. If yes, please provide the following information on all disruptions:

a. Date and duration of the disruption
April 10th to June 27th, 2022.

b. Description of the disruption
Yearly coal car maintenance was scheduled around April 10th, 2022. This is normally a 2-week evolution depending on identified repair scope. Union Pacific was delayed in getting power back on the car set until May 18th, 2022 thereby impacting deliveries to Nearman. Additionally, Union Pacific experienced a short-term labor dispute in 2022.

c. Quantity of coal expects and quantity of coal delivered
On average we expect to see between 45 to 60 KTONS/month in March and April we saw 27 KTONS.

d. Unit derating impact (if any)
Nearman 1 limited to 2 Mill (150-210 MW gross) operation May 27th to May 30th. Continued De-rate after observation until June 27th. On the 27th we released unit to 3 Mill on peak and 2 Mill off peak. Returned to Market dispatch July 5th.

e. Cost to BPU of the delay
It is anticipated that the coal constraints added an additional $960,000 in purchase power costs. This however does not consider the additional long-term wear and tear costs that were saved due to the de-rates.

1-16. Please state whether Nearman was online and available at full rating during winter storm Uri (February 13–17, 2021). If no, please provide the following information:

a. Explain the reason for the outage
b. Provide the time and date the outage began
c. Provide the time and date the unit was available at full capacity again
d. Available capacity by hour between February 13 and February 17, 2021
e. Hourly generation between February 13 and February 17, 2021
f. Hourly LMPs at Nearman between February 13 and February 17, 2021
g. The source and cost of replacement power during the period that Nearman was offline between February 13 and 17, 2021

1-16 See Spreadsheet – Tab 1-16

1-17. State whether Nearman was online and available at full rating during winter storm Elliot (December 21 – 26, 2022). If no, please provide the following information:

a. Explain the reason for the outage
b. Provide the time and date the outage began
c. Provide the time and date the unit was available at full capacity again
d. Available capacity by hour between December 21 and December 26, 2022
e. Hourly generation between December 21 and December 26, 2022
f. Hourly LMPs at Nearman between December 21 and December 26, 2022
g. The source and cost of replacement power during the period that Nearman was offline between December 21 and December 26, 2022

1-17 See Spreadsheet – Tab 1-17

1-18. State the current retirement date for Nearman.
Based on the last analysis, the projected retirement date is 2040

1-19. State the date by which BPU expects Nearman to be fully depreciated.

As of 12/31/2022, the last asset will be depreciated on September of 2050

1-20. Has BPU conducted an economic or resource plan evaluation assessing any earlier retirement dates than the currently planned date for Nearman? If yes, please provide all documents reflecting such analyses.

There have not been any such studies conducted.

Exhibit SSH-2

1-17a N/A

1-17b N/A

1-17c N1 1 de-rate 12/22/22 @1837 to 12/24/24 @ 2111. Limited to 150MW net due to frozen instrument air lines inhibiting ability to convey fly ash in the B side circulating dry scrubber surge bins. A subsequent de-rate occurred from 12/26/22 @1644 to 12/27/22 @1957 to 230MW net. This was

1-17d De-Rates and Net MW ranges and times described in 1-17c

1-17e Hourly N1 Gen Net

Date	MDSL	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
12/21/2022	KACYNEAF	229	231	227	232	229	230	226	225	224	224	228	205	205	218	219	223	227	227	229	228	198	191	190	188
12/22/2022	KACYNEAF	187	188	189	188	191	188	192	195	198	190	190	205	228	225	229	221	212	217	211	185	190	187	155	148
12/23/2022	KACYNEAF	152	150	152	144	141	142	140	142	142	140	141	141	139	143	139	143	141	140	143	140	142	142	140	140
12/24/2022	KACYNEAF	142	142	141	141	140	142	141	140	141	141	140	143	140	144	142	143	144	159	182	183	210	231	232	233
12/25/2022	KACYNEAF	234	232	227	226	230	234	232	227	226	220	211	197	189	188	186	186	188	186	188	187	186	188	191	216
12/26/2022	KACYNEAF	200	193	189	187	187	188	188	188	190	192	197	201	190	215	231	232	219	218	219	228	227	225	228	228

1-17f Hourly LMP

Date	Settlemen	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
12/21/2022	KACYNEAF	147.3	50.82	45.16	48.6	59.72	67.89	211.28	227.85	103.74	54.58	74.37	19.42	29.15	49.08	28.21	26.94	34.11	38.36	29.45	28.52	21.36	19.54	4.96	5.61
12/22/2022	KACYNEAF	6.82	-1.58	-4.46	-2.78	4.29	15.05	20.41	21.53	21	24.36	23.89	30.39	37.72	101.07	129.25	143.93	124.02	353.71	423.86	366.6	371.32	374.87	304.28	215.17
12/23/2022	KACYNEAF	171.4	178.56	283.98	320.81	314.69	385.61	426.4	462.55	492.03	331.92	361.93	243.55	259.98	203.25	214.55	246.47	279.66	1,390.52	430.23	315.76	336.64	207.32	253.15	197.88
12/24/2022	KACYNEAF	83.87	17.95	46.17	40.03	38.09	59.3	88.8	96.55	26.37	50.62	72.81	82.08	79.9	71.04	63.33	68.28	83.63	179.61	88.11	52.49	106.02	45.97	94.83	97.45
12/25/2022	KACYNEAF	86.61	98.3	63.7	63.11	79.85	79.23	87.49	68.34	35.89	33.72	26.8	19.41	9.87	3.41	-14.04	-6.92	20.57	-6.62	9.94	0.49	1.68	5.8	15.97	15.2
12/26/2022	KACYNEAF	15.93	-15.02	-21.73	-22.59	-35.38	-27.56	-37.91	-22.83	-16.98	10.1	18.1	26.02	30.48	73.68	174.39	123.78	105.22	123.81	104.65	122.87	102.58	90.84	75	113.63

1-17g Any replacement power would be purchased from the market at LMP Rate shown in 1-17f

PDF of BPU Provided Excel File:
Sheet "1-17" in "DR #1 Sierra Club Final.xlxs."

Exhibit SSH-2

1-21. Please provide unredacted, in native format with all formulas intact, all analyses or assessments that study the value of continued operation for Nearman (e.g., all retirement studies, unit condition assessments, or deactivation assessments) conducted since 2018, including, but not limited to, all studies, presentations, reports, or other assessments conducted to determine how to comply with any existing, impending, or potential environmental regulation.

There have not been any such analysis or assessments done.

1-22. Please provide the following for BPU, with supporting workpapers (in electronic, machine-readable format):

a. Annual peak load since 2018 (or earliest available).
b. Annual energy sales since 2018 (or earliest available).
c. Annual generation since 2018 (or earliest available).
d. Annual off-system energy sales in GWhs since 2018 (or earliest available).
e. Annual off-system energy sales revenues in dollars since 2018 (or earliest available)
f. Annual off-system energy purchases in GWhs since 2018 (or earliest available).
g. Annual off-system energy purchases revenues in dollars since 2018 (or earliest available).

1-22a		2018	2019	2020	2021	2022
	Peak Load (MW)	496	483	437	464	485
1-22b		2018	2019	2020	2021	2022
	Annual Energy Sales (MWh)	2,674,307.196	2,616,897.137	2,419,997.834	2,419,143.624	2,543,193.361
1-22c	Annual Generation (MWh)	2018	2019	2020	2021	2022
	N 1	968,881	1,059,210	1,070,251	1,272,074	1,189,220
	Q 1	10,846	-	-	-	-
	Q 2	14,573	-	-	-	-
	CT 2	844	2,866	1,210	4,619	4,950
	CT 3	1,234	2,867	1,871	5,983	4,575
	CT 4	7,420	8,809	5,547	54,028	36,586
	DOGWOOD	346,592	409,691	365,936	307,544	311,321
	BOWERSOCK	26,315	20,475	32,407	29,950	23,678
	OAK GROVE	19,510	14,808	16,419	11,818	15,040
	SMOKY HILLS	87,340	98,116	78,775	83,827	78,132
	SPA (Peaking)	46,320	46,320	48,090	46,320	46,317
	SPA (Supplemental)	48,065	100,636	89,358	71,587	50,638
	WAPA	14,719	14,790	14,790	14,776	14,790
	ALEXANDER	102,385	106,921	104,803	101,612	104,257
	CIMMARON	877,905	889,198	909,258	806,249	869,830
	BPU COMM SOLAR	1,707	1,728	1,807	1,736	1,819
1-22d	None					
1-22e	None					
1-22f	None					
1-22g	None					

1-23. Has BPU conducted any analyses or assessments evaluating the impacts of the Inflation Reduction Act on the continued operation, replacement, or retirement of Nearman (e.g., all retirement studies, unit condition assessments, or deactivation assessments)? If yes, please provide all analyses, unredacted and in native format with all formulae intact.

No, but we continue to evaluate all opportunities.

Via: E-Mail

April 24, 2023

M E M O R A N D U M

From: Sierra Club

Teresa A. Woody
Kansas Appleseed
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Re: Discovery for the Board of Public Utilities ("BPU")

Sierra Club respectfully requests that BPU provide responses to these data requests.

2-1. Please refer to the fixed capacity contract costs discussed on page 10 of Craig Brown's direct testimony.

a. Provide the fixed capacity value for each contract (e.g., $/kW-month, $/MW-day, etc.)

WAPA	4,787 KW	$4.80	KW/Month
SPA	38,600 KW	$4.53	KW/Month

b. Please provide fixed capacity contracts (or contracts with capacity components, including power purchase agreements, wholesale energy contracts, etc.).

Provided in a separate attachment are the PPAs that are not covered by a confidentiality provision. (See WAPA, SPA, and Community Solar/MCP)

2-2. Please refer to BPU's response to Sierra Club data request 1-9, total projected SPP market revenues.

a. State the date when these revenues were calculated. March 2023 Data

b. Are there more recent energy revenue projections? If so, please provide these most recent revenue projections to 2032. No

Expiration 9/2024

Department of Energy
Western Area Power Administration
Rocky Mountain Customer Service Region
P.O. Box 3700
Loveland, CO 80539-3003

SEP 25 2014

Mr. Don L. Gray
General Manager
Board of Public Utilities of
Kansas City, Kansas
540 Minnesota Avenue
Kansas City, KS 66101-2789

Dear Mr. Gray:

The following executed exhibits to Western Area Power Administration's (Western) Contract No. 04-RMR-1486 Firm Electric Service, with the Board of Public Utilities of the City of Kansas City, Kansas are enclosed.

1. Exhibit A, Revision No. 2 that identifies the delivery obligation; and
2. Exhibit B, Revision No. 2 that specifies the maximum purchase obligation.

Western appreciates your cooperation in executing these exhibits that become effective October 1, 2014.

Sincerely,

Linda Swails
Office of Power Marketing

2 Enclosures

EXHIBIT A
Revision No. 2
Contract No. 04-RMR-1486
BOARD OF PUBLIC UTILITIES
OF THE CITY OF KANSAS
CITY, KANSAS

DELIVERY OBLIGATION

1. This Exhibit A, made this 24th day of September, 2014, to be effective October 1, 2014, under and as a part of Contract No. 04-RMR-1486, dated September 22, 2004, hereinafter called the Contract, shall become effective on the date first written above and shall remain in effect until superseded by another Exhibit A; Provided, That this Exhibit A or any superseding Exhibit A shall terminate upon expiration of the Contract.

2. SEASONAL ENERGY AND CONTRACT RATES OF DELIVERY FOR FIRM POWER:

2.1 Upon the effective date of this Exhibit A and continuing through the last day of the September 2024 billing period, the Seasonal Energy during the Winter Season shall be 7,037,874 kilowatthours; and the Seasonal Energy during the Summer Season shall be 7,752,544 kilowatthours.

2.2 Upon the effective date of this Exhibit A and continuing through the last day of the September 2024 billing period, the Contract Rate of Delivery (CROD) for firm power during the Winter Season shall be 4,787 kilowatts, and the CROD for the Summer Season shall be 4,788 kilowatts.

3. MONTHLY ENERGY: Pursuant to Section 7.1 of the Contract, the amounts of Monthly Energy based upon the percentages of Seasonal Energy that Kansas City BPU is entitled to use each month are as follows. The Monthly Energy will be prorated to the Point(s) of Delivery based upon each Point of Delivery's share of the Contract Rate of Delivery as set forth in Section 5 of this Exhibit A:

Winter Season	MONTHLY ENERGY (kWh)	PERCENT OF SEASONAL ENERGY (%)
October	1,189,401	16.9
November	1,189,401	16.9
December	1,302,007	18.5
January	1,266,817	18.0
February	999,378	14.2
March	1,090,870	15.5
TOTAL WINTER SEASON ENERGY:	7,037,874	100

Summer Season	MONTHLY ENERGY (kWh)	PERCENT OF SEASONAL ENERGY (%)
April	1,131,871	14.6
May	1,186,139	15.3
June	1,364,448	17.6
July	1,705,560	22.0
August	1,364,448	17.6
September	1,000,078	12.9
TOTAL SUMMER SEASON ENERGY:	7,752,544	100

4. MONTHLY CAPACITY: Pursuant to Section 7.1 of the Contract, Kansas City BPU's Monthly Capacity based upon the percentages of the Contract Rate of Delivery listed below shall be as follows. The monthly percentages of CROD listed below will be applied to the CROD at the Point(s) of Delivery set forth in Section 5 of this Exhibit A:

Winter Season	MONTHLY CAPACITY (kW)	PERCENT OF CROD (%)
October	4,433	92.6
November	4,366	91.2
December	4,787	100.0
January	4,657	97.3
February	4,327	90.4
March	3,925	82.0

Summer Season	MONTHLY CAPACITY (kW)	PERCENT OF CROD (%)
April	3,955	82.6
May	3,711	77.5
June	4,453	93.0
July	4,788	100.0
August	4,209	87.9
September	4,089	85.4

5. POINTS OF DELIVERY AND VOLTAGES: The firm electric service being sold under the Contract will be delivered at the following point(s) and voltage(s) as provided in Section 7.5 of the Contract:

EXHIBIT A
Revision No. 2
Contract No. 04-RMR-1486
BOARD OF PUBLIC UTILITIES
OF THE CITY OF KANSAS
CITY, KANSAS

POINT OF DELIVERY	NOMINAL VOLTAGE (kV)	CROD Summer (kW)	CROD Winter (kW)
Sidney-East Substation			
TOTAL:		4,788	4,787

6. MINIMUM HOURLY DELIVERY: Kansas City BPU's Minimum Hourly Delivery as provided for in Section 7.4 of the Contract, shall be:

Winter Season	MINIMUM HOURLY DELIVERY (kW)	PERCENT OF CROD (%)
October	909	19
November	909	19
December	1,053	22
January	1,005	21
February	814	17
March	814	17

Summer Season	MINIMUM HOURLY DELIVERY (kW)	PERCENT OF CROD (%)
April	910	19
May	1,005	21
June	1,149	24
July	1,532	32
August	1,197	25
September	814	17

Exhibit SSH-2

The Parties have caused this Exhibit A to be duly executed the date first written above.

WESTERN AREA POWER ADMINISTRATION

By: /David Neumayer/
David Neumayer

Title: Power Marketing Manager
Rocky Mountain Region

Address: Western Area Power Administration
P.O. Box 3700
Loveland, CO 80539-3003

BOARD OF PUBLIC UTILITIES OF THE CITY OF KANSAS CITY, KANSAS

By: Don I Gray

Title: GEN MGR

Address: 540 MINNESOTA AVE.
Kansas City, KS 66101

(SEAL)

Attest:

By: Jenny Burley-Krenzer

Date: 9/9/14

Exhibit B
Revision No. 2
Contract No. 04-RMR-1486
BOARD OF PUBLIC UTILITIES
OF THE CITY OF KANSAS
CITY, KANSAS

MAXIMUM PURCHASE OBLIGATION

1. This Exhibit B, made this 24th day of September, 2014, to be effective October 1, 2014, under and as a part of Contract No. 04-RMR-1486, dated September 22, 2004, hereinafter called the Contract, shall become effective on the date first written above and shall remain in effect until superseded by another Exhibit B; Provided, That this Exhibit B or any superseding Exhibit B shall terminate upon expiration of the Contract.

2. The maximum amounts of capacity to be purchased by Western for Kansas City BPU pursuant to Section 7.1.2 of the Contract shall be the monthly amounts set forth below:

Winter Season	AMOUNTS TO BE PURCHASED (kW)
October	232
November	217
December	247
January	240
February	247
March	277

Summer Season	AMOUNTS TO BE PURCHASED (kW)
April	227
May	207
June	160
July	254
August	221
September	214

The Parties have caused this Exhibit B to be duly executed the date first written above.

WESTERN AREA POWER ADMINISTRATION

By: _____
David Neumayer

Title: Power Marketing Manager
Rocky Mountain Region

Address: Western Area Power Administration
P.O. Box 3700
Loveland, CO 80539-3003

BOARD OF PUBLIC UTILITIES OF THE CITY OF KANSAS CITY, KANSAS

By: Don L Gray

Title: GEN MGR

Address: 540 Minnesota Ave.
Kansas City, KS. 66101

(SEAL)

Attest:

By: Jerry Burley-Krenzer

Date: 9/9/14

KANSAS CITY BPU
THE POWER OF COMMUNITY

Exhibit SSH-2

April 15, 2020

Kristin Littlefield
Public Utilities Specialist
One W Third Street, Suite 1600
Tulsa, OK 74103

Dear Mrs. Littlefield

Enclosed are the two signed copies of the Power Sales Contract between Southwestern Power Administration and Kansas City Board of Public Utilities. It is understood that this contract has been designated by Southwestern as Contract No. DE-PM75-20SW00791 and it will replace Contract No. DE-PM75-07SW00556 upon the termination of Contract No. DE-PM75-07SW00556 on June 30, 2020. The proposed contract continues to provide for Southwestern to sell and deliver, and for BPU to purchase and receive or cause to be received, up to 47,200 kilowatts of hydroelectric power and associated energy, beginning July 1, 2020 and ending June 30, 2035.

Upon arrival, if there are any questions or concerns you may have, please feel free to contact me at 913-573-6821, or by email at dcalhoun@bpu.com.

Regards,

Darrell J. Calhoun
Sr. Electric Supply Planner
Electric Supply Administration Office

Department of Energy
Southwestern Power Administration
One West Third Street, Suite 1600
Tulsa, Oklahoma 74103-3502

Exhibit SSH-2

MAR 10 2020

Darrell J. Calhoun
Sr. Electric Supply Planner
Electric Supply Administration Office
Board of Public Utilities
312 N. 65th St.
Kansas City, KS 66102

Dear Mr. Calhoun:

Enclosed for execution are three copies of a proposed, partially executed Power Sales Contract between Southwestern Power Administration (Southwestern) and Kansas City Board of Public Utilities (BPU). This contract has been designated by Southwestern as Contract No. DE-PM75-20SW00791, and it will replace Contract No. DE-PM75-07SW00556 upon the termination of Contract No. DE-PM75-07SW00556 on June 30, 2020. The proposed contract continues to provide for Southwestern to sell and deliver, and for BPU to purchase and receive or cause to be received, up to 47,200 kilowatts of hydroelectric power and associated energy, beginning July 1, 2020 and ending June 30, 2035.

Please do not unstaple the stapled copies of the contract. An unstapled copy is included for your internal use.

If the proposed contract is satisfactory, please complete your processing as follows:

1. Have the appropriate official sign the three stapled copies of the contract in the BPU signature block.
2. Have the appropriate official attest the signature and affix BPU's official seal to the signature page of each stapled copy.
3. Date each stapled copy of the contract on page 1 with the date BPU signed the contract.
4. Send two copies of the fully executed contract to:
   ATTN: Kristin Littlefield
   Southwestern Power Administration
   1 W 3rd St, Suite 1600
   Tulsa, OK 74103-3502
5. Retain one copy of the fully executed contract for BPU's records.

Per the enclosed resolution, BPU's General Manager has been authorized to sign contracts with Southwestern relating to the purchase and sale of hydroelectric energy, so no further resolution is required at this time.

If additional information is needed about processing the proposed contract, please call me at (918) 595-67621or email kristin.littlefield@swpa.gov.

Sincerely,

Kristin Littlefield
Division of Power Marketing
and Transmission Strategy

Enclosures (3)(1)

Exhibit SSH-2

Contract No. DE-PM75-20SW00791

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

POWER SALES CONTRACT

BETWEEN

UNITED STATES OF AMERICA

AND

BOARD OF PUBLIC UTILITIES OF
THE CITY OF KANSAS CITY, KANSAS

Article		Title	Page
Preamble			
Preliminary Recitals			
I		DEFINITIONS	2
	1.	Contract Year	2
	2.	Demand Period	2
	4.	Excess Energy Rate Schedule	3
	5.	Federal Energy	3
	6.	Federal Power	3
	7.	General Contract Provisions	3
	8.	Hydro Peaking Power Rate Schedule	3
	9.	Month and Billing Period	3
	10.	Peaking Energy Scheduling Submission Time	3
	11.	Scheduling Agent	3
	12.	System of BPU	4
	13.	System of Southwestern	4
	14.	Transmission Agent	4
	15.	Uncontrollable Force	4
II		SALE OF HYDRO PEAKING POWER AND ASSOCIATED ENERGY BY SOUTHWESTERN	5
	1.	Sale of Hydro Peaking Power	5
	2.	Peaking Contract Demand	5
	3.	Sale of Peaking Energy by Southwestern	6
	4.	Utilization of Peaking Energy	6
	5.	Scheduling of Peaking Energy	7
	6.	Sale and Scheduling of Supplemental Peaking Energy	8
	7.	Compensation by BPU to Southwestern for Hydro Peaking Power and Associated Energy	9
	8.	Points of Delivery	10

III	SALE OF EXCESS ENERGY BY SOUTHWESTERN		11
	1.	Sale of Excess Energy	11
	2.	Notice of Availability	11
	3.	Notice of Purchase by BPU	11
	4.	Points of Delivery and Scheduling of Excess Energy	12
	5.	Compensation by BPU to Southwestern for Excess Energy	12
IV	DESIGNATION OF SCHEDULING AGENT AND TRANSMISSION AGENT BY BPU		12
	1.	Statement of Intent and Purpose	12
	2.	Designation and Authority of Scheduling Agent	13
	3.	Designation of Transmission Agent	13
	4.	Acceptance and Receipt by Agent(s)	13
	5.	Changes in Scheduling and Transmission Agent(s) or in Authority of Such Agent(s)	13
V	CHARACTER OF DELIVERIES, POWER FACTOR, AND INADVERTENT FLOW		14
	1.	Character of Deliveries	14
	2.	Power Factor	14
	3.	Inadvertent Flow and Balancing Off	14
VI	REIMBURSABLE WORK		15
	1.	Purpose	15
	2.	Reimbursable Work	16
VII	EFFECTIVE DATE, TERM, CONTINGENCIES, NOTICES, REPORTS, INFORMATION, AND OTHER GENERAL PROVISIONS		17
	1.	Effective Date and Term of Contract	17
	2.	Contingencies Related to Other Contracts	17
	3.	Notices	18
	4.	Reports and Information	19
	5.	General Contract Provisions	19
	6.	Choice of Law	19
	7.	Federal Statutes	19

Exhibits:
"1" – General Contract Provisions, 100517
"2" – Rate Schedule P-13A
"3" – Rate Schedule EE-13

Exhibit SSH-2

Contract No. DE-PM75-20SW00791

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

POWER SALES CONTRACT

BETWEEN

UNITED STATES OF AMERICA

AND

BOARD OF PUBLIC UTILITIES OF
THE CITY OF KANSAS CITY, KANSAS

THIS POWER SALES CONTRACT (hereinafter "Contract"), made and entered into this _____ day of _____, 2020, by and between the UNITED STATES OF AMERICA, represented by the Secretary of Energy, acting by and through the Administrator, Southwestern Power Administration (hereinafter "Southwestern"), an Administration within the Department of Energy, and the BOARD OF PUBLIC UTILITIES OF THE CITY OF KANSAS CITY, KANSAS (hereinafter "BPU"), a municipal corporation organized and existing under the laws of the State of Kansas, acting through its duly authorized officials (Southwestern and BPU being hereinafter sometimes referred to individually as "Party" and collectively as "Parties");

WITNESSETH, That,

WHEREAS, pursuant to Section 302(a)(1) of the Department of Energy Organization Act (91 Stat. 578; 42 U.S.C. 7152), Section 5 of the Flood Control Act of 1944 (58 Stat. 887, 890; 16 U.S.C. 825s), and Public Law 95-456 (92 Stat. 1230; 16 U.S.C. 825s-3), the Secretary of Energy is authorized to transmit and dispose of electric power and energy generated at reservoir projects under the control of the Department of the Army; and

WHEREAS, the Administrator of Southwestern has been delegated the authority to market available hydroelectric power and energy; and

WHERAS, on June 15, 2007, the parties entered into Contract No. DE-PM75-07SW00556 (hereinafter "Contract 556"), which provides for, among other things, the sale of Federal Power and Federal Energy and associated services; and

WHEREAS, Contract-556 is scheduled to expire June 30, 2020; and

WHEREAS, the Parties hereto desire to provide for the continued purchase by BPU of Federal Power and Federal Energy from Southwestern, all pursuant to the terms and conditions set forth hereunder; and

WHEREAS, BPU's electric facilities are not connected to transmission facilities owned and operated by Southwestern; and

WHEREAS, BPU is required to make separate Contractual arrangements in order to provide for scheduling and delivery of the Federal Power and Federal Energy purchased by BPU from Southwestern under this Contract;

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the Parties Contract and agree as follows:

ARTICLE I
DEFINITIONS

Section 1. Contract Year. The term "Contract Year," as used in this Contract, shall mean the 12-month period beginning on July 1st of each calendar year and extending through June 30th of the following year.

Section 2. Demand Period. The term "Demand Period," as used in this Contract, shall be as defined in Southwestern's applicable rate schedule.

Section 3. Excess Energy Rate Schedule. The term "Excess Energy Rate Schedule," as used in this Contract, shall mean Southwestern's "Wholesale Rates for Excess Energy" rate schedule, or its successor, as of the effective date of this Contract, EE-13.

Section 4. Federal Energy. The term "Federal Energy," as used in this Contract, shall mean energy provided from the System of Southwestern.

Section 5. Federal Power. The term "Federal Power," as used in this Contract, shall mean power provided from the System of Southwestern.

Section 6. General Contract Provisions. Provisions applicable to this Contract are set forth in Section 5 of Article VII of this Contract.

Section 7. Hydro Peaking Power Rate Schedule. The term "Hydro Peaking Power Rate Schedule," as used in this Contract, shall mean Southwestern's "Wholesale Rates for Hydro Peaking Power" rate schedule, or its successor, as of the effective date of this Contract, P-13A.

Section 8. Month and Billing Period. The terms "month" and "billing period," as used in this Contract, shall each mean the period beginning on the first day and extending through the last day of each calendar month.

Section 9. Peaking Energy Scheduling Submission Time. The term "Peaking Energy Scheduling Submission Time," as used in this Contract, shall mean the time Southwestern requires BPU to submit its Peaking Energy Schedule in accordance with Southwestern's Hydro Peaking Power Rate Schedule.

Section 10. Scheduling Agent. The term "Scheduling Agent," as used in this Contract, shall mean the entity which BPU has designated in writing to Southwestern as its agent pursuant to Section 2 of Article IV of this Contract.

Section 11. System of BPU. The term "System of BPU," as used in this Contract, shall mean the generation, transmission, and related facilities owned by BPU and/or the generation, transmission, and related facilities owned by others, the capacity of which, by Contract, is available to and utilized by BPU to satisfy its requirements and obligations to Southwestern under this Contract.

Section 12. System of Southwestern. The term "System of Southwestern," as used in this Contract, shall mean the generation, transmission, and related facilities owned by Southwestern and/or the generation, transmission, and related facilities owned by others, the capacity of which, by Contract, is available to and utilized by Southwestern to satisfy its requirements and obligations to BPU under this Contract.

Section 13. Transmission Agent. The term "Transmission Agent," as used in this Contract, shall mean the entity which BPU has designated, in writing, to Southwestern, as its agent pursuant to Section 3 of Article IV of this Contract.

Section 14. Uncontrollable Force. The term "Uncontrollable Force," as used in this Contract, shall mean any force which is not within the control of the Party affected, including, but not limited to, failure of water supply, failure of facilities, flood, earthquake, storm, lightning, fire, epidemic, riot, civil disturbance, labor disturbance, sabotage, war, act of war, terrorist acts, or restraint by court of general jurisdiction, which by exercise of due diligence and foresight such Party could not reasonably have been expected to avoid.

ARTICLE II

SALE OF HYDRO PEAKING POWER
AND ASSOCIATED ENERGY BY SOUTHWESTERN

Section 1. Sale of Hydro Peaking Power. (a) Subject to the provisions of Section 1(b) of this Article II, Southwestern shall sell and make available, and BPU shall purchase, up to 47,200 kilowatts of Federal Power (hereinafter "Hydro Peaking Power") as set forth below:

(i) Beginning on the first day of July 2020 through the term of this Contract:

38,600 kilowatts; and

(ii) Beginning on the first day of the month following the date that all six generating units at the Harry S. Truman project have been declared in commercial operation by Southwestern at full capacity (160,000 kilowatts) without operational constraints which would restrict the generating capability of such project and that such units are interconnected with the System of Southwestern, and thereafter during the remainder of the term of this Contract:

8,600 kilowatts.

Furthermore, BPU shall purchase and receive or cause to be received associated Federal Energy as set forth in this Article II. Nothing in this Section 1 shall require BPU to purchase and receive or cause to be received Hydro Peaking Power with associated Federal Energy in any manner or quantity except as provided for in this Contract.

(b) The Parties understand and agree that the sale of such Federal Power and Federal Energy under this Article II is contingent upon the absence of all Uncontrollable Forces and other contingencies set forth herein which may make any part or all of these quantities unavailable for sale by Southwestern.

(c) Notwithstanding Section 1(b) of this Article II, Southwestern shall make reasonable efforts to perform its obligations in the event of an Uncontrollable Force.

Section 2. Peaking Contract Demand. The "Peaking Contract Demand" shall be the maximum rate in kilowatts at which Southwestern is obligated to deliver Federal Energy

associated with Hydro Peaking Power as set forth in Section 1(a) of this Article II. The Peaking Contract Demand shall be equal to the quantity of Hydro Peaking Power specified in Section 1(a) of this Article II.

Section 3. Sale of Peaking Energy by Southwestern. During each Contract Year, Southwestern shall sell and make available, and BPU shall purchase and receive or cause to be received, a quantity of Federal Energy to accompany Hydro Peaking Power (hereinafter "Peaking Energy") equal to 1,200 kilowatt-hours per kilowatt of Peaking Contract Demand.

Section 4. Utilization of Peaking Energy. (a) Peaking Energy purchased by BPU under Section 3 of this Article II shall be utilized by BPU in quantities of:

(i) Not less than 60 kilowatt-hours per kilowatt of BPU's Peaking Contract Demand during any one month; and

(ii) Not greater than 200 kilowatt-hours per kilowatt of BPU's Peaking Contract Demand during any one month; and

(iii) Not greater than 600 kilowatt-hours per kilowatt of BPU's Peaking Contract Demand during any four consecutive months, irrespective of Contract Year.

(b) If, during any month, BPU or its Scheduling Agent fails to cause the utilization of the minimum quantity of Peaking Energy specified in Section 4(a)(i) of this Article II, Southwestern's invoice for service during such month shall include a charge for such minimum quantity of Peaking Energy.

(c) If, during any Contract Year, BPU or its Scheduling Agent fails to cause the utilization of the quantity of Peaking Energy specified in Section 3 of this Article II, Southwestern's invoice for service during the last month of such Contract Year shall include a charge for the quantity of Peaking Energy which BPU is obligated to purchase but which was not utilized in accordance with this Section 4.

(d) BPU understands that it forgoes entitlement to any quantity of Peaking Energy which was purchased pursuant to Sections 4(b) and 4(c) of this Article II, but which BPU or its Scheduling Agent did not cause to be utilized.

(e) If, during any month or Contract Year, BPU or its Scheduling Agent utilizes Peaking Energy in excess of the maximum quantities authorized pursuant to Section 3, 4(a)(ii), or 4(a)(iii) of this Article II, BPU shall pay an overrun penalty on such Peaking Energy (hereinafter "Energy Overrun Penalty") in accordance with Southwestern's then-effective Rate Schedule applicable to this Contract.

(f) The quantity of Peaking Energy purchased by BPU under Section 3 of this Article II shall be subject to adjustment as follows:

(i) If the sale of Hydro Peaking Power to BPU is initiated on other than the beginning of a Contract Year, the total number of kilowatt-hours of Peaking Energy to be furnished and delivered by Southwestern during the remainder of such Contract Year shall be computed as follows:

$$\text{Peaking Energy During Remainder of Contract Year (kilowatt-hours)} = 1{,}200 \text{ hours} \times \text{Peaking Contract Demand (kilowatts)} \times \left(\frac{\text{\# of Months Remaining}}{12} \right)$$

Provided, That, sales of Peaking Energy made to BPU under a preceding Contract during a Contract Year combined with the sales of Peaking Energy to BPU under this Contract shall not exceed 1,200 kilowatt-hours per kilowatt of Peaking Contract Demand for such Contract Year.

(ii) If the Peaking Contract Demand is increased or decreased during any Contract Year, the quantity of Peaking Energy sold by Southwestern to BPU during the remainder of such Contract Year shall be specified in an amendment to this Contract which will reflect the change in BPU's Peaking Contract Demand.

Section 5. Scheduling of Peaking Energy. BPU or its Scheduling Agent shall submit to Southwestern an hourly schedule each day in accordance with the Peaking Energy Schedule Submission Time with all energy quantities expressed in whole megawatt-hours for the delivery of Peaking Energy during the following day for the account of BPU.

(b) Subject to the provisions of Section 4 of this Article II, hourly schedules for Peaking Energy may be changed by BPU, or its Scheduling Agent, at any time, and from time to time, upon notice to Southwestern prior to the Peaking Energy Schedule Submission Time of the day preceding the day when the new schedule will be in effect. Such schedule changes shall be confirmed in writing at the request of Southwestern.

(c) Any specific terms applicable to scheduling of Peaking Energy that are set forth in the Hydro Peaking Power Rate Schedule shall have precedence over any provision contained in this Contract to the extent consistent with statutes and regulations of the United States.

(d) BPU or its Scheduling Agent may cause Peaking Energy for the account of BPU to be utilized at a rate less than the Peaking Contract Demand for any particular Demand Period, subject to the provisions of Sections 3 and 4 of this Article II and the limitations and penalties identified therein.

Section 6. Sale and Scheduling of Supplemental Peaking Energy. From time to time, Southwestern may have Federal Energy associated with Hydro Peaking Power available for purchase by BPU in addition to the quantity of Peaking Energy purchased by BPU under Section 3 of this Article II (hereinafter "Supplemental Peaking Energy"). When Southwestern, in its sole judgment and at its sole option, determines that Supplemental Peaking Energy will be available for utilization by BPU under this Contract, Southwestern shall, with as much notice as possible, notify BPU or its Scheduling Agent of such availability of Supplemental Peaking Energy, the approximate rate at which such Supplemental Peaking Energy may be delivered, and the period(s) of time during which such Supplemental Peaking Energy will be available. If BPU exercises its option to purchase such Supplemental Peaking Energy, Southwestern will establish with BPU or its Scheduling Agent an hourly schedule for the delivery of Supplemental Peaking Energy to be purchased by BPU.

Section 7. Compensation by BPU to Southwestern for Hydro Peaking Power and Associated Energy. (a) BPU shall compensate Southwestern each month for Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy purchased during the preceding month at the rates and under the terms and conditions set forth in the Hydro Peaking Power Rate Schedule, which is attached as Exhibit "2" to this Contract and by this reference incorporated herein. BPU understands and agrees that the rates and/or terms and conditions set forth in the Hydro Peaking Power Rate Schedule may, upon confirmation and/or approval by the appropriate authority having responsibility to so confirm and/or approve rate schedules, and whether on an interim basis or as finally confirmed and/or approved, be increased, decreased, modified, or superseded, at any time, and from time to time, and that if so increased, decreased, modified, or superseded, the rates and terms and conditions shall thereupon become effective and applicable to the purchase and sale under this Contract of Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy, in accordance with and on the effective date specified in the order of the appropriate authority.

(b) Southwestern shall promptly notify BPU in writing if the rates and/or terms and conditions set forth in the Hydro Peaking Power Rate Schedule, or then then-effective rate schedule for the sale of Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy have been increased, decreased, modified, or superseded.

(c) If the rates and/or terms and conditions in the Hydro Peaking Power Rate Schedule, or then then-effective rate schedule for the sale of Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy are increased, decreased, modified, or superseded, as provided in Section 7(a) of this Article II, and BPU does not wish to continue the purchase of Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy under this Contract, BPU shall, within six (6) months after the date of the notice from Southwestern under Section 7(b) of this Article II, notify Southwestern in writing of its election to terminate this Contract, such

termination to be effective as of midnight at the end of the Contract Year specified by BPU, but not earlier than six (6) months nor later than 36 months after the date of receipt by Southwestern of such notice from BPU. Hydro Peaking Power, Peaking Energy, and Supplemental Peaking Energy purchased by BPU during the period until the effective date of such termination shall be paid for at the then-effective rates and terms and conditions, whether in effect on an interim basis or as finally confirmed and/or approved by the appropriate authority.

Section 8. Points of Delivery. (a) The Parties recognize that:

(i) the facilities of the System of Southwestern and the System of BPU that are each owned by the respective Party are not directly interconnected; and

(ii) BPU has established Contracts with third parties for the receipt of Federal Power and Federal Energy for the account of BPU.

(b) The "Nominal Point of Delivery" shall mean one or more points of delivery for Federal Power and Federal Energy purchased by BPU from Southwestern under this Contract, and such Nominal Point of Delivery shall be at the transmission interface between the System of Southwestern and any single bulk transmission system directly connected to the System of Southwestern as designated by BPU or BPU's Scheduling Agent that is authorized to receive Federal Power and Federal Energy for the account of BPU pursuant to the terms and conditions of this Contract and the Contracts established by BPU identified in Section 8(a)(ii) of this Article II.

(c) Federal Power and Federal Energy purchased under this Contract will be delivered from the System of Southwestern into the system specified in Section 8(b) of this Article II, and BPU expressly understands and agrees that title to and responsibility for such Federal Power and Federal Energy passes to and is vested in BPU when such Federal Power and Federal Energy are delivered from the System of Southwestern at the Nominal Point of Delivery set forth in Section 8(b) of this Article II and that Southwestern neither has nor

assumes any responsibility or obligation under this Contract for the transmission or displacement of such Federal Power and Federal Energy from or beyond such Nominal Point of Delivery.

ARTICLE III
SALE OF EXCESS ENERGY BY SOUTHWESTERN

Section 1. Sale of Excess Energy. From time to time, Southwestern may have Federal Energy associated with Hydro Peaking Power available for purchase by BPU in addition to the quantity of Peaking Energy purchased by BPU under Section 3 of this Article II and in addition to the quantity of Supplemental Peaking Energy purchased by BPU under Section 6 of this Article II (hereinafter "Excess Energy"). Southwestern shall sell, and BPU may purchase such quantities of Excess Energy as Southwestern, in its sole judgment and at its sole option, determines are available for sale under this Contract, and which BPU determines it can utilize in lieu of other sources of non-Federal energy available to BPU.

Section 2. Notice of Availability. If Excess Energy is available, Southwestern shall notify BPU or its Scheduling Agent of the availability of Excess Energy, setting forth in such notice the period during which such Excess Energy is estimated to be available and the rate in kilowatts at which such Excess Energy may be scheduled. Southwestern shall, if possible, give notice as to the date and time of the termination of the availability of such Excess Energy. Southwestern reserves the right to reduce or terminate the sale of Excess Energy at any time, without advance notice, to BPU or its Scheduling Agent.

Section 3. Notice of Purchase by BPU. After notice of availability from Southwestern under Section 2 of this Article III, BPU or its Scheduling Agent shall notify Southwestern of the quantity, if any, of Excess Energy BPU desires to purchase and receive.

Section 4. Points of Delivery and Scheduling of Excess Energy. Excess Energy purchased by BPU shall be delivered by Southwestern at the Nominal Point of Delivery set forth in Section 8(b) of Article II of this Contract, in accordance with schedules developed and agreed upon by authorized representatives of Southwestern and BPU, and subject to all conditions set forth in the Excess Energy Rate Schedule, which is attached as Exhibit "3" to this Contract and by this reference incorporated herein.

Section 5. Compensation by BPU to Southwestern for Excess Energy. BPU shall compensate Southwestern each month for Excess Energy received during the preceding month at the rates and under the terms and conditions set forth in the Excess Energy Rate Schedule. BPU understands and agrees that the rates and/or terms and conditions set forth in Southwestern's Excess Energy Rate Schedule may, upon confirmation and/or approval by the appropriate authority having responsibility to so confirm and/or approve Rate Schedules, and whether on an interim basis or as finally confirmed and/or approved, be increased, decreased, modified, or superseded, at any time and from time to time, and that if so increased, decreased, modified, or superseded, the rates and/or terms and conditions shall thereupon become effective and applicable to the purchase and sale of Excess Energy under this Article III, in accordance with and on the effective date specified in the order of the appropriate authority.

ARTICLE IV
DESIGNATION OF SCHEDULING AGENT AND TRANSMISSION AGENT BY BPU

Section 1. Statement of Intent and Purpose. Federal Power and Federal Energy purchased by BPU from Southwestern under this Contract will be transmitted from the Nominal Point of Delivery through one or more third party transmission systems, whether scheduled for delivery by BPU or its designated Scheduling Agent, and whether received by BPU's Scheduling Agent or third parties for the account of BPU.

Section 2. Designation and Authority of Scheduling Agent. (a) Should BPU elect to secure third party Scheduling Agent services, BPU shall designate such third party in writing to Southwestern.

(b) The Scheduling Agent shall be, and hereby is, authorized and directed to:

(i) Accept title to and receive from Southwestern, for the account of BPU, the Federal Power and Federal Energy purchased by BPU under this Contract; and

(ii) Prepare and submit, and receive and accept, all necessary notices and accounting statements; and

(iii) Act for and on behalf of BPU about all matters arising under this Contract, other than matters pertaining to billing and payment, and in all respects and with the same force and effect as could BPU acting through its duly authorized officials.

Section 3. Designation of Transmission Agent. BPU shall designate, in writing to Southwestern, one or more third party transmission agent(s) responsible for transmitting Federal Power and Federal Energy from the System of Southwestern to BPU.

Section 4. Acceptance and Receipt by Agent(s). An agent or third party designated by BPU, or multiple agents or third parties designated by BPU, shall be responsible for accepting title to and receiving from Southwestern at the Nominal Point of Delivery, for the account of BPU and for delivery to BPU, the Federal Power and Federal Energy purchased by BPU under this Contract.

Section 5. Changes in Scheduling and Transmission Agent(s) or in Authority of Such Agent(s). Subject to the provisions of Section 2(b) of this Article IV, BPU may change its Scheduling Agent or transmission agent(s) or the responsibilities of such agent(s) at any time during the term of this Contract by giving written notice to Southwestern. Such change shall be effective not sooner than 60 days after the date of said notice.

ARTICLE V

CHARACTER OF DELIVERIES, POWER FACTOR, AND INADVERTENT FLOW

Section 1. Character of Deliveries. Federal Power and Federal Energy furnished by Southwestern under this Contract shall be delivered by Southwestern as three-phase alternating current and at a frequency of approximately 60 hertz.

Section 2. Power Factor. (a) The Parties recognize that, because the System of Southwestern and the System of BPU are interconnected with other electrical systems, neither Southwestern nor BPU will at all times have complete control of the power factor relating to the Federal Power and Federal Energy delivered to or received at the Nominal Point of Delivery.

(b) BPU shall cause Federal Power and Federal Energy to be taken from the System of Southwestern at the Nominal Point of Delivery at such power factor as will, from time to time, best fulfill the requirements of the party receiving such Federal Power and Federal Energy, but such party shall not impose a reactive power loading on the System of Southwestern which will impair the System of Southwestern.

(c) If the reactive power loading imposed at the Nominal Point of Delivery causes such impairment, Southwestern shall have the right to open, or cause to be opened, such interconnecting equipment as may be necessary to eliminate such impairment.

Section 3. Inadvertent Flow and Balancing Off. (a) The flow of Federal Power and Federal Energy to the Nominal Point of Delivery specified in Section 8(b) of Article II of this Contract will not be completely within the control of Southwestern but will be, in part, controlled by the electrical characteristics of the systems interconnected with Southwestern at such Nominal Point of Delivery and by the manner in which such systems are operated. By reason of such characteristics and operation, the delivery of Federal Power and Federal Energy may vary from scheduled deliveries, and such Federal Power and Federal Energy may flow inadvertently.

(b) Southwestern agrees to follow as closely as practicable the scheduled delivery and receipt of Federal Power and Federal Energy, but the inadvertent flow of Federal Power and Federal Energy in excess of, or less than, the amount scheduled shall not constitute a breach of this Contract.

(c) Such inadvertent deviations from schedule shall be balanced off between Southwestern and the Balancing Authority interconnected with Southwestern at the Nominal Point of Delivery as soon as practicable in the subsequent delivery and receipt of Federal Power and Federal Energy, and at a time of day as nearly as possible comparable to the time of day said inadvertent deviations occurred, and no charge shall be made for inadvertent flows of power and energy or for power and energy delivered to balance off the same.

(d) If any such inadvertent flow of power and energy causes an impairment to the System of Southwestern or to the system(s) interconnected with Southwestern at the Nominal Point of Delivery, or if such inadvertent flow interferes with service rendered by either Party to its customers, the Party adversely affected shall have the right to open, or cause the other to open, such interconnecting equipment as may be necessary to eliminate such impairment or interference.

ARTICLE VI
REIMBURSABLE WORK

Section 1. Purpose. Upon mutual agreement by Southwestern and BPU, and in accordance with applicable laws, regulations, and the provisions of this Contract:

(i) Southwestern may perform work or services for BPU on a reimbursable basis pursuant to Section 2(a) of this Article VI;

(ii) BPU may perform work or services for Southwestern on a reimbursable basis pursuant to Section 2(b) of this Article VI;

(iii) BPU may provide funds for work or services to be performed by the U.S. Army Corps of Engineers (hereinafter "Corps") which benefit Southwestern's customers pursuant to Section 2(c) of this Article VI; and

(iv) BPU may provide funds to Southwestern for work or services which benefit Southwestern's customers pursuant to Section 2(d) of this Article VI.

Section 2. Reimbursable Work. (a) An addendum to this Contract shall be entered into for each instance in which work or services are performed by Southwestern for BPU. Any applicable charges to BPU's account for work performed by Southwestern for BPU shall be identified in each addendum to this Contract which provides for the funding of such work or services.

(b) An addendum to this Contract shall be entered into for each instance in which work or services are performed by BPU for Southwestern. Any applicable crediting to BPU's account for work performed by BPU for Southwestern shall be identified in each addendum to this Contract which provides for the funding of such work or services.

(c) An addendum to this Contract shall be entered into for each instance in which BPU agrees to provide funds for work or services to be performed by the Corps which benefit Southwestern's customers. The funds provided by BPU pursuant to this Section 2(c) for work or services to be performed by the Corps which benefit Southwestern's customers and/or which will result in repairs, replacements, or modifications to facilities of the Corps, whose cost of operation, modifications, maintenance, and replacements is recovered through any of Southwestern's rates, shall be credited to BPU's account in Southwestern's invoice(s) for the sale of Federal Power and Federal Energy pursuant to this Contract during the same month such funds were provided by BPU.

(d) An addendum to this Contract shall be entered into and/or invoices shall be made under this Contract for each instance in which BPU agrees to provide funds to Southwestern for work or services which benefit Southwestern's customers. The funds

provided to Southwestern pursuant to this Section 2(d) for work or services which benefit Southwestern's customers and/or which will result in repairs, replacements, or modifications to facilities of Southwestern, whose cost of operation, modifications, maintenance, and replacements is recovered through any of Southwestern's rates, shall be credited to BPU's account in Southwestern's invoice(s) for the sale of Federal Power and Federal Energy pursuant to this Contract during the same month such funds were provided by BPU.

ARTICLE VII

EFFECTIVE DATE, TERM, CONTINGENCIES, NOTICES, REPORTS, INFORMATION, AND OTHER GENERAL PROVISIONS

Section 1. Effective Date and Term of Contract. This Contract shall become effective at 12:01 a.m. on July 1, 2020, and shall remain in force and effect until 12:00 a.m., midnight, June 30, 2035, unless sooner terminated, in whole or in part, pursuant to provisions set forth herein. Both Parties hereto agree that no further notice of termination need be given. All times identified in this Section 1 shall be Central Prevailing Time (CPT).

Section 2. Contingencies Related to Other Contracts. (a) The Parties hereto recognize that the quantity of Federal Power and Federal Energy available to Southwestern for marketing is limited by the generating capability and operating characteristics of the reservoir projects from which Southwestern markets Federal Power and Federal Energy, and that Southwestern shall not be obligated to make available to BPU quantities of Federal Power and Federal Energy in excess of the quantities set forth in this Contract.

(b) The Parties hereto also recognize that operations under this Contract are conditioned and contingent on the contractual arrangements BPU has made with its Scheduling Agent and Transmission agent(s). If BPU has not made suitable arrangements with its Scheduling Agent or Transmission agent(s) for receipt of the Federal Power and Federal Energy

purchased under this Contract, Southwestern, in its sole judgment and at its sole option, shall have the right to terminate this Contract.

(c) If, for any reason, BPU terminates, suspends, or renders inoperative its contract(s) with its Scheduling Agent and/or Transmission agent(s), then and in that event, upon mutual agreement of the Parties, this Contract shall terminate and be without further force or effect as of the effective date of such termination, suspension, or having been rendered inoperative.

(d) Termination of this Contract pursuant to the provisions of this Section 2 shall be without penalty to either of the Parties, except that the rights of the Parties which accrued prior to the date of such termination, if any, shall be and hereby are preserved.

(e) Notwithstanding the provisions of this Section 2, this Contract shall not terminate for the reasons set forth herein if BPU has made other contractual arrangements satisfactory to Southwestern for the receipt of Federal Power and Federal Energy purchased hereunder and has coordinated the establishment of such arrangements with Southwestern.

Section 3. Notices. Any written notice, demand, or request required or authorized under this Contract shall be deemed properly given to or served on Southwestern if mailed by certified mail, courier service, or some other trackable means to:

Administrator
Southwestern Power Administration
1 W. 3rd Street, Suite 1600
Tulsa, OK 74103-3519

Any such notice, demand, or request shall be deemed properly given to or served on BPU if mailed by certified mail, courier service, or some other trackable means to:

General Manager
Kansas City Board of Public Utilities
540 Minnesota Avenue
Kansas City, KS 66101

The designation of the person to be notified, or the address of such person, may be changed at any time by either Party upon written notice of such change to the other Party.

Section 4. Reports and Information. To the extent consistent with statutes and regulations of the United States, each Party to this Contract shall furnish to the other such reports and information concerning its operations as the other Party may reasonably request from time to time.

Section 5. General Contract Provisions. (a) Provisions applicable to this Contract are set forth in Southwestern's General Contract Provisions, which is attached as Exhibit "1" to this Contract and by this reference incorporated herein. Definitions set forth in the Articles of this Contract shall also apply to their respective terms used in Exhibit "1," and the term "Customer," used in Exhibit "1," shall mean BPU.

(b) Any specific terms and conditions set forth in the Articles of this Contract shall have precedence over any provision contained in Exhibit "1," to the extent consistent with statutes and regulations of the United States.

Section 6. Choice of Law. Federal law shall control the obligations and procedures established by this Contract and the performance and enforcement thereof. The forum for litigation arising from this Contract shall exclusively be a Federal court of the United States.

Section 7. Federal Statutes. The interpretation, enforcement, and performance of this Contract shall be subject to Southwestern fulfilling its responsibilities and obligations under Federal statutes and regulations applicable to Southwestern, including, but not limited to, Section 302(a)(1) of the Department of Energy Organization Act (91 Stat. 578; 42 U.S.C. 7152), Section 5 of the Flood Control Act of 1944 (58 Stat. 887, 890; 16 U.S.C. 825s), and Public Law 95-456 (92 Stat. 1230; 16 U.S.C. 825s-3).

IT IS RECOGNIZED THAT, Contract-556 is hereby rescinded, revoked, canceled, expired, and terminated as of the effective date of this Contract. After such effective date, the previously effective Contract-556 shall be without further force or effect, except that the rights and obligations of the Parties which accrued prior to the date of such termination, if any, shall be and hereby are preserved.

IN WITNESS WHEREOF, the Parties have jointly executed this Contract in several counterparts as of the day and year first above written, each of which shall constitute an original.

UNITED STATES OF AMERICA

By _____

Fritha Ohlson
Senior Vice President/COO
Office of Corporate Operations
Southwestern Power Administration

BOARD OF PUBLIC UTILITIES OF THE
CITY OF KANSAS CITY, KANSAS

By _____

Title General Manager

ATTEST:

I, Christine L. May, certify that I am the Admin. Assistant of the BOARD OF PUBLIC UTILITIES OF THE CITY OF KANSAS CITY, KANSAS, and that William Johnson, who signed this Contract on behalf of the said City, was then the General Manager of the said City, and that the said Contract was duly signed for and on behalf of the said City by authority of its governing body, which has within the scope of its corporate powers the authority to legally bind such City under the foregoing Contract.

(SEAL)

By _____

Southwestern Power Administration
GENERAL CONTRACT PROVISIONS

Provision		Title	Page
A.		ACCOUNTING, BILLING, PAYMENT, AND LATE PAYMENT CHARGES	2
	1.	Billing by Southwestern	2
	2.	Payment Terms	2
	3.	Net Billing	2
	4.	Payments By Southwestern	3
	5.	Propriety of Rates	3
	6.	Late Payment Charge	3
	7.	Late Payment Interest Charge	3
	8.	Penalty Charge for Late Payment	3
	9.	Late Payment Administrative Charge	3
	10.	Partial Payment	4
	11.	Discontinuance of Service	4
B.		STANDARD PROVISIONS	4
	1.	Convict Labor	4
	2.	Equal Employment Opportunity	4
	3.	Resale Rates	4
	4.	Availability of Funds to Southwestern	4
	5.	Termination for Breach	5
	6.	Waivers	5
	7.	Reliability and Adequacy of Service	5
	8.	Continuity of Service	5
	9.	Transfer of Interest by Customer	5
	10.	Uncontrollable Force	6
	11.	Liability	6
C.		FACILITIES AND CONDITIONS OF SERVICE	6
	1.	Facilities to be Furnished by Southwestern and the Customer	6
	2.	Reliability, Safety, Health, and Environmental Requirements in Regard to Construction, Operation, and Maintenance of Non-Federal Facilities on U.S. Government Property	6
	3.	Right of Installation and Access	8
	4.	Rights for Land Use Acquired by the Customer	9
	5.	Right of Removal	9
	6.	Right to Upgrade Facilities	9
	7.	Limitation on Rights of Entry	10
	8.	Assistance by Contracting Parties	10

A. ACCOUNTING, BILLING, PAYMENT, AND LATE PAYMENT CHARGES

1. **Billing by Southwestern**. (a) Southwestern shall maintain an accurate record of power, energy, and any other services purchased by the Customer under this Contract.

   (b) For each billing period in which the Customer makes one or more purchases under this Contract, Southwestern shall prepare an invoice in which such purchases are set forth in necessary detail, including the specific quantities of power, energy, and other services provided to the Customer during such billing period, and in which the compensation due Southwestern for such purchases is specified.

   (c) Invoiced quantities may be based on estimates if actual quantities are not available. Adjustments, if any, due to a difference between estimated and actual quantities will be made on an invoice prepared during the billing cycle following the invoice which was based on estimated quantities.

2. **Payment Terms**. (a) Invoices shall be due and payable by the Customer on or before the close of business 20 calendar days after the invoice date, or shall be due and payable on the next business day thereafter if the said due date should fall on a Saturday, Sunday, or official Federal holiday.

   (b) Payment of amounts due to Southwestern may be made through electronic funds transfer (EFT) or may be submitted as checks and mailed to:

   Southwestern Power Administration
   One West Third Street
   Tulsa, Oklahoma 74103-3502

   (c) EFT payments shall conform to Southwestern protocols for electronic transfer of funds in effect at the time of the transaction.

   (d) The designation of the address where payment is to be submitted may be changed by Southwestern upon 30 days' written notice to the Customer.

   (e) Invoices shall be considered paid when payment is received into Southwestern's designated depository account or credited to Southwestern's depository account in the U.S. Treasury by the end of the business day; Provided, That payments received by mail are accepted as timely and will not be assessed late charges if a U.S. Postal Service postmark for first class mail shows that the payment was received by the Postal Service at least 2 calendar days before the due date; Provided Further, That payments received through EFT are accepted as timely and will not be assessed late charges if they are credited to Southwestern's depository account in the U.S. Treasury on or before the third day after the due date or on the next business day thereafter if said third day is a Saturday, Sunday, or official Federal holiday.

3. **Net Billing**. (a) Whenever the parties agree, payments due Southwestern by the Customer may be offset against payments due the Customer by Southwestern for the sale or exchange of electric power, energy, and other services.

   (b) For services included in net billing procedures, payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists.

(c) The parties shall exchange such reports and information as either party requires for billing purposes.

(d) Net billing procedures shall not be used for any amounts which Southwestern determines, in its sole judgment, to be in dispute.

4. **Payments By Southwestern**. Any payment due the Customer not satisfied by the Net Billing provision of Section 3 of this Provision A, shall be made by Southwestern to the banking account of the Customer by Electronic Funds Transfer.

5. **Propriety of Rates**. (a) Southwestern shall bill the Customer for the Customer's purchases of power, energy, and other services in accordance with the rates placed in effect pursuant to statute.

(b) The Customer hereby agrees to promptly pay Southwestern under such rate schedules, whether or not the Customer agrees with the propriety or the levels of the rates placed into effect pursuant to law, regulation, or the order of an appropriate authority.

(c) In the event that the U.S. Congress amends the manner in which Southwestern calculates or charges for its power sales, the Customer hereby agrees to promptly pay in such an amended manner, subject to the Customer's right to terminate.

6. **Late Payment Charge**. (a) Southwestern shall assess the Customer a Late Payment Charge for each instance in which the Customer is delinquent in making payment to Southwestern.

(b) Such Late Payment Charge shall be computed by dividing by 12 the then-effective annual interest rate published in the Federal Register by the Department of Treasury, and multiplying the resultant monthly rate times the principal amount past due.

(c) Such Late Payment Charge shall be assessed only once for a particular invoiced amount which is past due, irrespective of the number of days between the due date and the final payment of such particular invoiced amount.

7. **Late Payment Interest Charge**. (a) In addition to the Late Payment Charge provided in Section 6 of this Provision A, a daily interest charge shall be assessed on the principal amount past due for each day after the due date until the said amount is paid in full.

(b) Such daily interest rate shall be computed by recalculating the annual interest rate cited in Section 6(b) of this Provision A for a daily rate.

8. **Penalty Charge for Late Payment**. (a) In the event that the Customer should fail to pay Southwestern any portion of an invoiced amount for a period of more than 90 days past its due date, Southwestern shall assess a penalty charge of 6 percent per year on such outstanding amount.

(b) This penalty charge shall accrue for the period from the date that the debt became past due until the date when such invoiced amount is paid, and shall be assessed in addition to other charges for late payment which are specified in this Provision A.

9. **Late Payment Administrative Charge**. (a) Southwestern shall assess charges to cover administrative costs incurred as a result of a collection action against the Customer to cover the additional costs incurred in processing and handling such debt collection.

(b) Calculation of administrative costs shall be based upon actual costs incurred by Southwestern in processing and handling claims against other debtors in similar stages of delinquency.

10. **Partial Payment**. In the event that an invoice is not paid in full, amounts received by Southwestern shall be applied first to outstanding Late Payment penalty and administrative charges; second to outstanding daily interest charges for late payments assessed on the principal; and finally, to payment of the principal amount past due, unless a different rule is prescribed by Federal statute or regulation.

11. **Discontinuance of Service**. (a) If the Customer fails to pay any amount due under this Contract, Southwestern may, at its option, cause the delivery of power, energy, and other services under this Contract to be discontinued upon 90 days' prior written notice to the Customer, unless payment of the amounts due is made by the Customer within such 90-day period.

(b) Such discontinuance of the delivery of power, energy, and other services, as herein provided, shall not relieve the Customer of liability for any minimum Southwestern charges under rate schedules applicable to this Contract during the period of such discontinuance.

(c) The rights granted Southwestern herein shall be in addition to all other remedies available to Southwestern, either by law or in equity, for the breach of any of the provisions of this Contract.

B. STANDARD PROVISIONS

1. **Convict Labor**. In connection with the performance of work under this Contract, the Customer agrees not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. § 3622(c)), and Executive Order 11755, December 29, 1973, as amended.

2. **Equal Employment Opportunity**. During the performance of this Contract, the Customer agrees to abide by and to fulfill the nondiscrimination requirements of the "equal opportunity clause" contained in Section 202 of Executive Order 11246 dated September 28, 1965 (30 F.R. 12319), any Executive Order amending such order, and any other Executive Order superseding such order.

3. **Resale Rates**. The parties hereto understand and agree that the purpose of making federally generated power available is to encourage the most widespread use thereof, and the Customer therefore agrees that the benefits of any federally generated power received pursuant to this Contract shall be made available at fair and reasonable terms to all of its consumers at the lowest possible rates consistent with sound business principles.

4. **Availability of Funds to Southwestern**. (a) This Contract and all rights and obligations hereunder, and the expenditure of funds by Southwestern under the provisions hereof, are expressly conditioned and contingent upon the Congress making available (through direct appropriation, authorization of a revolving fund, the authority to borrow funds, or through such other means as it may provide) the necessary funds or the authority to accept funds from others to enable Southwestern to carry out the provisions of this Contract, and if such funds or authorities are not available, this Contract shall terminate and have no further force or effect as of the last day for which

funds or authorities were available, and the Customer hereby releases Southwestern from any and all liability for failure to perform and fulfill its obligations under this Contract for that reason.

(b) No obligation contained herein for the future payment of money by Southwestern, or liability on the part of Southwestern for breach of any of the provisions contained herein, shall be binding upon or enforceable against Southwestern unless and until funds, as provided in Section 4(a) of this Provision B, are available out of which such obligations or liability can be legally paid.

(c) Nothing in this Contract may be considered as implying that Congress will, at a later date, appropriate funds sufficient to meet any deficiencies or obligations incurred under this Contract.

5. **Termination for Breach**. (a) If either party hereto breaches a material provision of this Contract, the other party, at its option, may terminate this Contract upon 30 days' prior written notice of its intention to do so, and this Contract ipso facto shall terminate at the end of such 30-day period unless such violation is corrected within that period.

(b) Neither party hereto shall be considered to be in default or breach with respect to any obligation under this Contract if prevented from fulfilling such obligation by reason of an Uncontrollable Force as herein defined.

6. **Waivers**. Waiver at any time of rights with respect to a default or any other matter arising in connection with this Contract shall not be deemed to be a waiver with respect to any subsequent default or matter.

7. **Reliability and Adequacy of Service**. (a) Electric service rendered by Southwestern under this Contract shall meet accepted standards of reliability and adequacy.

(b) If questions are raised concerning the quality of service, factual data shall be obtained with respect to the character of such service, and appropriate corrective or remedial action shall be promptly taken by the party at fault.

8. **Continuity of Service**. (a) Services provided by Southwestern to the Customer under this Contract shall be delivered by Southwestern as scheduled, except for interruptions or curtailments in delivery caused by an Uncontrollable Force as herein defined, by the operation of devices or dispatcher action for system protection, or by the necessary installation, maintenance, repair, and replacement of equipment.

(b) Such interruptions or reductions in service, as hereinbefore set forth, shall not constitute a breach of this Contract, and neither party shall be liable to the other for damages resulting therefrom.

(c) Except in case of an emergency, Southwestern shall give the Customer reasonable advance notice of temporary interruptions or curtailments in service necessary for such installation, maintenance, repair, and replacement of equipment, and shall, insofar as is practicable, schedule such interruptions or curtailments so as to cause the least inconvenience to the Customer.

9. **Transfer of Interest by Customer**. (a) No voluntary transfer of this Contract or of the rights of the Customer hereunder shall be made without the written approval of the Administrator, Southwestern; Provided, That any successor to or assignee of the rights of the Customer, whether by voluntary transfer, judicial sale, foreclosure sale, or otherwise, shall be subject to all the provisions and conditions of this Contract to the same extent as though such successor or assignee were the original contractor

hereunder; Provided Further, That the execution of a mortgage or trust deed, or judicial or foreclosure sale made thereunder, shall not be deemed voluntary transfers within the meaning of this Section 9.

(b) If receiving Federal power pursuant to this contract, the Customer will not sell, lease, or otherwise dispose of its electrical distribution system without giving Southwestern at least 120 days' prior written notice.

(c) The Customer's rights to Federal power and concomitant services, as may be set forth in this Contract and in Southwestern's Final Power Allocations (1980-1988), 45 F.R. 19032 (1980), come by virtue of the Customer's status as an entity entitled to preference in Southwestern's marketing of Federal power pursuant to Section 5 of the Flood Control Act of 1944 (58 Stat. 887,890; 16 U.S.C. 825s). If the Administrator, Southwestern, determines, in his or her sole judgment, that actions taken by the Customer have abrogated the Customer's status as a "preference" entity, then the Administrator may, at his or her sole option, terminate this Contract, such termination to become effective on the date specified by Southwestern, in an official written notice to the Customer.

10. **Uncontrollable Force**. The term "Uncontrollable Force," as used herein, shall mean any force which is not within the control of the party affected, including, but not limited to, failure of water supply, failure of facilities, flood, earthquake, storm, lightning, fire, epidemic, riot, civil disturbance, labor disturbance, sabotage, war, act of war, terrorist acts, or restraint by court of general jurisdiction, which by exercise of due diligence and foresight such party could not reasonably have been expected to avoid.

11. **Liability**. The Customer hereby agrees to indemnify and hold harmless the United States, its employees, agents, or contractors from any loss or damage and from any liability on account of personal injury, death, or property damage, or claims for personal injury, death, or property damage of any nature whatsoever and by whomsoever made arising out of the Customer's, its employees', agents', or subcontractors' construction, operation, maintenance, or replacement activities under the contract. The United States shall be liable only for negligence on the part of its officers and employees in accordance with the Federal Tort Claims Act, 28 U.S.C. §§ 1346(b), 1346(c), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

C. FACILITIES AND CONDITIONS OF SERVICE

1. **Facilities to be Furnished by Southwestern and the Customer**. Southwestern and the Customer shall furnish, install, maintain, and operate, or cause to be furnished, installed, maintained, and operated, such facilities and equipment, including metering equipment, as may be necessary to fulfill their respective obligations under this Contract and to assure reasonable protection to the facilities of others.

2. **Reliability, Safety, Health, and Environmental Requirements in Regard to Construction, Operation, and Maintenance of Non-Federal Facilities on U.S. Government Property**. (a) The provisions of this Section 2 shall apply only if the Customer, its agents or contractors, or its member entities perform maintenance, operations, or construction on the property of the U.S. Government (Government), or on easements shared by the Government and the Customer.

(b) Such construction, maintenance, and operation shall be performed in accordance with standards at least equal to those provided by the National Electrical Safety Code and shall conform to safety, environmental, and security procedures identified by Southwestern as appropriate to each facility in which such work is performed. Southwestern provides such written procedures in each of the facilities it maintains and to affected customers.

(c) The Customer and/or its member entities shall take all reasonable precautions in the performance of such work to protect the public and the environment. The Customer and/or its member entities shall comply with all applicable local, state, and Federal regulations and requirements in the performance of such work, including, but not limited to, the National Environmental Policy Act; the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Responsibility, Compensation, and Liability Act; the Toxic Substances Control Act; the Oil Pollution Act; the Resource Conservation and Recovery Act; the Superfund Amendments and Reauthorization Act (SARA); SARA Title III (Emergency Planning and Community Right-to-Know Act of 1986); and the Occupational Safety and Health Act.

(d) In the event that Southwestern, at its sole option and in its sole judgment, determines that construction, maintenance, or operation of facilities which are performed under this Contract by the Customer, and/or one of its member entities, do not meet the standards and/or regulations and requirements specified in this Section 2, or if Southwestern determines, in its sole judgment, that a condition exists which provides a potentially adverse impact (1) on the reliability of services provided by Southwestern to its customers, (2) on the safety and/or health of the public or employees and agents of the parties hereto, and/or (3) on the environment, then Southwestern may provide written notice to the Customer and/or its member entity of the deficient condition; Provided, That if such condition, in Southwestern's sole judgment and at Southwestern's sole option, requires immediate attention and does not allow time for such notice, Southwestern will remedy the condition and, where appropriate, bill the Customer in accordance with Section 8(b) of this Provision C.

(e) Where, in Southwestern's sole judgment, remedy of the said deficient condition is not time critical, the Customer and/or its member entity shall provide a written plan and schedule to Southwestern within 30 days of receipt of the said written notice. Such plan and schedule shall provide for correction of the said deficiency at the earliest possible time available to the Customer and/or its member entity; Provided, That the maximum time allowed for the Customer and/or its member entity to correct any such deficiency shall not exceed 18 months from receipt of the said written notice. The Customer shall coordinate or, if applicable, cause its member entity to coordinate, any work and outages which may involve Southwestern's facilities with Southwestern's Dispatch Center (Dispatch Center) in Springfield, Missouri.

(f) Unless otherwise agreed in writing, correction of deficiencies pursuant to this Section 2 shall be at the expense of the Customer.

(g) If the Customer and/or its member entity fails to correct the deficiency within the time provided pursuant to this Section 2, Southwestern shall have the right, at its sole option and in its sole discretion, to terminate service through the affected facilities until such deficiencies are corrected to the satisfaction of Southwestern.

(h) If, within the time period provided pursuant to this Section 2, an emergency condition occurs which, in the sole judgment of Southwestern, may cause an adverse impact on the reliability of the System of Southwestern and/or on the environment, or which poses a hazard to the safety and/or health of the public or employees and agents of

the parties hereto, then Southwestern may, at its sole option, remedy or repair such condition or equipment and bill the Customer in accordance with Section 8(b) of this Provision C, and the Customer agrees to render Southwestern reimbursement as provided in the said Section 8(b).

3. **Right of Installation and Access**. (a) Each party hereto grants to the other permission, or will obtain such permission for the other party, to install, maintain, and operate, or cause to be installed, maintained, and operated, on the System of Southwestern and on the System of the Customer, at the points of delivery between the System of Southwestern and the System of the Customer described in this Contract, any and all terminal equipment and associated electrical apparatus and devices necessary in the performance of this Contract.

   (b) Each party hereto shall permit, or shall obtain permission for, duly authorized representatives and employees of the other party to enter upon the System of Southwestern and the System of the Customer at the said points of delivery for the purpose of reading or checking meters; for inspecting, testing, repairing, renewing, or exchanging any or all of the equipment owned by the other party located on such premises; or for the purpose of performing any other work necessary in the performance of this Contract.

   (c) Access for any work performed by one party under this Section 3 which may affect the other party's equipment shall normally be preceded by at least one day's notice to the affected party, except in the event of an emergency, in which case such notice shall be made as soon as possible after such emergency occurrence. Notice to Southwestern pursuant to this Section 3 shall be made to the Dispatch Center.

   (d) Any access to property controlled by Southwestern shall include notification to Southwestern at the time of entry. Any employee or agent of the Customer, or of its member entities, who enters a Southwestern facility is expected to call the Dispatch Center from a telephone located in the control building in that facility and to identify himself or herself. Security devices located in the control buildings at Southwestern facilities sound an alarm in the Dispatch Center when the building is entered. Local law enforcement officers may be asked to investigate any unidentified entry.

   (e) Any equipment, apparatus, or devices installed on the System of Southwestern by the Customer, as provided under this Section 3, shall be clearly and permanently marked to indicate ownership, and, in addition, a detailed description of each item so installed (including, if applicable, manufacturer's name, serial number, model number, etc.) shall be transmitted to Southwestern to aid in maintenance of plant accounts.

   (f) In the event the equipment, apparatus, or devices are not marked in accordance with Section 3(e) of this Provision C, ownership of said equipment, apparatus, or devices shall be presumed to be vested in Southwestern.

   (g) The Customer agrees that, if requested by Southwestern, the description required under Section 3(e) of this Provision C shall include a detailed analysis of all dielectrical oil, including, but not limited to, tests for polychlorinated biphenyls (PCBs). If such analysis indicates the presence of a known hazardous substance, which, in Southwestern's sole judgment, presents a significant hazard to the environment or to the health and safety of employees of the parties hereto, Southwestern may require, at its sole option, by written request, removal of any equipment containing such substance, and the Customer agrees to comply with such request for removal at no cost to Southwestern.

4. **Rights for Land Use Acquired by the Customer**. (a) The System of Southwestern is constructed, operated, and maintained by Southwestern subject to and in accordance with the terms and conditions of certain transmission line right-of-way easements. Rights and privileges granted thereunder to the Government may not be available to the Customer for operations connected with performance of this Contract.

   (b) The Customer is therefore responsible for acquiring, or causing to be acquired, from the appropriate landowners, any and all rights and privileges for land use, by good and sufficient legal instruments, to authorize and permit entry by the Customer upon and across tracts affected by such land use as may be necessary and appropriate for performance of this Contract.

5. **Right of Removal**. Any and all equipment, apparatus, or devices placed or installed or caused to be placed or installed by the parties hereto on or in the System of Southwestern or the System of the Customer shall be and shall remain the property of the party owning and installing such equipment, apparatus, devices, or facilities, regardless of the mode or manner of annexation or attachment to real property, and, upon the termination of this Contract, the owner thereof shall have the right to enter upon the premises or system of the other and shall, within a reasonable time, remove such equipment, apparatus, devices, or facilities, subject to the provisions of Section 3 of this Provision C.

6. **Right to Upgrade Facilities**. (a) Southwestern reserves the right to modify or upgrade its transmission system and any of the elements which support the Southwestern transmission system, including, but not limited to, changes in: (1) Southwestern's transmission voltages, (2) Southwestern's transmission system components, (3) Southwestern's communications system, (4) Southwestern's Supervisory Control and Data Acquisition (SCADA) System, and (5) other modifications necessary to comply with the standards and/or regulations and requirements mentioned in Section 2 of this Provision C.

   (b) If, during the term of this Contract, Southwestern determines, in its sole judgment and at its sole option, that modifications or upgrades to its transmission system and associated facilities are required, then, in that event, the Customer shall be responsible for any and all costs and expenses incurred by the Customer in order to continue to receive services provided under this Contract.

   (c) If the Customer elects not to make changes in its facilities which, in Southwestern's judgment, are required for the Customer to continue to receive reliable service from Southwestern's modified or upgraded facilities, then the Customer will discontinue receipt of the services provided under this Contract which are dependent on such modified or upgraded facilities, and the provisions of this Contract which describe such services shall be terminated or, at Southwestern's sole option, suspended, until the Customer completes the changes in its facilities which Southwestern, in its sole judgment, deems necessary for reliable service to the Customer under the aforesaid provisions.

   (d) Southwestern shall notify the Customer of the specific sections or articles of the Contract which are to be terminated or suspended pursuant to Section 6(c) of this Provision C.

   (e) The provisions of this Contract which are not specifically terminated or suspended pursuant to Section 6(d) of this Provision C shall not in any way be affected and shall remain in full force and effect except insofar as the services provided pursuant to the

terminated or suspended provisions which are reflected in other provisions of this Contract will also be terminated or suspended.

(f) Termination or suspension of specific provisions of this Contract pursuant to Section 6(c) of this Provision C shall be without penalty to either of the parties hereto, except that the rights of the parties hereto, if any, which accrued prior to the date of such termination or suspension shall be and hereby are preserved.

7. **Limitation on Rights of Entry**. Southwestern reserves the right, upon notice to the Customer, to revoke or cancel the rights of entry granted under this Contract with regard to any particular representative of the Customer, if, in the sole judgment of Southwestern, such revocation or cancellation is required in the interest of national security.

8. **Assistance by Contracting Parties**. If assistance in maintenance and utilization of their respective systems is rendered by Southwestern and/or the Customer, the following terms and conditions shall apply:

(a) If, in the maintenance or utilization of their respective transmission systems and related facilities for the purpose of this Contract, it becomes necessary by reason of any emergency or extraordinary condition for Southwestern or the Customer to request the other to furnish personnel, materials, tools, and equipment for the maintenance or modification of, or other work on, such transmission systems and related facilities to insure continuity of power and energy deliveries, the party requested shall cooperate with the other and render such assistance as the party requested may determine to be available.

(b) The party making such request, upon receipt of properly itemized bills, shall reimburse the party rendering such assistance, including overhead and administrative and general expenses. The Customer and Southwestern agree to account for any incurred costs under a Work Order accounting procedure and in accordance with the Uniform System of Accounts prescribed for public utilities by the Federal Energy Regulatory Commission. Billing statements rendered by the Customer and Southwestern for such reimbursement shall be due 20 days from the date thereof.

(c) No laborer or mechanic in the employ of the Customer, or its agents and contractors, for any of the work contemplated by this Section 8 shall be required or permitted to work in excess of 40 hours in any workweek except upon the condition that compensation is paid to such laborer or mechanic in accordance with the provisions of this Section 8.

(d) The wages of each laborer or mechanic employed by the Customer, or its agents and contractors, in the performance of any of the work contemplated by this Section 8 shall be computed on the basis of a standard workweek of 40 hours, and work performed in excess of such standard workweek may be permitted only upon the condition that each laborer or mechanic receives compensation at a rate not less than 1.5 times that worker's basic rate of pay for all hours worked in excess of 40 hours in any such workweek.

(e) For each violation of this Section 8, the Customer, or its agents and contractors, will be liable to the employee for his unpaid wages and, in addition, a penalty shall be imposed upon the Customer in the amount of ten dollars ($10) for each laborer or mechanic for each calendar day in which such laborer or mechanic is required or permitted to work in excess of the standard workweek of 40 hours upon said work without receiving compensation computed in accordance with this Section 8, and all

penalties thus imposed shall be withheld for the use and benefit of the Government; Provided, That this Section 8 is subject to the provisions of the Contract Work Hours and Safety Standards Act of 1962 (Public Law 87-581, 76 Stat. 357-360), as amended; Provided Further, That if, from time to time, there is a conflict or inconsistency between the terms and conditions hereinbefore set forth and the provisions of any contract between the Customer and a labor union, the provisions of the labor union contract shall prevail if determined to be in compliance with then-applicable statutes and regulations issued thereunder.

UNITED STATES DEPARTMENT OF ENERGY

SOUTHWESTERN POWER ADMINISTRATION

RATE SCHEDULE P-13A[1]**

WHOLESALE RATES FOR HYDRO PEAKING POWER

[1] Supersedes Rate Schedule P-13.
** Extended through September 30, 2021 by approval of Rate Order No. SWPA-74 by the Assistant Secretary for Electricity.

Effective:

During the period October 1, 2013, through September 30, 2021**, in accordance with Federal Energy Regulatory Commission (FERC) order issued in Docket No. EF14-1-000 (January 9, 2014), extension approved by the Deputy Secretary in Docket No. EF14-1-002 (September 13, 2017), modification approved by FERC in Docket No. EF14-1-003 (August 29, 2019), and extension approved by Assistant Secretary in Rate Order No. SWPA-74 (September 22, 2019).

Available:

In the marketing area of Southwestern Power Administration (Southwestern), described generally as the States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

Applicable:

To wholesale Customers which have contractual rights from Southwestern to purchase Hydro Peaking Power and associated energy (Peaking Energy and Supplemental Peaking Energy).

Character and Conditions of Service:

Three-phase, alternating current, delivered at approximately 60 Hertz, at the nominal voltage(s), at the point(s) of delivery, and in such quantities as are specified by contract.

1. Definitions of Terms

1.1. Ancillary Services

The services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the System of Southwestern in accordance with good utility practice, which include the following:

1.1.1. Scheduling, System Control, and Dispatch Service

is provided by Southwestern as Balancing Authority Area operator and is in regard to interchange and load-match scheduling and related system control and dispatch functions.

1.1.2. Reactive Supply and Voltage Control from Generation Sources Service

is provided at transmission facilities in the System of Southwestern to produce or absorb reactive power and to maintain transmission voltages within specific limits.

1.1.3. Regulation and Frequency Response Service

is the continuous balancing of generation and interchange resources accomplished by raising or lowering the output of on-line generation as necessary to follow the moment-by-moment changes in load and to maintain frequency within a Balancing Authority Area.

1.1.4. Spinning Operating Reserve Service

maintains generating units on-line, but loaded at less than maximum output, which may be used to service load immediately when disturbance conditions are experienced due to a sudden loss of generation or load.

1.1.5. Supplemental Operating Reserve Service

provides an additional amount of operating reserve sufficient to reduce Area Control Error to zero within 10 minutes following loss of generating capacity which would result from the most severe single contingency.

1.1.6. Energy Imbalance Service

corrects for differences over a period of time between schedules and actual hourly deliveries of energy to a load. Energy delivered or received within the authorized bandwidth for this service is accounted for as an inadvertent flow and is returned to the providing party by the receiving party in accordance with standard utility practice or a contractual arrangement between the parties.

1.2. **Customer**

The entity which is utilizing and/or purchasing Federal Power and Federal Energy and services from Southwestern pursuant to this Rate Schedule.

1.3. **Demand Period**

The period of time used to determine maximum integrated rates of delivery for the purpose of power accounting which is the 60-minute period that begins with the change of hour.

1.4. **Federal Power and Energy**

The power and energy provided from the System of Southwestern.

1.5. **Hydro Peaking Power**

The Federal Power that Southwestern sells and makes available to the Customers through their respective Power Sales Contracts in accordance with this Rate Schedule.

1.6. **Peaking Billing Demand**

The quantity equal to the Peaking Contract Demand for any month unless otherwise provided by the Customer's Power Sales Contract.

1.7. **Peaking Contract Demand**

The maximum rate in kilowatts at which Southwestern is obligated to deliver Federal Energy associated with Hydro Peaking Power as set forth in the Customer's Power Sales Contract.

1.8. **Peaking Energy**

The Federal Energy associated with Hydro Peaking Power that Southwestern sells and makes available to the Customer in accordance with the terms and conditions of the Customer's Power Sales Contract.

1.9. **Peaking Energy Schedule Submission Time**

The time by which Southwestern requires the Customer to submit Peaking Energy schedules to Southwestern as provided for in this Rate Schedule and in accordance with the terms and conditions of the Customer's Power Sales Contract.

1.10. **Power Sales Contract**

The Customer's contract with Southwestern for the sale of Federal Power and Federal Energy.

1.11. **Supplemental Peaking Energy**

The Federal Energy associated with Hydro Peaking Power that Southwestern sells and makes available to the Customer if determined by Southwestern to be available and that is in addition to the quantity of Peaking Energy purchased by the Customer in accordance with the terms and conditions of the Customer's Power Sales Contract.

1.12. **System of Southwestern**

The transmission and related facilities owned by Southwestern, and/or the generation, transmission, and related facilities owned by others, the capacity of which, by contract, is available to and utilized by Southwestern to satisfy its contractual obligations to the Customer.

1.13. **Uncontrollable Force**

Any force which is not within the control of the party affected, including, but not limited to failure of water supply, failure of facilities, flood, earthquake, storm, lightning, fire, epidemic, riot, civil disturbance, labor disturbance, sabotage, war, act of war, terrorist acts, or restraint by court of general jurisdiction, which by exercise of due diligence and foresight such party could not reasonably have been expected to avoid.

2. Wholesale Rates, Terms, and Conditions for Hydro Peaking Power, Peaking Energy, Supplemental Peaking Energy, and Associated Services

Unless otherwise specified, this Section 2 is applicable to all sales under the Customer's Power Sales Contract.

2.1. Hydro Peaking Power Rates, Terms, and Conditions

2.1.1. Monthly Capacity Charge for Hydro Peaking Power

$4.50 per kilowatt of Peaking Billing Demand.

2.1.2. Services Associated with Capacity Charge for Hydro Peaking Power

The capacity charge for Hydro Peaking Power includes such transmission services as are necessary to integrate Southwestern's resources in order to reliably deliver Hydro Peaking Power and associated energy to the Customer. This capacity charge also includes two Ancillary Services charges: Scheduling, System Control, and Dispatch Service; and Reactive Supply and Voltage Control from Generation Sources Service.

2.1.3. Secondary Transmission Service under Capacity Associated with Hydro Peaking Power

Customers may utilize the transmission capacity associated with Peaking Contract Demand for the transmission of non-Federal energy, on a non-firm, as-available basis, at no additional charge for such transmission service or associated Ancillary Services, under the following terms and conditions:

2.1.3.1. The sum of the capacity, for any hour, which is used for Peaking Energy, Supplemental Peaking Energy, and Secondary Transmission Service, may not exceed the Peaking Contract Demand;

2.1.3.2. The non-Federal energy transmitted under such secondary service is delivered to the Customer's point of delivery for Hydro Peaking Power;

2.1.3.3. The Customer commits to provide Real Power Losses associated with such deliveries of non-Federal energy; and

2.1.3.4. Sufficient transfer capability exists between the point of receipt into the System of Southwestern of such non-Federal energy and the Customer's point of delivery for Hydro Peaking Power for the time period that such secondary transmission service is requested.

2.1.4. Adjustment for Reduction in Service

If, during any month, the Peaking Contract Demand associated with a Power Sales Contract in which Southwestern has the obligation to provide 1,200

kilowatthours of Peaking Energy per kilowatt of Peaking Contract Demand is reduced by Southwestern for a period or periods of not less than two consecutive hours by reason of an outage caused by either an Uncontrollable Force or by the installation, maintenance, replacement or malfunction of generation, transmission and/or related facilities on the System of Southwestern, or insufficient pool levels, the Customer's capacity charges for such month will be reduced for each such reduction in service by an amount computed under the formula:

$$R = (C \times K \times H) \div S$$

with the factors defined as follows:

R = The dollar amount of reduction in the monthly total capacity charges for a particular reduction of not less than two consecutive hours during any month, except that the total amount of any such reduction shall not exceed the product of the Customer's capacity charges associated with Hydro Peaking Power times the Peaking Billing Demand.

C = The Customer's capacity charges associated with Hydro Peaking Power for the Peaking Billing Demand for such month.

K = The reduction in kilowatts in Peaking Billing Demand for a particular event.

H = The number of hours duration of such particular reduction.

S = The number of hours that Peaking Energy is scheduled during such month, but not less than 60 hours times the Peaking Contract Demand.

Such reduction in charges shall fulfill Southwestern's obligation to deliver Hydro Peaking Power and Peaking Energy.

2.2. Peaking Energy and Supplemental Peaking Energy Rates, Terms, and Conditions

2.2.1. Peaking Energy Charge

$0.0094 per kilowatthour of Peaking Energy delivered plus the Purchased Power Adder as defined in Section 2.2.3 of this Rate Schedule.

2.2.2. Supplemental Energy Charge

$0.0094 per kilowatthour of Supplemental Peaking Energy delivered.

2.2.3. Purchased Power Adder

A purchased power adder of $0.0059 per kilowatthour of Peaking Energy delivered, as adjusted by the Administrator, Southwestern, in accordance with the procedure within this Rate Schedule.

2.2.3.1. Applicability of Purchased Power Adder

The Purchased Power Adder shall apply to sales of Peaking Energy. The Purchased Power Adder shall not apply to sales of Supplemental Peaking Energy or sales to any Customer which, by contract, has assumed the obligation to supply energy to fulfill the minimum of 1,200 kilowatthours of Peaking Energy per kilowatt of Peaking Contract Demand during a contract year (hereinafter "Contract Support Arrangements").

2.2.3.2. Procedure for Determining Net Purchased Power Adder Adjustment

Not more than twice annually, the Purchased Power Adder of $0.0059 (5.9 mills) per kilowatthour of Peaking Energy, as noted in this Rate Schedule, may be adjusted by the Administrator, Southwestern, by an amount up to a total of ±$0.0059 (5.9 mills) per kilowatthour per year, as calculated by the following formula:

$$ADJ = (PURCH - EST + DIF) \div SALES$$

with the factors defined as follows:

ADJ = The dollar per kilowatthour amount of the total adjustment, plus or minus, to be applied to the net Purchased Power Adder, rounded to the nearest $0.0001 per kilowatthour, provided that the total ADJ to be applied in any year shall not vary from the then-effective ADJ by more than $0.0059 per kilowatthour;

PURCH = The actual total dollar cost of Southwestern's System Direct Purchases as accounted for in the financial records of the Southwestern Federal Power System for the period;

EST = The estimated total dollar cost ($13,273,800 per year) of Southwestern's System Direct Purchases used as the basis for the Purchased Power Adder of $0.0059 per kilowatthour of Peaking Energy;

DIF = The accumulated remainder of the difference in the actual and estimated total dollar cost of Southwestern's System Direct Purchases since the effective date of the currently approved Purchased Power Adder set forth in this Rate Schedule, which remainder is not projected for recovery through the ADJ in any previous periods;

SALES = The annual Total Peaking Energy sales projected to be delivered (2,241,300,000 KWh per year) from the System of Southwestern, which total was used as the basis for the $0.0059 per kilowatthour Purchased Power Adder.

2.3. Transformation Service Rates, Terms, and Conditions

2.3.1. Monthly Capacity Charge for Transformation Service

$0.46 per kilowatt will be assessed for capacity used to deliver energy at any point of delivery at which Southwestern provides transformation service for deliveries at voltages of 69 kilovolts or less from higher voltage facilities.

2.3.2. Applicability of Capacity Charge for Transformation Service

Unless otherwise specified by contract, for any particular month, a charge for transformation service will be assessed on the greater of (1) that month's highest metered demand, or (2) the highest metered demand recorded during the previous 11 months, at any point of delivery. For the purpose of this Rate Schedule, the highest metered demand will be based on all deliveries, of both Federal and non-Federal energy, from the System of Southwestern, at such point during such month.

2.4. Ancillary Services Rates, Terms, and Conditions

2.4.1. Capacity Charges for Ancillary Services

2.4.1.1. Regulation and Frequency Response Service

Monthly rate of $0.07 per kilowatt of Peaking Billing Demand plus the Regulation Purchased Adder as defined in Section 2.4.5 of this Rate Schedule.

2.4.1.2. Spinning Operating Reserve Service

Monthly rate of $0.0146 per kilowatt of Peaking Billing Demand.

Daily rate of $0.00066 per kilowatt for non-Federal generation inside Southwestern's Balancing Authority Area.

2.4.1.3. Supplemental Operating Reserve Service

Monthly rate of $0.0146 per kilowatt of Peaking Billing Demand.

Daily rate of $0.00066 per kilowatt for non-Federal generation inside Southwestern's Balancing Authority Area.

2.4.1.4. Energy Imbalance Service

$0.0 per kilowatt for all reservation periods.

2.4.2. Availability of Ancillary Services

Regulation and Frequency Response Service and Energy Imbalance Service are available only for deliveries of power and energy to load within Southwestern's Balancing Authority Area. Spinning Operating Reserve Service and Supplemental Operating Reserve Service are available only for deliveries of non-Federal power and energy generated by resources located within Southwestern's Balancing Authority Area and for deliveries of all Hydro Peaking Power and associated energy from and within Southwestern's Balancing Authority Area. Where available, such Ancillary Services must be taken from Southwestern; unless, arrangements are made in accordance with Section 2.4.4 of this Rate Schedule.

2.4.3. Applicability of Charges for Ancillary Services

For any month, the charges for Ancillary Services for deliveries of Hydro Peaking Power shall be based on the Peaking Billing Demand.

The daily charge for Spinning Operating Reserve Service and Supplemental Operating Reserve Service for non-Federal generation inside Southwestern's Balancing Authority Area shall be applied to the greater of Southwestern's previous day's estimate of the peak, or the actual peak, in kilowatts, of the internal non-Federal generation.

2.4.4. Provision of Ancillary Services by Others

Customers for which Ancillary Services are made available as specified above, must inform Southwestern by written notice of the Ancillary Services which they do not intend to take and purchase from Southwestern, and of their election to provide all or part of such Ancillary Services from their own resources or from a third party.

Subject to Southwestern's approval of the ability of such resources or third parties to meet Southwestern's technical and operational requirements for provision of such Ancillary Services, the Customer may change the Ancillary Services which it takes from Southwestern and/or from other sources at the beginning of any month upon the greater of 60 days notice or upon completion of any necessary equipment modifications necessary to accommodate such change; Provided, That, if the Customer chooses not to take Regulation and Frequency Response Service, which includes the associated Regulation Purchased Adder, the Customer must pursue these services from a different host Balancing Authority; thereby moving all metered loads and resources from Southwestern's Balancing Authority Area to the Balancing Authority Area of the new host Balancing Authority. Until such time as that meter reconfiguration is accomplished, the Customer will be charged for the Regulation and Frequency Response Service and applicable Adder then in effect. The Customer must notify Southwestern by July 1 of this choice, to be effective the subsequent calendar

year.

2.4.5. Regulation Purchased Adder

Southwestern has determined the amount of energy used from storage to provide Regulation and Frequency Response Service in order to meet Southwestern's Balancing Authority Area requirements. The replacement value of such energy used shall be recovered through the Regulation Purchased Adder. The Regulation Purchased Adder during the time period of January 1 through December 31 of the current calendar year is based on the average annual use of energy from storage[1] for Regulation and Frequency Response Service and Southwestern's estimated purchased power price for the corresponding year from the most currently approved Power Repayment Studies.

The Regulation Purchased Adder will be phased in over a period of four (4) years as follows:

Year	Regulation Purchased Adder for the Incremental Replacement Value of Energy Used from Storage
2014	¼ of the average annual use of energy from storage × 2014 Purchased Power price
2015	½ of the average annual use of energy from storage × 2015 Purchased Power price
2016	¾ of the average annual use of energy from storage × 2016 Purchased Power price
2017 and thereafter	The total average annual use of energy from storage × the applicable Purchased Power price

[1] The average annual use of energy from storage for Regulation and Frequency Response Service is based on Southwestern studies.

2.4.5.1. Applicability of Regulation Purchased Adder

The replacement value of the estimated annual use of energy from storage for Regulation and Frequency Response Service shall be recovered by Customers located within Southwestern's Balancing Authority Area on a non-coincident peak ratio share basis, divided into twelve equal monthly payments, in accordance with the formula in Section 2.4.5.2.

If the Regulation Purchased Adder is determined and applied under Southwestern's Rate Schedule NFTS-13A, then it shall not be applied here.

2.4.5.2. Procedure for Determining Regulation Purchased Adder

Unless otherwise specified by contract, the Regulation Purchased Adder for an individual Customer shall be based on the following formula rate,

calculated to include the replacement value of the estimated annual use of energy from storage by Southwestern for Regulation and Frequency Response Service.

RPA = The Regulation Purchased Adder for an individual Customer per month, which is as follows:

$$[(L_{Customer} \div L_{Total}) \times RP_{Total}] \div 12$$

with the factors defined as follows:

$L_{Customer}$ = The sum in MW of the following three factors:

(1) The Customer's highest metered load plus generation used to serve the Customer's load that is accounted for through a reduction in the Customer's metered load (referred to as 'generation behind the meter') during the previous calendar year, and
(2) The Customer's highest rate of Scheduled Exports[2] during the previous calendar year, and
(3) The Customer's highest rate of Scheduled Imports[2] during the previous calendar year.

L_{Total} = The sum of all $L_{Customer}$ factors for all Customers that were inside Southwestern's Balancing Authority Area at the beginning of the previous calendar year in MW.

RP_{Total} = The "net" cost in dollars and cents based on Southwestern's estimated purchased power price for the corresponding year from the most currently approved Power Repayment Studies multiplied by the average annual use of energy from storage, as provided for in the table in Section 2.4.5, to support Southwestern's ability to regulate within its Balancing Authority Area. The "net" cost in dollars and cents shall be adjusted by subtracting the product of the quantity of such average annual use of energy from storage in MWh and Southwestern's highest rate in dollars per MWh for Supplemental Peaking Energy during the previous calendar year.

[2] Scheduled Exports and Scheduled Imports are transactions, such as sales and purchases respectively, which are in addition to a Customer's metered load that contribute to Southwestern's Balancing Authority Area need for regulation.

For Customers that have aggregated their load, resources, and scheduling into a single node by contract within Southwestern's Balancing Authority Area, the individual Customer's respective Regulation Purchased Adder shall be that Customer's ratio share of the Regulation Purchased Adder established for the node. Such ratio share shall be determined for the Customer on a non-coincident basis and shall

be calculated for the Customer from their highest metered load plus generation behind the meter.

2.4.6. Energy Imbalance Service Limitations

Energy Imbalance Service primarily applies to deliveries of power and energy which are required to satisfy a Customer's load. As Hydro Peaking Power and associated energy are limited by contract, the Energy Imbalance Service bandwidth specified for Non-Federal Transmission Service does not apply to deliveries of Hydro Peaking Power, and therefore Energy Imbalance Service is not charged on such deliveries. Customers who consume a capacity of Hydro Peaking Power greater than their Peaking Contract Demand may be subject to a Capacity Overrun Penalty.

3. Hydro Peaking Power Penalties, Terms, and Conditions

3.1. Capacity Overrun Penalty

3.1.1. Penalty Charge for Capacity Overrun

For each hour during which Hydro Peaking Power was provided at a rate greater than that to which the Customer is entitled, the Customer will be charged a Capacity Overrun Penalty at the following rates:

Months Associated With Charge	Rate per Kilowatt
March, April, May, October, November, December	$0.15
January, February, June, July, August, September	$0.30

3.1.2. Applicability of Capacity Overrun Penalty

Customers which have loads within Southwestern's Balancing Authority Area are obligated by contract to provide resources, over and above the Hydro Peaking Power and associated energy purchased from Southwestern, sufficient to meet their loads. A Capacity Overrun Penalty shall be applied only when the formulas provided in Customers' respective Power Sales Contracts indicate an overrun on Hydro Peaking Power, and investigation determines that all resources, both firm and non-firm, which were available at the time of the apparent overrun were insufficient to meet the Customer's load.

3.2. Energy Overrun Penalty

3.2.1. Penalty Charge for Energy Overrun

$0.1034 per kilowatthour for each kilowatthour of overrun.

3.2.2. Applicability of Energy Overrun Penalty

By contract, the Customer is subject to limitations on the maximum amounts of Peaking Energy which may be scheduled under the Customer's Power Sales Contract. When the Customer schedules an amount in excess of such maximum amounts, such Customer is subject to the Energy Overrun Penalty.

3.3. Power Factor Penalty

3.3.1. Requirements Related to Power Factor

Any Customer served from facilities owned by or available by contract to Southwestern will be required to maintain a power factor of not less than 95 percent and will be subject to the following provisions.

3.3.2. Determination of Power Factor

The power factor will be determined for all Demand Periods and shall be calculated under the formula:

$$PF = (kWh) \div \sqrt{(kWh^2 + rkVAh^2)}$$

with the factors defined as follows:

PF = The power factor for any Demand Period of the month.

kWh = The total quantity of energy which is delivered during such Demand Period to the point of delivery or interconnection in accordance with Section 3.3.4.

rkVAh = The total quantity of reactive kilovolt-ampere-hours (kVARs) delivered during such Demand Period to the point of delivery or interconnection in accordance with Section 3.3.4.

3.3.3. Penalty Charge for Power Factor

The Customer shall be assessed a penalty for all Demand Periods of a month where the power factor is less than 95 percent lagging. For any Demand Period during a particular month such penalty shall be in accordance with the following formula:

$$C = D \times (0.95 - LPF) \times \$0.10$$

with the factors defined as follows:

C = The charge in dollars to be assessed for any particular Demand Period of such month that the determination of power factor "PF" is calculated to be less than 95 percent lagging.

D = The Customer's demand in kilowatts at the point of delivery for such Demand Period in which a low power factor was calculated.

LPF = The lagging power factor, if any, determined by the formula "PF" for such Demand Period.

If C is negative, then C = zero (0).

3.3.4. Applicability of Power Factor Penalty

The Power Factor Penalty is applicable to radial interconnections with the System of Southwestern. The total Power Factor Penalty for any month shall be the sum of all charges "C" for all Demand Periods of such month. No penalty is

assessed for leading power factor. Southwestern, in its sole judgment and at its sole option, may determine whether power factor calculations should be applied to (i) a single physical point of delivery, (ii) a combination of physical points of delivery where a Customer has a single, electrically integrated load, (iii) or interconnections. The general criteria for such decision shall be that, given the configuration of the Customer's and Southwestern's systems, Southwestern will determine, in its sole judgment and at its sole option, whether the power factor calculation more accurately assesses the detrimental impact on Southwestern's system when the above formula is calculated for a single physical point of delivery, a combination of physical points of delivery, or for an interconnection as specified by an Interconnection Agreement.

Southwestern, at its sole option, may reduce or waive Power Factor Penalties when, in Southwestern's sole judgment, low power factor conditions were not detrimental to the System of Southwestern due to particular loading and voltage conditions at the time the power factor dropped below 95 percent lagging.

4. Hydro Peaking Power Miscellaneous Rates, Terms, and Conditions

4.1. Real Power Losses

Customers are required to self-provide all Real Power Losses for non-Federal energy transmitted by Southwestern on behalf of such Customers under the provisions detailed below.

Real Power Losses are computed as four (4) percent of the total amount of non-Federal energy transmitted by Southwestern. The Customer's monthly Real Power Losses are computed each month on a megawatthour basis as follows:

$$ML = 0.04 \times NFE$$

with the factors defined as follows:

ML = The total monthly loss energy, rounded to the nearest megawatthour, to be scheduled by a Customer for receipt by Southwestern for Real Power Losses associated with non-Federal energy transmitted on behalf of such Customer; and

NFE = The amount of non-Federal energy that was transmitted by Southwestern on behalf of a Customer during a particular month.

The Customer must schedule or cause to be scheduled to Southwestern, Real Power Losses for which it is responsible subject to the following conditions:

4.1.1. The Customer shall schedule and deliver Real Power Losses back to Southwestern during the second month after they were incurred by Southwestern in the transmission of the Customer's non-Federal power and energy over the System of Southwestern unless such Customer has accounted for Real Power Losses as part of a metering arrangement with Southwestern.

4.1.2. On or before the twentieth day of each month, Southwestern shall determine the amount of non-Federal loss energy it provided on behalf of the Customer during the previous month and provide a written schedule to the Customer setting forth hour-by-hour the quantities of non-Federal energy to be delivered to Southwestern as losses during the next month.

4.1.3. Real Power Losses not delivered to Southwestern by the Customer, according to the schedule provided, during the month in which such losses are due shall be billed by Southwestern to the Customer to adjust the end-of-month loss energy balance to zero (0) megawatthours and the Customer shall be obliged to purchase such energy at the following rates:

Months Associated With Charge	Rate per Kilowatthour
March, April, May, October, November, December	$0.15
January, February, June, July, August, September	$0.30

4.1.4. Real Power Losses delivered to Southwestern by the Customer in excess of the losses due during the month shall be purchased by Southwestern from the Customer at a rate per megawatthour equal to Southwestern's rate per megawatthour for Supplemental Peaking Energy, as set forth in Southwestern's then-effective Rate Schedule for Hydro Peaking Power to adjust such hourly end-of-month loss energy balance to zero (0) megawatthours.

4.2. Peaking Energy Schedule Submission Time

Southwestern's Peaking Energy Schedule Submission Time is on or before 2:30 p.m. Central Prevailing Time (CPT), as adjusted by the Administrator, Southwestern, in accordance with Section 4.2.2 in this Rate Schedule, of the day preceding the day for the delivery of Peaking Energy. The Peaking Energy Schedule Submission Time supersedes the Peaking Energy schedule submission time provided in the Customer's Power Sales Contract, pursuant to Section 4.2.1 of this Rate Schedule.

4.2.1 Applicability of Peaking Energy Schedule Submission Time

The Peaking Energy Schedule Submission Time shall apply to the scheduling of Peaking Energy. The Peaking Energy Schedule Submission Time shall not apply to the scheduling of Supplemental Peaking Energy or to Contract Support Arrangements.

4.2.2 Procedure for Adjusting the Peaking Energy Schedule Submission Time

Not more than once annually, the Peaking Energy Schedule Submission Time of 2:30 p.m. CPT, as noted in Section 4.2 of this Rate Schedule, may be adjusted by the Administrator, Southwestern, to a time no earlier than 2:00 p.m. CPT and no later than 3:00 p.m. CPT.

4.2.2.1 Determination of Need to Adjust the Peaking Energy Schedule Submission Time

The Administrator, Southwestern, will make a determination on the need to adjust the Peaking Energy Schedule Submission Time based on Southwestern's studies involving financial analysis, regional energy market conditions, and/or operational considerations.

4.2.2.2 Notification of Peaking Energy Schedule Submission Time Adjustment

The Administrator, Southwestern, will notify customers of the determination to adjust the Peaking Energy Schedule Submission Time in writing no later than 30 calendar days prior to the effective date of the Peaking Energy Schedule Submission Time adjustment.

UNITED STATES DEPARTMENT OF ENERGY

SOUTHWESTERN POWER ADMINISTRATION

RATE SCHEDULE EE-13[1]**

WHOLESALE RATES FOR EXCESS ENERGY

[1] Supersedes Rate Schedule EE-11.

** Extended through September 30, 2021 by approval of Rate Order No. SWPA-74 by the Assistant Secretary for Electricity.

Effective:

During the period October 1, 2013, through September 30, 2021**, in accordance with Federal Energy Regulatory Commission (FERC) order issued in Docket Nos. EF14-1-000 (January 9, 2014), extension approved by the Deputy Secretary in Docket No. EF14-1-002 (September 13, 2017), and extension approved by Assistant Secretary in Rate Order No. SWPA-74 (September 22, 2019).

Available:

In the marketing area of Southwestern Power Administration (Southwestern), described generally as the States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

Applicable:

To electric utilities which, by contract, may purchase Excess Energy from Southwestern.

Character and Conditions of Service:

Three-phase, alternating current, delivered at approximately 60 Hertz, at the nominal voltage(s) and at the point(s) of delivery specified by contract.

1. Wholesale Rates, Terms, and Conditions for Excess Energy

Excess Energy will be furnished at such times and in such amounts as Southwestern determines to be available.

1.1. Transmission and Related Ancillary Services

Transmission service for the delivery of Excess Energy shall be the sole responsibility of such customer purchasing Excess Energy.

1.2. Excess Energy Charge

$0.0094 per kilowatthour of Excess Energy delivered.

KCBPU RENEWABLE POWER PURCHASE AGREEMENT

BETWEEN

KCBPU,

MCP-KCBPU, LLC

AND

GARDNER CAPITAL, INC.

FOR THE

KCBPU SOLAR GENERATING PROJECT

RENEWABLE POWER PURCHASE AGREEMENT FOR THE KCBPU SOLAR GENERATING PROJECT

This RENEWABLE POWER PURCHASE AGREEMENT ("Agreement" or "RPPA") is made and entered into this 10th day of November, 2016 ("Contract Date"), by and between KCBPU ("Buyer"), an administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas, organized and existing under the laws of the State of Kansas, and MCP-KCBPU, LLC, a limited liability company organized and existing under the laws of the State of Missouri and Gardner Capital, Inc., a Missouri corporation (MCP-KCBPU, LLC and Gardner Capital Inc., are collectively the "Seller" hereunder). KCBPU, MCP-KCBPU LLC and Gardner Capital, Inc. each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

1. MCP-KCBPU, LLC will construct and will own and operate the Generating Facility at the Nearman Creek Power Station, Kansas City, KS. The Generating Facility has a nameplate capacity of 1.0 MWs (AC).

2. Contemporaneously with the execution of this Agreement, MC Power Companies, Inc. will transfer ownership of MCP-KCBPU, LLC (and therefore indirectly ownership of the Project, as defined below) to Gardner Capital, Inc., with the result that MCP-KCBPU, LLC and Gardner Capital, Inc. collectively will constitute the successor Seller and will assume all obligations and rights of Seller under this Agreement as such obligations and rights pertain to the Generating Facility.

3. The Parties agree that this Agreement is limited to the sale of Capacity and Net Energy from the Generating Facility to the KCBPU's Electric System and therefore does not contemplate or otherwise impose on Buyer or Seller any obligation: (a) to provide for, or incur the costs of, interconnection of the Generating Facility with any transmission facilities beyond KCBPU's Electric System, or (b) to comply with any regulatory or contractual requirements applicable to use of such transmission facilities in connection with the sale to Buyer hereunder of Net Energy.

NOW THEREFORE, in consideration of these premises and the mutual promises set forth below, Seller and Buyer agree as follows:

AGREEMENT

ARTICLE I
DEFINITIONS

As used in this Agreement, the following terms, when initially capitalized, shall have the meanings specified in this Article I. Words, phrases or expressions not otherwise defined herein that (i) are defined in the Glossary Of Terms (Annex B to the Interconnection and Operating Agreement) shall have the meanings specified in that Glossary Of Terms, or (ii) have a generally accepted meaning in Good Utility Practice shall have such meaning in this Agreement or (iii) do

not have well known and generally accepted meaning in Good Utility Practice but that have well known and generally accepted technical or trade meanings, shall have such recognized meanings.

Agreement. This contract, including all annexes, for the purchase of Capacity and Net Energy entered into between Seller and Buyer and as amended by the Parties from time to time.

Attachment Facilities. As defined in the Interconnection and Operating Agreement.

Business Day. Means any day except Saturday, Sunday or any day on which banks are generally not open for business in Wyandotte County, Kansas or Kansas City, Kansas.

Buyer. KCBPU and its permitted successors and assigns.

Capacity. The output potential a generator can produce under specified conditions. The capacity of generating equipment is generally expressed in kW or MW.

City. Kansas City, KS

Claim. Any demand, assertion, claim, action or proceeding, judicial, governmental or otherwise, initiated or pressed by any third party in connection with the Generating Facility, the Project or this Agreement.

Commercial Operation Date. The Commercial Operation Date is the first calendar day following a successful demonstration that the Generating Facility is capable of delivering power to Buyer's meter and has reached an operating level of at least the Generating Facility's full nameplate capacity, as adjusted for the conversion from DC to AC and the estimated loss from the inverter to the Point of Delivery where the meter is measuring the output of the Generating Facility, for at least five (5) days within a thirty (30) day period after initial start-up. The nameplate capacity for the Generating Facility is 1.0 MW AC.

Confidential Information. Confidential Information is defined in Section 10.12 of this Agreement.

Contract Date. The date of execution of this Agreement as set forth in the first paragraph above.

Contract Year. The Contract Year is each period of one (1) year commencing on the Commercial Operation Date or anniversary thereof, and ending on the day immediately prior to the next anniversary of the Commercial Operation Date.

Emergency Condition. A condition or situation requiring actions or inactions deemed necessary by the sole but reasonable judgment of the Party in order to (i) comply with any order issued by the Buyer or the applicable Reliability Coordinator under NERC reliability standards, (ii) preserve public health and safety, (iii) limit or prevent damage, or (iv) expedite restoration of service. For purposes of this definition, ability of a Party to purchase energy at a price lower than the Guaranteed Price shall not be considered as a condition or situation that would impact public health or safety or create damage.

Energy. The amount of electricity either used or generated over a period of time; expressed in terms of kilowatt-hours (kWh) or megawatt-hours (MWh).

Environmental Attributes. All attributes (environmental or other) that are created or otherwise arise from the Generating Facility's generation of electricity using sunlight as a fuel in contrast to the generation of electricity using nuclear or fossil fuels or non-renewable resources, including, but not limited to, renewable energy credits, solar renewable energy credits, tags, certificates or similar products or rights associated with solar as a "green" or "renewable" electric generation resource. These attributes include all local, state or federal credits, allowances, offsets and similar rights issued, recognized, created or otherwise arising from the photovoltaic Generating Facility, Energy, or the delivery of the Net Energy to Buyer, which can be used to claim responsibility for any avoidance or reduction of emissions or pollutants, including, but not limited to, mercury, nitrogen oxide, sulfur dioxide, carbon dioxide, carbon monoxide, particulate matter or similar pollutants or contaminants of air, water or soil, under any governmental, regulatory or voluntary program, including the United Nations Framework Convention on Climate Change and related Kyoto Protocol or other program. Notwithstanding the foregoing, the term "Environmental Attributes" shall not include investment tax credits within the meaning of Section 48 of the Internal Revenue Code or any successor to such section.

Environmental Law. Any federal, state and local jurisdictional laws including statutes, regulations, rulings, orders, administrative interpretations and other governmental restrictions and requirements relating to the discharge of air pollutants, water pollutants or process waste water or otherwise relating to the environment or hazardous substances as amended from time to time.

Environmental Liability. Any and all liability arising under, resulting from or imposed by any Environmental Law.

Force Majeure. As defined in Section 6.1 of this Agreement.

Generating Facility. The Seller's facility and equipment used to generate and transmit electricity through KCBPU's Attachment Facilities to the Electric System, as described in greater detail in the Interconnection and Operating Agreement.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result of the lowest reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be generally accepted and consistently adhered to acceptable practices, methods, or acts relevant to the activity and facts in question.

Governmental Authority. Any nation or government, any state or other political subdivision thereof, whether foreign or domestic, including, without limitation, any municipality, township and county, and any entity exercising executive, legislative, judicial, regulatory or

administrative functions of or pertaining to government, including, without limitation, any corporation or other entity owned or controlled by any of the foregoing.

Guaranteed Price. In each Contract Year, the price used as the basis for determining payments by Buyer to Seller for the Net Energy (including Test Energy) and Capacity of the Generating Facility shall be $.082 per kWh (AC). For the avoidance of doubt, the Guaranteed Price includes payment by and transfer to the Buyer of all Environmental Attributes. KCBPU will agree not to curtail the plant's generations unless required to do so by the SPP or other authority having jurisdiction, or to avoid or react to an Emergency Condition.

Interconnection and Operating Agreement. The agreement between Seller and Buyer governing the interconnection of the Generating Facility to the KCBPU's Electric System. The Interconnection and Operating Agreement is included herein as Annex B.

KORA. KORA is defined in Section 10.12 of this Agreement.

kW. Kilowatt.

MW. Megawatt.

NERC. North American Electric Reliability Corporation and its successors, if any.

Net Energy. The actual number of kWh generated by the Generating Facility during the period being considered, net of any generating output in kWh used for the Generating Facility's Station Auxiliary, as measured by the meters installed pursuant to Section 3.1.

Outage. A physical state in which all or a portion of the Generating Facility is unavailable to provide Energy, or in which any other system, facility or equipment is unable to perform its intended function.

Parties. Buyer and Seller, and their respective successors and permitted assignees.

Party. Buyer or Seller, and their respective successors and permitted assignees.

Permits. All state, federal, and local authorizations, certificates, permits, licenses and approvals required by any Governmental Authority for the construction, operation and maintenance of the Generating Facility.

Person. An individual, partnership, corporation (including a business trust), limited liability company, joint stock company, trust, unincorporated association, joint venture, Governmental Authority, or other entity.

Planned Outage. The prescheduled removal of all or any portion of the Generating Facility from service to perform routine maintenance or improvement including, but not limited to, periodic cleaning, repair or replacement of photovoltaic panels or other components, inspections and testing where such removal reduces or eliminates the ability of the Generating Facility to generate and deliver Energy to the Point of Delivery or the ability to transmit Net Energy to Buyer.

Point of Delivery. The point at which the Generating Facility is connected to the Buyer's Electric System at a line voltage of 12.47 kV (or other voltage specified in the Interconnection and Operating Agreement), generally as depicted by the switch in the one-line drawing attached to the Interconnection and Operating Agreement.

Project. The photovoltaic Generating Facility owned and operated by Seller with a nameplate capacity of 1.0 MW (AC), as described in more detail in the Interconnection and Operating Agreement, plus all leasehold, ownership or option for ownership, or similar rights and interests of Seller pursuant to arrangements entered into between Seller and KCBPU in connection with said facilities, as well as all real property interests of any nature held by Seller with respect to the Project Site.

Project Site. The specific location specified in the Interconnection and Operating Agreement.

Reliability Coordinator. The entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, has the wide area view of the bulk electric system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. As of the Contract Date, the Reliability Coordinator is the Buyer.

Requirements of Law. The certificate of incorporation and bylaws or other organizational or governing documents of Seller or Buyer, respectively, and any material United States federal, state, county or local law, treaty, franchise, rule, regulation, order, writ, judgment, injunction, decree, award or determination of any arbitrator or a court or other Governmental Authority, in each case applicable to or binding upon Seller or Buyer, respectively or to any of its respective property.

Seller. MCP-KCBPU, LLC, Gardner Capital, Inc., and their respective permitted successors and assigns. Gardner Capital Inc. shall perform all obligations of Seller hereunder as the agent for MCP-KCBPU, LLC, unless Buyer expressly consents to a successor Seller.

Station Auxiliary. Energy provided by Buyer and used by Seller to operate the Generating Facility, as explained in Section 4.2(c).

Term. The meaning given to such term in Section 2.1 hereof.

Transmission Provider. The entity that provides transmission service to Buyer (and which may, in fact, be the Buyer, or any purchaser therefrom) in connection with the delivery of Net Energy from the Generating Facility.

Test Energy. Any Net Energy generated by the Generating Facility and delivered to the Point of Delivery prior to the Commercial Operation Date.

ARTICLE II
PURCHASE AND SALE

2.1 Term. The term of this Agreement shall commence on the Contract Date, and shall continue unless otherwise terminated in accordance with its terms until the end of the twenty-fifth (25th) year after the Commercial Operation Date ("Term"). Subject to Section 2.4, Buyer's obligation to purchase and Seller's obligation to sell the Capacity and Net Energy created by the Generating Facility as set forth herein shall be effective when the Generating Facility begins to generate Test Energy.

2.2 Sale and Purchase. Buyer agrees to purchase the entire Capacity and Net Energy of the Generating Facility during the Term and to accept delivery of the Capacity and Net Energy at the Point of Delivery during the Term, subject to the terms of the Agreement. Seller agrees to sell to Buyer the entire Capacity and Net Energy of the Generating Facility during the Term and to deliver the entire Capacity and Net Energy from the Generating Facility to Buyer at the Point of Delivery during the Term. The Net Energy will be provided on a unit-contingent basis. Seller shall not contract to sell any Capacity or Net Energy from the Generating Facility to any Person other than Buyer at any time during the Term, and Seller acknowledges that Buyer is entitled to receive all Capacity and Net Energy from the Generating Facility during the Term. Net Energy will be delivered at 12.47 kilovolts, or such other voltage as is specified for the Generating Facility in the Interconnection and Operating Agreement. Title to and risk of loss for the Capacity and Net Energy from the Generating Facility shall transfer to Buyer at the Point of Delivery. Seller warrants that it will deliver to Buyer the Capacity and Net Energy at the Point of Delivery free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any Person. The Parties acknowledge that the sale of Capacity and Net Energy from the Generating Facility to Buyer hereunder includes all Environmental Attributes related to the Project, except as may be expressly and separately arranged by the Parties.

2.3 Guaranteed Price. Buyer shall pay Seller for the Net Energy delivered to Buyer at the Guaranteed Price for each Contract Year in which service is provided. Buyer shall purchase all Test Energy produced by the Generating Facility during startup and testing at the Guaranteed Price. Buyer and Seller agree that the Guaranteed Price is intended to compensate Seller for the Net Energy and Capacity delivered to Buyer, and that Seller is not entitled to a separate price or payment for the Capacity associated with the Project to which Buyer is entitled. Seller acknowledges that payment of the Guaranteed Price entitles Buyer to all Environmental Attributes associated with the Generating Facility.

2.4 Marketing. With the prior consent of Buyer, which such consent shall be deemed given if Buyer does not respond within ten (10) days of notice provided by Seller pursuant to Section 10.2, Seller may undertake any marketing of power from the Generating Facility or produce or distribute any marketing materials relating to the Generating Facility or the renewable resources associated with the Generating Facility.

2.5 Capacity Accreditation. Seller agrees to cooperate with Buyer in taking such reasonable actions as are necessary for Buyer to obtain accreditation of the Capacity of the Generating Facility to the maximum extent practicable, in order to permit Buyer to (a) count such Capacity in connection with satisfying applicable resource adequacy requirements and (b)

designate this Agreement as a designated network resource under the terms of any applicable transmission tariff, provided however, that this provision shall not impose on Seller any obligation to incur costs associated with such cooperation.

2.6 Environmental Attributes and Accreditation. All Environmental Attributes at any time allocated to the Generating Facility and/or associated with Net Energy produced from the Generating Facility shall remain with and be the sole property of the Buyer. Buyer agrees to cooperate with Seller in taking such reasonable actions as are necessary to obtain accreditation of Environmental Attributes associated with the Generating Facility to the maximum extent practicable, provided however, that this provision shall not impose on Buyer any obligation to incur costs associated with such cooperation.

2.7 [INTENTIONALLY OMITTED]

2.8 [INTENTIONALLY OMITTED]

2.9 Buyer Option to Purchase Generating Facility and Terminate Agreement. Buyer may (but is under no obligation to) acquire the Project and terminate this Agreement as of a date on or after the end of the seventh Contract Year. The purchase price for such acquisition shall be the greater of the amount identified in Annex A or the fair market value of the Generating Facility equipment as determined by an appraiser chosen by Buyer assuming the equipment has been removed from its current location and placed in a warehouse. Buyer shall be obligated to provide written notice of Buyer's intention to exercise its purchase rights under this option to Seller no later than eight months prior to the proposed closing date for the acquisition. Within thirty (30) days of such written notification, Seller shall provide to Buyer a good-faith estimate of any anticipated major expenses or capital costs to be incurred in the next 24-month period, and such other information as Buyer reasonably requests in connection with its due diligence review. Within thirty (30) days after its receipt of such data, Buyer shall either withdraw its notice or confirm its continued intention to exercise its purchase rights under this option. If Buyer elects to acquire the Project, the Parties shall negotiate, execute, and close on an asset purchase agreement and all necessary related documents to convey ownership of the Project (including all necessary Permits) to Buyer effective as of the acquisition date. For purposes of clarity, upon Buyer's acquisition of the Project, this Agreement shall be terminated, except that the Parties shall continue to be bound by any terms of this Agreement which expressly survive termination of the Agreement..

2.10 Obligations After Contract Term. Upon termination of this Agreement, other than pursuant to acquisition of the Project by Buyer in accordance with Section 2.9, Buyer shall have the right to require Seller to remove the Project and restore the Project Site to its pre-Project condition, at Seller's sole expense in accordance with the terms of that certain Solar Energy Site Lease by and between the Parties dated as of [Date] (the "Site Lease"). If the Project has caused any damage to the Project Site of any kind, Seller shall be financially responsible for all related costs and liabilities from the damage. If Buyer does not acquire the Project and does not require Seller to remove the Project upon termination of this Agreement, then Seller shall be free to sell the Project and/or the Capacity and Net Energy from the Generating Facility to any other Person(s), unless the Parties mutually agree to a new contract. Any sale by the Seller of Capacity and/or Net Energy from the Generating Facility to any other Person(s) shall be subject to a

contract to use the Buyer's distribution and transmission services to deliver the Capacity and/or Net Energy to such other Person(s).

ARTICLE III
METERING AND PAYMENT

3.1 Metering Equipment. Buyer shall, at its own expense, provide, install, own, operate, and maintain revenue-quality meters that measure the power at the Point of Delivery and associated telecommunications equipment necessary for accurately determining the Capacity and Net Energy delivered under this Agreement. Except as provided in Sections 3.2 and 3.3, Buyer's meters shall be used for quantity measurements and billing under this Agreement. Seller, at its sole expense, may install and maintain check meters and all associated measuring equipment necessary to permit an accurate determination of the quantities of Capacity and Net Energy delivered under this Agreement; provided, however, that such equipment shall be operated and maintained in a manner that does not interfere with the installation, maintenance, and operation of Buyer's meters. Buyer and Seller shall each provide to the other (a) real-time power generation data obtained from Buyer's and Seller's metering equipment; and (b) consistent with Section 3.3, reasonable access to test the other party's metering equipment. Buyer and Seller shall share the data from their respective metering equipment on a daily (Monday – Friday) basis.

3.2 Measurements. Readings of Buyer's meters made by Buyer shall be conclusive as to the amount of Capacity and Net Energy delivered to Buyer hereunder; provided, however, that if any of Buyer's meters is out of service or is determined, pursuant to Section 3.3 hereof, to be registering inaccurately, measurement of Capacity and Net Energy delivered hereunder shall be determined by, in the following order:

(a) Seller's check meter at the Point of Delivery, if installed, annually tested and registering accurately; or

(b) in the absence of an installed, annually tested and accurately registering check meter belonging to Seller, making a mathematical calculation if, upon a calibration test of Buyer's meter, a percentage error is ascertainable; or

(c) in the absence of an installed, annually tested and properly registering check meter belonging to the Seller, and an ascertainable percentage of error in Buyer's meter, estimating by reference to quantities measured during periods of similar conditions when Buyer's meter was registering accurately.

If no reliable information exists as to the period over which Buyer's meter was registering inaccurately, it shall be assumed for correction purposes hereunder that such inaccuracy began at a point in time midway between the testing date and the last previous date on which such meter was tested and found to be accurate; provided, however, that the deemed period of the inaccuracy shall not exceed one hundred eighty (180) days.

3.3 Testing and Correction. The accuracy of each of Buyer's meters shall be tested and verified by Buyer annually. Buyer and Seller shall each have the right, at its own expense, to test and verify the other's meters upon reasonable notice, provided such testing shall not

exceed one test of the meter(s) for the Generating Facility during a calendar year, or more frequently if there is just cause. If Seller has installed check meters in accordance with Section 3.1 hereof, Seller shall test and verify such meters annually. Each Party shall bear the cost of the annual testing of its own meters. Each meter shall be accurate within a one-percent (1%) variance. If either Party disputes a meter's accuracy or condition, it shall so advise the meter's owner in writing. The meter's owner shall, within fifteen (15) days after receiving such notice, advise the other Party in writing as to its position concerning the meter's accuracy and reasons for taking such position. If the Parties are unable to resolve their disagreement through reasonable negotiations, either Party may submit such dispute to an unaffiliated third-party engineering company mutually acceptable to the Parties to test the meter. Should the meter be found to be registering within the permitted one-percent (1%) variance, the Party contesting the meter's accuracy shall bear the cost of inspection; otherwise, the cost shall be borne by the meter's owner. Any repair or replacement of such a meter found to be operating beyond the permitted variance shall be made at the expense of the owner of that meter as soon as practicable, based on the third-party engineer's report. If, upon testing, any meter is found to be in error by an amount exceeding the permitted one-percent (1%) variance, such meter shall be promptly adjusted to record properly, any previous recordings by such meter shall be adjusted in accordance with Section 3.2, any prior payments made for Capacity and Net Energy and/or invoices for payments not yet made shall be adjusted to reflect the corrected measurements determined pursuant to Section 3.2. If the difference of the payments actually made by Buyer minus the payment based upon the corrected measurements is a positive number, Seller shall pay the difference to Buyer; if the difference is a negative number, Buyer shall pay the difference to Seller. In either case, the Party paying such difference shall also pay interest as described in Section 3.5(c) for late payments and such payment (including such interest) shall be made within ten (10) days of receipt of a corrected billing statement.

3.4 Maintenance and Records. In addition to providing real-time generation data pursuant to Section 3.1, Buyer shall provide Seller on a monthly basis reports indicating Seller's daily production of Capacity and Net Energy. Seller shall have the right to be present whenever Buyer tests and/or calibrates the equipment used in measuring or checking the measurement of the Capacity and Net Energy delivered hereunder. Buyer shall endeavor to give five (5) days, but in no event less than forty-eight (48) hours, notice to Seller in advance of taking any such actions. Buyer will also use best efforts to provide Seller advance notice when Buyer reads, cleans, adjusts, changes or repairs the equipment to allow Seller to be present. The records from the measuring equipment shall remain the property of Seller or Buyer, respectively, but, upon request, each Party will provide access to the other, upon reasonable notice and during normal business hours, to review the Party's metering and billing and maintenance records, including supporting documentation, necessary to verify the accuracy of bills. Each Party shall be permitted to audit such records of the other Party no more frequently than once each calendar year.

3.5 Invoicing and Payment.

(a) Buyer shall read the meter(s) or cause the meter(s) to be read and shall provide the results of the reading(s) to Seller as soon as practicable after the last day of the previous calendar month and Seller shall invoice Buyer based on such readings for the total Net Energy and Capacity delivered for the previous calendar month.

(b) Buyer's payment to Seller for the total Net Energy and Capacity received shall be paid by electronic funds transfer by the twentieth (20^{th}) of each month or ten (10) days following Buyer's receipt of Seller's invoice, whichever is later. If such date falls on a weekend or legal holiday, the due date shall be the next Business Day.

(c) Payments made after the due date shall be considered late and shall bear interest on the unpaid balance at a rate equal to an annual rate of two percent (2%) calculated daily plus the average daily prime rate as determined from the "Money Rates" section of the Midwest Edition of the Wall Street Journal, for the days of the late payment period multiplied by the number of days elapsed from and including the due date, to but excluding the payment date. In the event this index is discontinued or its basis is substantially modified, the Parties shall agree on a substitute equivalent index.

(d) Buyer may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice rendered under this Agreement on the grounds that the sum is erroneous in the calculation of the amount due or that the actual amount of electricity provided is incorrect within eighteen (18) months of the date of the invoice. If Buyer in good faith disputes the amount of any invoice, it shall promptly notify Seller in writing of the disputed amount and the reason therefor and shall pay only the undisputed amount of such invoice. All invoices shall be conclusively presumed to be true and correct after eighteen (18) months of the date on which the invoice is sent, except that, if Buyer has disputed the invoice within that period, Buyer's rights shall continue as to that invoice until the dispute is resolved. Any billing disputes shall be settled in accordance with the provisions of Article IX. Payments (or refunds) determined to be due by one Party to the other shall be made within five (5) Business Days of the conclusion of the dispute resolution, with interest as provided for in Section 3.5(c).

ARTICLE IV
SELLER'S OBLIGATIONS

4.1 Design, Construction and Operation of the Generating Facility. Subject to the provisions of Article VI, Seller shall:

(a) At its sole expense, design and construct the Generating Facility in accordance with Good Utility Practice. The nominal nameplate capacity of the Generating Facility will be 1.0 MW (AC). The voltage of the power delivered by the Generating Facility to the Point of Delivery will be 12.47 kV AC, or as otherwise specified in the Interconnection and Operating Agreement.

(b) Seek, obtain, maintain, comply with and, as necessary, renew and modify from time to time, at Seller's sole expense, the Permits and all other permits, certificates or other authorizations which are required by any Requirement of Law or Governmental Authority as prerequisites to engaging in the sale of Capacity and Net Energy at the Point of Delivery as envisioned by the Agreement and to meeting Seller's obligation to operate the Generating Facility consistently with the terms of the Agreement.

(c) At Seller's sole expense, operate, maintain, repair and provide security (including a fence to delineate the Project Site, as defined in the Interconnection and Operating

Agreement) for the Generating Facility in accordance with this Agreement and Good Utility Practice, and bathroom or other sanitary facilities for Seller's employees, agents and contractors during construction or maintenance activities. (Note: Seller's employees, agents and contractors will not normally have access to any of the bathroom or other sanitary facilities at Buyer's Nearman Creek Power Station during construction activities). Seller shall ensure that the Capacity of the Generating Facility does not exceed 1.272 MW (DC) for each unit of 1.0 MW (AC) installed absent the express written consent of Buyer.

(d) At Seller's sole expense, obtain and maintain policies of general liability insurance in the minimum amount of $2 million throughout the Term of the Agreement. The insurance policies shall (i) be obtained from insurers rated at least A-/VII by AM Best (or a comparable rating agency), (ii) at Buyer's election, list Buyer as an additional insured and additional party for the receipt of all notices, provided that Buyer shall reimburse Seller for any increase in premiums that result solely from adding Buyer to the policy; and (iii) not be cancelable without ten (10) days prior written notice for nonpayment of premium or thirty (30) days prior written notice for all other events, such notice to be provided by the insurer to Buyer. Seller's insurance shall in all cases be primary and non-contributory. Any insurance proceeds received with respect to the destruction of all or any part of the Generating Facility will be applied to the reconstruction of the Generating Facility or the affected portion unless Seller can demonstrate to Buyer that it is not commercially reasonable to do so.

(e) Comply with any directives of Buyer (KCBPU) pursuant to the Interconnection and Operating Agreement, or of a Transmission Provider, balancing authority, or Reliability Coordinator (in each case with jurisdiction over the transmission or distribution system to which KCBPU is connected), and cooperate with all reasonable requests by Buyer relating to Buyer's compliance with any such directives relating to deliveries of Net Energy from the Generating Facility. The Parties recognize that Seller's compliance with (i) any directives from KCBPU pursuant to the Interconnection and Operating Agreement due to conditions on the KCBPU's Electric System or (ii) directives of a Transmission Provider, balancing authority, or Reliability Coordinator (in each case with jurisdiction over the transmission or distribution system to which KCBPU is connected) that in either event requires curtailment or interruption of Net Energy deliveries will result in reduced sales hereunder, without liability of either Party. If any directive of a Transmission Provider, balancing authority, or Reliability Coordinator (in each case with jurisdiction over the transmission or distribution system to which KCBPU is connected) would require installation of additional systems or equipment, the Parties shall negotiate in good faith an appropriate allocation of the costs of compliance with such directive, and if the Parties cannot agree the matter shall be subject to dispute resolution under Article IX.

(f) Use reasonable endeavors to schedule Planned Outages in conjunction with Buyer and make commercially reasonable efforts to schedule Planned Outages for off-peak hours and the non-peak season; provided, however, Seller's reasonable endeavors and commercially reasonable efforts shall not include Seller altering its planned or scheduled maintenance if making such alterations would cause Seller to (i) violate any operating guidelines of the generator manufacturer for solar panels or inverters included in the Generating Facility; or (ii) take an action inconsistent with Good Utility Practice with respect to the care of any of the equipment in the Generating Facility. All Planned Outages shall have an estimated duration and be communicated by Seller to Buyer in a monthly or weekly notification. Seller shall also

provide to Buyer, as soon as practicable, information relating to full or partial unplanned Outages of the Generating Facility, including Seller's estimate of the duration of any such Outages.

(g) Allow Buyer reasonable access to the Project, subject to reasonable advance notice and Buyer's compliance with Seller's safety and security measures.

4.2 General Obligations.

(a) Seller, during the Term of the Agreement, shall pay all present or future federal, state, municipal, or other lawful taxes or fees applicable to Seller, or the Project, or by reason of the sale of Energy or Capacity to the Buyer up to each Point of Delivery under the Agreement.

(b) Seller shall obtain in its own name and at its own expense any and all pollution or environmental credits or offsets necessary to operate the Generating Facility in compliance with Environmental Laws.

(c) Seller shall purchase from KCBPU all Station Auxiliary power and Energy not provided by the Generating Facility itself, pursuant to the applicable KCBPU rate schedule or tariff.

(d) Seller shall continue to (i) to the extent applicable, preserve, renew and keep in full force and effect its organizational existence and good standing, and take all reasonable action to maintain all permits, rights, privileges, licenses, and franchises necessary or desirable in the ordinary course of its business; (ii) comply with all Requirements of Law applicable to Seller, and (iii) comply with all material agreements, instruments and undertakings related to the Project except to the extent that any failure to so comply has not had, or is not reasonably likely to have, a material adverse effect on Seller's performance of its material obligations under this Agreement.

(e) Seller shall make available for Buyer's review such other information regarding the permitting, engineering, construction, condition and operations of the Project, as Buyer may, from time to time, reasonably request.

(f) As between Seller and Buyer, Seller shall be exclusively responsible for all Environmental Liability at the Project Site, and shall indemnify Buyer from and against all such liability; provided that Buyer shall be liable for, and shall indemnify Seller from and against, any Environmental Liability resulting from a release of hazardous substances by Buyer or its contractors or subcontractors.

4.3 Interconnection. Seller shall comply with all obligations of Interconnection Customer under the Interconnection and Operating Agreement.

ARTICLE V
BUYER OBLIGATIONS

5.1 Transmission Service. Buyer shall, at its expense, be responsible for obtaining service over distribution and/or transmission facilities to the extent such service is necessary for

delivery of the Net Energy and Capacity of the Generating Facility from the Point of Delivery. Buyer shall provide Seller written notice that all essential facilities within Buyer's control are in place and operational prior to the Commercial Operation Date.

5.2 Cooperation. Buyer agrees to cooperate with Seller in any applications for permits, certificates or other authorizations as described in Section 4.1(b). Buyer's obligation under this section shall consist only of providing nonproprietary information in its possession, custody or control necessary to complete any applications and responding to requests from the relevant Governmental Authorities or other Person.

ARTICLE VI
FORCE MAJEURE

6.1 Force Majeure. The performance of each Party under the Agreement may be subject to interruptions or reductions due to an event of Force Majeure. The term "Force Majeure" shall mean an event or circumstance beyond the control of the Party claiming Force Majeure, which, by exercise of reasonable diligence and foresight, could not reasonably have been avoided, including, but not limited to, an Emergency Condition, flood, earthquake, storm, fire, tsunami, lightning, hurricanes, heavy rains, tornadoes, ice storms, landslides, mudslides, epidemic, war, riot, civil disturbance, sabotage, strike, and act of God or any other cause beyond the control of the Party claiming Force Majeure. The Party rendered unable to fulfill any obligation by reason of Force Majeure shall take all action necessary to remove such inability with all due speed and diligence. The nonperforming Party shall be prompt and diligent in attempting to remove the cause of its failure to perform. and nothing herein shall be construed as permitting that Party to continue to fail to perform after said cause has been removed. However, the obligation to use reasonable diligence shall not be interpreted to require resolution of labor disputes by acceding to demands of the opposition when such course is inadvisable in the discretion of the Party having such difficulty. Buyer's obligations to make payments already due and/or related to partial performance shall not be suspended by Force Majeure.

6.2 Remedial Action. A Party shall not be liable to the other Party to the extent it is prevented from performing its obligations due to an event of Force Majeure. The Party rendered unable to fulfill any obligation by reason of a Force Majeure shall take all reasonable actions necessary to remove such inability with all due speed and diligence. Such partially performing or nonperforming Party shall be prompt and diligent in attempting to remove the cause of its failure to perform. Neither Party shall be required to remedy, in whole or in part, an event of Force Majeure if such remedy is inconsistent with Good Utility Practices.

6.3 Exclusions from Definition of Force Majeure. Notwithstanding anything in the Agreement to the contrary, "Force Majeure" shall not mean:

(a) Inclement weather affecting construction, start-up, or operation of the Generating Facility or related facilities that does not otherwise meet the definition of "Force Majeure."

(b) Changes in market conditions or governmental action that affect Buyer or Seller, as applicable, the cost of Seller's supply of Net Energy from the Generating Facility, or the ability of Buyer to obtain energy at a rate lower than the Guaranteed Price.

(c) Unavailability of sunlight.

(d) Unavailability of equipment, repairs or spare parts for the Generating Facility, except to the extent due to a qualifying event of Force Majeure.

(e) Inability to obtain, maintain or renew any Permit or any undue delay in obtaining, maintaining, or renewing any Permit, in either case, due to Seller's failure to diligently pursue obtaining, maintaining or renewing such Permit.

(f) Scheduled maintenance on the distribution or transmission system;

(g) Litigation or administrative or judicial action pertaining to the Agreement, the Generating Facility, the Project Site, the Project, the acquisition, maintenance or renewal of financing or any Permits, or the design, construction, maintenance or operation of the Generating Facility that are (i) the result of the actions or omissions of either Buyer or Seller, or (ii) instituted by the Buyer or Seller.

6.4 Notice. In the event of any delay or nonperformance resulting from Force Majeure, the Party suffering the event of Force Majeure shall, as soon as practicable after the occurrence of the Force Majeure event, notify the other Party in writing of the nature, cause, date of commencement thereof, and the anticipated extent of any delay or interruption in performance.

ARTICLE VII
TERMINATION/DEFAULT/REMEDIES

7.1 Events of Default by Buyer. The following shall each constitute an Event of Default by Buyer:

(a) Buyer fails to make any payment due under the Agreement within thirty (30) days after such payment is due, and fails to cure such non-payment within ten (10) Business Days after receipt of written notice of such delinquent payment by Seller, unless such payment is contested or a right of set-off has been claimed by Buyer.

(b) Any other material breach of the Agreement by Buyer not specifically enumerated in this Section 7.1, which is not cured within thirty (30) days after notification by Seller of the breach by Buyer.

(c) Buyer ceases making payments under this Agreement pursuant to the filing of a petition for voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state, or Buyer voluntarily takes advantage of any such law or act by answer or otherwise, or Buyer makes an assignment of all or a significant part of its assets for the benefit of creditors.

(d) A case in bankruptcy or any proceeding under any other insolvency law is filed against Buyer as debtor that materially impacts Buyer's ability to perform its obligations hereunder and Buyer has failed to have such proceeding dismissed or stayed within one hundred eighty (180) days after the date of the filing of such proceeding.

7.2 Events of Default by Seller. The following shall each constitute an Event of Default by the Seller:

(a) Seller fails to make any payment due under the Agreement within thirty (30) days after such payment is due and fails to cure such non-payment within ten (10) Business Days after receipt of written notice of such delinquent payment by Buyer, unless such payment is contested or a right of set-off has been claimed by Seller.

(b) Any other material breach of the Agreement by Seller not specifically enumerated in this Section 7.2, which is not cured within thirty (30) days after notification by Buyer of the breach by Seller.

(c) Seller ceases to generate power at the Generating Facility pursuant to the filing of a petition for voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state, or Seller voluntarily takes advantage of any such law or act by answer or otherwise, or Seller makes an assignment of all or a significant part of its assets for the benefit of creditors.

(d) A case in bankruptcy or any proceeding under any other insolvency law is filed against Seller as debtor that materially impacts Seller's ability to perform its obligations hereunder and Seller has failed to have such proceeding dismissed or stayed within one hundred eighty (180) days after the date of the filing of such proceeding.

7.3 Termination.

(a) In the event the defaulting Party fails to cure the Event of Default within the period for curative action under Section 7.1 or 7.2, as applicable, the non-defaulting Party may terminate the Agreement by notifying the defaulting Party in writing of the decision to terminate and the effective date of the termination; provided, however, that the non-defaulting Party shall not be entitled to terminate this Agreement in the case of an Event of Default that is not reasonably capable of being cured within the applicable cure period, if the defaulting Party (i) has commenced to cure the default within such applicable cure period, (ii) is diligently pursuing such cure, (iii) such Event of Default is capable of being cured by the defaulting Party within a reasonable time after the expiration of such cure period, and (iv) such Event of Default is in fact cured within such reasonable period of time; provided, further, that the extended cure period provided for in this Section 7.3(a) shall in no case be for longer than three months after the date of expiration of the original cure period set out in either Section 7.1 or 7.2.

(b) Upon termination of the Agreement by Buyer due to an Event of Default by Seller pursuant to Section 7.3(a), Buyer shall have no future or further obligation to purchase the Capacity or Net Energy of the Generating Facility from Seller or to satisfy any other obligation under this Agreement, except for payments or other obligations arising or accruing prior to the effective date of termination.

(c) Upon termination of the Agreement by Seller due to an Event of Default by Buyer pursuant to Section 7.3(a), Seller shall have no future or further obligation to deliver the Capacity or Net Energy of the Generating Facility to Buyer or to satisfy any other obligation under this Agreement, except for payments or other obligations arising or accruing prior to the effective date of termination, and Buyer may, at its sole option, require Seller, at Seller's sole cost, to (i) remove the Generating Facility and (ii) restore the Project site to its pre-Project condition, pursuant to a reasonable schedule provided in writing from Buyer to Seller, all in accordance with the Site Lease and Interconnection and Operating Agreement. In case of abandonment of the facility after the Lease has expired or terminated, Seller is making a one time payment of $7,382.57 that will be paid upon commissioning for the buyer to use for the removal or dismantling of the solar farm. The $7,382.57 was calculated upon the Net Present Value of $25,000 compounded annually at a 5% interest rate.

7.4 Other Damages. Neither Party shall be liable to the other Party for special, incidental, exemplary, indirect or consequential damages whether the claim arises in tort, contract, or otherwise as a result of this Agreement or the breach of this Agreement. For all other claims, causes of action and damages the Parties shall be entitled to the recovery of actual damages allowed by law unless otherwise limited by this Agreement. Except as provided herein, neither the enumeration of Events of Default in Sections 7.1 and 7.2, nor the termination of this Agreement by a non-defaulting Party pursuant to Section 7.3(a), shall limit the right of a non-defaulting Party to rights and remedies available at law, including, but not limited to, claims for breach of contract or failure to perform by the other Party.

ARTICLE VIII
INDEMNIFICATION

8.1 General. Neither Party shall indemnify, defend or hold harmless the other Party under this Agreement for any reason.

ARTICLE IX
DISPUTE RESOLUTION

9.1 Negotiations. The Parties shall attempt in good faith to resolve all disputes arising out of, related to or in connection with this Agreement promptly by negotiation, as follows. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels at least one level above the personnel who have previously been involved in the dispute shall meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days after the referral of the dispute to such senior executives, or if no meeting of such senior executives has taken place within fifteen (15) days after such referral, either Party may initiate litigation as provided hereinafter.

9.2 Place of Contract Formation; Choice of Forum. Each Party irrevocably consents and agrees that any legal action or proceeding arising out of this Agreement or the actions of the Parties leading up to the Agreement shall be brought exclusively in the United States District

Court for the Eastern District of Kansas, or if such court does not have jurisdiction, in the State Courts of Kansas. By execution and delivery hereof, each Party (a) accepts the exclusive jurisdiction of such courts and waives any objection that it may now or hereafter have to the exercise of personal jurisdiction by such courts over each Party for the purpose of any proceeding related to this Agreement, (b) irrevocably agrees to be bound by any final judgment (after any and all appeals) of any such courts in any such proceeding, (c) irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of venue of any such suit, action or proceedings brought in such courts (including any claim that any such suit, action or proceeding has been brought in an inconvenient forum) in connection herewith, (d) agrees that service of process in any such action may be effected by mailing a copy thereof by registered or certified mail, postage prepaid, to such Party at its address as set forth herein and (e) agrees that nothing herein shall affect the right to effect service of process in any other manner permitted by law.

9.3 Settlement Discussions. No statements of position or offers of settlement made in the course of the negotiation process described in Section 9.1 may be offered into evidence for any purpose in any litigation between the Parties, nor will any such statements or offers of settlement be used in any manner against either Party in any such litigation. Further, no such statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation. At the request of either Party, any such statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

ARTICLE X
MISCELLANEOUS

10.1 Assignment. The rights and obligations of this Agreement may not be assigned by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld or conditioned; provided, however, Seller may, with notice to but without the consent of Buyer (and without relieving Seller from liability hereunder) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any third-party lender financing or other financial arrangements. Any purported assignment of this Agreement in the absence of the required consent shall be void. All permitted successors and assigns shall be subject to all rights and obligations contemplated herein. The Parties acknowledge that Gardner Capital Inc. is the managing member of the MCP-KCBPU, LLC and that the MCP-KCBPU, LLC has been created for the tax equity investor; notwithstanding anything to the contrary in this Agreement, (i) Gardner Capital Inc. shall remain a Seller hereunder and shall perform all obligations of Seller hereunder as the agent for such special purpose entity, and (ii) Gardner Capital Inc. shall require the MCP-KCBPU, LLC to abide by all applicable terms of this Agreement, including without limitation Seller's obligation to transfer ownership of the Project to Buyer upon Buyer's exercise of its rights pursuant to Section 2.9. Seller shall (subject to the aforementioned consent requirement) assign this Agreement to any third-party purchaser of the Generating Facility or of the Project, and Seller shall only be relieved of its obligations hereunder upon the execution by the assignee of an assignment and assumption agreement that is in form and substance reasonably acceptable to Buyer.

10.2 Notices. Any notice, demand, request, or communication required or authorized by the Agreement shall be delivered either by hand, facsimile, overnight courier or mailed by certified mail, return receipt requested, with postage prepaid, to:

If to Seller:

Gardner Capital, Inc.
1414 E. Primrose St., Suite 100
Springfield, MO 65804
P: (417) 447-1800

If to Buyer:

Kansas City Board of Public Utilities
Attention: General Manager
540 Minnesota Avenue
Kansas City, KS 66101-2930
P: (913) 573-9175

with copies to:

Attention: Manger of Electric Production
Nearman Creek Power Station
PO Box 4088
4240 North 55th Street
Kansas City, KS 66104
Phone: (913) 573-9701

and

Chief Counsel
Unified Government of Wyandotte County
And Kansas City, Kansas
701 N. 7th Street
Kansas City, KS 66101
P: (913) 573-5070

The designation and titles of the person to be notified or the address of such person may be changed at any time by written notice. Any such notice, demand, request, or communication shall be deemed delivered on receipt if delivered by hand or facsimile and on deposit by the sending Party if delivered by courier or U.S. mail.

10.3 Captions. All titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience and are not intended to be inclusive, definitive or to affect the meaning of the contents or scope of the Agreement.

10.4 No Third-Party Beneficiary. No provision of the Agreement is intended to nor shall it in any way inure to the benefit of any customer, property owner or any other third party, so as to constitute any such Person a third-party beneficiary under the Agreement, or of any one or more of the terms hereof, or otherwise give rise to any cause of action in any Person not a Party hereto.

10.5 No Dedication. No undertaking by one Party to the other under any provision of the Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of Buyer as an administrative agency of a body public and corporate or Seller as an independent individual or entity and not a public utility.

10.6 Integration; Amendment. The Agreement, together with all annexes attached hereto, constitutes the entire agreement between the Parties relating to the transaction described herein and supersedes any and all prior oral or written understandings. No amendment, addition to, or modification of any provision hereof shall be binding upon the Parties, and neither Party shall be deemed to have waived any provision or any remedy available to it unless such amendment, addition, modification or waiver is in writing and signed by a duly authorized officer or representative of the applicable Party or Parties.

10.7 Governing Law. The Agreement is made in the State of Kansas and shall be interpreted and governed by the laws of the State of Kansas and/or the laws of the United States, as applicable, excluding any choice of law rules that may direct the application of the laws of another jurisdiction.

10.8 Relationship of Parties.

(a) Unless otherwise specified in this Agreement (such as in the case of MCP-KCBPU, LLC and Gardner Capital Inc., collectively as the Seller), the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. The Agreement shall not be interpreted or construed to create an association, joint venture, fiduciary relationship or partnership between Seller and Buyer or to impose any partnership obligation or liability or any trust or agency obligation or relationship upon either Party. Seller and Buyer shall not have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

(b) The relationship between Buyer and Seller shall be that of contracting party to independent contractor. Accordingly, subject to the specific terms of the Agreement, Buyer shall have no general right to prescribe the means by which Seller shall meet its obligations under the Agreement.

(c) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons to perform Seller's obligations under the Agreement, including all federal, state, and local income, social security, payroll, and employment taxes, and statutorily mandated workers' compensation coverage. None of the persons employed by Seller shall be considered employees of Buyer for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Buyer, employee, or agent.

10.9 Good Faith and Fair Dealing; Reasonableness. The Parties agree to act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, (i) wherever the Agreement requires the consent, approval, or similar action by a Party, such consent, approval or similar action shall not be unreasonably withheld or delayed, and (ii) wherever the Agreement gives a Party a right to determine, require, specify or take similar action with respect to matters, such determination, requirement, specification or similar action shall be reasonable.

10.10 Severability. Should any provision of the Agreement be or become void, illegal, or unenforceable, the validity or enforceability of the other provisions of the Agreement shall not be affected and shall continue in force. The Parties will, however, use their reasonable efforts to agree on the replacement of the void, illegal, or unenforceable provision(s) with legally acceptable clauses which correspond as closely as possible to the sense and purpose of the affected provision and the Agreement as a whole.

10.11 Representations and Warranties. MCP-KCBPU, LLC, Gardner Capital, Inc., and Buyer each represents and warrants to the others that, as of the Contract Date:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its organization or incorporation;

(b) it has the power to execute and deliver this Agreement and to perform its obligations under this Agreement and has taken all necessary corporate, company, partnership, governmental and/or other actions to authorize such execution and delivery and performance of such obligations;

(c) its execution and delivery of this Agreement and its performance of its obligations under this Agreement do not violate or conflict with any law applicable to it; with any provision of its charter or bylaws (or comparable constituent documents); with any order or judgment of any court or other agency of government applicable to it or any of its assets; or with any contractual restriction binding on or affecting it or any of its assets;

(d) except as otherwise permitted herein, it has neither initiated nor received written notice of any action, proceeding or investigation pending, nor to its knowledge is any such action, proceeding or investigation threatened (or any basis therefor known to it) that questions the validity of this Agreement, or that would materially or adversely affect its rights or obligations as a Party;

(e) all authorizations of and exemptions, actions or approvals by, and all notices to or filings with, any Governmental Authority that are required to have been obtained or made by it at the time this representation is made with respect to this Agreement have been obtained or made and are in full force and effect, and all conditions of any such authorizations, exemptions, actions or approvals have been complied with; and

(f) this Agreement constitutes the Party's legal, valid and binding obligation, enforceable against it in accordance with its terms (subject to applicable bankruptcy, reorganization, insolvency, moratorium or similar laws affecting creditors' rights generally and

subject, as to enforceability, to equitable principles of general application, regardless of whether enforcement is sought in a proceeding in equity or at law).

10.12 Confidentiality.

(a) Confidential Information. Except as may otherwise be required by Requirements of Law, including the Kansas Open Records Act (K.S.A. 45-215, et seq.) ("**KORA**"), the Parties hereby agree to keep confidential, and shall not disclose any information relating to the business, strategy, policies, prospects, assets or plans of the other Party and, to the extent identified with specificity in writing as confidential at the time of disclosure, all other information provided by the Parties to one another pursuant to this Agreement (collectively, "**Confidential Information**"). A Party shall mark all information that it believes to be Confidential Information as "Confidential." Confidential Information shall not include (a) information that is or becomes available to the public through no breach of this Agreement, (b) information that was previously known by the receiving Party without any obligation to hold it in confidence, (c) information that the receiving Party receives from a third party who may disclose that information without breach of law or agreement, (d) information that the receiving Party develops independently without using the Confidential Information, (e) information that the providing Party approves for release in writing, (f) information that is required to be disclosed under KORA or other similar statutes or regulations, and (g) this Agreement. Furthermore, the Parties agree that information will need to be provided to the governing body of the Buyer and/or the Unified Government of Wyandotte County/Kansas City, Kansas, in meetings open to the public and the Parties consent in advance to information concerning the operation, lease, maintenance, and marketing being provided in meetings open to the public.

(b) Treatment of Confidential Information. Notwithstanding the foregoing, each Party may provide any Confidential Information: (i) to a Governmental Authority or any other Person (including contractors, consultants, accountants, financial advisors, experts, legal counsel and other professional advisors to the Parties) as required for scheduling, settlement and billing or otherwise to perform its obligations under or administer this Agreement and (ii) in the case of Seller, to lenders or potential lenders, affiliates and lessors, owners of and potential bidders and bidders for, and potential purchasers and purchasers of, direct or indirect interests in the Generating Facility or Seller and to any credit rating agency that has issued a credit rating for Seller or any of its affiliates. Each Party shall use commercially reasonable efforts to cause its personnel and all Persons to whom it discloses the Confidential Information to treat it confidentially and to not disclose it to any other Person in any manner whatsoever, except as permitted hereunder. The obligation to provide confidential treatment to Confidential Information shall not be affected by the inadvertent disclosure of Confidential Information by either Party.

(c) Specific Performance. A receiving Party may use and disclose Confidential Information where required to do so in litigation, administrative, regulatory or other legal proceedings or otherwise by Requirements of Law, but (to the extent reasonably possible under Requirements of Law) only after providing written notice to the providing Party and affording the providing Party an opportunity to seek a protective order or other relief to prevent or limit disclosure of the Confidential Information. In no event shall the receiving Party be required to provide notice when making a required disclosure pursuant to KORA, or when in

litigation. In such event, the receiving Party shall (to the extent permitted under Requirements of Law) reasonably cooperate in connection with the providing Party's efforts to obtain such protective order or other relief. In no event shall a receiving Party be required to provide such a written notice to the providing Party when making a required disclosure in any litigation where the Parties are adverse litigants. Further, each Party shall use commercially reasonable efforts to maintain the confidentiality of the Confidential Information in any litigation or administrative or regulatory proceeding or in any other instance where disclosure is required by Requirements of Law and there is an opportunity to maintain the confidentiality of the Confidential Information under the Requirements of Law, and shall promptly notify the providing Party of any attempt by any Person to obtain the Confidential Information through legal process or otherwise under Requirements of Law. In addition, to the extent either Party requires additional details or other information from the other Party in order to comply with Requirements of Law and such additional details or other information is in such other Party's possession or reasonably available to such other Party, such other Party shall promptly provide such additional details or other information to the first Party upon request therefor from the first Party to such other Party.

(d) Either Party shall be entitled to disclose or use proprietary data in any proceeding before the Federal Energy Regulatory Commission, the Kansas Corporation Commission, the Environmental Protection Agency, the Kansas Department of Health and Environment, or any similar regulatory commission or agency if it is required or advantageous to do so, in Buyer's sole discretion and upon written notice to Seller. In such an event, Buyer will take all reasonable actions to limit the scope of any disclosure, shall only disclose any proprietary data subject to applicable rules and regulations protecting its proprietary nature, and shall resist the efforts by any Person to obtain, any such proprietary data. It shall not be a violation of this Section 10.12 for Buyer to disclose any proprietary data as required pursuant to its obligations under applicable Kansas public meeting or open records laws.

(e) Subject to this Section 10.12, the Guaranteed Price provisions of this Agreement and amendments hereto shall be considered proprietary and shall not be provided to a third party without prior written approval of the other Party, provided, however, that (i) either Party may disclose the terms of this Agreements and amendments hereto if a Party is required to disclose such information by law or court order, or (ii) either Party may disclose such information that is already in the public domain. In the event certain information must be provided pursuant to a regulatory proceeding, the Parties shall take reasonable steps to protect the confidentiality of proprietary information.

(f) Public Statements. Subject to this Section 10.12, neither Party shall issue, or permit any agent, member or affiliate of such Party to issue, any press releases or otherwise make any public statements with respect to this Agreement or the transactions contemplated hereby, except (i) when such release or statement is deemed in good faith by the releasing Party to be required by law or (ii) with the other Party's prior consent, which shall not be unreasonably conditioned or delayed. In each case to which such exception applies, the releasing Party shall provide a copy of such proposed release or statement to the other Party at least two Business Days before releasing it to the public and incorporate any reasonable changes which are suggested by the non-releasing Party prior to issuing the release or making the statement. Buyer's receipt of prior consent from Gardner Capital, Inc. shall be sufficient to satisfy Buyer's obligations under this Section 10.12(f). Notwithstanding the foregoing

provisions of this Section 10.12(f), it shall not be a breach of this Agreement to inform the Seller's Board of any and all aspects of the terms of this Agreement in a Board meeting open to the public, except for the Guaranteed Price provisions, which may only be discussed with the Seller's Board in a duly noticed closed session.

(g) Survival. The obligations of the Parties under this Section will remain in full force and effect for three (3) years following the expiration or termination of this Agreement.

10.13 Cooperation. The Parties agree to reasonably cooperate with each other in the implementation and performance of the Agreement. In this regard, Buyer agrees to provide such documents (and supporting resolutions) as Seller may reasonably request in connection with Seller's arrangements for bond financing or third-party financing. Such duty to cooperate shall not require either Party to act in a manner inconsistent with its rights under the Agreement; without limitation, Buyer shall have no obligation to agree to any documents requested by potential lenders that would diminish Buyer's rights hereunder in any respect.

10.14 Forward Contract. The Parties acknowledge and agree that this Agreement and the transactions contemplated by this Agreement constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Seller and Buyer are "forward contract merchants" within the meaning of the United States Bankruptcy Code.

[Signatures on Next Page]

IN WITNESS WHEREOF, the Parties have caused the Agreement to be duly executed as of the day and year first above written.

MCP-KCBPU, LLC

By: _____

Name: Anthony Ross

Title: Pres.

Gardner Capital, Inc.

By: _____

Name: _____

Title: _____

KCBPU

By: _____

Name: DON L GRAY

Title: GEN MGR

Annex A

PURCHASE PRICE FOR OPTION

Pursuant to Section 2.9, the purchase price for Buyer's acquisition of the Generating Facility shall be the greater of (a) the fair market value of the Generating Facility equipment as determined by an appraiser chosen by Buyer assuming the equipment is removed from its current location and placed in a warehouse, or (b) the following stated purchase price for the Contract Year in which the closing of the acquisition occurs:

Contract Year 7	$2,487,798
Contract Year 8	$2,398,810
Contract Year 9	$2,244,048
Contract Year 10	$2,089,286
Contract Year 11	$1,934,524
Contract Year 12	$1,760,417
Contract Year 13	$1,652,083
Contract Year 14	$1,539,881
Contract Year 15	$1,408,333
Contract Year 16	$1,276,786
Contract Year 17	$1,145,238
Contract Year 18	$1,083,333
Contract Year 19	$1,013,690
Contract Year 20	$947,917
Contract Year 21	$882,143
Contract Year 22	$835,714
Contract Year 23	$835,714
Contract Year 24	$835,714
Contract Year 25	$835,714

Annex B

INTERCONNECTION AND OPERATING AGREEMENT

BETWEEN SELLER AND KCBPU

[SEE ATTACHED]

 Exhibit SSH-2

Via: E-Mail

April 24, 2023

M E M O R A N D U M

From: Sierra Club

Teresa A. Woody
Kansas Appleseed
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Re: Discovery for the Board of Public Utilities ("BPU")

Sierra Club respectfully requests that BPU provide responses to these data requests.

2-1. Please refer to the fixed capacity contract costs discussed on page 10 of Craig Brown's direct testimony.

a. Provide the fixed capacity value for each contract (e.g., $/kW-month, $/MW-day, etc.)

WAPA	4,787 KW	$4.80	KW/Month
SPA	38,600 KW	$4.53	KW/Month

b. Please provide fixed capacity contracts (or contracts with capacity components, including power purchase agreements, wholesale energy contracts, etc.).

Provided in a separate attachment are the PPAs that are not covered by a confidentiality provision. (See WAPA, SPA, and Community Solar/MCP)

2-2. Please refer to BPU's response to Sierra Club data request 1-9, total projected SPP market revenues.

a. State the date when these revenues were calculated. March 2023 Data

b. Are there more recent energy revenue projections? If so, please provide these most recent revenue projections to 2032. No

c. Please provide the electricity market price forecasts to 2032 that were used to calculate projected energy revenues, and state when the price forecasts were developed or acquired. March 2023 Data

March 2023

	2023	2024	2025	2026	2027
January	$31 / $16	$33 / $16	$33 / $16	$34 / $16	$34 / $16
February	$24 / $13	$28 / $15	$28 / $15	$28 / $15	$29 / $15
March	$26 / $14	$26 / $14	$26 / $13	$26 / $13	$26 / $13
April	$26 / $14	$26 / $14	$26 / $13	$26 / $13	$26 / $13
May	$28 / $14	$28 / $14	$29 / $14	$29 / $14	$30 / $14
June	$34 / $16	$34 / $16	$35 / $16	$35 / $16	$36 / $17
July	$40 / $20	$41 / $21	$41 / $21	$42 / $22	$42 / $22
August	$40 / $20	$41 / $21	$41 / $21	$42 / $22	$42 / $22
September	$36 / $18	$36 / $18	$36 / $18	$37 / $18	$37 / $18
October	$28 / $13	$28 / $13	$27 / $13	$27 / $13	$27 / $13
November	$28 / $13	$28 / $13	$28 / $13	$28 / $13	$28 / $13
December	$30 / $15	$32 / $15	$32 / $15	$33 / $15	$33 / $15

	2028	2029	2030	2031	2032
January	$35 / $17	$35 / $17	$35 / $17	$35 / $17	$36 / $18
February	$31 / $15	$31 / $15	$32 / $16	$33 / $16	$33 / $16
March	$27 / $13	$27 / $13	$27 / $13	$27 / $13	$27 / $13
April	$27 / $13	$27 / $13	$27 / $13	$27 / $13	$27 / $13
May	$30 / $15	$30 / $15	$30 / $15	$30 / $15	$31 / $16
June	$36 / $17	$37 / $18	$37 / $18	$38 / $19	$38 / $19
July	$43 / $22	$43 / $22	$44 / $22	$44 / $23	$45 / $23
August	$43 / $22	$43 / $22	$44 / $22	$44 / $23	$45 / $23
September	$38 / $19	$38 / $19	$38 / $19	$39 / $20	$39 / $20
October	$27 / $13	$27 / $13	$27 / $13	$27 / $13	$27 / $13
November	$28 / $13	$29 / $13	$29 / $13	$29 / $13	$30 / $13
December	$33 / $15	$33 / $15	$33 / $15	$33 / $16	$34 / $17

d. Please provide the energy generation forecasts to 2032 that were used to calculate projected energy revenues, and state when the generation forecasts were developed.

2023	901,404
2024	965,790
2025	1,008,714
2026	1,051,638
2027	1,094,562
2028	1,137,486
2029	1,180,410
2030	1,223,334
2031	1,223,334
2032	1,223,334

2-3. Please provide BPU's estimate of the cost of new resources, including solar, wind, batteries, and natural gas plants.

Natural Gas	$1.1 - $1.5 million per MW
Wind	$24 - $30 per MWh PPA (after all tax credits)
Solar	$48 - $58 per MWh PPA (after all tax credits)
Battery	$11 - $14 per KW per Month (after all tax credits)

2-4. For each of BPU's coal supply contracts, please state the contract length (months or years), the average cost per MMBtu, and the contract's expiration date.

The contract between Western Fuels association and Peabody Coal Sales LLC expires December 31st 2024, unless the parties choose to extend. The contract between Union Pacific Railroad Company and Western Fuels association potentially expires December 31, 2025.

The current average price per MMBtu is $2.04 delivered.

2-5. Please refer to BPU's responses to Sierra Club data requests 1-2, 1-3, 1-6 through 1-9, 1-16 and 1-17. Confirm that these values refer specifically to the Nearman Creek Power Station coal unit (or common expenses), and exclude Nearman CT.

Data Request 1-2, 1-3, 1-6 through 1-9, 1-16 and 1-17 costs do not include CT4 at Nearman.

2-6. Describe the projects/investments/upgrades that BPU expects will be required to comply with the following environmental regulations and rules for the Nearman coal unit. For each project, please also provide the expected costs and implementation timeline required for compliance.

a. EPA's Effluent Limitations Guidelines ("ELG Rule") BPU meets all current requirements.

 Exhibit SSH-2

Via: E-Mail

April 25, 2023

M E M O R A N D U M

From: Sierra Club

Teresa A. Woody
Kansas Appleseed
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Re: Discovery for the Board of Public Utilities ("BPU")

Sierra Club respectfully requests that BPU provide responses to these data requests.

3-1. Refer to the direct testimony of BPU witness Ferris, March 2023 draft, on the Demand Forecast issue.

a. Does BPU self-commit the Nearman coal unit into the SPP day ahead energy market? If yes:

i. Please explain the process by which BPU determines to self-commit the Nearman coal unit into the SPP day ahead energy market.

BPU's process is to only self-commit Nearman coal when required for testing (EPA, NERC, etc.), cold weather, avoid risk of environmental noncompliance from dumping air slides, and to mitigate a contingency identified in a next-day study. BPU's primary intention is to keep Nearman coal in a Market commitment status by default.

ii. Please provide the percentage of time that the Nearman coal unit was self-committed for each of the last five years.

Nearman 1's self-commitment percentage by year.
2018 – 54%
2019 – 73%
2020 – 71%
2021 – 4%
2022 – 5%

b. Do BPU's forecasts of generation, provided in response to Sierra Club's first set of data requests, assume that the Nearman coal unit will be self-committed or not?

BPU's forecast assumes that the vast majority of all generating hours will come from a Market commitment status.

3-2. Is BPU a 501(c)(12) entity for federal tax purposes? If not, under what state and federal designation(s) is BPU registered as a nonprofit municipal entity for tax purposes?

BPU is not a 501(c)(12) entity for federal tax purposes.

The Board of Public Utilities (the "BPU") of the Unified Government is an administrative agency charged with the responsibility for the daily management, operation, maintenance and control of the Unified Government's water and electric facilities.

The Unified Government is a municipal corporation duly organized and existing under the laws of the State of Kansas as a consolidated city-county, and became the successor to the City of Kansas City, Kansas and Wyandotte County, Kansas upon the consolidation of the City and the County effective October 1, 1997.

3-3. Has BPU estimated the cost of converting the Nearman coal unit to gas? If yes, produce such cost estimate and any documents reflecting BPU's consideration of converting the coal unit to gas.

See Attached document.

3-4. Refer to BPU's response to Sierra Club data request 1-13.

a. How does BPU contract for the supply of coal? Does another entity contract for the supply of coal on BPU's behalf? What is the longest term of an existing coal contract that supplies coal to Nearman?
b. How does BPU contract for the transport of coal? Does another entity contract for the transport of coal on BPU's behalf? What is the longest term of an existing contract for the transport of coal to Nearman?

WFA contracts with coal producers and railroads to meet its coal supply and delivery commitments for the BPU.

Western Fuels is presently under a two year extension of the original 3 year coal contract between Western Fuels Association and Peabody Coal Sales LLC. The contract expiration date is December 31st 2024.

KANSAS CITY BOARD OF PUBLIC UTILITIES
NEARMAN CREEK STATION

Natural Gas Firing Feasibility Study

B&V PROJECT NO. 177281

B&V FILE NO. 41.3400

RILEY CONTRACT NUMBER 100658

26 JUNE 2014

Riley Power

BLACK & VEATCH
Building a world of difference.

Table of Contents

1.0 Introduction 1-1
2.0 Analysis 2-1
2.1 Natural Gas Supply and Combustion Equipment 2-1
2.1.1 Natural Gas Supply Equipment 2-1
2.1.2 Natural Gas Co-Firing Versus 100 Percent Natural Gas Combustion 2-3
2.1.3 Existing Generating Unit Combustion Equipment 2-5
2.1.4 Natural Gas Combustion Equipment 2-5
2.1.5 Equipment Delivery Schedule 2-6
2.2 Generating Unit Performance Impacts 2-6
2.2.1 Potential Benefits 2-6
2.2.2 Heat Rate Impacts 2-6
2.2.3 Potential Negative Impacts 2-7
2.3 Order-of-Magnitude Cost Estimate 2-8
Attachment A. Riley Power Natural Gas Firing Feasibility Study A-1
Attachment B. Riley Power Order of Magnitude Pricing for Gas Conversion Equipment Supply and Installation B-1

LIST OF TABLES

Table 2-1 Natural Gas Supply Piping Equipment 2-3
Table 2-2 Natural Gas Combustion Equipment 2-5
Table 2-3 Nearman Creek Coal/ Natural Gas Performance Characteristics 2-8
Table 2-4 Gas Conversion Cost Estimate 2-11

1.0 Introduction

The conceptual design and order-of-magnitude cost analysis for equipment modifications required to enable conversion to 100 percent natural gas fuel at the Nearman Creek Station have been performed and are summarized herein. Currently, natural gas is supplied to the station only for use by the simple cycle combustion turbine (CT5). Full load operation of the Unit 1 boiler being fired on natural gas would require approximately 3 times the quantity of gas currently required by CT5. After conversion of Unit 1 to burn gas, capacity expansion and/or hourly flexibility arrangements with the gas pipeline will be needed.

The Unit 1 boiler has one level of coal burners on the boiler front and rear furnace walls. There are nine burners per level on both the front and rear walls, each provided with a relocated oil igniter and a modified flame scanner.

When burning natural gas, flue gas emissions reductions from the boilers for particulate matter (PM), sulfur dioxide (SO_2), and mercury (Hg) would be reduced directly proportional to the reduction in coal combustion. Flue gas emissions of NO_x and carbon monoxide (CO) while firing gas would also be expected to be reduced compared to firing 100 percent coal.

2.0 Analysis

The following is a summary of the investigation of order-of-magnitude costs and performance impacts of natural gas firing on Unit 1 at Nearman Creek Station.

2.1 NATURAL GAS SUPPLY AND COMBUSTION EQUIPMENT

2.1.1 Natural Gas Supply Equipment

Current gas availability to the Nearman Creek Station is from the Southern Star Central pipeline and limited to 28,000 DTH/day. The maximum current gas requirement of CT4 is approximately 18,000 DTH/day. Conversion of Unit 1 would require an additional flow of approximately 58,800 DTH/day that would result in a total gas flow of 76,800 DTH/day with both generating units in operation.

Existing connection capacity from the Southern Star Central pipeline will most likely meet peak hourly requirements by subscribing to the pipeline's Interruptible Transportation Service. Firm Capacity however may not be available from Southern Star Central for Nearman's projected usage.

A second source of gas could be from the PostRock KPC Pipeline by installing a new supply pipe to a connection point located approximately 4 miles West on the Nearman Creek Station. It is estimated that PostRock KPC currently has 80,000 to 100,000 DTH/day of firm transportation availability and therefore KCBPU should be able to contract for Firm or Interruptible Capacity.

The aerial view included in Figure 2-1 shows the proposed routing of a new natural gas supply line to support natural gas firing with the main burners on the Unit 1 boiler. As superimposed on the aerial view, a new natural gas distribution header would run from the existing pipeline to a new on-site gas metering station located east of the Unit 1 boiler. From the outlet of the metering station, the new distribution header would be routed underground to the Unit 1 boiler. From there, the line would be supported from the Unit 1 boiler column rows routed vertically to near the top of the boiler and then would be routed to a new gas pressure regulator to reduce the gas pressure prior to entering the generation building. The pipe would be sized to enable full load operation of Unit 1 operating at 100 psig at the outlet of the metering station. The distribution piping would be sized to maintain conventional gas velocities not greater than 7,500 feet per minute (ft/min).

From the metering station, the piping would be routed to the generating unit pressure regulator. Pressure regulation equipment would be provided to reduce the pressure to meet burner vendor requirements. Pressure at the unit pressure regulator would be controlled to limit the gas pressure to approximately 50 psig inside the generation building. Because of the limited space and the preference to keep higher pressure fuel gas outside of the building enclosures for safety reasons, it was assumed that the unit pressure regulator would be located outside the boiler building enclosures along the rear boiler building column row close the roof of the generating unit.

Natural gas system safety valves and venting systems would be provided in accordance with NFPA 85 Boiler and Combustion Systems Hazards Code recommendations. Flow control valves and

double block and vent valve arrangements would be required downstream of the unit pressure regulator to control flow to the burners. These would be in the scope of supply of the burner vendor.

The characteristics of the new gas piping and equipment are summarized in Table 2-1.

Figure 2-1 Gas Supply Pipeline Addition

Table 2-1 Natural Gas Supply Piping and Equipment

COMPONENT	UNIT 1
Station Supply Piping	14 inch nominal pipe size, sized for 100 psig, 2000 feet routed from the plant boundary at the metering station to the generation building roof elevation
In-Plant Supply Piping	18 inch nominal pipe size, sized for 50 psig, 150 feet routed from the generation building roof elevation to the burner elevation
Unit Pressure Regulators	1 x 100% capacity, to reduce 100 psig inlet to 50 psig, safety shutoff and vent valves; 18 inch nominal pipe size at unit pressure regulator outlet
Unit Supply Header Distribution Piping Valves, and Pressure Regulators	As provided by burner vendor--burner flow control valve burner isolation valves and double block and vent valve arrangements

2.1.2 Natural Gas Co-Firing Versus 100 Percent Natural Gas Combustion

Generally speaking, natural gas can be burned in conjunction with coal to supplement coal combustion or the generating unit can be operated with 100 percent gas combustion in lieu of the existing coal fuel. For co-firing, a portion of the coal burners would be provided with gas supply piping and gas injection nozzles. These gas components would then be selectively utilized in lieu of coal fuel on a pulverizer/burner group basis. Because of the lower radiant flame characteristics of natural gas combustion compared to coal, the radiant heat transfer to the furnace walls from natural gas is less than it is for coal and results in a greater fraction of the heat from natural gas being carried to the convective heat transfer sections of the boiler. This results in elevated superheater metal temperatures, which increases the potential need for secondary superheater (SSH) pendent tubing material upgrades to higher heat resisting materials for the leading edge and trailing edge tubes of the SSH assemblies. Because the additional boiler modifications are expected to be required for a co-firing option, this capability has not been considered for the Nearman Creek Boiler. Only 100 percent coal firing or 100 percent gas firing have been considered.

To convert to 100 percent gas fired boiler operation, all of the 18 coal burners on Unit 1 would be equipped with gas supply piping and gas injection nozzles. The elimination of coal would result in cleaner furnace and convection pass surfaces. However, the lower radiant flame characteristics of natural gas combustion would result in less radiant heat transfer to the furnace walls from natural gas compared to coal and would be expected to result in a greater fraction of the heat from natural gas being carried to the convective heat transfer sections of the boiler.

Riley Power has been contracted to perform this thermal modeling to predict the thermal impacts of converting from coal to gas fueled steam generation. The results of this analysis are presented in Appendix A. The conclusions of this analysis indicated that following a seasoning period, without supplemental modifications, the main steam temperature would be well below the 1005° F main steam design temperature. This would result in the inability to meet the current full load net electrical generating capacity as well as full load net unit heat rate. To alleviate the main steam temperature shortfall, Riley Power has proposed a remedy that includes the installation of a flue gas recirculation system from the economizer outlet to the combustion air windbox supply duct. This would enable the unit to achieve current 1005° F main steam temperature as well as full load electrical output. In addition to the installation of a flue gas recirculation system, Riley Power also envisions abandoning in place the pulverizers but the primary air system would need to be modified to support the FD fans in providing sufficient combustion air to the windbox to enable full load operation with 100 percent natural gas. This could consist of the installation of supplemental PA fan ducts that would supply hot air from the primary air system to the secondary air system leaving the air heater. Should the conversion to 100 percent natural gas be further considered, a detailed thermal analysis of the boiler pressure parts while firing gas should be performed to confirm the results of this initial analysis. The expected burner and boiler equipment modifications needed to fire up to 100 percent load with natural gas are listed in Table 2-2.

Table 2-2 Natural Gas Combustion Equipment

COMPONENT	UNIT DESIGN PARAMETERS
Unit Supply	18 inch diameter, 50 psig operating pressure
Gas Control Valves	Safety shutoff valves and flow regulators suitable for flow control to 18 coal burners modified to enable gas firing
Burner Modifications	18 coal burners modified to accept natural gas guns to support natural gas combustion in similar capacity to the coal burning rating of the burner; each of the existing oil igniters would be relocated to one of the flame scanner locations on each burner, each of the burner the flame scanners would be provided with a with a quartz fiber-optic extension to replace the glass fiber optic extension to allow existing UV/IR flame scanner heads to monitor the oil igniter or main gas flame.
Flue Gas Recirculation System	Two (2) 50% capacity FGR fans including inlet vane control, and isolation dampers, motor and & turning gear to recirculate up to 21% flue gas from the air heater inlet to the windbox.
Boiler pressure part modifications	None
PA fans and motors	Remain in service to supply a portion of the combustion air to the windbox.
Trisector air heaters and ductwork	Remain in service without modification except for modification to the hot primary air ductwork to supply air to the windbox rather than to the mills.

The coal and ash handling equipment would be abandoned in place and with periodic maintenance should be ready for conversion back to coal firing in the future. The new flue gas recirculation system would include new flue gas ductwork from economizer outlets to a pair of half-capacity flue gas recirculation fans that would return approximately 20 percent of the flue gas to the combustion air windbox supply ducts. The primary air ductwork from the trisector air heater outlets would be modified to deliver the hot primary air to the windbox rather than to the pulverizers.

2.1.3 Existing Generating Unit Combustion Equipment

Units 1 is currently equipped with 18 low NO_x coal burners with light oil igniters. The Unit 1 boiler was originally provided by Riley Power in 1970 with directional flame burners that were subsequently replaced with the existing Low NO_x Tilting Directional burners also provided by Riley Power.

2.1.4 Natural Gas Combustion Equipment

To enable full natural gas firing up to full load heat input, the gas combustion equipment for the generating unit would receive gas from the unit pressure regulator at 50 psi and distribute the gas to each of the 18 new low NO_x coal burners located on the front and rear furnace walls. The

equipment would include gas piping to the burners, flow regulators, and valve racks, including safety shutoff valves, vent valves and piping, and manual shutoff valves. Conceptual design is based on the use of one main gas control valve for the generating unit.

The 18 new low NO_x coal burners would be provided with gas burner equipment and dual fuel flame scanners. These modifications would not preclude the ability to burn 100 percent coal in the future with minor modifications such as reinstatement of the coal pulverizers, primary air supply as well as installation of "high blockage" perforated plates to replace the "low blockage" perforated plates that are expected to be installed in the gas burners. With "high blockage" perforated plates installed in the gas burners, gas firing could still be performed but would be limited to approximately 70 to 80% of full load heat input.

Should this project to convert the existing boilers and combustion equipment from coal to gas proceed, further evaluation of the suitability of existing equipment for use with natural gas would be performed. The cost estimates are based on relocation of existing burner auxiliaries such as scanners and igniters rather than wholesale replacement and the adequacy of the existing FD fans and motors. These alternatives should be considered during the next stage of design and procurement to optimize the design and performance for the most economical scope of existing equipment modifications.

2.1.5 Equipment Delivery Schedule

The typical project duration for the design, fabrication and supply of the burner and accessories for the conversion to natural gas combustion of approximately 30 weeks would be expected. Following equipment delivery, the outage duration of 4 to 6 weeks would be expected for completion of the burner equipment installation to replace or supplement the existing coal burners. Fuel gas piping and valves would typically be designed, fabricated and installed during this 36 week schedule envisioned for the burner equipment with the tie-in during the 4 to 6 week outage.

2.2 GENERATING UNIT PERFORMANCE IMPACTS

2.2.1 Potential Benefits

Black & Veatch has estimated performance for each of the cases, as provided in Table 2-3. As shown on Table 2-3, the gas burners would provide reductions in PM, Hg, and SO_2 emissions in proportion to the fraction of natural gas being utilized. The conversion to 100 percent natural gas would also result in reduced NO_x and CO emissions compared to coal firing.

2.2.2 Heat Rate Impacts

In addition to the boiler efficiency impacts that would result with the conversion from coal to natural gas fuel, there would also be a reduction in the auxiliary power requirements that are associated with the coal and ash handling equipment. With the conversion to gas, the coal mills would be removed from service and would represent approximately a 2 percent increase in net plant output during full load operation compared to similar turbine generator output with coal. As shown in Table 2-3 there is a slight reduction in total combustion air and flue gas flow rates when

changing from PRB coal to natural gas, so the impacts on FD and ID fan power requirements would be relatively small. Since Riley Power has indicated the need to include up to 20 percent flue gas recirculation to the windbox to maintain main steam temperature, there will be the additional auxiliary power demand for flue gas recirculation fans. These fans would be expected to be approximately 500 HP each so would partially offset the auxiliary power reduction provided by the discontinued use of the coal mills. After a short operating period following the conversion to natural gas, the ESP power input could also be reduced, this would represent an additional 0.1 percent increase in net plant output.

It is expected that a slight increase in boiler efficiency would also occur with the conversion to gas based on the estimated reduction in air heater flue gas exit temperature provided by the Riley Power thermal modeling report. With the absence of sulfur in the natural gas, the average airheater cold end average set point temperature could be reduced to approximately 150F compared to a minimum of 155F for low sulfur coal. As shown in Table 2-3 the actual fuel heat input (HHV basis) would be reduced by approximately 0.4 percent with the conversion to natural gas and the net unit output would be expected to increase approximately 1 percent due to the lower plant auxiliary power requirements.

2.2.3 Potential Negative Impacts

In the case of gas co-firing with coal, a higher furnace exit gas temperatures (FEGT) would be expected, which would aggravate slagging on radiant heat transfer surfaces, and reduce the cleanliness of the surfaces, which in turn would result in lower radiant heat transfer. The higher FEGT would result in higher metal temperatures in the SSH; tubing material upgrades would be needed to avoid overstressing the tubes during normal full load operation. Because of the improved furnace wall cleanliness that would occur with 100 percent gas firing, after an initial period of furnace cleaning that would take place with natural gas firing, the FEGT is expected to drop compared to full load operation with coal. Even though the FEGT would be reduced, it is expected that the higher moisture content of the furnace exit flue gas would result in higher convective section tubing metal temperatures. In some cases with conversion from coal to natural gas combustion tubing material upgrades may be recommended to avoid overstressing the tubes during full load operation. The results of the initial Natural Gas Firing Feasibility Study performed by Riley Power have found there is no need for superheater or reheater tubing material upgrades. If the conversion to natural gas combustion is to be further considered, the determination of the need for superheater or reheater surface material upgrades should be confirmed by the equipment contractor that is selected to provide the gas combustion equipment and perform the modification work.

Table 2-3 Nearman Creek Coal/ Natural Gas Performance Characteristics

PARAMETER	UNIT 1	
	100% COAL FUEL FULL LOAD	100% NATURAL GAS FUEL FULL LOAD
Combustion Equipment	Existing PC Burners	New Gas Spuds for existing burners Flue Gas Recirculation System for steam temperature
Natural Gas Heat Input, percent	0	100
Fuel Heat Input, MBtu/h	2460	2450
Percent Full Load Heat Input	100	99.6
Percent Full Load Heat to Steam	100	100
Coal Mass Input, 1,000 lb/h	289	0
Gas Mass Input, 1,000 lb/h	0	109
Coal Excess Air, percent	11	N/A
Gas Excess Air, percent	N/A	10
Flue Gas Leaving Air Heater, 1,000 lb/h	2646	2414
Air Heater Flue Gas Exit Temperature, °F	328	254
Approximate Flue Gas Density at ESP inlet, lb/ft^3	0.048	0.050
Flue Gas Volume Flow to ESP, 1,000 acfm	930	807
Fly Ash Flow to ESP, tph	6	0
Fly Ash Flow to ESP, grains/acf	1.22	0
SO_x Production Rates, lb/MBtu	0.613	0
NO_x Production Rates, lb/MBtu	<0.25	0.14
CO Production Rates, ppm	<150	<150
Hg Production Rates, lb/TBtu	8.7	0
Net Unit Output, MW	220	222
Full Load Net Plant Heat Rate, Btu/kWh	11,180	11,040

2.3 ORDER-OF-MAGNITUDE COST ESTIMATE

Order-of-magnitude direct costs for installation of the natural gas supply, control, and combustion equipment are summarized in Table 2-4. The costs are based on natural gas supply and combustion equipment installation that would allow 100 percent of full load heat input and electric generating capacity with natural gas. The following are descriptions of the capital cost items included in the estimate and additional cost estimating assumptions:

- The scope of the gas supply piping starts at the connection to the existing KPC PostRock Pipeline located west of the generating unit.
- The new gas supply piping would also include a new metering station with sufficient capacity for both Unit 1 as well as CT4 and one future simple cycle combustion turbine. From the new metering station new piping would be provided to the unit pressure regulator located outdoors near the roof of the generating unit. The piping and pressure regulating equipment would include pressure regulation from 100 psig leaving the metering station to 50 psig prior to entering the power generation building, safety shutoff valves, and safety relief valves. There have not been allowances made for new platforms. Cathodic protection for the underground portion of the pipe would also be provided.
- Boiler modifications and gas distribution piping have been included with the burner front piping and valves to supply and control gas flow to each of the generating units. Riley Power has provided budgetary estimates for the gas burner and flue gas recirculation equipment. This budgetary estimate is included in Appendix A. Major boiler combustion equipment modifications would include the following:
  - The 18 existing coal burners would be modified to achieve 100% MCR steam flow while firing natural gas by installing a 5-1/2" OD gas gun in the center slot of each burner. The existing igniter and HESI for each coal burner would be relocated to support natural gas ignition in each main burner. The remaining flame scanner would be modified to replace the existing glass fiber optic extension with a quartz fiber optic extension. The center slot perforated plate or diffuser plate would be removed and replaced with a new perforated plated designed to have more open free area.
  - One main gas valve train assembly would be provided to supply and control natural gas to the gas guns. Each burner would be provided with two individual safety shutoff valves, one vent valve and a metal flex hose from the safety shutoff valves to the gas gun.
- Primary air supply duct modifications to provide hot primary air directly to the windbox to supplement the combustion air flow from the FD fans to bypass the coal mills.
- Flue gas recirculation equipment structural and electrical installation provisions for fan and motor foundations, power supplies and provisions to flue gas supply and return ductwork from the economizer outlet duct to the combustion air windboxes.
- Control equipment BMS/DCS modification costs have been included to integrate the new natural gas controls and instrumentation into the boiler BMS/DCS. This includes hardware and programming modifications for the additional input/output (I/O) associated with the natural gas control equipment and flame scanners, flue gas recirculation and impacts the ability to burn gas would have on the existing BMS and DCS relative to existing coal combustion control equipment. The costs are

based on the ability to fire either 100 percent coal or 100 percent natural gas with no co-firing of the two fuels.

- Allowances have been included for installing this power and control equipment by extending existing systems for the new gas piping and gas control and combustion equipment.
- Due to the outdoor locations of most of the new fuel gas supply piping and valves and limited electrical equipment in the area, only minor electrical equipment modifications are expected to be required because of the hazardous area classification that is expected to exist around the individual generating unit pressure regulators. This is expected to include items such as Class 1, Division 2, ratings for components of the fuel gas control equipment and upgrades to existing equipment located adjacent to the fuel gas regulating stations. In cases where the cost of this modification may be excessive, natural gas detection equipment may be provided to enable safe shutdown of operating equipment in the vicinity of the fuel gas equipment in the event of a detected fuel gas leak. Downstream of the unit pressure regulators in the generation building, most of the gas supply and control piping and valve equipment would be located close to the boilers that would be inherent ignition sources should a sufficient gas leak occur to raise the gas concentration above the lower explosive limit (LEL). Although leak detection equipment may be provided, special provisions for new or existing electrical equipment to provide a Class 1, Division 2 rating may not be required. This should be confirmed with the Authority Having Jurisdiction (AHJ) prior to the final decision to go forward with this gas conversion of the generating unit.
- The order-of-magnitude costs reported in Table 2-4 are the expected direct costs for the supply and installation of the equipment modifications and additions. These tabulated costs are for the gas conversion equipment materials and labor for the gas supply pipeline modifications needed to get the gas to the site as well as on-site modifications from the on-site metering station up to and including the gas burners and control equipment. Additional allowances for contingency and indirect costs for engineering and construction management have also been included. The costs for estimated internal KCBPU labor, overheads and project contingency have not been included in Table 2-4

Table 2-4 Gas Conversion Cost Estimate

ITEM	100% NATURAL GAS FIRING TOTAL FOR STATION $1,000
Gas Supply Piping and Equipment Installed	
Piping from KPC tie point through plant boundary	3600
Plant piping from plant boundary to generating unit	3800
Unit Pressure Regulators and Valves	500
Burner and Header vent piping	1000
Subtotal Installed Costs	8900
Boiler Modifications and Gas Distribution Piping Equipment and Installation Costs	
Low NO_x Burners Piping, and Isolation Valves	5500
Main Gas Header Trains	Included
Local Gas Piping and Valve Racks at Burner Levels	Included
Burner and Header Vent Valves	Included
Flue Gas Recirculation System Equipment	Included
Primary Air System Ductwork Modifications	750
Electrical Construction	400
FGR system installation and integration	1000
Control Equipment (BMS/DCS) Modifications	400
Subtotal Boiler and Ductwork Modification and Distribution Piping Installed Costs	8050
Subtotal Direct Installed Costs Piping and Equipment Modifications	**16,950**
Contingency, 20%	3190
Engineering, 10%	1600
Escalation, 0%	0
Construction Management, 8%	1280
Total Installed Costs Piping and Equipment Modifications	**23,020**

Attachment A. Riley Power Natural Gas Firing Feasibility Study

Riley Power

NATURAL GAS FIRING WITH FGR FEASIBILITY STUDY

For

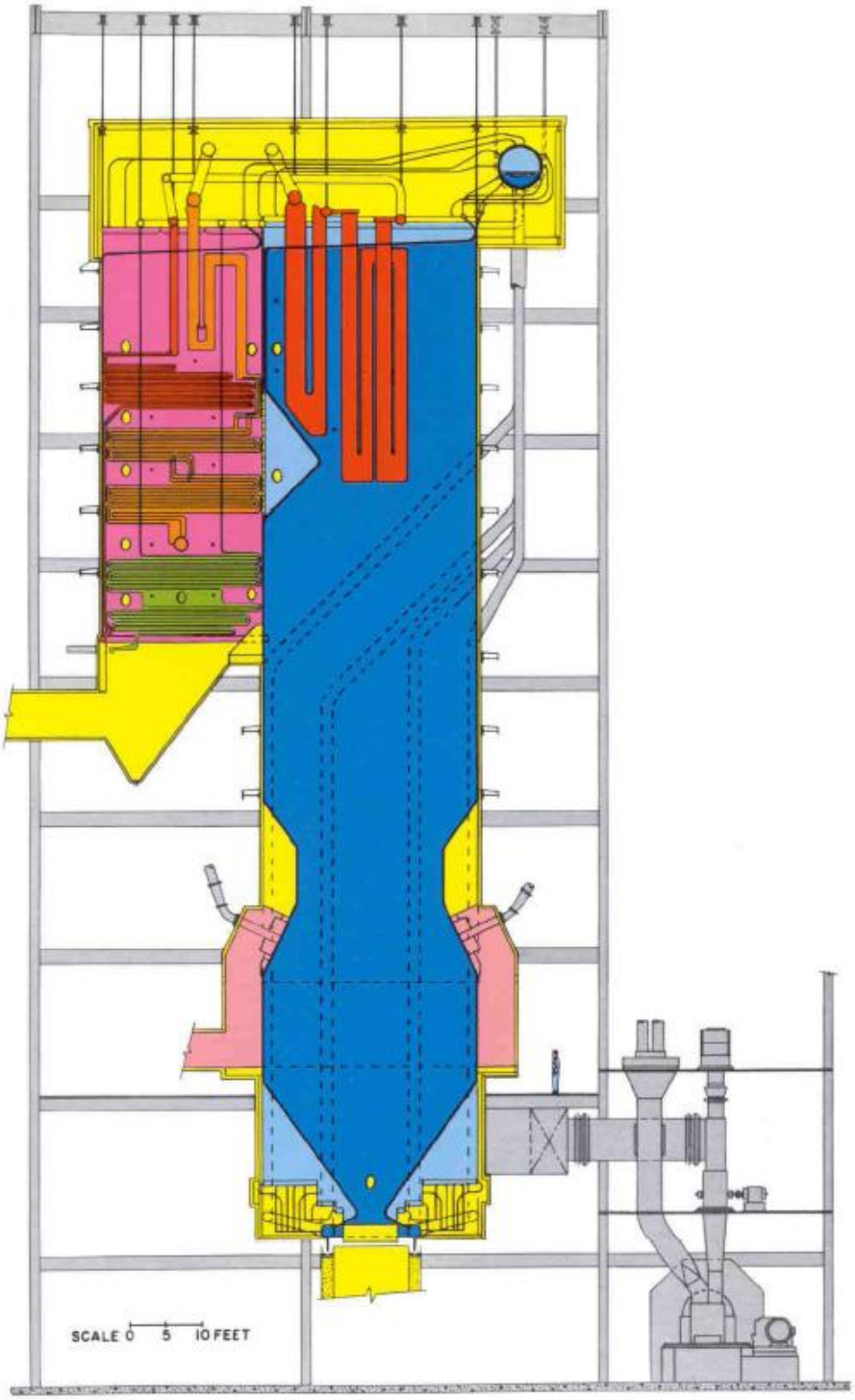
Kansas City Board of Public Utilities

Nearman Creek
Unit 1
Kansas City, KS

Revision 1

RPI Contract No. 100658

Date Issued: January 8, 2014



NEARMAN CREEK POWER STATION
UNIT NO. 1
City of Kansas City
Kansas
1,750,000 lbs/hr. — 2250 psig design — 1990 psig operating — 1005/1005F
Fired by Pulverized Coal
Lutz, Daily & Brain, Consulting Engineers

75005

NATURAL GAS FIRING WITH FGR FEASIBILITY STUDY

FOR

Kansas City Board of Public Utilities

Nearman Creek
Unit 1
Kansas City, KS

RPI Contract No. 100658

Distribution:

External:
John Frick (KCBPU)
Fred Freeland (Black and Veatch)

Internal:
C. Gillum
M.Lewis
M. Lynch
C. Penterson
K. Joshi

FED File: 100658

Riley Power

NATURAL GAS FIRING WITH FGR FEASIBILITY STUDY

FOR

Kansas City Board of Public Utilities

Nearman Creek
Unit 1
Kansas City, KS

RPI Contract No. 100658

Prepared by:
01/06/2014
Kushi Sellahennedige
Engineer
Boiler Performance Engineering

Approved by:
1/8/14
Craig Gillum
Manager
Boiler Performance Engineering

Prepared by:
Jan-8-2014
Kulbushan Joshi
Engineer
Fuel Equipment Design

Approved by:
1/8/14
Craig Penterson
Manager
Fuel Equipment Design

Revision History:

Revision: 0	First Issue	09/06/2013
Revision 1	Per Discussion with B&V	01/08/2014

Table of Contents

List of Tables ..... **v**

List of Figures ..... **v**

1.0 Introduction and Background **6**

1.1 Introduction ***6***

1.2 Objectives ***6***

1.3 Background ***7***

2.0 Discussion – Baseline Coal Firing **8**

2.1 Analysis of Current Operating Data ***8***

2.1.1 Review of Operating Data 8

2.1.2 Operating Data Assumptions 8

2.1.3 Coal Fuel Analysis 9

2.2 Heat Transfer Model ***10***

2.3 Calibration Results ***14***

3.0 Discussion – Natural Gas Firing **16**

3.1 Boiler Performance Model ***16***

3.2 Natural Gas Fuel Analysis ***16***

3.3 Boiler Performance Comparison ***17***

3.3.1 Radiant Surface Heat Absorption 20

3.3.2 Flue Gas Temperatures 21

3.3.3 Water/ Steam Temperatures 22

3.4 Current Combustion System ***23***

3.5 Proposed Burner Modifications ***23***

3.6 Effect of Flue Gas Recirculation ***24***

3.7 Predicted Emissions ***28***

4.0 Conclusions **29**

5.0 Recommendations **30**

6.0 Recommended Scope of Supply **31**

Appendix A : Summary of DCS Data, Baseline Coal Model, and Natural Gas Model Predicted Performance **33**

Appendix B : Q&A with Black & Veatch **40**

: Drawings **44**

List of Tables

Table 1: Plant Information 7
Table 2: Design Steam Conditions 7
Table 3: Boiler Operating Data Citation 8
Table 4: Coal Analysis 9
Table 5: Natural Gas Fuel Analysis 17
Table 6: Boiler Performance Comparison 17
Table 7. FD Fan Flows for Coal and Natural Gas Firing 19

List of Figures

Figure 1: Water and Steam Side Circuit Arrangement 11
Figure 2: Flue Gas Side Arrangement of Heating Surfaces 12
Figure 3: Side View of Nearman Creek Unit 4 with Bundle Designations 13
Figure 4: Flue Gas Temperature Distribution vs. Location – Baseline Coal Model 100% MCR 14
Figure 5: Water/Steam Temperature Distribution vs. Location – Baseline Coal Model 100% MCR 15
Figure 6: Radiant Surface Heat Flux -100% MCR 20
Figure 7: Flue Gas Temperature Distribution vs. Location-Natural Gas Model -100% MCR 21
Figure 8: Water/Steam Temperature Distribution vs. Location – Natural Gas Model 100% MCR 22
Figure 9: FGR Schematic 25
Figure 10: Radiant Surface Heat Flux with FGR-100% MCR 26
Figure 11: Flue Gas Temperature with FGR for Natural Gas Firing 27
Figure 12: Water/Steam Temperature with FGR for Natural Gas Firing 28

1.0 Introduction and Background

1.1 Introduction

Kansas City Board of Public Utilities (KCBPU) contracted Riley Power Inc. (RPI) to evaluate the feasibility of natural gas firing for Nearman Creek Unit 1. A baseline heat transfer model for coal fired boiler operation was developed using boiler geometry information and current operating data provided by KCBPU. The model was then used to predict boiler performance when firing natural gas with and without Flue Gas Recirculation (FGR).

1.2 Objectives

The first objective of this feasibility study is to evaluate the ability for Nearman Creek Unit 1 to retrofit the boiler to fire natural gas and achieve the boiler design capacity. The current coal firing capabilities will be maintained. The amount of FGR necessary to maintain the design superheat steam temperatures at all loads while firing natural gas is also evaluated. The results of the analysis, which are summarized in this report, include:

- Determination of boiler thermal performance while firing natural gas at 100%, 75%, 50% and 25% MCR.
- Determination of flue gas and air flow rates.
- Determination of the fuel flow requirements.
- Determination of heat transfer through all sections of the boiler.
- Prediction of boiler efficiency.
- Furnace and economizer exit flue gas temperatures.
- The water/steam temperature profile.
- Determination of SH/RH spray flow requirements.
- Determination of the required minimum FGR percent rate when firing natural gas to maintain main steam temperatures and its impacts on emissions.

The second objective of this feasibility study was to recommend the required burner modifications to enable 100% natural gas firing at the plant. This includes:

- The recommended burner modifications needed to fire 100% natural gas and retain coal firing capabilities.
- The expected scope of supply for the natural gas system, starting at the inlet header to the gas and oil guns in each burner.
- Emissions performance for the revised combustion system.

1.3 Background

Table 1: Plant Information

Plant Name	Nearman Creek
Location	Kansas City, KS
Subject Unit	1
Startup Year, Approx.	1970
Steam Generator Manufacturer	Riley Stoker Corporation
Type	Turbo Dry Bottom
Original Fuel	Sub Bituminous Coal
Mills	3 Double End Ball Tube
Burners	(18) Directional Flame Burners (Original) (18) Low NOx Tilting Directional Flame (TDF) Burners (Current)
Air Heaters	2 Ljungstrom Tri-Sector Air Heaters
Precipitator	Hot Side Precipitator (Original) Cold Side Precipitator (Current)

The original boiler full load steam conditions for pulverized coal firing are outlined in Table 2.

Table 2: Design Steam Conditions

		Main Steam	Reheat Steam
Steam Flow Rate	lb/hr	1,750,000	1,551,000
Feedwater Temperature	^{o}F	470	-
Steam Temperature	^{o}F	1,005	1,005
Steam Pressure	psig	1,990	485

2.0 Discussion – Baseline Coal Firing

2.1 Analysis of Current Operating Data

In order to determine the predicted performance when Nearman Creek Unit 1 fires natural gas, RPI had to first review current boiler operating data for coal firing and develop a baseline boiler heat transfer model.

2.1.1 Review of Operating Data

KCBPU provided a set of summarized boiler DCS data reflecting current coal fired operating conditions at various boiler loads, which were used for the study (Table 3). The 100% MCR load data points were taken from the acceptance test conducted in 2012 while firing sub-bituminous coal to confirm the performance guarantee of the unit after the retrofit of the new low NOx coal fired burner system.

Table 3: Boiler Operating Data Citation

Date of Operation	Time Frame	Boiler Load	Fuel Fired	Gross Load	Issued By
Nov.09, 2012	14:30 hrs to 17:30 hrs	100% MCR	Coal	247 MW	KCBPU*
July 19, 2013	02:15 hrs to 04:15 hrs	77% MCR	Coal	202 MW	KCBPU
July 27, 2013	13:30 hrs to 15:30 hrs	67% MCR**	Coal	173 MW	KCBPU
July 28, 2013	01:30 hrs to 03:30 hrs	57% MCR**	Coal	149 MW	KCBPU
July 16, 2013	18:58 hrs	24% MCR	Coal	60 MW	KCBPU

* From the acceptance test, 2012

** Used to estimate performance at 50% load

The complete set of data used in the development and calibration of the heat transfer model can be found in Appendix A.

2.1.2 Operating Data Assumptions

Below is a list of the assumptions made when implementing the DCS data in the baseline coal heat transfer model.

In the acceptance test data at full load, the RH inlet steam pressure was lower than the RH outlet steam pressure. The RH outlet steam pressure value was close to the original design sheet value at full load; therefore, the measured output RH pressure was used along with the RH pressure drop from the original design sheet in order to calculate the RH inlet pressure. A trend of the RH pressure drop vs.

load was created to determine the RH inlet pressure at the other loads to maintain consistency.

The economizer inlet pressure was not available. Therefore, the trend of main steam flow vs. economizer pressure drop (taken from the original design sheet) was used. This is consistent with the method used for the acceptance test performance calculations.

2.1.3 Coal Fuel Analysis

Table 4 shows the fuel analysis of the coal used in the baseline heat transfer model. This was extracted from a fuel analysis from acceptance testing conducted by RPI in 2012.

Table 4: Coal Analysis

FUEL ANALYSIS	Unit	
Carbon	% wt	48.71
Hydrogen	% wt	3.45
Oxygen	% wt	13.08
Nitrogen	% wt	0.76
Sulfur	% wt	0.26
Ash	% wt	5.23
Moisture	% wt	28.51
HHV	Btu/lb	8,503

2.2 Heat Transfer Model

A heat transfer model of the furnace and backpass was previously constructed for the study "*Boiler Impact Study for Turbine Upgrade*" (September 28th, 2012) using boiler arrangement drawings. This model has been calibrated using the data provided by KCBPU in Table 3. The model accounts for heat transfer through both the furnace and convective backpass.

The furnace model incorporates the interaction between the furnace walls, radiant superheat surfaces and the radiant heat from combustion. The backpass heat transfer calculation uses the boiler geometry and individual surface arrangements to calculate convective heat absorption in each of the bundles in the backpass. The furnace and backpass heat transfer calculations interface at the furnace exit. Outputs from the furnace thermal heat balance calculations include the furnace exit gas temperature (FEGT) and direct furnace radiation and are used as inputs for the backpass heat transfer model.

The theoretical model was then calibrated using the DCS data provided for coal firing. Small incremental adjustments in the effectiveness on each surface allow for the effects of surface configuration, fouling, and flow stratification. Once the baseline coal model is calibrated, the results agree with the DCS data provided by the plant. This calibration process increases the accuracy and results when using the model to predict boiler performance when firing natural gas.

Figure 1 depicts the water and steam side circuit arrangements for the baseline coal and natural gas heat transfer models. Figure 2 shows the flue gas side arrangement for the heating surfaces as they are modeled in the convective backpass. Each block in the schematics represents a physical bundle and includes the heat transfer properties associated with it.

Figure 3 shows a side elevation of the boiler with heating surface labeling corresponding to the schematics in Figure 1 and Figure 2.

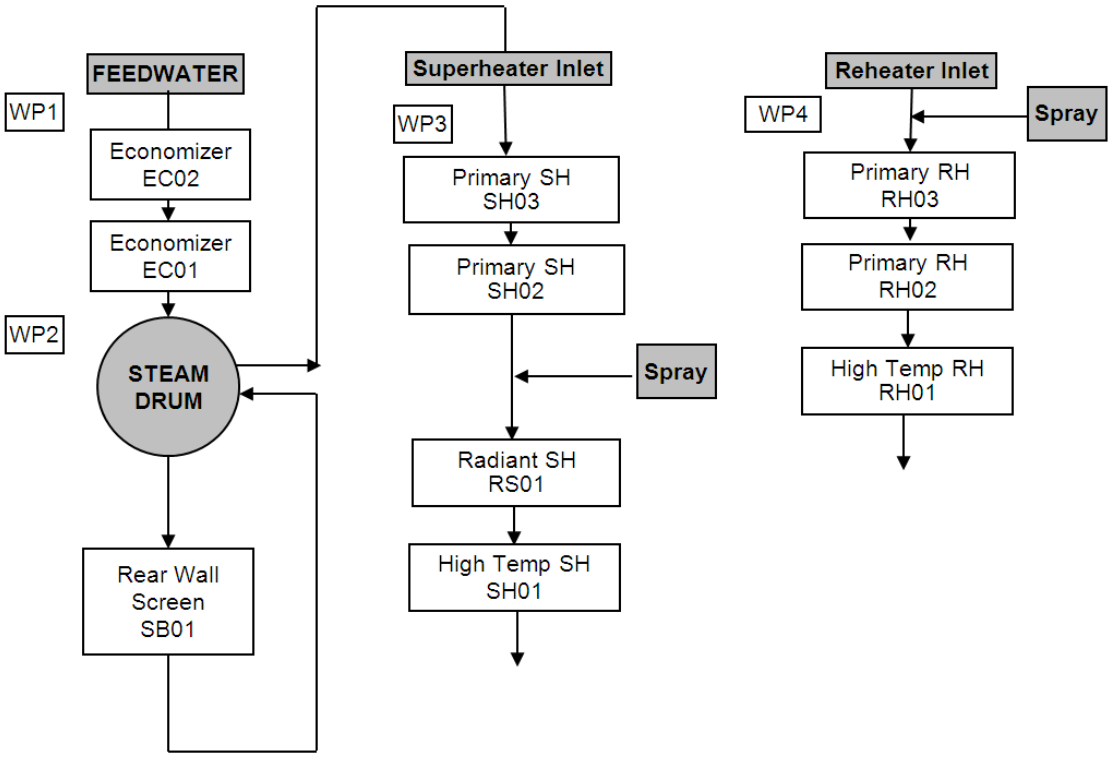


Figure 1: Water and Steam Side Circuit Arrangement

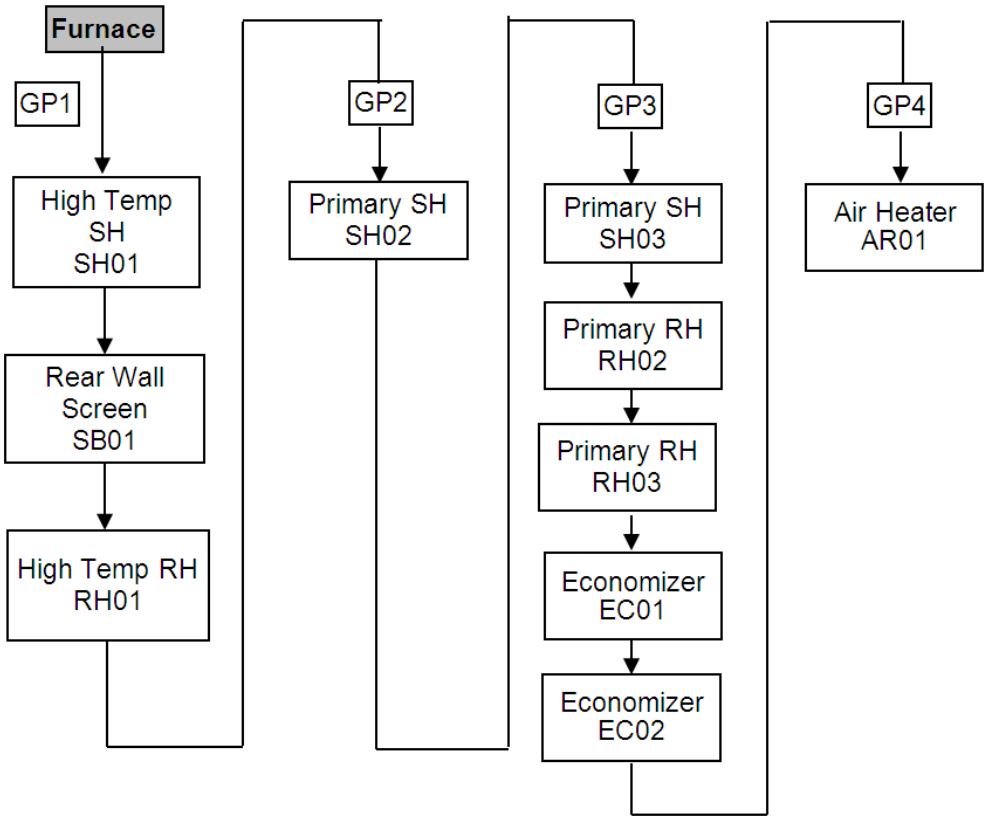


Figure 2: Flue Gas Side Arrangement of Heating Surfaces

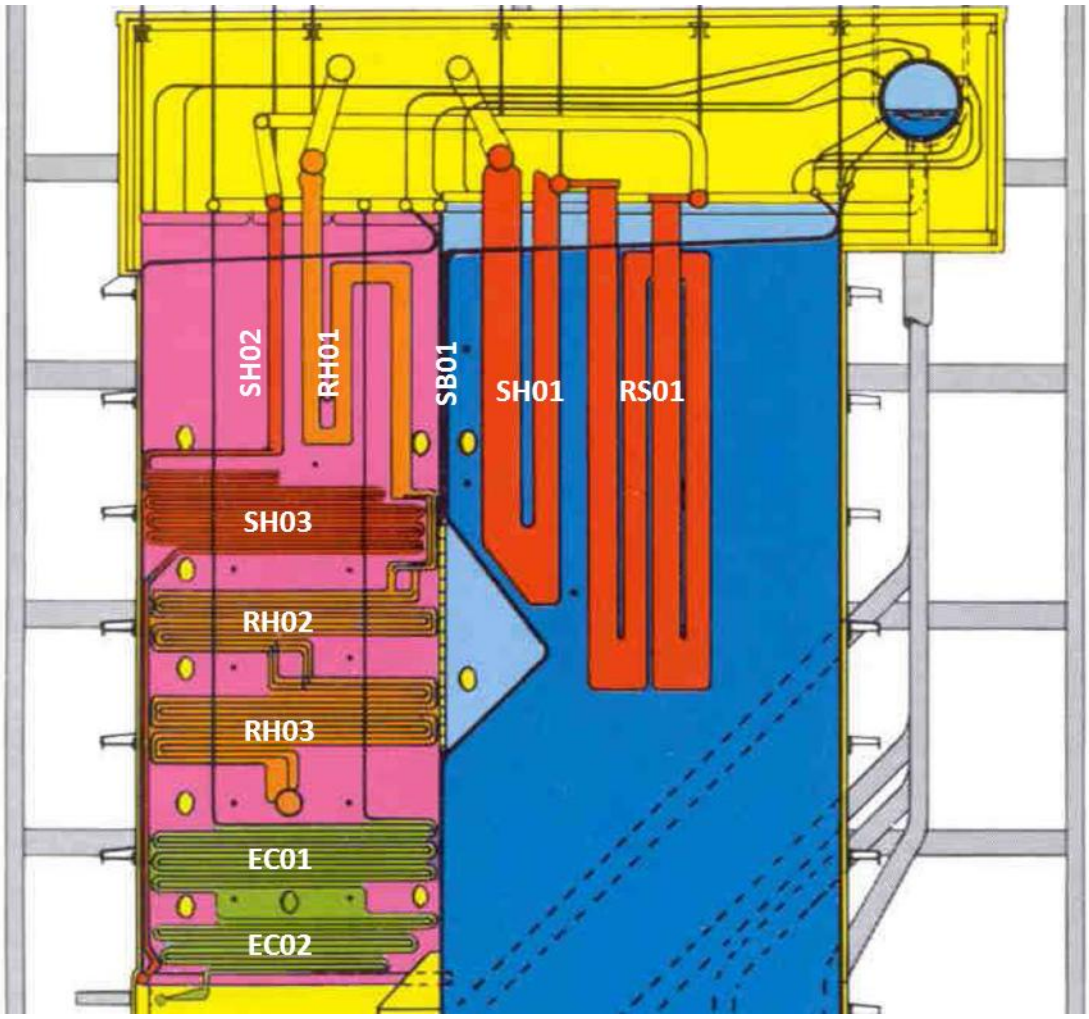


Figure 3: Side View of Nearman Creek Unit 4 with Bundle Designations

2.3 Calibration Results

Figure 4 summarizes the flue gas temperatures measured from the DCS, as well as flue gas temperatures calculated from the baseline coal heat transfer model at the furnace and economizer outlet.

Note the DCS did not have measured flue gas temperatures at the furnace exit. Therefore, it was back calculated using the available DCS data to create a heat and mass balance around each heating surface. The data from the DCS and the outputs from the calibrated thermal model are shown separately for the 100% MCR case. Figure 4 shows that there is a very good alignment between the DCS data and the thermal model for flue gas temperatures. The other boiler loads are shown in Appendix A.

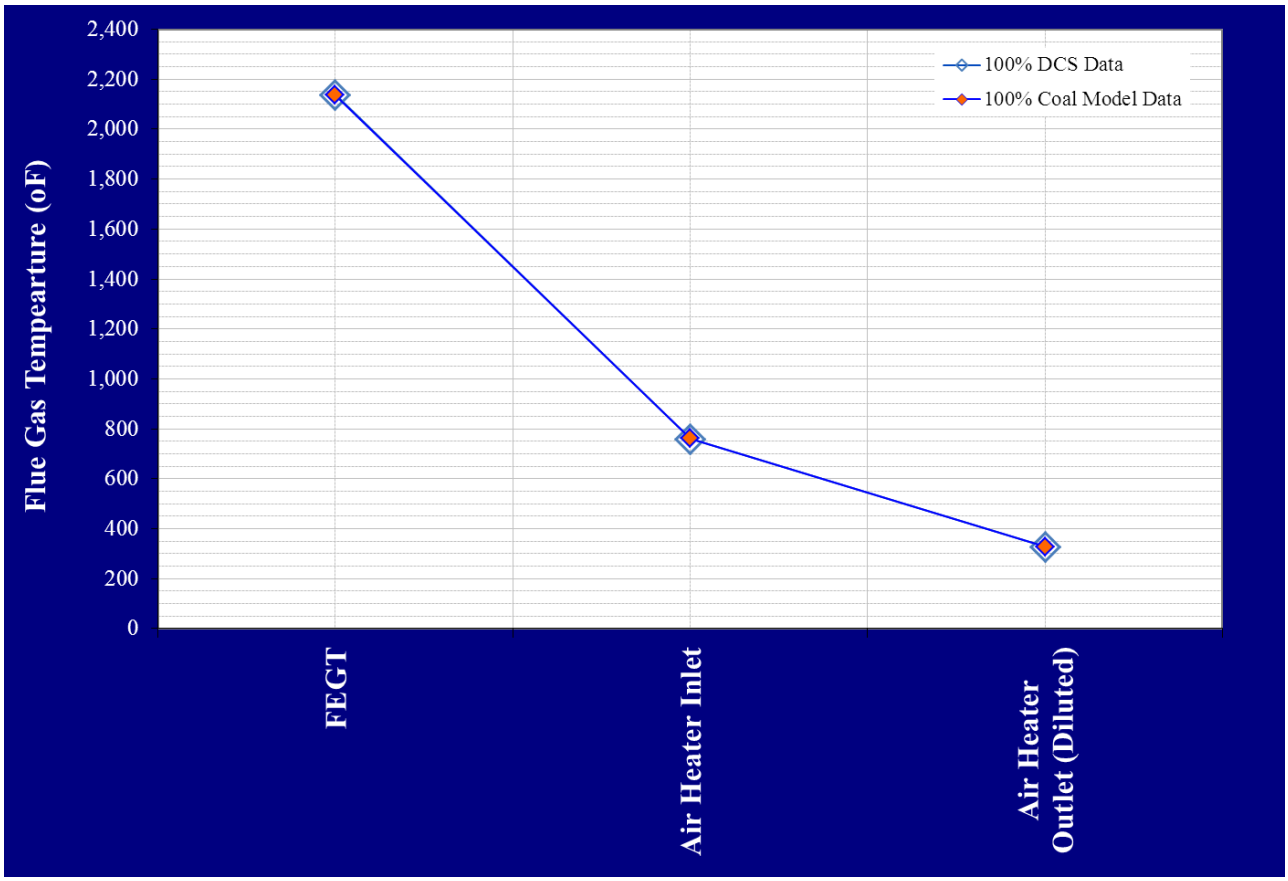


Figure 4: Flue Gas Temperature Distribution vs. Location – Baseline Coal Model 100% MCR

Figure 5 depicts the water/steam temperature at the inlet and outlet of each heat transfer surface, from both the DCS data and the baseline coal heat transfer model for 100% MCR. The baseline coal heat transfer model was calibrated to match the water and steam circuit temperatures from the DCS data. Therefore Figure 5 shows the alignment of these parameters. Additional boiler loads are shown in Appendix A.

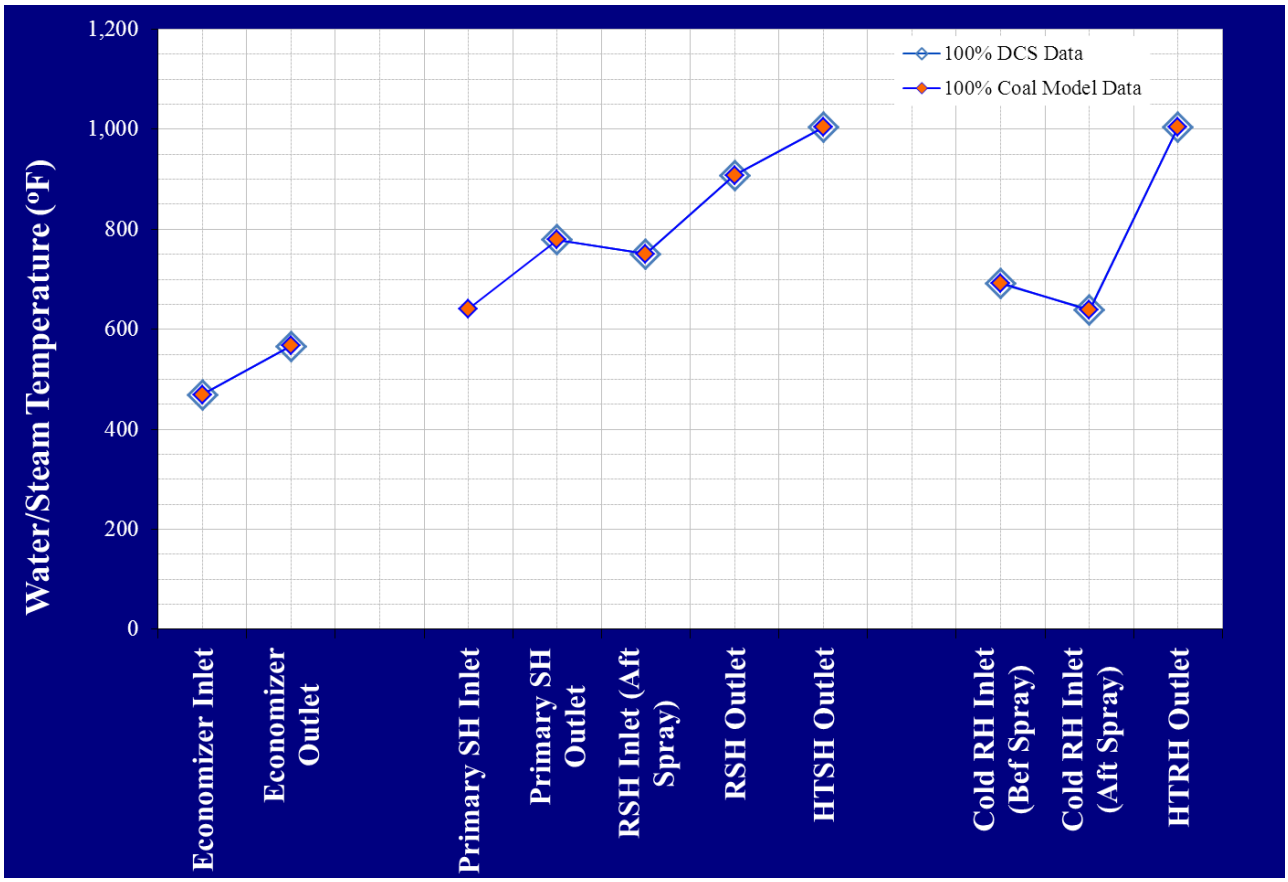


Figure 5: Water/Steam Temperature Distribution vs. Location – Baseline Coal Model 100% MCR

3.0 Discussion – Natural Gas Firing

3.1 Boiler Performance Model

After calibrating the baseline coal heat transfer model to match current coal firing performance, RPI was then able to predict boiler performance when firing natural gas. To do this, steps were taken to adjust the model for certain effects that occur when firing natural gas. These are outlined below.

Switching fuel from coal to natural gas will have an effect on the furnace thermal performance due to the decrease in flame emissivity. This could result in an increase in FEGT. However, natural gas is also a cleaner fuel and will not cause slag buildup on the radiant surface; therefore, it is expected to increase in the radiant surface heat transfer, counteracting the decreased flame emissivity and reducing FEGT. The FEGT and radiant superheat heat flux must therefore be recalculated for natural gas firing. RPI performed this task by utilizing our design furnace performance curves, which are based on empirical data. The curves take multiple factors into account such as fuel type, furnace configuration, coal slagging tendency, and excess air. Using the overall furnace heat release rate, RPI calculated a new FEGT and radiant superheater heat flux for natural gas firing.

Since natural gas does not contain ash, this increases the relative cleanliness of the heat transfer surfaces. The result is a modest increase in heat transfer effectiveness. Surface effectiveness was adjusted in the model according to typical RPI design parameters.

3.2 Natural Gas Fuel Analysis

A typical natural gas fuel analysis was implemented in the heat transfer model. This is shown in Table 5. The amount of excess air used was based on typical industry values for natural gas firing, usually ranging from 8-10% for boiler full load. RPI used 10% excess air for the model at full boiler load. All excess air values used in this study can be seen in the data summary in Appendix A.

Table 5: Natural Gas Fuel Analysis

FUEL ULTIMATE ANALYSIS		
	Unit	
Carbon	% wt	72.55
Hydrogen	% wt	23.58
Oxygen	% wt	0.93
Nitrogen	% wt	2.94
Sulfur	% wt	-
Ash	% wt	-
Moisture	% wt	-
Chlorine	% wt	-
HHV	Btu/lb	22,666

3.3 Boiler Performance Comparison

Incorporating natural gas into the coal model results in changes to boiler performance, as shown in Table 6 for 100% load. All other loads are shown in Appendix A. Switching the unit from firing coal to natural gas causes the following effects:

- Decrease in furnace exit gas temperature
- Increase in radiant superheater heat flux
- Decrease in excess air (except at the lowest load of 25% MCR)
- Decrease in superheater spray water flow
- Decrease in combustion air flow
- Decrease in flue gas flow
- Increase in overall boiler efficiency

Table 6: Boiler Performance Comparison

	Units	Baseline Coal Model 100% MCR	Natural Gas Model 100% MCR
FEGT	°F	2,136	1,760
Air Heater Gas Outlet Temp. (Diluted)	°F	328	254
Excess Air	%	11.37	10.00
FGR	%	-	-
Main Steam Temp.	°F	1,004	923
SH Spray Flow	lb/hr	41,584	0
Reheat Steam Temp.	°F	1,005	867
RH Spray Flow	lb/hr	47,443	0
Total Fuel Flow	lb/hr	279,129	94,233
Total Combustion Air Flow	lb/hr	1,957,000	1,722,000
Flue Gas @ Furnace Exit	lb/hr	2,221,000	1,816,000
Efficiency	%	85.17	85.31

Radiation is the primary mechanism of heat transfer within the furnace. The flame characteristics of natural gas are less effective at transferring heat by radiation. However, since the current coal being fired has the characteristics of a high slagging coal and firing natural gas will not create slag buildup, the furnace will absorb more heat to the water wall and radiant superheater thus lowering FEGT as compared to coal.

As shown in Table 6, no spray is required for natural gas firing because main steam and hot reheat steam temperatures are not met due to the decrease in FEGT and flue gas flow. The decrease in main steam temperature causes a decrease in the cold reheat temperature which contributes to the large decrease in hot reheat temperature.

To increase the steam temperatures, the model was run with FGR. At full load, a minimum of approximately 21% FGR is needed to produce the required main steam temperature. Superheat spray water flow will increase when firing natural gas at higher FGR levels. See Appendix A for the minimum required FGR level to maintain main steam temperature for all other loads.

Compared to coal, natural gas requires less excess air for complete combustion. Therefore, the total combustion air flow required decreased with natural gas, resulting in a decrease in the total flue gas flow. However for the lowest boiler load considered (25% MCR), there is an increase in excess air from that required at high load when firing natural gas and the main steam temperatures are met. No FGR is required for this case.

When firing natural gas, all of the combustion air flows through the air heater since there is no cold air bypassing the air heater. This increases the air heater's efficiency above the value for firing coal. Also, the boiler modeling was performed based on air heater performance without the PA section of the air heater contributing to the heat transfer. Natural gas is also a clean burning fuel and therefore the furnace walls do not have slag buildup on them. Overall, these two items help to increase the boiler efficiency by reducing the flue gas stack temperature. Coincidentally, the high moisture content in the current PRB coal generally has a lower boiler efficiency than a bituminous coal mainly due to the moisture losses, therefore when converting to natural gas there is a very small change to the total boiler efficiency.

Table 7. FD Fan Flows for Coal and Natural Gas Firing

	PRB Firing Full Load	NG Full Load No FGR	NG Full Load with FGR	Original FD Fan Design
Combustion Air (pph)	1,956,567	1,722,196	1,850,392	--
AH Leakage (pph) SA to FG	222,053	181,644	195,165	--
AH Leakage (pph) PA to SA	20,649*	na	na	--
PA Fan Flow (pph)	661,536	--	--	--
Total FD Fan Flow (pph)	1,496,435	1,903,840	2,045,557	1,878,000
FD Fan Flow per fan (pph)	748,218	951,920	1,022,779	939,000

*This is an estimated value based on typical tri-sector airheater performance.

Further discussion of the airheaters and fan capacity with Black & Veatch resulted in a more detailed review of the fans. During this study it was assumed the FD fans would have sufficient capacity. The results are presented in Table 7 above, which compares the FD fan flows for both coal and NG firing. Also included for reference is the original fan test block information. Based on this analysis the FD fans do not have sufficient capacity without using the PA fans for combustion air. The tri-sector air heater is expected to have some leakage from the PA section to the SA section; this was estimated for this evaluation since there is no way to measure this leakage. Including the PA fans in the thermal model does not impact the overall predicted boiler performance.

3.3.1 Radiant Surface Heat Absorption

Figure 6 depicts the radiant surface's heat absorption profile for coal firing which was used in the thermal model. It was developed using the DCS data from 100% and 75% loads along with design curves from Riley Power. The radiant surface heat absorption is higher for natural gas. This is mainly due to the cleaner fuel characteristics of natural gas where the radiant surfaces will absorb more heat compared to coal firing. The low emissivity of natural gas causes less heat to be taken at the evaporative walls allowing more heat to go up to the radiant surfaces.

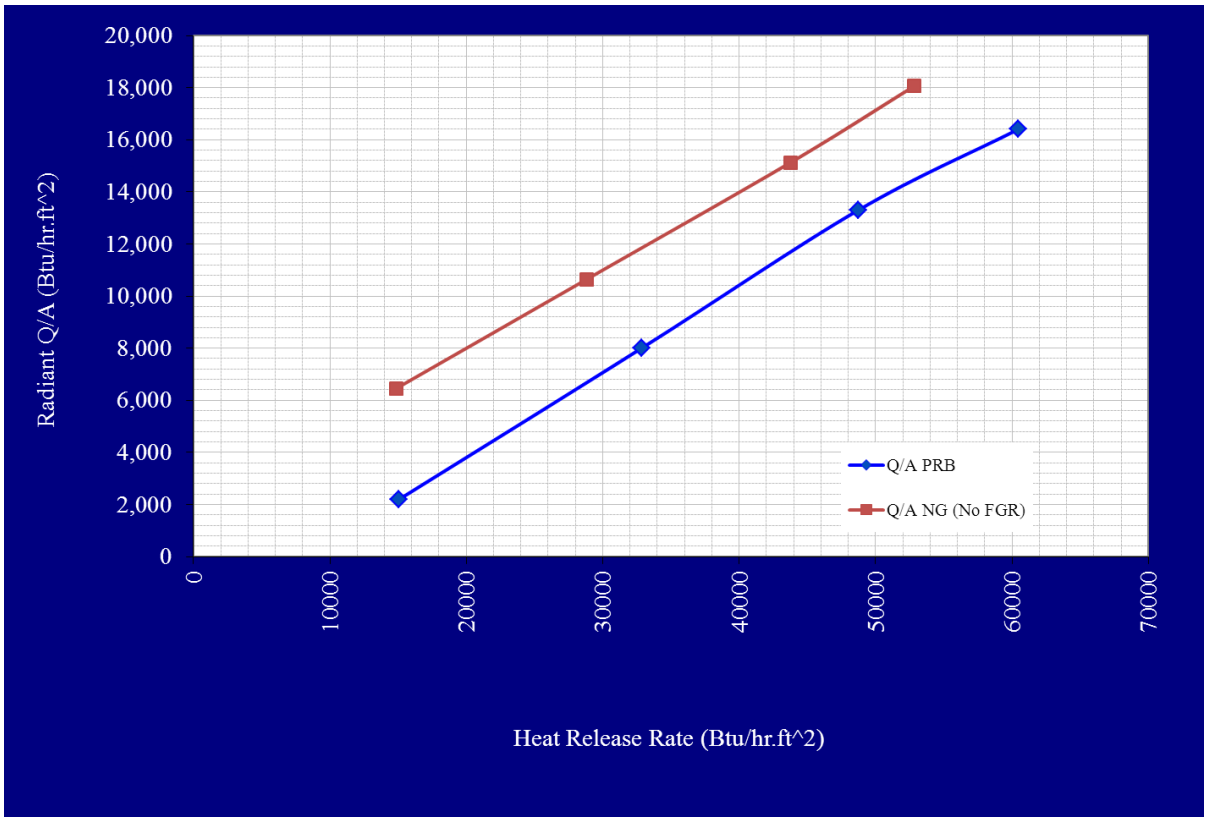


Figure 6: Radiant Surface Heat Flux -100% MCR

3.3.2 Flue Gas Temperatures

The flue gas temperature at the furnace exit, economizer outlet and air heater outlet was calculated using the thermal heat transfer model. The comparisons of flue gas temperatures between the coal and natural gas models are shown in Figure 7. As there is less fuel fired and less combustion air required, the flue gas flow and temperature leaving the furnace will reduce. Since the flue gas temperatures are lower for natural gas firing, the tube metal temperature will not exceed their metallurgical limits.

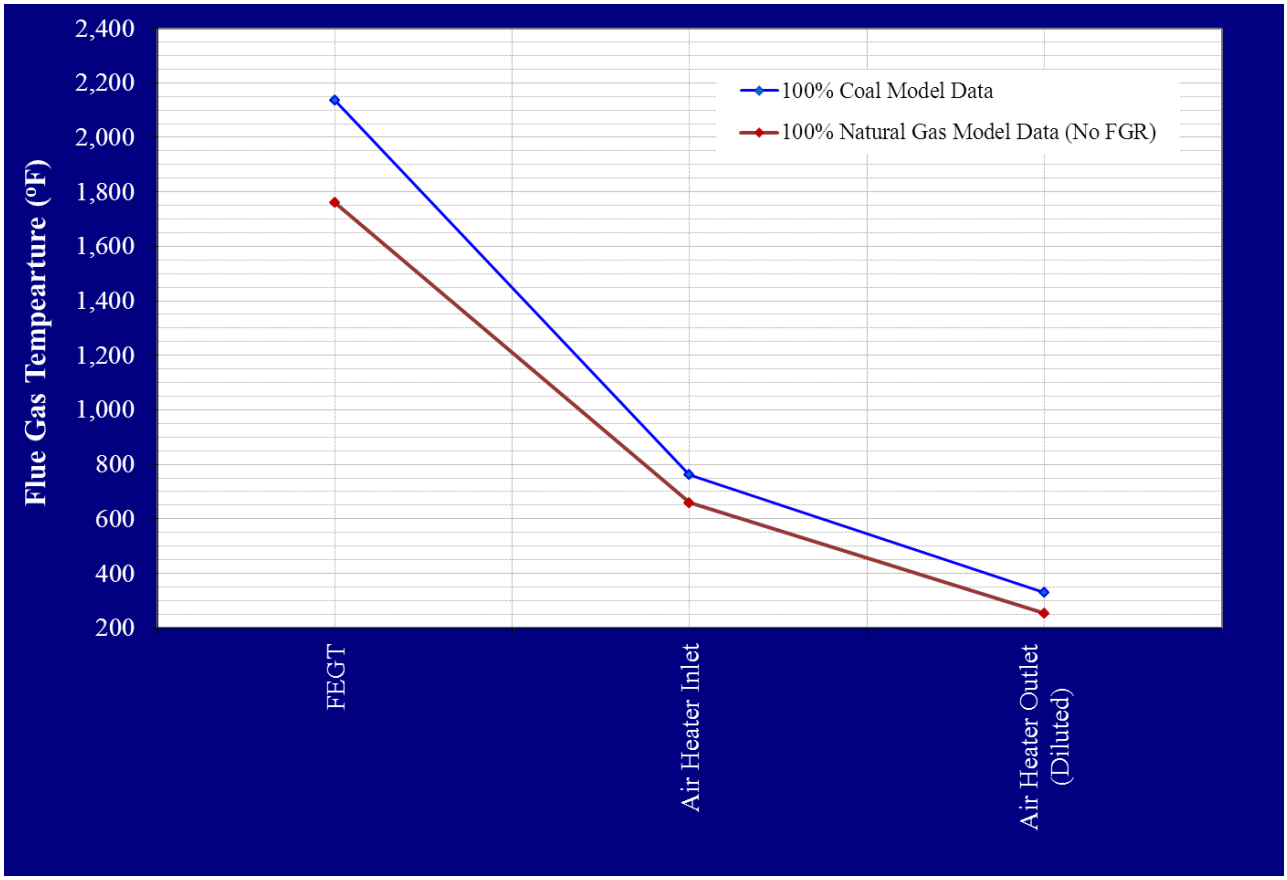


Figure 7: Flue Gas Temperature Distribution vs. Location-Natural Gas Model - 100% MCR

3.3.3 Water/ Steam Temperatures

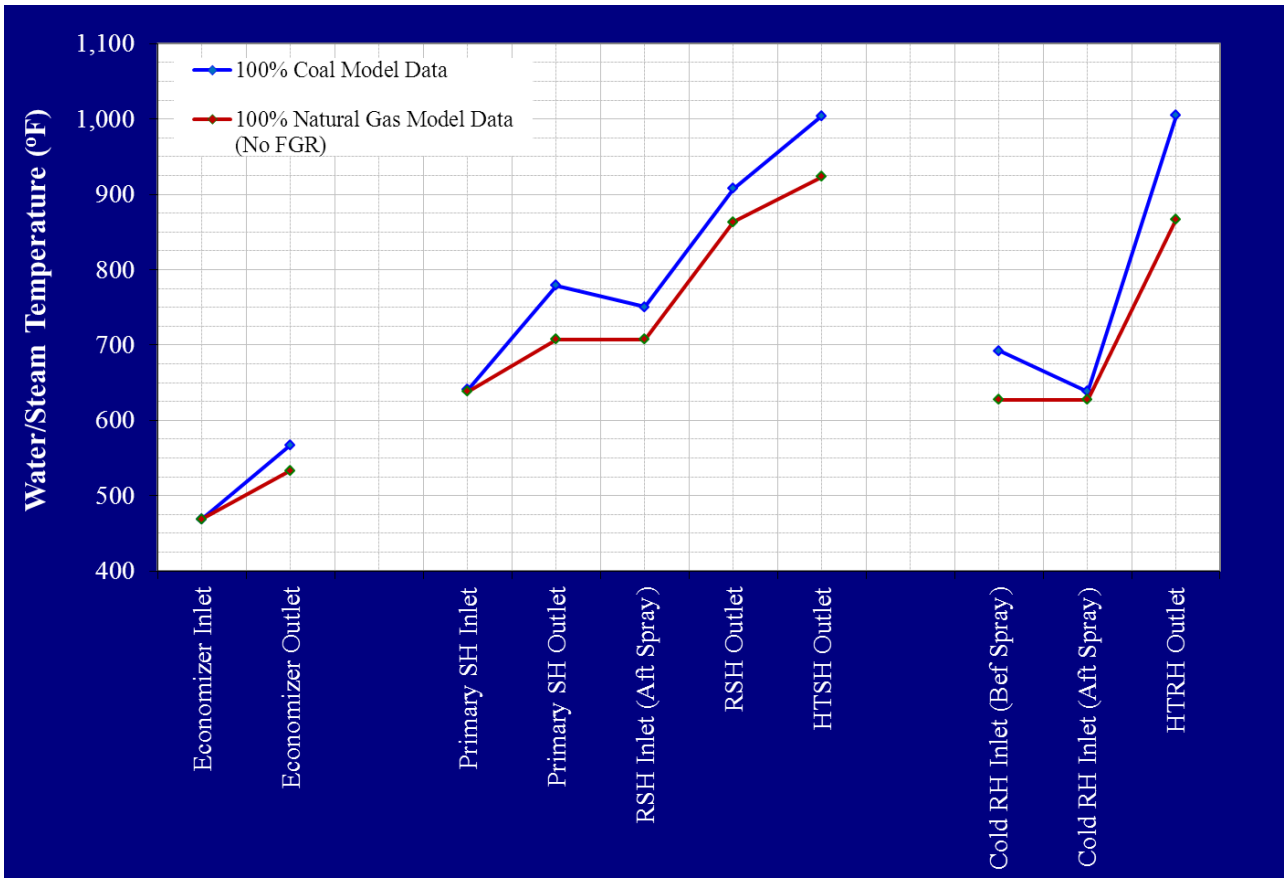


Figure 8: Water/Steam Temperature Distribution vs. Location – Natural Gas Model 100% MCR

Figure 8 depicts the predicted water and steam temperature distribution for each surface, from the furnace to the high temperature RH for natural gas firing. For comparison, the figure also shows the distribution for the baseline coal model.

The water/steam temperatures for natural gas are lower. As previously discussed, the excess air and FEGT are lower so the main steam temperature is reduced. One method of increasing steam temperature pickup is to increase the convective duty. This can be accomplished with FGR. See Section 3.6 for more details.

3.4 Current Combustion System

Nearman Creek Unit 1 was recently retrofitted in 2012 with (18) eighteen Riley Power Low NO_x Tilting Directional Flame (TDF) burners, Overfire Air (OFA), Underfire Air (UFA) and Boundary Air (BA). Each burner is equipped with (1) one oil ignitor, (1) one main flame scanner and (1) one ignitor flame scanner (not by RPI).

3.5 Proposed Burner Modifications

The conceptual burner modifications for natural gas firing are shown on RPI drawing 100658-079721100 located in Appendix B. RPI has determined that the existing TDF burners (with existing coal nozzles installed) can me modified to achieve 100% MCR steam flow while firing natural gas by installing a 5 ½" OD gas gun in the center slot of each TDF burner. Each gas gun would provide a heat input capacity of approximately 128 MMBtu/hr in order to achieve 100% MCR steam flow. The existing center opening is 6 ½" wide between the tubes and could accommodate the proposed gas gun provided it is installed along the horizontal centerline of the burner. The existing ignitor would be relocated to one of the existing flame scanner locations. The remaining flame scanner would be modified such that the existing glass fiber optic extension would be replaced with a quartz fiber optic extension. This would allow the existing UV/IR flame scanner head to monitor the oil igniter, main gas or main coal flames. The current windbox to furnace pressure differential range is about 3 to 5 iwc at full load. This is suitable for the NG firing equipment modifications envisioned.

If coal and natural gas are to be fired simultaneously in the same burner, further analysis of the flame scanner configuration would be necessary. This study is limited to addition of gas firing capability only.

Since the coal nozzles on the existing TDF burners are designed for approximately 50% of the combustion air passing through the burner throat (supplied as primary air) during coal firing, there is limited burner throat free area to pass all the combustion air airflow required during natural gas firing. Therefore, a "low blockage" perforated plate would be required in the center burner throat air slot to maintain acceptable burner throat velocity during gas only firing at 100% MCR. Additionally, the existing OFA, UFA and BA systems would need to be utilized during gas firing at high boiler loads. However, this center slot perforated plate modification would not be compatible with maintaining existing performance during coal firing. Therefore, before coal firing is resumed, a new "high blockage" perforated plate similar the perforated plate currently installed in the burner (and that accommodates the main gas gun) would need to be installed. Following installation of the "high blockage" perforated plate, boiler load during natural gas firing would be limited to approximately 70-

80% MCR steam flow, depending upon whether or not FGR is used to elevate main steam outlet temperature. If 100% MCR steam flow is required with either coal or natural gas firing, additional options would need to be investigated in a future study. Further study could include investigating potential options for introducing combustion air of sufficient quantity and temperature through the coal nozzles.

When switching from coal to natural gas, the required seasoning period varies based on plant conditions, the amount of slag that is in the boiler, how sticky the ash is and how tightly it adheres to the tubes. Overheating of SH surfaces is not a concern as gas temperatures firing NG are cooler than PRB firing. Slag remaining on tube surfaces when switching from coal to NG, will work in favor of keeping up the gas temperatures. By controlling the amount of FGR during initial operation, a short seasoning period can be expected. Riley Power is aware of units with seasoning periods of 2-3 days to 2 weeks. The seasoning period for Nearman Creek will be determined by field testing.

The Burner Management System and Combustion Controls will require modifications to accommodate the fuel conversion but are also beyond the scope of this feasibility study and therefore have not been reviewed.

3.6 Effect of Flue Gas Recirculation

The addition of FGR through the Windbox generally has two benefits. One is to reduce NOx emissions and the other is to increase the steam temperature. Flue gas is extracted from the economizer outlet by the use of an FGR fan as shown in Figure 9. The FGR flow mixes with the secondary air and enters the furnace through the Windbox.

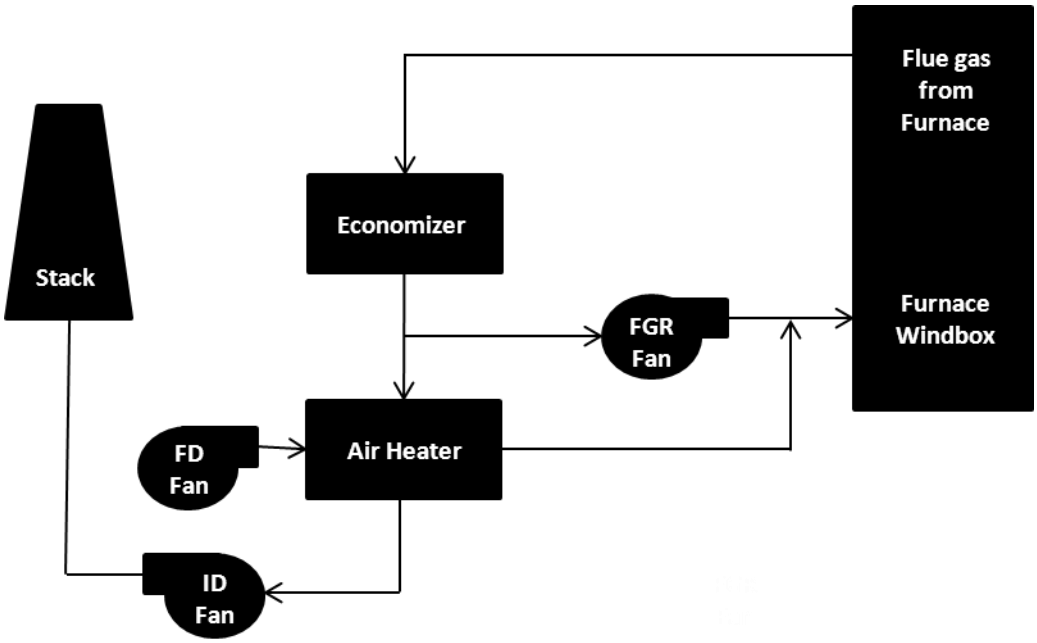


Figure 9: FGR Schematic

By adding FGR to the system, the total flue gas through the backpass increases thus increasing the SH and RH steam temperatures. The complete effect of FGR can be seen in Appendix A. Effects on emissions are discussed in Section 3.7.

Figure 10 shows the behavior of the radiant heat flux with FGR for full boiler load. There is a notable increase in the heat release rate when adding FGR which increases the radiant heat flux and will cause an increase in the main steam temperature.

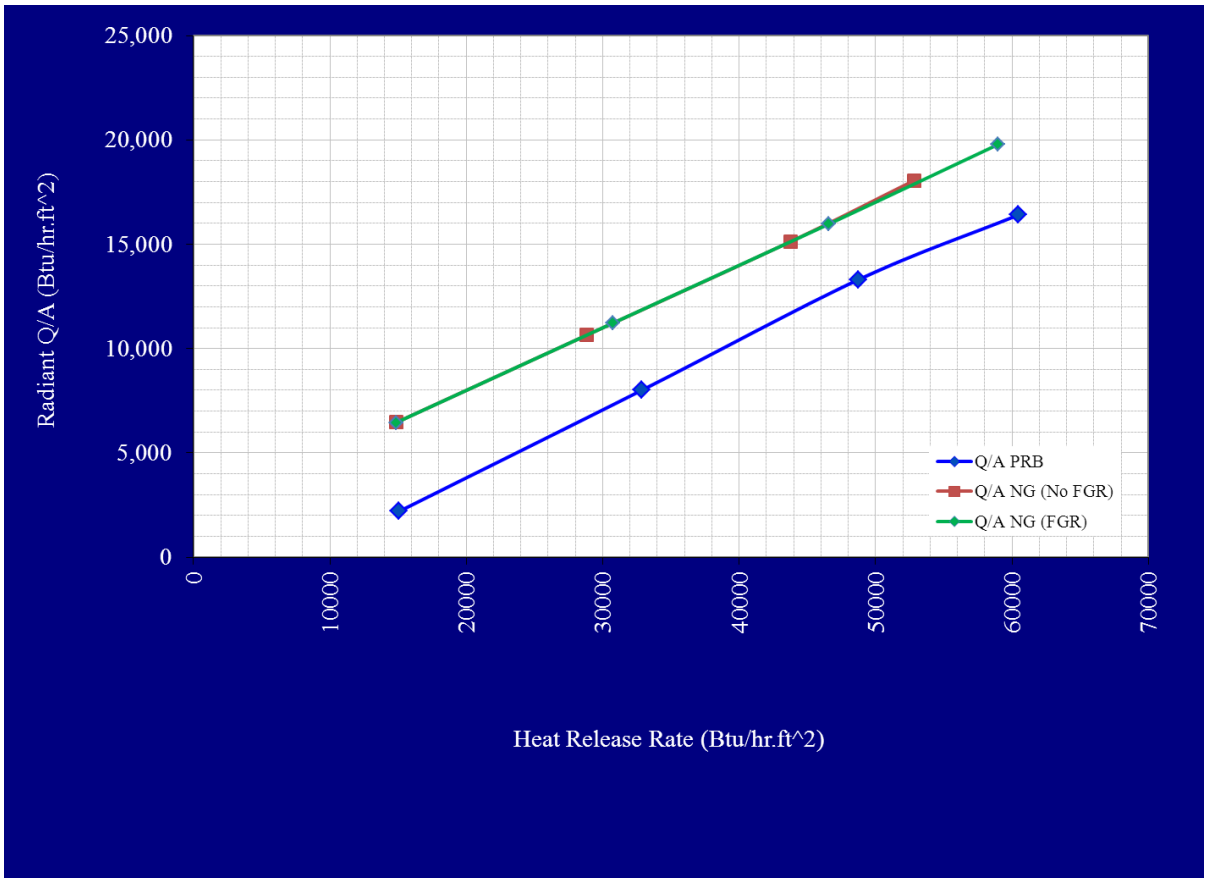


Figure 10: Radiant Surface Heat Flux with FGR-100% MCR

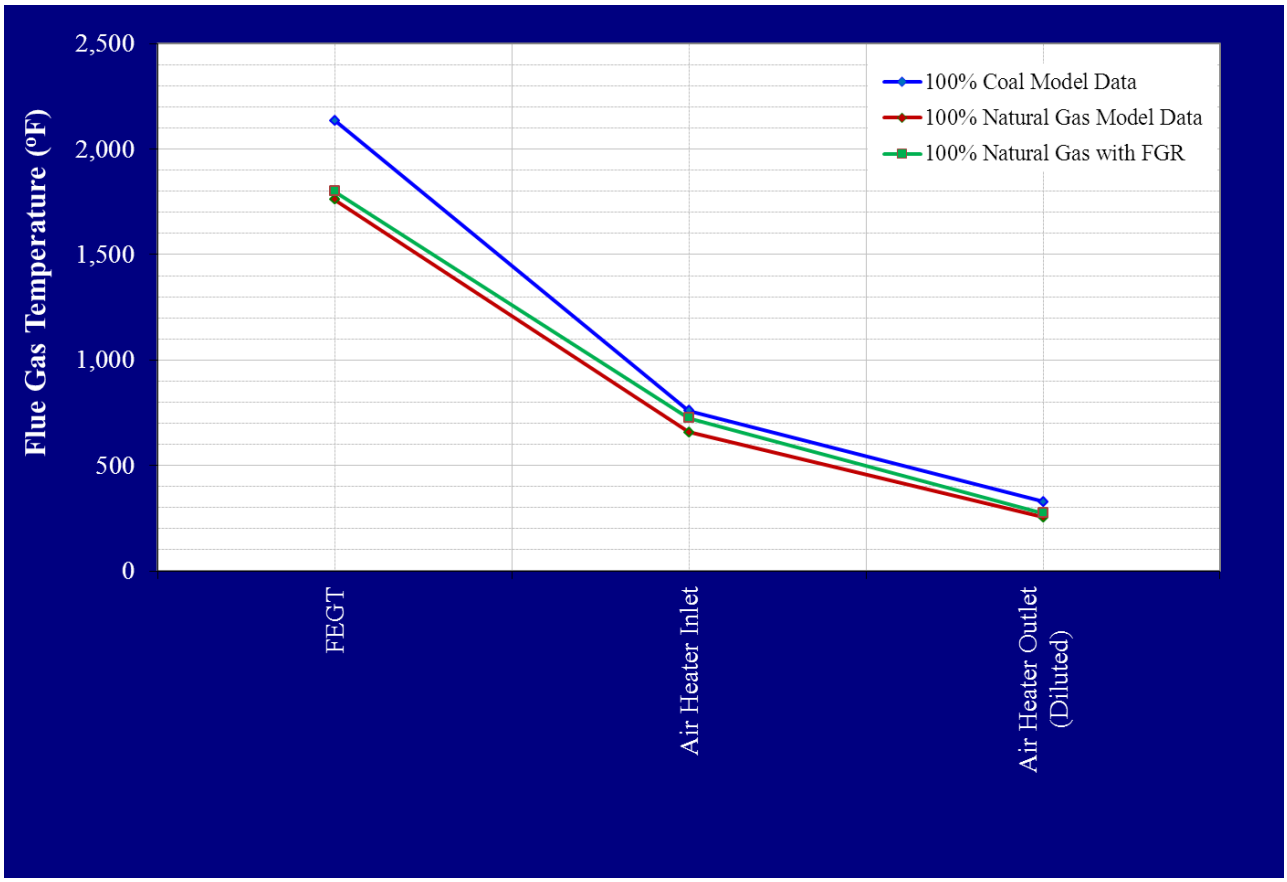


Figure 11: Flue Gas Temperature with FGR for Natural Gas Firing

It can be seen in Figure 11 that for 100% MCR, the target main steam temperature is met with the addition of roughly 21% FGR. The FGR flow rate was evaluated as the minimum necessary to achieve the design steam temperatures. The FGR fans would be sized with a reasonable margin to allow for some operating flexibility. Increasing the FGR flow rate is acceptable as the additional heat transfer would result in additional spray attemperation flow rates. In addition, increasing FGR tends to increase the stack temperature thereby lowering the boiler efficiency. The spray flow rates and impact on boiler efficiency would have to be evaluated further to determine a maximum FGR flow rate. FGR fan test block margins are recommended to be within normal industry practices, having excessive margin tends to result in fans that are oversized and difficult to control.

The effect of FGR on the flue gas temperatures are shown in Figure 12. This figure shows there is a slight increase in flue gas temperature from the natural gas model without FGR.

Since the boiler modeling was done with 10% excess air, when mixed with the FGR the oxygen content of the combustion air is 17 to 18% O_2 at full load conditions.

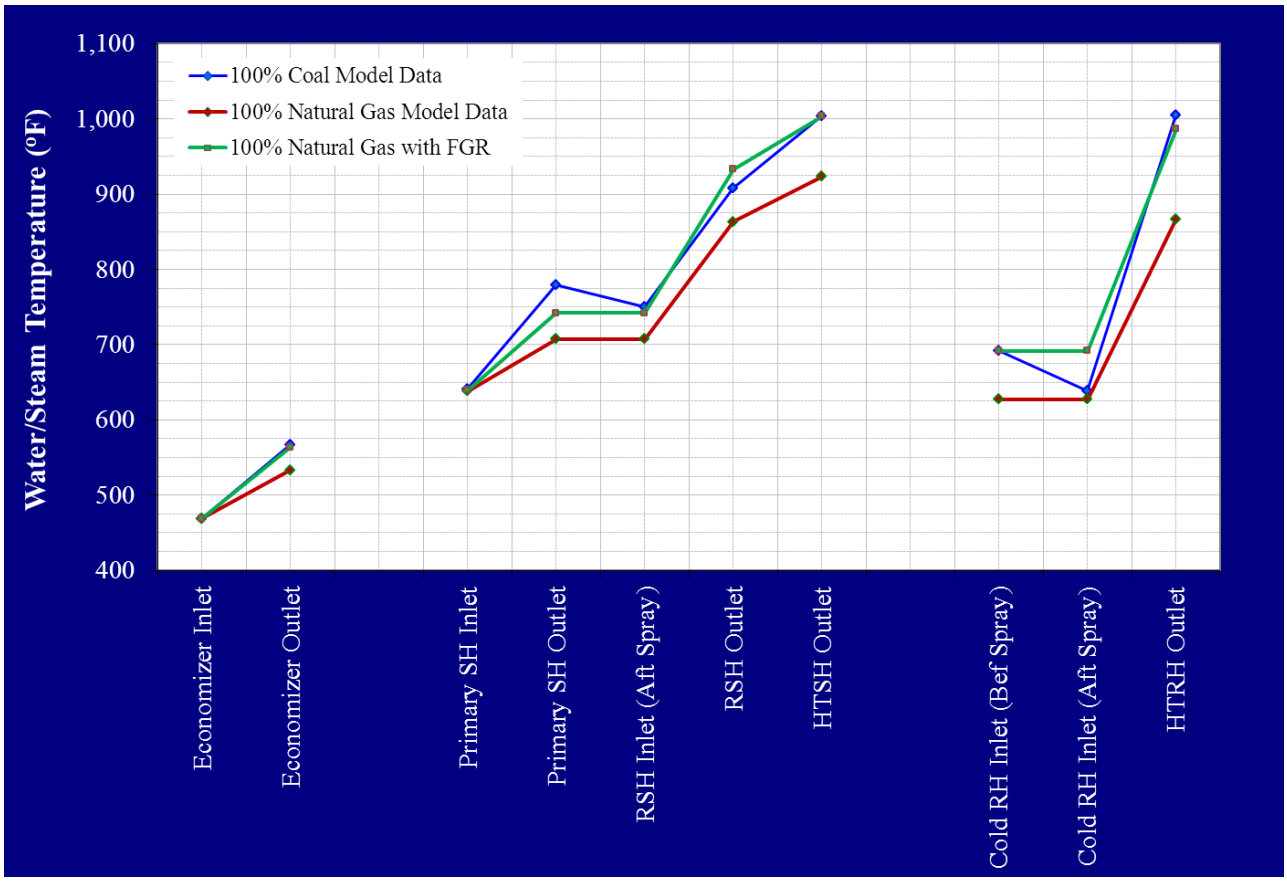


Figure 12: Water/Steam Temperature with FGR for Natural Gas Firing

3.7 Predicted Emissions

The Nearman Creek Unit 1 is equipped with Over Fire Air (OFA), Under Fire Air (UFA) and Boundary Air (BA) which allows deep staging in the combustion zone of these units. RPI anticipates the O_2 for full load can be reduced to approximately 2% for natural gas firing. It typically averages 2.5% (% Vol. dry) for coal firing. After converting to natural gas as described in this study and when in combination with OFA and UFA, Nearman Creek Unit 1 could expect NOx emission levels of approximately 0.20 – 0.25 lb/MMBtu and CO emissions less than 150 ppm.

FGR when introduced through the burner windox can provide a further reduction in NOx levels beyond NOx reductions achieved from burners and air staging

alone. As part of this study, the effects of 20% FGR on the unit's thermal performance was evaluated. From an emissions standpoint, 20% windbox FGR has the potential to reduce NOx levels by an additional 45%, to a predicted level of 0.11 – 0.14 lb/MMBtu.
Please note that an implosion study to evaluate furnace and duct work integrity is beyond the scope of this study.

4.0 Conclusions

- Natural gas firing is a feasible option for Nearman Creek Unit 1 although without FGR steam temperatures are predicted to be lower than baseline and design steam temperatures when firing coal.
- Boiler excess air can be reduced to 10% for 100% MCR boiler loads for natural gas firing. This is a reduction of 2 to 3% from typical excess air during coal firing (12 to 13% excess air).
- The unit is capable of achieving the current main steam temperatures with 21% FGR when firing natural gas.
- Boiler efficiency increases approximately 0.15% when firing natural gas at full load. This is due to increased air heater efficiency and the cleaner burning fuel characteristics of firing natural gas.
- The existing TDF burners can be modified to achieve 100% MCR firing natural gas only, provided coal firing is not required during this period.
- The existing TDF burners can be modified to fire natural gas up to approximately 70-80% MCR, while maintaining coal firing capacity at 100% MCR.
- Predicted emissions when firing natural gas at 100% MCR and utilizing the existing OFA and UFA systems are 0.20-0.25 lb/MMBtu NOx and < 150 ppm CO.
- The use of 20% windbox FGR during natural gas firing at 100% MCR is expected to reduce NOx emissions levels to a predicted range of 0.11-0.14 lb/MMBtu .
- No problems with excessive spray flows are expected when firing natural gas with FGR.
- Burner modifications for addition of natural gas firing capability include new central gas gun assembly with piping and valve trains, and new "low blockage" perforated diffuser plate.
- Also, existing oil ignitor would be relocated to one of the existing flame scanner locations. The remaining flame scanner will be modified to replace the existing glass fiber optic extension with a quartz fiber optic extension.

5.0 Recommendations

- In order to achieve design main steam temperatures when firing natural gas, an FGR system will be required.
- Prior to firing natural gas, a baseline test should be conducted to record the current boiler performance at multiple loads. This data will be used to verify the current boiler performance, along with assumptions made in this study as to radiant superheater duty and the calibration of the heat transfer thermal model.
- When transferring from coal to natural gas firing, boiler load will need to be reduced until the furnace slag is burned off the waterwalls. This will typically take approximately two days. Riley Power recommends that the load be reduced to the lowest point possible with one pulverizer in operation when the switch to natural gas is made.

6.0 Recommended Scope of Supply

RPI proposes the following upgrades for Nearman Creek Unit 1 to add natural gas firing capability.

- **TDF burner modifications shown on RPI drawing 100658-079721100 (Appendix B)**
  - Quantity per burner
    - (1) Gas gun assembly with support roller
    - (1) Gas gun support with packing gland
    - (1) Gasket and elbow with flanges
    - (1) Quartz fiber optic extension
    - (1) New “low blockage” diffuser plate with (4) clips
    - (1) Retraction cylinder assembly
    - Nuts and bolts
- **(1) One Main Natural Gas Fuel Piping/Valve Trains**
  - From Gas supply to main header (Quantities per valve skid)
    - (1) Main safety shutoff valve
    - (1) Burner header atmospheric vent valve
    - (1) Main fuel control valve
    - (1) Minimum flow bypass valve
    - (1) Constant fuel pressure regulator
    - (1) Flow meter
    - (1) Strainer
    - (1) Burner header high fuel pressure switch
    - (1) Burner header flow fuel pressure switch
    - (1) Low fuel supply pressure switch
    - (2) Fuel pressure gauge
    - (1) Manual shutoff valve
    - (1) Lot of piping
- **(18) Eighteen Main Header to Gas Gun Connections Piping/Valve Trains (1 per burner)**
    - (2) Individual burner safety shutoff valves
    - (1) Individual burner atmospheric vent valve
    - (1) Lot of piping and fittings
    - (1) Metal flex hose

If an FGR system is desired, the major system components would include the following items as conceptually illustrated on RPI drawing 100658-076454100 (Appendix B):

- Two (2) 50% capacity FGR fans including inlet vane control, motor & turning gear

- Four (4) tight shut off double damper assemblies including seal air blowers mounted on damper assembly for positive fan isolation and cold fan start
- Expansion joints
- Two (2) air foil mixing modules
- Interconnecting ductwork with supports
- Two (2) FGR flow measurement stations

Appendix A:

Summary of DCS Data, Baseline Coal Model, and Natural Gas Model Predicted Performance

100% Load
75% Load

Exhibit SSH-2

BPU Provided Attachment to SC 3-3: 177281.41.3400 140626
Natural Gas Firing Feasibility Study_B&V

RILEYPower
A Babcock Power Inc. Company

DATA SUMMARY
Name: Kansas City Board of Utilities
Station: Nearman Creek Unit 1
Location: Kansas City, KS

Issued By: Kushi.S | Date: 6-Sep-2013 | Notes: Tube Metal Temperatures / Calculated Values

Contract Number: 100658

		TIME		-	14:30 - 17:25							
		LOAD	MW (gross)		247	-			-	-		
		BURNERS IN SERVICE	No.	18	18	18			18	18		
	TEST NUMBER:			-	4	-			-	-		
	TEST OBJECTIVE:		UNITS	PB Sheet	DCS Data PRB 100% MCR Acceptance Test 4 Day 6 (11/09/2012)	PRB Thermal Model 100% MCR	Natural Gas Model 100% MCR	Natural Gas Model 100% MCR 21.07% FGR	PRB DCS Data 75% MCR	PRB Thermal Model 75% MCR	Natural Gas Model 75% MCR	Natural Gas Model 75% MCR 12.55% FGR
1.0 WATER/STEAM FLOWS	MAIN STEAM PATH		% MCR	100%	95%	95%	95%	95%	77%	78%	78%	78%
1.01	MAIN STEAM FLOW		KLBS/HR	1750	1,661	1,661	1,661	1,661	1,351	1,359	1,359	1,359
1.02	FEEDWATER FLOW		KLBS/HR	-	1619	1619	1,661	1,661	1328	1,328	1364	1363
1.03	AUXILIARY FLOW		KLBS/HR	0	0	0	0	0	3	3	3	3
1.04	BLOWDOWN		KLBS/HR	0	0	0	0	0	2	2	2	2
1.05	SUPERHEAT SPRAY FLOW		KLBS/HR	-	33	-	-	-	27	-	-	-
1.06	SUPERHEAT SPRAY FLOW (HEAT BALANCE)		KLBS/HR	-	42	42	0	0	36	36	0	0
	REHEAT STEAM PATH											
1.07	HOT REHEAT STEAM FLOW		KLBS/HR	1551	1,520	1,522	1,474	1,474	1,199	1207	1207	1207
1.08	COLD REHEAT STEAM FLOW		KLBS/HR	-	1,475	1,474	1,474	1,474	1,199	1207	1207	1207
1.09	REHEAT SPRAY FLOW (HEAT BALANCE)		KLBS/HR	-	-	47	0	0	-	-	-	-
1.10	REHEAT SPRAY FLOW		KLBS/HR	-	45	-	-	-	0	0	0	0
2.0 WATER/STEAM TEMP	MAIN STEAM PATH											
2.01	TOP FWH EXTRACTION TEMP		℉	-	692	-	-	-	655	-	-	-
2.02	TOP FWH FEEDWATER IN TEMP		℉	-	374	-	-	-	390	-	-	-
2.03	TOP FWH FEEDWATER OUT TEMP		℉	-	469	-	-	-	449	-	-	-
2.04	FEEDWATER TO ECONOMIZER TEMP		℉	470	469	469	469	469	449	449	449	449
2.05	ECONOMIZER OUTLET TEMP - A SIDE		℉	-	564	-	-	-	542	-	-	-
2.06	ECONOMIZER OUTLET TEMP - B SIDE		℉	-	569	-	-	-	548	-	-	-
2.07	ECONOMIZER OUTLET TEMP - AVG		℉	564	567	567	533	564	545	545	511	529
2.08	PRIMARY SUPERHEATER INLET (AFTER BOILER CAVITIES)		℉	-	-	641	638	639	-	636	635	635
2.09	SUPERHEATER BEFORE SPRAY TEMP - A SIDE		℉	-	787	-	-	-	786	-	-	-
2.10	SUPERHEATER BEFORE SPRAY TEMP - B SIDE		℉	-	772	-	-	-	761	-	-	-
2.11	SUPERHEATER BEFORE SPRAY TEMP - AVG		℉		779	779	708	742	774	774	710	733
2.12	SUPERHEATER AFTER SPRAY TEMP - A SIDE		℉	-	751	-	-	-	743	-	-	-
2.13	SUPERHEATER AFTER SPRAY TEMP - B SIDE		℉	-	750	-	-	-	743	-	-	-
2.14	SUPERHEATER AFTER SPRAY TEMP - AVG		℉		750	751	708	742	743	743	710	733
2.15	RADIANT OUTLET TEMP.		℉		908	908	863	933	899	899	875	920
2.16	SUPERHEATER OUTLET TEMP		℉	1005	1,004	1,004	923	1,004	996	996	944	956
2.17	SUPERHEAT SPRAY TEMP		℉	373	374	374	374	374	357	357	357	357
	REHEAT STEAM PATH											
2.17	REHEAT BEFORE SPRAY TEMP		℉	-	692	692	628	692	662	662	620	662
2.18	RHEATER AFTER SPRAY TEMP		℉	675	639	638	628	692	662	662	620	662
2.19	REHEAT OUTLET TEMP		℉	1005	1,005	1,005	867	986	985	985	847	917
2.20	REHEAT SPRAY TEMP		℉	373	374	374	374	374	306	306	306	306
3.0 WATER/STEAM PRESS	MAIN STEAM PATH											
3.01	BFP DISCHARGE PRESS - AVG		PSIG	-	2,627	-	-	-	2,753	-	-	-
3.02	ECONOMIZER FEEDWATER INLET PRESSURE		PSIG	-	2,008	2,010	2,010	2,010	1,940	1,941	1,941	1,941
3.03	DRUM PRESS		PSIG	2150	1,972	1,972	1,972	1,972	1,917	1918	1918	1918
3.05	SUPERHEATER OUTLET PRESS		PSIG	-	1,864	1,864	1,864	1,864	1,845	1845	1845	1845
3.06	SUPERHEATER SPRAY WATER PRESS		PSIG	-	2,627	2,627	2,627	2,627	2,753	2753	2753	2753
	REHEAT STEAM PATH											
3.07	REHEAT INLET PRESS - A SIDE		PSIG	-	457	-	-	-	-	-	-	-
3.08	REHEAT INLET PRESS - B SIDE		PSIG	-	-	-	-	-	-	-	-	-
3.09	REHEAT INLET PRESS - C SIDE		PSIG	-	479	-	-	-	-	-	-	-
3.10	REHEAT INLET PRESS - AVG		PSIG	512	468	498	499	499	396	396	396	396
3.12	REHEAT OUTLET PRESS - A SIDE		PSIG	-	472	-	-	-	-	-	-	-
3.13	REHEAT OUTLET PRESS - B SIDE		PSIG	-	-	-	-	-	-	-	-	-
3.14	REHEAT OUTLET PRESS - AVG		PSIG	485	472	472	472	472	375	375	375	375
3.15	REHEAT SPRAY WATER PRESSURE		PSIG		986	986	986	986	1,019	1019	1019	1019

RILEYPower
A Babcock Power Inc. Company

DATA SUMMARY
Name: Kansas City Board of Utilities
Station: Nearman Creek Unit 1
Location: Kansas City, KS

Issued By: Kushi.S | Date: 6-Sep-2013 | Notes: Tube Metal Temperatures / Calculated Values

Contract Number: 100658	TIME		-	14:30 - 17:25							
	LOAD	MW (gross)		247	-			-	-		
	BURNERS IN SERVICE	No.	18	18	18			18	18		
TEST NUMBER:			-	4	-			-	-		
TEST OBJECTIVE:		UNITS	PB Sheet	DCS Data PRB 100% MCR Acceptance Test 4 Day 6 (11/09/2012)	PRB Thermal Model 100% MCR	Natural Gas Model 100% MCR	Natural Gas Model 100% MCR 21.07% FGR	PRB DCS Data 75% MCR	PRB Thermal Model 75% MCR	Natural Gas Model 75% MCR	Natural Gas Model 75% MCR 12.55% FGR
4.0 FUEL AND AIR FLOWS											
4.01	FLUE GAS FROM COMBUSTION	KPPH	-	-	2,221	1,816	1,952	-	1,922	1,514	1,580
4.02	TOTAL COMBUSTION AIR	KPPH	2,408	2,692	1,957	1,722	1,850	2,292	1,709	1,435	1,498
4.03	FUEL FLOW	PPH	282,139	285,510	279,129	94,247	101,263	230,000	224,993	78,556	81,960
4.04	A SECONDARY AIR FLOW (0 - 1934 klb/hr)	%	-	-	-	-	-	54.70	-	-	-
4.05	B SECONDARY AIR FLOW (0 - 1934 klb/hr)	%	-	-	-	-	-	66.90	-	-	-
4.06	AVG SECONDARY AIR FLOW	%	-	-	-	-	-	60.80	-	-	-
4.07	SECONDARY AIR FLOW	KPPH	-	-	-	-	-	1,394	-	-	-
4.08	TOTAL TEMPERING AIR	KPPH	258	-	-	-	-	258	-	-	-
4.09	PRIMARY AIR FLOW	KPPH	-	-		-	-	641	-	-	-
4.10	AH BYPASS AIR	%		-	11%	-	-	11%	11%	-	-
5.0 AIR TEMPERATURES											
5.01	AMBIENT AIR TEMP	°F		77	77	77	77	85	85	85	85
5.02	FD FAN DISCHARGE TEMP	°F	80	77	77	77	77	90	90	90	90
5.03	AH AIR INLET TEMP - A SIDE	°F	-	-	-	-	-	90	-	-	-
5.04	AH AIR INLET TEMP - B SIDE	°F	-	-	-	-	-	90	-	-	-
5.05	AH AIR INLET TEMP - AVG	°F	-	-	77	77	77	90	90	90	90
5.06	AH PA OUTLET TEMP - A SIDE	°F	-	-	-	-	-	661	-	-	-
5.07	AH SA OUTLET TEMP - ASIDE	°F	-	-	-	-	-	575	-	-	-
5.08	AH PA OUTLET TEMP - BSIDE	°F	-	-	-	-	-	651	-	-	-
5.09	AH SA OUTLET TEMP - BSIDE	°F	-	-	-	-	-	639	-	-	-
5.10	AVG AH PA OUTLET TEMP	°F	-	-	-	-	-	656	-	-	-
5.11	AVG AH SA OUTLET TEMP	°F	-	-	-	-	-	607	-	-	-
5.12	AH AIR OUTLET TEMP 1	°F	-	693	-	-	-	-	-	-	-
5.13	AH AIR OUTLET TEMP 2	°F	-	704	-	-	-	-	-	-	-
5.14	AH AIR OUTLET TEMP AVG	°F	670	698	644	532	586	623	605	508	538
6.0 FLUE GAS TEMPERATURES											
6.01	FURNACE EXIT GAS TEMPERATURE	°F	1960	2,138	2,136	1,760	1,801	1,928	1,928	1,682	1,708
6.02	AH GAS INLET TEMP - A SIDE	°F	-	765	-	-	-	692	-	-	-
6.03	AH GAS INLET TEMP - B SIDE	°F	-	754	-	-	-	711	-	-	-
6.04	AH GAS INLET TEMP - AVG	°F	787	760	761	658	725	701	703	612	648
6.05	AH GAS OUTLET TEMP - A SIDE	°F	-	306	-	-	-	337	-	-	-
6.06	AH GAS OUTLET TEMP - B SIDE	°F	-	351	-	-	-	276	-	-	-
6.07	AH GAS OUTLET TEMP - AVG	°F	265	328	328	254	274	306	306	241	251
12.0 EFFICIENCY											
12.01	DRY FLUE GAS LOSS	%	4.31	-	5.61	3.45	3.86	-	5.47	3.15	3.36
12.02	MOIST. (LIQUID) IN FUEL LOSS	%	-	-	3.93	0.00	0.00	-	3.88	0.00	0.00
12.03	MOIST. (VAPOR) IN FUEL LOSS	%	-	-	0.00	0.00	0.00	-	0.00	0.00	0.00
12.04	AIR MOISTURE LOSS	%	0.10	-	0.13	0.09	0.10	-	0.13	0.08	0.09
12.05	WATER FROM HYDROGEN LOSS	%	7.85	-	4.25	10.55	10.65	-	4.20	10.45	10.50
12.06	UNBURNED CARBON LOSS	%	0.35	-	0.35	0.00	0.00	-	0.35	0.00	0.00
12.07	RADIATION LOSS	%	0.19	-	0.19	0.19	0.19	-	0.24	0.24	0.24
12.08	UNACCOUNTED LOSS	%	-	-	0.37	0.41	0.40	-	0.37	0.42	0.41
12.09	OTHER	%	0.53	-	-	-	-	-	-	-	-
12.10	TOTAL LOSS	%	13.33	-	14.83	14.69	15.20	-	14.64	14.34	14.60
12.11	BOILER EFFICIENCY	%	86.67	-	85.17	85.31	84.80	-	85.36	85.66	85.40
12.12	EXCESS AIR	%	20.00	-	11.37	10.00	10.00	-	20.68	10.00	10.00
12.13	O2 SET POINT	% Vol Wet	-	-	2.17 (Dry, Estimate	2.10 (Dry)	2.1 (Dry)	3.17	3.17	1.70	1.70
13.0 EMISSIONS											
13.01	NOx	lbs/MMBtu	-	-	-	0.20 - 0.25	0.11 - 0.14	-	-	-	-
13.02	CO	PPM	-	-	-	<150	<150	-	-	-	-

50% Load
25% Load

RILEYPower
A Babcock Power Inc. Company

DATA SUMMARY
Name: Kansas City Board of Utilities
Station: Nearman Creek Unit 1
Location: Kansas City, KS

Issued By: Kushi.S | Date: 6-Sep-2013 | Notes: Tube Metal Temperatures / Calculated Values

Contract Number: 100658

		TIME		-						
		LOAD	MW (gross)		-			-	-	-
		BURNERS IN SERVICE	No.	18	12			18	-	-
	TEST NUMBER:			-	-			-	-	-
	TEST OBJECTIVE:		UNITS	PB Sheet	PRB Thermal Model 50% MCR (Predicted)	Natural Gas Model 50% MCR	Natural Gas Model 50% MCR 15.61% FGR	PRB/OIL DCS Data 25% MCR	PRB/OILThermal Model 25% MCR	Natural Gas Model 25% MCR
1.0 WATER/STEAM FLOWS	MAIN STEAM PATH		% MCR	100%	50%	50%	50%	24%	24%	24%
1.01	MAIN STEAM FLOW		KLBS/HR	1750	875	875	875	420	420	420
1.02	FEEDWATER FLOW		KLBS/HR	-	864	878	878	431	431	405
1.03	AUXILIARY FLOW		KLBS/HR	0	3	3	3	4	4	4
1.04	BLOWDOWN		KLBS/HR	0	-	-	-	8	8	8
1.05	SUPERHEAT SPRAY FLOW		KLBS/HR	-	-	-	-	6	-	-
1.06	SUPERHEAT SPRAY FLOW (HEAT BALANCE)		KLBS/HR	-	14	0	0	1	1	27
	REHEAT STEAM PATH									
1.07	HOT REHEAT STEAM FLOW		KLBS/HR	1551	777	777	777	373	373	373
1.08	COLD REHEAT STEAM FLOW		KLBS/HR	-	777	777	777	373	373	373
1.09	REHEAT SPRAY FLOW (HEAT BALANCE)		KLBS/HR	-	-	-	-	-	-	-
1.10	REHEAT SPRAY FLOW		KLBS/HR	-	0	0	0	0	0	0
2.0 WATER/STEAM TEMP	MAIN STEAM PATH									
2.01	TOP FWH EXTRACTION TEMP		℉	-	-	-	-	378	-	-
2.02	TOP FWH FEEDWATER IN TEMP		℉	-	-	-	-	177	-	-
2.03	TOP FWH FEEDWATER OUT TEMP		℉	-	-	-	-	213	-	-
2.04	FEEDWATER TO ECONOMIZER TEMP		℉	470	409	409	409	312	312	312
2.05	ECONOMIZER OUTLET TEMP - A SIDE		℉	-	-	-	-	422	-	-
2.06	ECONOMIZER OUTLET TEMP - B SIDE		℉	-	-	-	-	423	-	-
2.07	ECONOMIZER OUTLET TEMP - AVG		℉	564	522	475	496	423	423	417
2.08	PRIMARY SUPERHEATER INLET (AFTER BOILER CAVITIES)		℉	-	633	630	631	-	619	617
2.09	SUPERHEATER BEFORE SPRAY TEMP - A SIDE		℉	-	-	-	-	676	-	-
2.10	SUPERHEATER BEFORE SPRAY TEMP - B SIDE		℉	-	-	-	-	684	-	-
2.11	SUPERHEATER BEFORE SPRAY TEMP - AVG		℉		755	692	711	680	680	663
2.12	SUPERHEATER AFTER SPRAY TEMP - A SIDE		℉	-	-	-	-	678	-	-
2.13	SUPERHEATER AFTER SPRAY TEMP - B SIDE		℉	-	-	-	-	678	-	-
2.14	SUPERHEATER AFTER SPRAY TEMP - AVG		℉		736	692	711	678	678	610
2.15	RADIANT OUTLET TEMP.		℉		881	869	912	849	748	790
2.16	SUPERHEATER OUTLET TEMP		℉	1005	996	946	956	870	870	870
2.17	SUPERHEAT SPRAY TEMP		℉	373	323	323	323	91	100	100
	REHEAT STEAM PATH									
2.17	REHEAT BEFORE SPRAY TEMP		℉	-	618	578	618	422	422	422
2.18	RHEATER AFTER SPRAY TEMP		℉	675	618	578	618	394	422	422
2.19	REHEAT OUTLET TEMP		℉	1005	944	790	859	766	766	706
2.20	REHEAT SPRAY TEMP		℉	373	-	-	-	102	102	102
3.0 WATER/STEAM PRESS	MAIN STEAM PATH									
3.01	BFP DISCHARGE PRESS - AVG		PSIG	-	-	-	-	3,022	-	-
3.02	ECONOMIZER FEEDWATER INLET PRESSURE		PSIG	-	1,852	1,852	1,852	1,643	1,643	1,643
3.03	DRUM PRESS		PSIG	2150	1842	1842	1842	1,640	1,640	1,640
3.05	SUPERHEATER OUTLET PRESS		PSIG	-	1820	1820	1820	1,628	1,628	1,628
3.06	SUPERHEATER SPRAY WATER PRESS		PSIG	-	2480	2480	2480	3,022	3,022	3,022
	REHEAT STEAM PATH									
3.07	REHEAT INLET PRESS - A SIDE		PSIG	-	-	-	-	-	-	-
3.08	REHEAT INLET PRESS - B SIDE		PSIG	-	-	-	-	-	-	-
3.09	REHEAT INLET PRESS - C SIDE		PSIG	-	-	-	-	-	-	-
3.10	REHEAT INLET PRESS - AVG		PSIG	512	253	253	253	123	123	123
3.12	REHEAT OUTLET PRESS - A SIDE		PSIG	-	-	-	-	-	-	-
3.13	REHEAT OUTLET PRESS - B SIDE		PSIG	-	-	-	-	-	-	-
3.14	REHEAT OUTLET PRESS - AVG		PSIG	485	240	240	240	117	116	116
3.15	REHEAT SPRAY WATER PRESSURE		PSIG		-	-	-	1,043	1,043	1,043

RILEYPower
A Babcock Power Inc. Company

DATA SUMMARY
Name: Kansas City Board of Utilities
Station: Nearman Creek Unit 1
Location: Kansas City, KS

Issued By:	Date:	Notes:
Kushi.S	6-Sep-2013	Tube Metal Temperatures / Calculated Values

Contract Number: 100658		TIME		-						
		LOAD	MW (gross)		-			-	-	-
		BURNERS IN SERVICE	No.	18	12			18	-	-
	TEST NUMBER:			-	-			-	-	-
	TEST OBJECTIVE:		UNITS	PB Sheet	PRB Thermal Model 50% MCR (Predicted)	Natural Gas Model 50% MCR	Natural Gas Model 50% MCR 15.61% FGR	PRB/OIL DCS Data 25% MCR	PRB/OILThermal Model 25% MCR	Natural Gas Model 25% MCR
4.0 FUEL AND AIR FLOWS										
4.01	FLUE GAS FROM COMBUSTION		KPPH	-	1,460	1,024	1,066	-	632	634
4.02	TOTAL COMBUSTION AIR		KPPH	2,408	1,316	972	1,012	1,293	585	607
4.03	FUEL FLOW		PPH	282,139	151,867	52,316	54,487	46,280	48,215	27,669
4.04	A SECONDARY AIR FLOW (0 - 1934 klb/hr)		%	-	-	-	-	26.81	-	-
4.05	B SECONDARY AIR FLOW (0 - 1934 klb/hr)		%	-	-	-	-	28.74	-	-
4.06	AVG SECONDARY AIR FLOW		%	-	-	-	-	27.77	-	-
4.07	SECONDARY AIR FLOW		KPPH	-	-	-	-	359	-	-
4.08	TOTAL TEMPERING AIR		KPPH	258	-	-	-	170	-	-
4.09	PRIMARY AIR FLOW		KPPH	-	-	-	-	764	-	-
4.10	AH BYPASS AIR		%		15%	-	-	13%	13%	-
5.0 AIR TEMPERATURES										
5.01	AMBIENT AIR TEMP		°F		71	71	71	93	-	-
5.02	FD FAN DISCHARGE TEMP		°F	80	-	-	-	110	-	-
5.03	AH AIR INLET TEMP - A SIDE		°F	-	-	-	-	112	-	-
5.04	AH AIR INLET TEMP - B SIDE		°F	-	-	-	-	109	-	-
5.05	AH AIR INLET TEMP - AVG		°F	-	71	71	71	110	110	110
5.06	AH PA OUTLET TEMP - A SIDE		°F	-	-	-	-	313	-	-
5.07	AH SA OUTLET TEMP - ASIDE		°F	-	-	-	-	398	-	-
5.08	AH PA OUTLET TEMP - BSIDE		°F	-	-	-	-	351	-	-
5.09	AH SA OUTLET TEMP - BSIDE		°F	-	-	-	-	404	-	-
5.10	AVG AH PA OUTLET TEMP		°F	-	-	-	-	332	-	-
5.11	AVG AH SA OUTLET TEMP		°F	-	-	-	-	401	-	-
5.12	AH AIR OUTLET TEMP 1		°F	-	-	-	-	-	-	-
5.13	AH AIR OUTLET TEMP 2		°F	-	-	-	-	-	-	-
5.14	AH AIR OUTLET TEMP AVG		°F	670	558	452	482	354	301	313
6.0 FLUE GAS TEMPERATURES										
6.01	FURNACE EXIT GAS TEMPERATURE		°F	1960	1,754	1,534	1,551	1,589	1,585	1,311
6.02	AH GAS INLET TEMP - A SIDE		°F	-	-	-	-	454	-	-
6.03	AH GAS INLET TEMP - B SIDE		°F	-	-	-	-	447	-	-
6.04	AH GAS INLET TEMP - AVG		°F	787	668	563	602	451	451	426
6.05	AH GAS OUTLET TEMP - A SIDE		°F	-	-	-	-	306	-	-
6.06	AH GAS OUTLET TEMP - B SIDE		°F	-	-	-	-	252	-	-
6.07	AH GAS OUTLET TEMP - AVG		°F	265	300	233	235	279	278	236
12.0 EFFICIENCY										
12.01	DRY FLUE GAS LOSS		%	4.31	6.11	2.90	3.14	-	4.82	3.66
12.02	MOIST. (LIQUID) IN FUEL LOSS		%	-	3.89	0.00	0.00	-	1.51	0.00
12.03	MOIST. (VAPOR) IN FUEL LOSS		%	-	0.00	0.00	0.00	-	0.00	0.00
12.04	AIR MOISTURE LOSS		%	0.10	0.14	0.07	0.08	-	0.12	0.09
12.05	WATER FROM HYDROGEN LOSS		%	7.85	4.21	10.42	10.48	-	5.58	10.37
12.06	UNBURNED CARBON LOSS		%	0.35	0.35	0.00	0.00	-	0.27	0.00
12.07	RADIATION LOSS		%	0.19	0.31	0.31	0.31	-	0.60	0.60
12.08	UNACCOUNTED LOSS		%	-	0.36	0.43	0.42	-	0.38	0.41
12.09	OTHER		%	0.53	-	-	-	-	-	-
12.10	TOTAL LOSS		%	13.33	15.37	14.13	14.43	-	13.28	15.13
12.11	BOILER EFFICIENCY		%	86.67	84.63	85.87	85.57	-	86.72	84.87
12.12	EXCESS AIR		%	20.00	37.71	11.80	11.80	-	26.90	32.00
12.13	O2 SET POINT		% Vol Wet	-	5.13	1.98	1.98	4.06	4.06	4.61
13.0 EMISSIONS										
13.01	NOx		lbs/MMBtu	-	-	-	-	-	-	-
13.02	CO		PPM	-	-	-	-	-	-	-

Appendix B:

Q&A with Black & Veatch

[Questions in Black and Responses in Blue]

1. Has the trisector air heater performance been evaluated for natural gas combustion with or without the primary air fans supplying combustion air though that portion of the airheaters?
The study was evaluated for natural gas combustion without primary air fans. Refer to section 3.3 Table 7 and the related discussion on page 19.
2. Is the current windbox to furnace pressure differential while burning coal suitable for burning gas?
The current windbox to furnace pressure differential range is about 3 to 5 iwc at full load. This is suitable for the NG firing equipment modifications envisioned.
3. We understand the assumptions made regarding the cleanliness of the radiant and convective boiler heat transfer surfaces will have a large impact on the analysis results regarding steaming capacity and steam temperatures. Dirty furnace conditions would be expected to inhibit steaming capacity but result in excessive tube metal and final steam temperature. Gas cofiring with coal would also be expected to result in elevated FEGT due to the lower radiant heat characteristics of natural gas combustion.
Yes, we agree there is a possibility for this based on the following boiler factors:

- % Excess air
- % Natural gas to coal ratio
- If there is FGR in the system
- Resulting NOx values

4. Would the modifications proposed for gas conversion enable any significant natural gas cofiring without boiler surface modifications?
No surface modifications would be needed
5. Would the superheater and reheater tube metal temperatures be expected to increase with gas co-firing?
100% coal and 100% NG can be done without surface modification. Tube metal temperatures will increase, but are not expected to exceed their Code or oxidation temperature limits.
6. With conversion to natural gas from coal, what would be the expected seasoning period required prior to the ability to meet full steaming capacity without overheating superheat surfaces?
Seasoning periods vary based on plant conditions, the amount of slag that is in the boiler, how sticky the ash is and how tightly it adheres to the tubes. Overheating of SH surfaces is not a concern as gas temperatures firing NG are cooler than PRB firing. Slag remaining on tube surfaces when switching from coal to NG, will work in favor of keeping up the gas temperatures. By controlling the amount of FGR during initial operation, a short seasoning period can be expected. Riley Power is aware of units with seasoning periods of 2-3 days to 2 weeks. The seasoning period for Nearman Creek will be determined by field testing.

7. Following the installation of the proposed flue gas recirc to the windbox system, would this equipment also be useable and of NOx reduction benefit while burning coal?
The flue gas recirculation system is applicable for NG firing only for NOx reduction benefits.
8. Is there any redundancy provided with the proposed FGR equipment?
Two (2) 50% capacity FGR fans are proposed at this point that do not provide any redundancy.
9. Previous natural gas conversion studies that B&V has received that have been performed by US boiler OEM's for conventional wall fired and T-fired units have not concluded that flue gas recirc to the windbox would be required to enable operation at the design basis steam temperatures. On the other hand, these studies have regularly resulted in the recommendation for material upgrades to SH and RH surface due to potential overheating. Is the Turbo-furnace firing system and surface configuration of the Nearman boiler responsible for this departure from normal expectations?

The flue gas recirculation (FGR) requirement arises due to the expected drop in temperature when switching the fuel from PRB coal to NG. This decrease in temperature would not typically be seen in conversions from bituminous coal to NG. The Turbo furnace firing system or surface configuration are not directly responsible for FGR requirement.
10. Have there been turbo units of this capacity either designed for gas or converted to burn 100% gas or co-fire gas with coal that can be used to confirm this predicted performance impact of inadequate steam temperature?

Yes. Riley Power has gas and coal firing capability at AEPCO Apache Units 2 & 3 which uses an FGR system. Recently, Riley Power performed a study for NRG Big Cajun II Unit 2 Turbo furnace gas conversion. This unit fired PRB coal and conversion to NG firing will require the use of a FGR system.
11. Regarding the ability of the existing FD fans to meet the combustion air requirements following the removal of PA fans from service;
Was the effect of air heater leakage and the current contribution of the PA fans to the secondary air system considered in this assessment? We expect the PA fans are also currently providing a portion of the secondary air via leakage in the air heater

	PRB Firing Full Load	NG Full Load No FGR	NG Full Load with FGR	Original FD Fan Design
Combustion Air (pph)	1,956,567	1,722,196	1,850,392	--
AH Leakage (pph) SA to FG	222,053	181,644	195,165	--
AH Leakage (pph) PA to SA	20,649*	na	na	--

PA Fan Flow (pph)	661,536	--	--	--
Total FD Fan Flow (pph)	1,496,435	1,903,840	2,045,557	1,878,000
FD Fan Flow per fan (pph)	748,218	951,920	1,022,779	939,000

*This is an estimated value based on typical tri-sector airheater performance.

We appreciate the further discussion of the airheaters and fan capacity and have performed a more detailed review of the fans. During the study it was assumed the FD fans would have sufficient capacity. The results are presented in the table above, which compares the FD fan flows for both coal and NG firing. Also included for reference is the original fan test block information. Based on this analysis, the FD fans do not have sufficient capacity without using the PA fans for combustion air. The tri-sector air heater is expected to have some leakage from the PA section to the SA section; this was estimated for this evaluation since there is no way to measure this leakage. Including the PA fans in the thermal model does not impact the overall predicted boiler performance.

12. Was the effect of removing the PA fans from service included in the assessment of the air heater flue gas exit temperature prediction following the conversion to natural gas?

The boiler modeling was performed based on air heater performance without the PA section of the air heater contributing to the heat transfer.

13. The previous question (#4) regarding the minimum windbox oxygen content was not addressed.

The boiler modeling was done with 10% excess air, when mixed with the FGR the oxygen content of the combustion air is 17 to 18% O2.

14. This question was asked to clarify the maximum recommended flue gas recirculation rate.

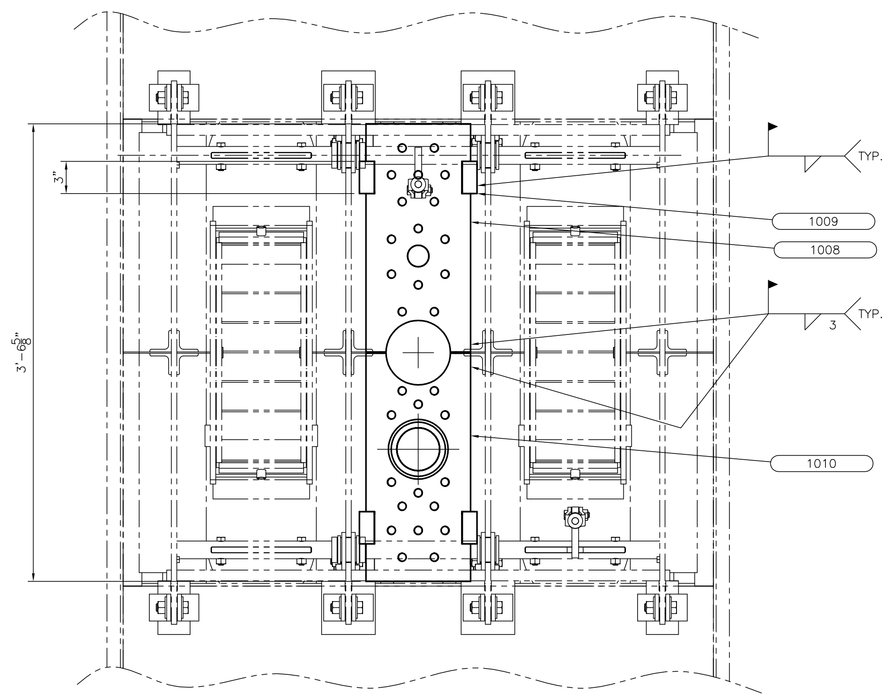
The FGR flow rate was evaluated as the minimum necessary to achieve the design steam temperatures. The FGR fans would be sized with a reasonable margin to allow for some operating flexibility. Increasing the FGR flow rate is acceptable as the additional heat transfer would result in additional spray attemperation flow rates. In addition, increasing FGR tends to increase the stack temperature thereby lowering the boiler efficiency. The spray flow rates and impact on boiler efficiency would have to be evaluated further to determine a maximum FGR flow rate. FGR fan test block margins are recommended to be within normal industry practices, having excessive margin tends to result in fans that are oversized and difficult to control.

Appendix C:

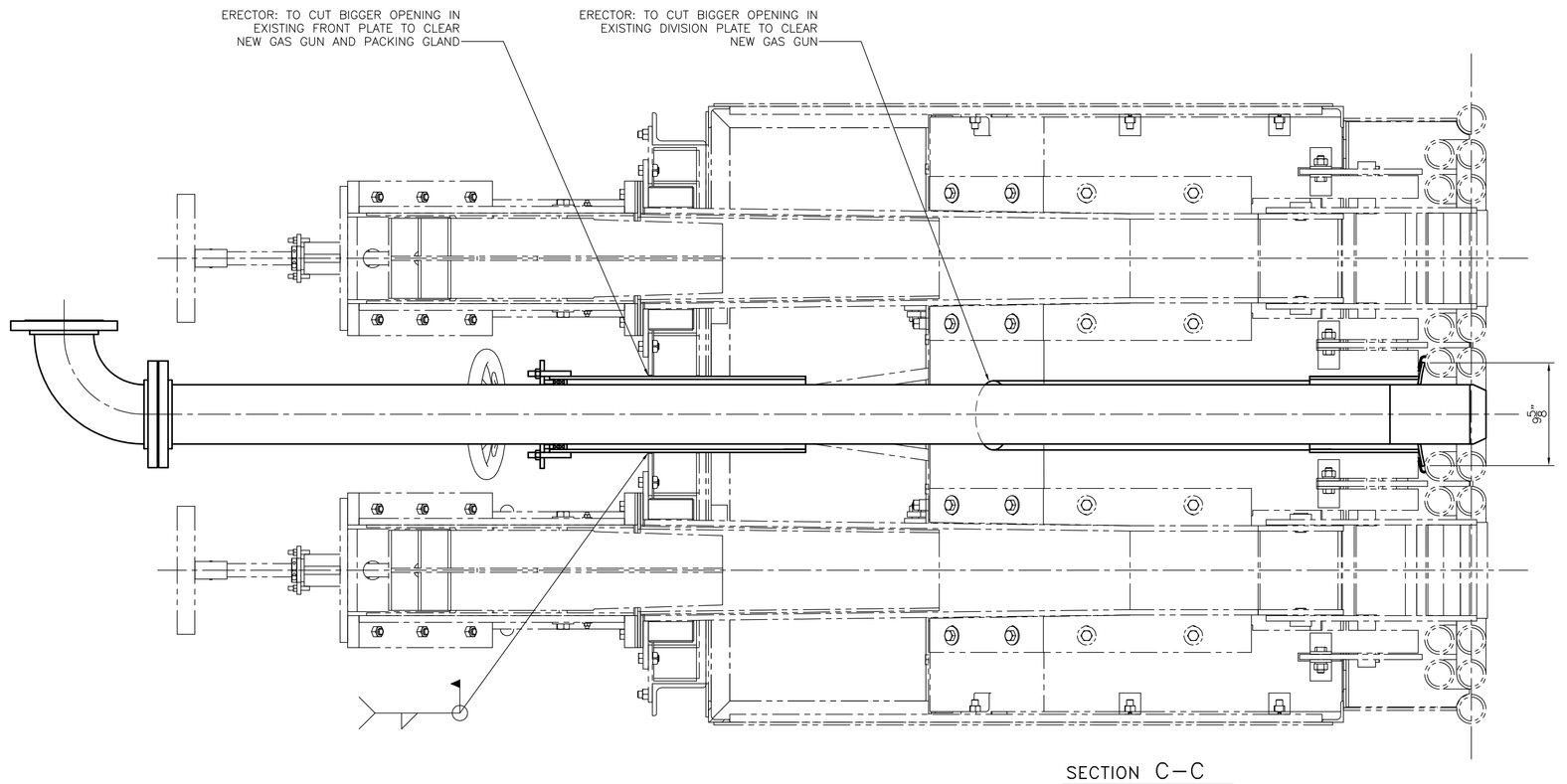
Drawings

DWG. NO. 100658-079721100-00

Exhibit RSH-2



SECTION A-A
(100 - E,10)



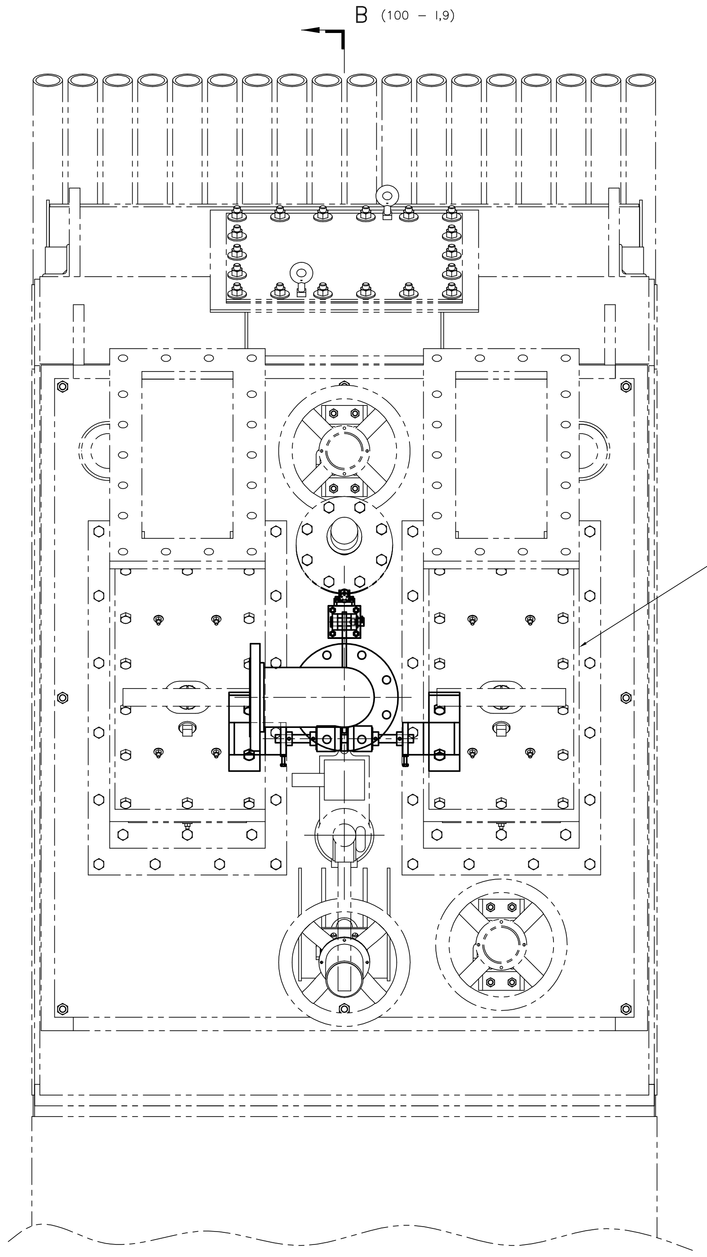
SECTION C-C
(100 - G,5)

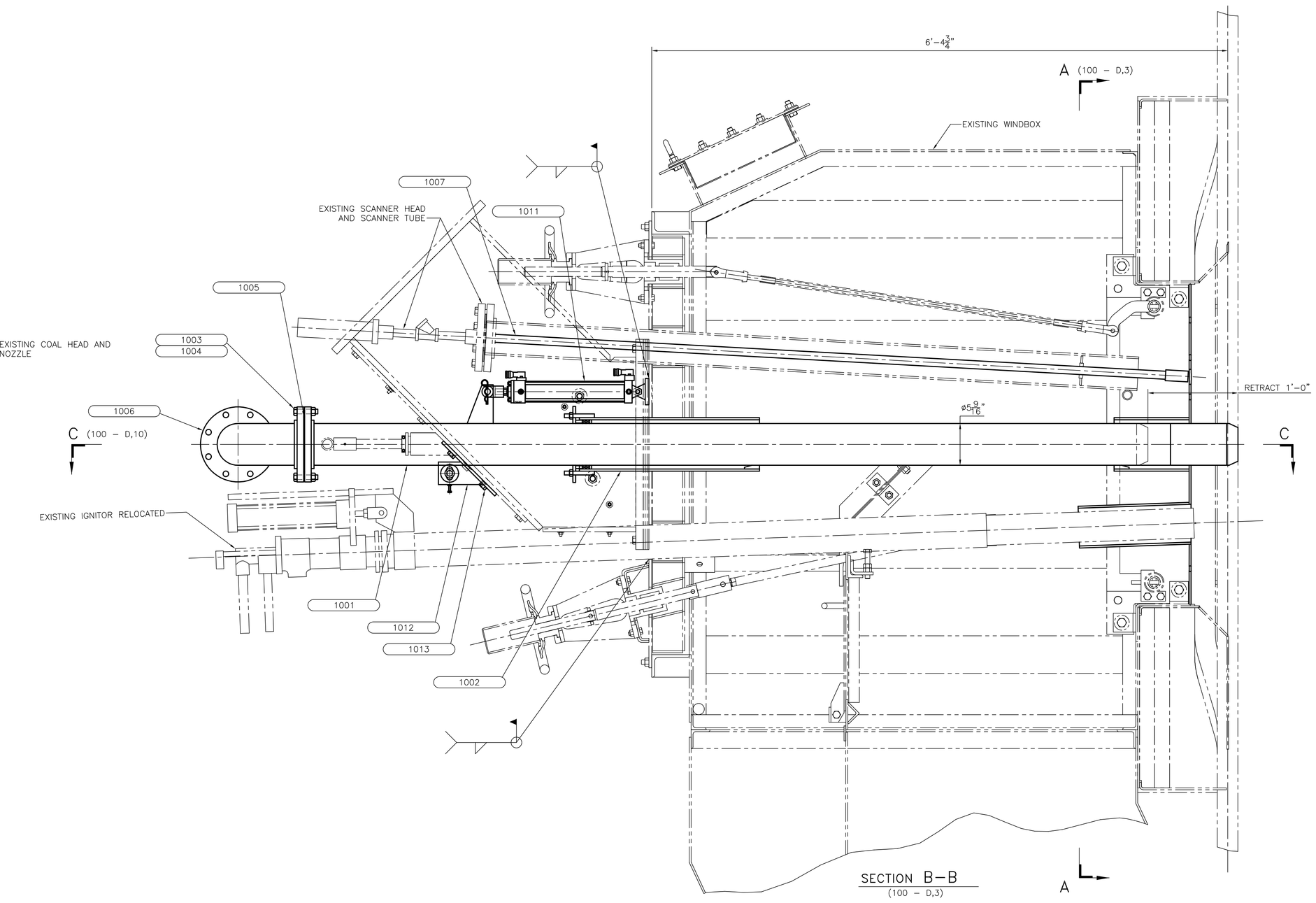
BILL OF MATERIAL FOR 18 BURNERS

ITEM	NO.REQ'D	DESCRIPTION	MAT'L	WEIGHT
1001	18	GAS GUN	310/106B	130 LBS
1002	18	GAS GUN SUPPORT W/PACKING GLAND	STL	100 LBS
1003	144	BOLT, HEX 3/4"-10UNC X 3" LG.	J429 GR2	
1004	144	NUT, HEX 3/4"-10UNC	J995 GR2	
1005	18	GASKET, FOR 5" PIPE	STL	10
1006	18	ELBOW WITH FLANGES	STL	30
1007	18	QUARTZ FIBER OPTIC EXTENSION	–	
1008	18	DIFFUSER PLATES, 1/4" X 9 5/8" X 1'-9 1/4" LG.	310 SST	25
1009	72	DIFFUSER CLIPS B4008-7-9721-00	A387 GR22	
1010	18	DIFFUSER PLATES, 1/4" X 9 5/8" X 1'-9 1/4" LG.	310 SST	
1011	18	CYLINDER, AIR 12" STROKE, W/FEMALE ROD CLEVIS, MOUNTING PLATE W/PIVOT PIN	–	
1012	18	GAS GUN SUPPORT ROLLER	–	
1013	72	BOLT, HEX 5/8"-11UNC X 1-1/2" LG.	J429 GR5	

WEIGHT SHOWN IS CALCULATED MATERIAL WEIGHT ONLY. TEMPORARY BRACING AND WELD WEIGHT NOT INCLUDED

THIS DRAWING IS CONCEPTUAL IN NATURE AND IS NOT A COMPLETE OR FINAL WORK PRODUCT. THE ILLUSTRATED PROCESSES, SYSTEMS, DIMENSIONS, PARTS AND EQUIPMENT SET FORTH ON THIS DRAWING ARE PRELIMINARY AND SUBJECT TO REVISION. THIS DRAWING IS NOT SUITABLE FOR PROCUREMENT, MANUFACTURE OR INSTALLATION.





SECTION B-B
(100 - D,3)

WORK IN PROGRESS
NOT TO BE USED
FOR CONSTRUCTION
09-06-2013

REVISION	NO.	BY	CHK	DATE	APP'D	DATE

RELEASED & APPROVED _____ DATE _____

THIRD ANGLE PROJECTION

DO NOT SCALE
USE DIMENSIONS ONLY

DRAWN R. LEGAULT
DATE 06-SEP-13
CHECKED
DATE
APP'D
DATE
SCALE 1 1/2 IN. = 1 FT.

RILEY POWER INC.

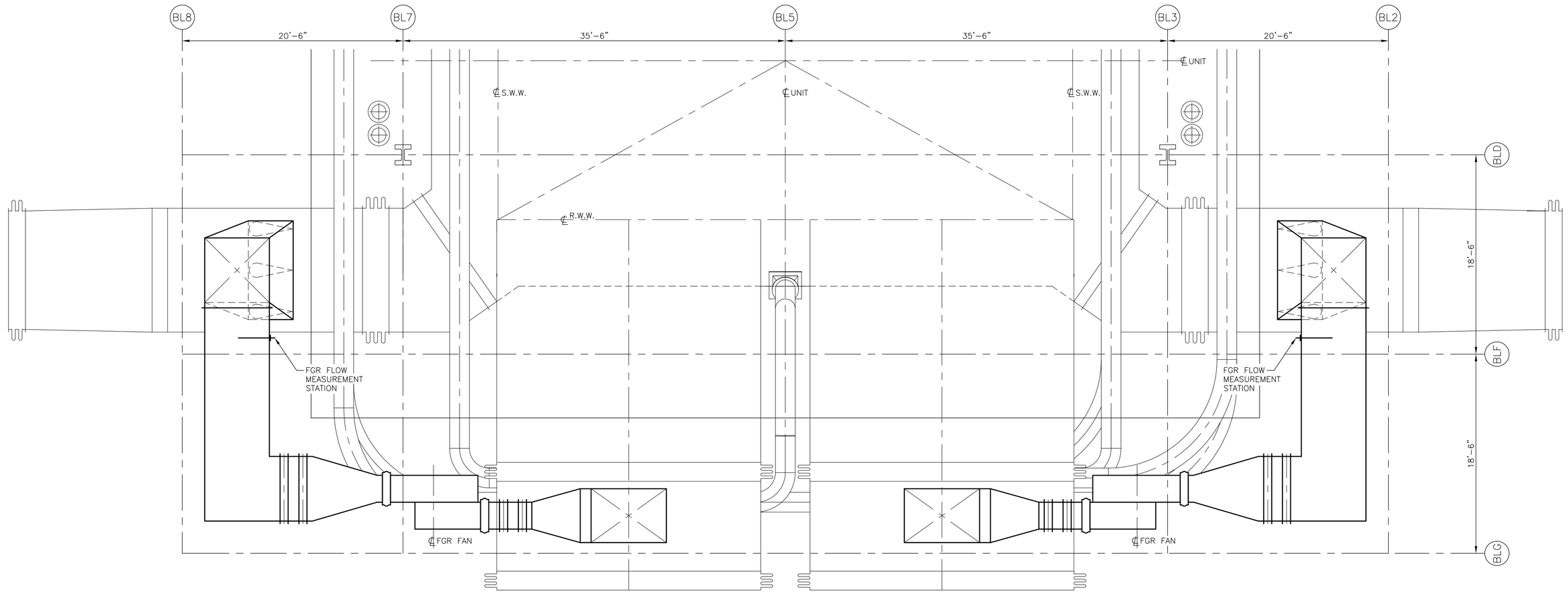
PROPOSED DIRECTIONAL FLAME BURNER
ASSEMBLY GAS STUDY

KANSAS CITY BOARD OF PUBLIC UTILITIES
NEARMAN CREEK UNIT #1
KANSAS CITY, KS

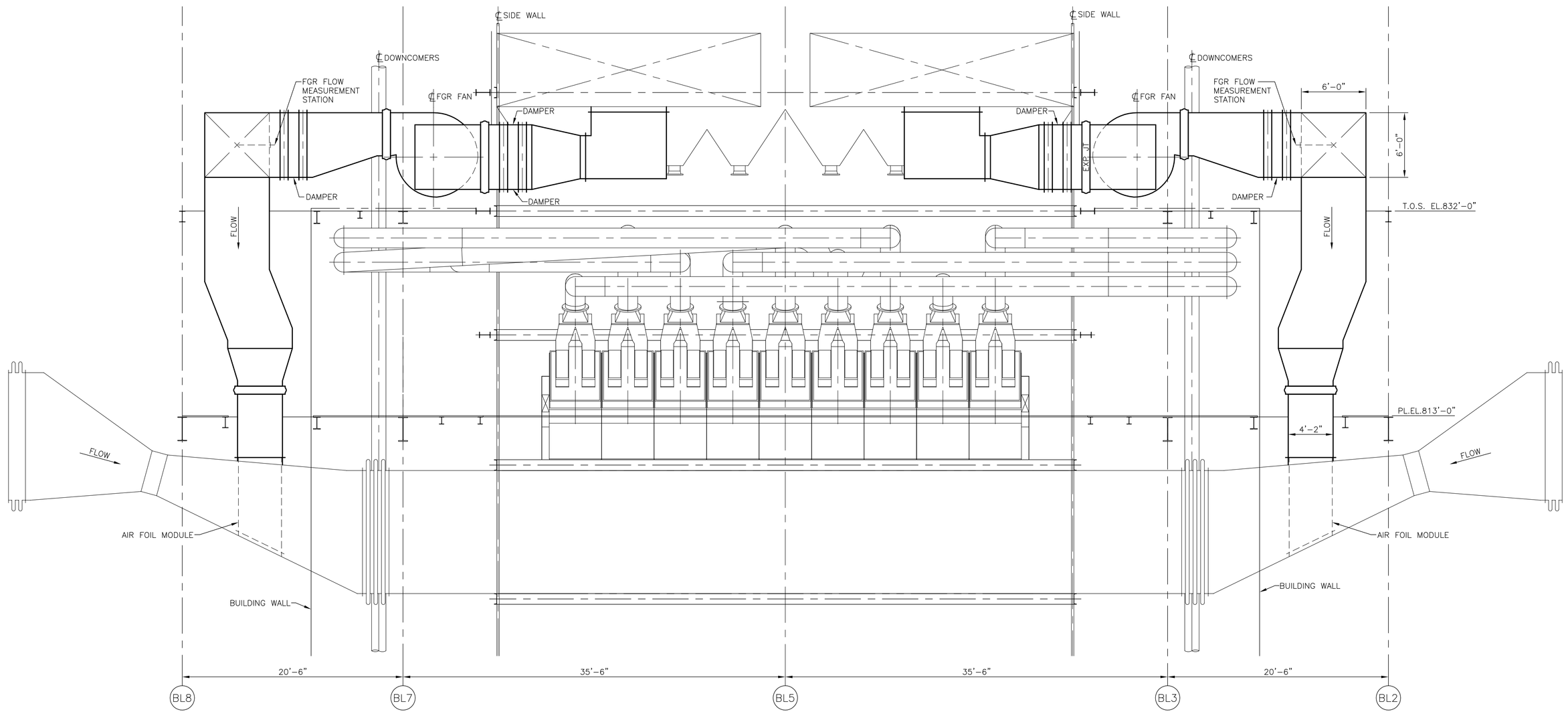
DWG. NO. 100658-079721100-00

DWG. NO. 100658-076454100

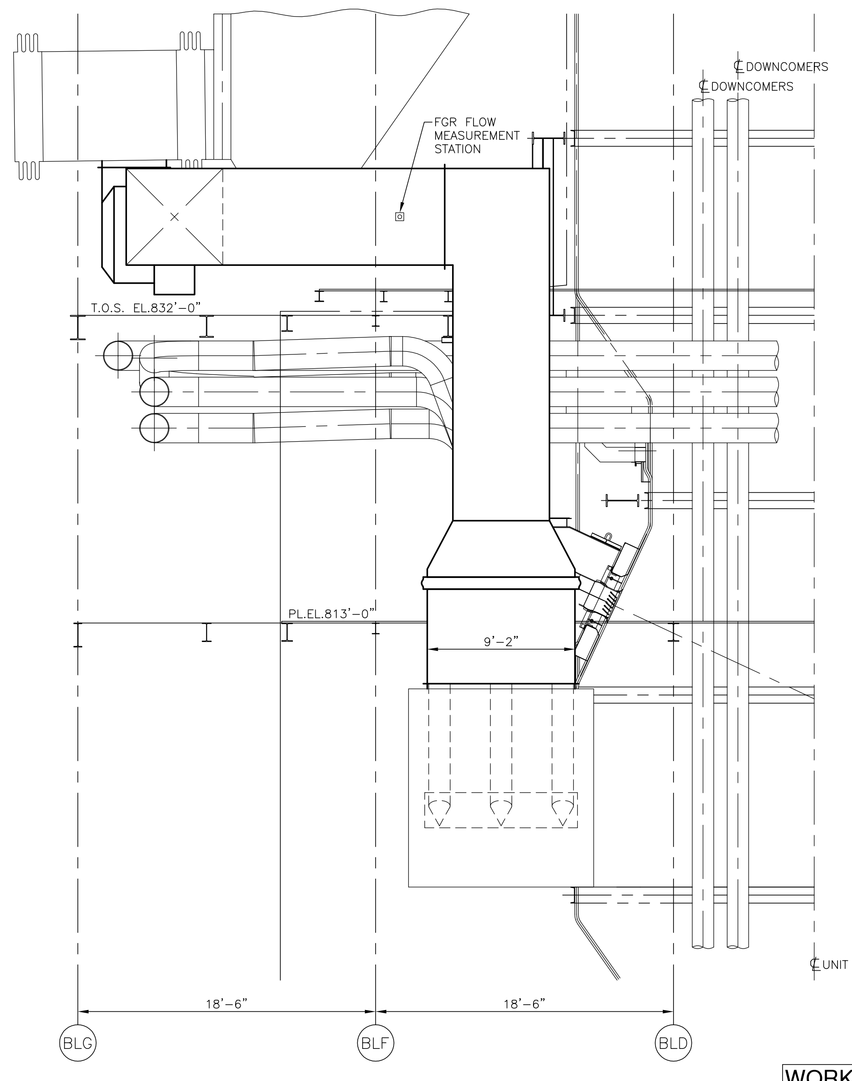
Exhibit SSH-2



PLAN VIEW



REAR VIEW
LOOKING SOUTH



LEFT HAND SIDE VIEW
LOOKING EAST

WORK IN PROGRESS
NOT TO BE USED
FOR CONSTRUCTION
9/6/13

THIS DRAWING IS CONCEPTUAL IN NATURE AND IS NOT A COMPLETE OR FINAL WORK PRODUCT. THE ILLUSTRATED PROCESSES, SYSTEMS, DIMENSIONS, PARTS AND EQUIPMENT SET FORTH ON THIS DRAWING ARE PRELIMINARY AND SUBJECT TO REVISION. THIS DRAWING IS NOT SUITABLE FOR PROCUREMENT, MANUFACTURE OR INSTALLATION.

REVISION	NO.	BY	CHK	DATE	APP'D	DATE

THIS DRAWING IS NOT APPROVED FOR CONSTRUCTION UNLESS IT CONTAINS DATE AND SIGNATURE OF APPROVAL AND THE COMPANY RESERVES THE RIGHT TO CORRECT ANY ERRORS OR OMISSIONS PRIOR TO ACTUAL START OF WORK.

RELEASED & APPROVED _____ DATE _____

THIRD ANGLE PROJECTION

DO NOT SCALE
USE DIMENSIONS ONLY

DRAWN M. SCRICCO
DATE 06-SEP-13
CHECKED
DATE
APP'D
DATE
SCALE 3/16 IN. = 1 FT.

RILEY POWER INC.

PROPOSED ARRANGEMENT FGR STUDY

KANSAS CITY BOARD OF PUBLIC UTILITIES
NEARMAN CREEK UNIT #1
KANSAS CITY, KS

DWG. NO. 100658-076454100-00

BPU Provided Attachment to BC 3-3 - 177281.41.3400_140626
Natural Gas Firing Feasibility Study - R&V

AC_E

Attachment B. Riley Power Order of Magnitude Pricing for Gas Conversion Equipment Supply and Installation

Riley Power
5 Neponset Street
Worcester, MA 01615-0040

October 11, 2013

Black and Veatch Corporation
11401 Lamar
Overland Park, Kansas. 66211

Attention: Fred Freeland

Subject **Addendum 1: Order of Magnitude Pricing for NG Gas Firing with FGR for Nearman Creek Unit 1**

Dear Fred,

As an Addendum to the "Natural Gas Firing with FGR Feasibility Study", the following is a scope description and order of magnitude pricing for the design and install of a gas firing and flue gas recirculation system to the Nearman Creek Unit 1.

Scope;

The following preliminary scope description summarizes the material required for addition of Natural gas firing ability to Kansas City Board of Public Utility Nearman Creek Unit 1.

RPI Design Gas Guns and Proposed Burner Modifications

The conceptual burner modifications for natural gas firing are shown on RPI drawing 100658-079721100. The existing TDF burners (with existing coal nozzles installed) will be modified to achieve 100% MCR steam flow while firing natural gas by installing a 5 ½" OD gas gun in the center slot of each burner. The existing igniter will be relocated to one of the existing flame scanner locations. The remaining flame scanner will be modified to replace the existing glass fiber optic extension with a quartz fiber optic extension. The center slot perforated or diffuser plate will be removed and replaced with a new perforated plate designed to have more open free area.

Firing Equipment

- (18) Gas guns
- (18) Gas gun supports with packing gland
- (18) Gas gun support rollers

- (18) Quartz fiber optic extension for existing flame scanner
- (18) Air cylinders for gas gun retraction with 12” stroke
- (18) Diffuser plates
- (72) Diffuser clips
- (18) Elbows with flanges
- (18) Gaskets for 5” pipe
- Lot of nuts and bolts

Main Natural Gas Fuel Piping and Valve Train

(1) One valve train assembly to supply and control natural gas to the gas guns. Main gas valve train will consist of following components:

- (1) Main safety shutoff valve
- (1) Burner header atmospheric vent valve
- (1) Main fuel control valve
- (1) Minimum flow bypass valve
- (1) Constant fuel pressure regulator
- (1) Flow meter
- (1) Strainer
- (1) Burner header high fuel pressure switch
- (1) Burner header flow fuel pressure switch
- (1) Low fuel supply pressure switch
- (2) Fuel pressure gauge
- (1) Manual shutoff valve
- Lot of piping

Foot print and weight will be specified during actual contract specification.

Main Header to Gas Gun Connection Piping and Valve Trains

RPI will supply eighteen (18) burner front valve trains for field assembly and installation. Each burner front valve train will be supplied with:

- (2) Individual burner safety shutoff valves

- (1) Individual burner atmospheric vent valve
- (1) Lot of piping and fittings
- (1) Metal flex hose

Flue Gas Recirculation System

For the FGR system, the major system components are conceptually illustrated on RPI drawing 100658-076454100. Equipment required for the FGR system includes:

- Two (2) 50% capacity FGR fans including inlet vane control, motor & turning gear
- Four (4) tight shut off double damper assemblies including seal air blowers mounted on damper assembly for positive fan isolation and cold fan start
- Expansion joints
- Two (2) air foil mixing modules
- Interconnecting ductwork with supports
- Two (2) FGR flow measurement stations

All ductwork field welds to be gas tight.

Performance Summary;

One of the challenges of adding gas firing capability to Nearman Creek Unit 1 is the effect it will have on main steam and reheat steam and the amount of temperature decay the unit will experience. As is indicated in the study report, without Flue Gas Recirculation (FGR), steam temperatures are predicted to be lower than baseline which will limit the unit to approximately 70 – 80% MCR.

With the addition of FGR through the windbox, along with reducing NOx emissions, by applying 21% FGR, Nearman Creek will regain steam temperatures and allow the unit to perform once again to 100% MCR.

Pricing options;

The following are several pricing options to consider during BPU's final evaluation. Keep in mind that this is a budget price (+/- 20%). Pricing would be firmed up when BPU decides on a direction going forward;

1. For design, material, fabrication, and installation of the addition of gas firing capability as well as flue gas recirculation, total budget price will be approximately **Five Million, Five Hundred and Thirty Three Thousand, Six Hundred and Twenty Eight Dollars ($5,533,628.00).**
2. For the design, material, fabrication, and installation of gas firing capability only without the addition of flue gas recirculation, limiting the unit to operating at approximately 70 – 80% MCR, total budget price will be approximately **Four Million, Four Hundred and Fifteen Thousand, and Eight Eight Dollars ($4,415,088.00).**

Once BPU determines a direction going forward and if the decision included adding gas firing capability, Riley Power Inc (RPI) will work with BPU / B&V to develop a final design and firm price offering.

If there are any questions, please advise.

Sincerely,

Michael J. Lynch
Senior Project Manager
Babcock Power Services Inc.
5 Neponset Street
Worcester, MA 01606

T: 508-854-4001 F: 508-854-4091
M: 508-735-5614

b. Do BPU's forecasts of generation, provided in response to Sierra Club's first set of data requests, assume that the Nearman coal unit will be self-committed or not?

BPU's forecast assumes that the vast majority of all generating hours will come from a Market commitment status.

3-2. Is BPU a 501(c)(12) entity for federal tax purposes? If not, under what state and federal designation(s) is BPU registered as a nonprofit municipal entity for tax purposes?

BPU is not a 501(c)(12) entity for federal tax purposes.

The Board of Public Utilities (the "BPU") of the Unified Government is an administrative agency charged with the responsibility for the daily management, operation, maintenance and control of the Unified Government's water and electric facilities.

The Unified Government is a municipal corporation duly organized and existing under the laws of the State of Kansas as a consolidated city-county, and became the successor to the City of Kansas City, Kansas and Wyandotte County, Kansas upon the consolidation of the City and the County effective October 1, 1997.

3-3. Has BPU estimated the cost of converting the Nearman coal unit to gas? If yes, produce such cost estimate and any documents reflecting BPU's consideration of converting the coal unit to gas.

See Attached document.

3-4. Refer to BPU's response to Sierra Club data request 1-13.

a. How does BPU contract for the supply of coal? Does another entity contract for the supply of coal on BPU's behalf? What is the longest term of an existing coal contract that supplies coal to Nearman?
b. How does BPU contract for the transport of coal? Does another entity contract for the transport of coal on BPU's behalf? What is the longest term of an existing contract for the transport of coal to Nearman?

WFA contracts with coal producers and railroads to meet its coal supply and delivery commitments for the BPU.

Western Fuels is presently under a two year extension of the original 3 year coal contract between Western Fuels Association and Peabody Coal Sales LLC. The contract expiration date is December 31st 2024.

Coal transportation is provided by a contract between Western Fuels Association and Union Pacific Railroad. They are in the first year of a contractual extension that renews year after year for 3 years, potentially expiring December 31st 2025.

3-5. Describe the model(s), software, and/or other tools BPU uses to estimate forward projections of Nearman's operations and costs (e.g., capacity factors, forced outrage rates, O&M costs, etc.)

The BPU utilizes the Portfolio Optimization e7 Software System from Hitachi Energy USA.

3-6. Please refer to BPU's response to Sierra Club data request 1-7. Please justify and explain the assumption that the Nearman coal unit's capacity factors will increase steadily to 2030.

The current assumption is that N1 will see a small gradual output increase over the next decade. This is likely primarily due to the push toward electrification in the heating and transportation space. Other factors that may also contribute is the aging and retirement of numerous conventional resources in SPP, the growth of distant distributed resources which will likely add to transmission congestion constraints within the area, and the price and demand of natural gas.

/s/ Teresa A. Woody
Teresa A. Woody
Kansas Appleseed Center for Law and Justice, Inc.
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Attorney for Sierra Club

Via: E-Mail

April 26, 2023

M E M O R A N D U M

From: Sierra Club

Teresa A. Woody
Kansas Appleseed
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Re: Discovery for the Board of Public Utilities ("BPU")

Sierra Club respectfully requests that BPU provide responses to these data requests.

4-1 Refer to BPU's 2021 Financial Report on BPU's website, and the statement on page 56: "Coal delivery to Nearman is contracted between WFA and Union Pacific Railroad which is effective until December 31, 2022. The delivery cost is established from a base price and is adjusted by indices set out in the contract."

a. Did the contract terminate on December 31, 2022? If yes, is there a new transport contract for Nearman and, if so, what is the new termination date? If not, under what contract has transport of coal occurred since December 31, 2022?

Western Fuels is presently under a two-year extension of the original 3-year coal contract between Western Fuels Association and Peabody Coal Sales LLC. The contract expiration date is December 31st 2024.

Coal transportation is provided by a contract between Western Fuels Association and Union Pacific Railroad. They are in the first year of a contractual extension that renews year after year for 3 years, potentially expiring December 31st 2025.

4-3 Refer to BPU's response to Sierra Club data request 1-18.

a. Provide BPU's rationale for selecting 2040 as a retirement date for Nearman.
The bonds on Nearman Power will be paid off in 2045. No official retirement date has been announced. The 2040 date is just an estimate.

b. Describe the analysis that was used to determine 2040 as a retirement date, and state when that analysis was completed. No analysis has been completed

c. Provide the analysis, including workpapers with all formula intact. No analysis has been completed

d. If alternate dates were considered, please provide the analysis. If no other dates were considered, explain the rationale for excluding alternative retirement dates in the analysis. No analysis has been completed

4-4 Refer to BPU's response to Sierra Club data requests 1-7, 1-9 and 1-10b. Please confirm that these values are in real dollars and state the base year.

These are nominal dollars and based on 2023 numbers.

/s/ Teresa A. Woody
Teresa A. Woody
Kansas Appleseed Center for Law and Justice, Inc.
211 E. 8th St., Ste. D
Lawrence, KS 66044
(785) 251-8160
twoody@kansasappleseed.org

Attorney for Sierra Club