RACT Evaluation Report –Lake Side Power Plant

UTAH $PM_{2.5}$ SIP RACT

Provo, Utah Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2014

Company: PacifiCorp Energy - Lake Side P
Site ID: 13031
Project: PM10 SIP
Date: 3/17/2015

County FIPS	Category NAICS	NAICS	SIC	Site ID
49	3	333611	4911	13031
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49	3	333611	4911	13031

'ower Plant

Site Name	Comp ID	Process ID	Process Code
PacifiCorp Energy - Lake Side Power Plant	177216	1	a
PacifiCorp Energy - Lake Side Power Plant	177217	1	a
PacifiCorp Energy - Lake Side Power Plant	177218	1	a
PacifiCorp Energy - Lake Side Power Plant	177219	1	a
PacifiCorp Energy - Lake Side Power Plant	177220	1	a
PacifiCorp Energy - Lake Side Power Plant	177221	1	a
PacifiCorp Energy - Lake Side Power Plant	177222	1	a

Site Name	Comp ID	Process ID	Process Code
PacifiCorp Energy - Lake Side Power Plant	177216	1	a
PacifiCorp Energy - Lake Side Power Plant	177217	1	a
PacifiCorp Energy - Lake Side Power Plant	177571	1	a
PacifiCorp Energy - Lake Side Power Plant	177572	1	a
PacifiCorp Energy - Lake Side Power Plant	177218	1	a
PacifiCorp Energy - Lake Side Power Plant	177573	1	a
PacifiCorp Energy - Lake Side Power Plant	177219	1	a
PacifiCorp Energy - Lake Side Power Plant	177220	1	a
PacifiCorp Energy - Lake Side Power Plant	177574	1	a
PacifiCorp Energy - Lake Side Power Plant	177221	1	a
PacifiCorp Energy - Lake Side Power Plant	177222	1	a

Site Name	Comp ID	Process ID	Process Code
PacifiCorp Energy - Lake Side Power Plant	177216	1	a
PacifiCorp Energy - Lake Side Power Plant	177217	1	a
PacifiCorp Energy - Lake Side Power Plant	177218	1	a
PacifiCorp Energy - Lake Side Power Plant	177219	1	a
PacifiCorp Energy - Lake Side Power Plant	177220	1	a
PacifiCorp Energy - Lake Side Power Plant	177221	1	a
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PacifiCorp Energy - Lake Side Power Plant	177219	1	a
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PacifiCorp Energy - Lake Side Power Plant	177220	1	a
PacifiCorp Energy - Lake Side Power Plant	177221	1	a
PacifiCorp Energy - Lake Side Power Plant	177222	1	a

Component Description	Material or Fuel	Component SCC	ID	Height
Combined Cycle 11	Natural Gas	20100201	178523	150
Combined Cycle 12	Natural Gas	20100201	178524	150
Auxiliary Boiler	Natural Gas	10100604	178525	45
Fuel Gas Heater	Natural Gas	10100604	178526	20
Cooling Tower	Water	30600701	965753	10
Emergency Generator	Distillate Oil (Diesel)	20200401	178527	12
Emergency Fire Pump	Distillate Oil (Diesel)	20200401	178528	12

Component Description	Material or Fuel	Component SCC	ID	Height
Combined Cycle 11	Natural Gas	20100201	178523	150
Combined Cycle 12	Natural Gas	20100201	178524	150
CT/HRSG #3	Natural Gas	20100201	178831	149.934
CT/HRSG#4	Natural Gas	20100201	178832	149.934
Auxiliary Boiler	Natural Gas	10100604	178525	45
Aux. Boiler #2	Natural Gas	10100604	178833	60.039
Fuel Gas Heater	Natural Gas	10100604	178526	20
Cooling Tower	Water	30600701	965753	10
Cooling Tower #2	Water	30600701	965774	10
Emergency Generator	Distillate Oil (Diesel)	20200401	178527	12
Emergency Fire Pump	Distillate Oil (Diesel)	20200401	178528	12

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			ID	Height
Combined Cycle 11	Natural Gas	20100201	178523	150
Combined Cycle 12	Natural Gas	20100201	178524	150
Auxiliary Boiler	Natural Gas	10100604	178525	45
Fuel Gas Heater	Natural Gas	10100604	178526	20
Cooling Tower	Water	30600701	965753	10
Emergency Generator	Distillate Oil (Diesel)	20200401	178527	12
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Stack					Location			
Diameter	Temp	Flow	Area	Velocity	Lat	Long	Hrs/Day	Days/Wk
18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

Stack					Location			
Diameter	Temp	Flow	Area	Velocity	Lat	Long	Hrs/Day	Days/Wk
18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
18.996	178	12757.11	283.4094	45.013	40.32858	-111.7534	24	7
18.996	178	12757.11	283.4094	45.013	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
3.609	440.69	422.8863	10.22972	41.339	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.003	72	0	7.07E-06	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

Stack					Location			
Diameter	Temp	Flow	Area	Velocity	Lat	Long	Hrs/Day	Days/Wk
18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

Stack					Location			
Diameter	Temp	Flow	Area	Velocity	Lat	Long	Hrs/Day	Days/Wk
18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

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18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

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18	179	12272	254.469	48.23	40.32858	-111.7534	24	7
18	178	11832	254.469	46.5	40.32858	-111.7534	24	7
2.5	72	12	4.908739	2.44	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0	72	0	0	0	40.32858	-111.7534	24	7
0.75	72	12	0.441786	27.16	40.32858	-111.7534	24	7
0.75	72	5	0.441786	11.32	40.32858	-111.7534	24	7

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	4798	13.04	10.17	1.21	6.57	7.74	0	8.72
52	4880	9.84	10.81	5.93	5.6	8.71	0	8.6
0	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	0	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	5617	13.04	10.17	1.21	6.57	7.74	0	8.72
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	1650	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	1650	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	1650	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

Temporal Operating Information								
Wks/Yr	Hrs/Yr	% Jan	% Feb	% Mar	% Apr	% May	% Jun	% Jul

52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	1650	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

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Wks/Yr	**Hrs/Yr**	**% Jan**	**% Feb**	**% Mar**	**% Apr**	**% May**	**% Jun**	**% Jul**
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	1650	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	8760	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33
52	25	8.33	8.33	8.33	8.33	8.33	8.33	8.33

PM10	PM2.5	SO2
31.693	26.583	4.178

% Aug	% Sep	% Oct	% Nov	% Dec	Permit Status	PM10	PM2.5	SO2
10.73	10.24	9.42	9.99	12.19	Yes	18.446	18.446	2.012
10.57	10.42	10	5.5	14.04	Yes	8.016	8.016	2.070
8.33	8.33	8.33	8.33	8.33	Yes	0.072	0.072	0.006
8.33	8.33	8.33	8.33	8.33	Yes	0.000	0.000	0.000
10.73	10.24	9.42	9.99	12.19	Yes	5.110	0.000	
8.33	8.33	8.33	8.33	8.33	Yes	0.047	0.047	0.075
8.33	8.33	8.33	8.33	8.33	Yes	0.003	0.003	0.015

PM10	PM2.5	SO2
215.383	202.483	55.641

Condensables included

Does the 2019 True-Up In

% Aug	% Sep	% Oct	% Nov	% Dec	Permit Status	PM10	PM2.5	SO2
8.33	8.33	8.33	8.33	8.33	Yes	45.30	45.30	13.50
8.33	8.33	8.33	8.33	8.33	Yes	45.30	45.30	13.50
8.33	8.33	8.33	8.33	8.33	Yes	55.85	55.85	14.27
8.33	8.33	8.33	8.33	8.33	Yes	55.85	55.85	14.27
8.33	8.33	8.33	8.33	8.33	Yes	0.04	0.04	0.00
8.33	8.33	8.33	8.33	8.33	Yes	0.10	0.10	0.01
8.33	8.33	8.33	8.33	8.33	Yes	0.03	0.03	0.00
8.33	8.33	8.33	8.33	8.33	Yes	6.40	0.00	0.00
8.33	8.33	8.33	8.33	8.33	Yes	6.50	0.00	0.00
8.33	8.33	8.33	8.33	8.33	Yes	0.02	0.02	0.08
8.33	8.33	8.33	8.33	8.33	Yes	0.00	0.00	0.01

PM10	PM2.5	SO2
104.517	97.627	29.165

					Permit			
% Aug	% Sep	% Oct	% Nov	% Dec	Status	PM10	PM2.5	SO2
8.33	8.33	8.33	8.33	8.33	Yes	48.76854	48.76854	14.53367
8.33	8.33	8.33	8.33	8.33	Yes	48.76854	48.76854	14.53367
8.33	8.33	8.33	8.33	8.33	Yes	0.04091	0.04091	0.00323
8.33	8.33	8.33	8.33	8.33	Yes	0.030144	0.030144	0.002153
8.33	8.33	8.33	8.33	8.33	Yes	6.890037	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.016215	0.016215	0.080743
8.33	8.33	8.33	8.33	8.33	Yes	0.002272	0.002272	0.011842

PM10	PM2.5	SO2
116.925	109.217	32.628

					Permit			
% Aug	% Sep	% Oct	% Nov	% Dec	Status	PM10	PM2.5	SO2
8.33	8.33	8.33	8.33	8.33	Yes	54.55837	54.55837	16.25912
8.33	8.33	8.33	8.33	8.33	Yes	54.55837	54.55837	16.25912
8.33	8.33	8.33	8.33	8.33	Yes	0.045766	0.045766	0.003613
8.33	8.33	8.33	8.33	8.33	Yes	0.033723	0.033723	0.002409
8.33	8.33	8.33	8.33	8.33	Yes	7.708026	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.01814	0.01814	0.090328
8.33	8.33	8.33	8.33	8.33	Yes	0.002542	0.002542	0.013248

PM10	PM2.5	SO2
127.374	118.977	35.544

					Permit			
% Aug	% Sep	% Oct	% Nov	% Dec	Status	PM10	PM2.5	SO2

8.33	8.33	8.33	8.33	8.33	Yes	59.43418	59.43418	17.71217
8.33	8.33	8.33	8.33	8.33	Yes	59.43418	59.43418	17.71217
8.33	8.33	8.33	8.33	8.33	Yes	0.049856	0.049856	0.003936
8.33	8.33	8.33	8.33	8.33	Yes	0.036736	0.036736	0.002624
8.33	8.33	8.33	8.33	8.33	Yes	8.396882	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.019761	0.019761	0.098401
8.33	8.33	8.33	8.33	8.33	Yes	0.002769	0.002769	0.014432

PM10	**PM2.5**	**SO2**
132.982	124.216	37.109

					Permit			
% Aug	**% Sep**	**% Oct**	**% Nov**	**% Dec**	**Status**	**PM10**	**PM2.5**	**SO2**
8.33	8.33	8.33	8.33	8.33	Yes	62.05093	62.05093	18.492
8.33	8.33	8.33	8.33	8.33	Yes	62.05093	62.05093	18.492
8.33	8.33	8.33	8.33	8.33	Yes	0.052052	0.052052	0.004109
8.33	8.33	8.33	8.33	8.33	Yes	0.038354	0.038354	0.00274
8.33	8.33	8.33	8.33	8.33	Yes	8.766578	0	0
8.33	8.33	8.33	8.33	8.33	Yes	0.020631	0.020631	0.102733
8.33	8.33	8.33	8.33	8.33	Yes	0.002891	0.002891	0.015068

2011 Actual Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
86.468	14.353	69.154	60.579	0.072	0.000	0.000

2011 Actual Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
43.588	7.041	33.830	29.844	0.035			0.000
41.396	7.244	34.405	30.705	0.036			0.000
0.948	0.052	0.796	0.030	0.000			0.000
0.000	0.000	0.000	0.000	0.000			0.000
	0.000						5.110
0.447	0.013	0.102	0.000	0.000			0.000
0.089	0.003	0.020	0.000	0.000			0.000

2019 True-Up Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
280.899	169.704	1139.604	150.128	0.400	0.000	0.000

clude Growth?	No

This is a PTE validation true-up - no growth should b

2019 True-Up Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
68.31	35.97	274.50	35.00	0.10	0.00	0.00	0.000
68.31	35.97	274.50	35.00	0.10	0.00	0.00	0.000
71.08	48.80	294.50	40.00	0.10	0.00	0.00	
71.08	48.80	294.50	40.00	0.10	0.00	0.00	
0.51	0.03	0.43	0.02	0.00	0.00	0.00	0.000
0.75	0.10	0.75	0.10	0.00	0.00	0.00	
0.37	0.02	0.31	0.01	0.00	0.00	0.00	0.000
0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.400
0.00	0.00	0.00	0.00	0.00	0.00	0.00	
0.45	0.01	0.10	0.00	0.00	0.00	0.00	0.000
0.06	0.00	0.01	0.00	0.00	0.00	0.00	0.000

2019 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
148.565	77.517	591.955	75.390	0.215	0.000	0.000

2019 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
73.535	38.72416	295.518	37.67989	0.107657	0	0	0.000
73.535	38.72416	295.518	37.67989	0.107657	0	0	0.000
0.544744	0.030144	0.457542	0.017225	1.08E-05	0	0	0.000
0.40156	0.022608	0.336966	0.012919	1.08E-05	0	0	0.000
0	0	0	0	0	0	0	6.890
0.481226	0.013995	0.10981	0	0.000113	0	0	0.000
0.067824	0.002153	0.015072	0	1.61E-05	0	0	0.000

2024 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
166.203	86.720	662.233	84.340	0.241	0.000	0.000

2024 Projected Emissions							
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl	
82.26511	43.32152	330.6021	42.15327	0.120438	0	0	0.000
82.26511	43.32152	330.6021	42.15327	0.120438	0	0	0.000
0.609416	0.033723	0.511861	0.01927	1.2E-05	0	0	0.000
0.449233	0.025292	0.376971	0.014453	1.2E-05	0	0	0.000
0	0	0	0	0	0	0	7.708
0.538357	0.015657	0.122847	0	0.000126	0	0	0.000
0.075876	0.002409	0.016861	0	1.81E-05	0	0	0.000

2028 Projected Emissions (tons/yr)						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl
181.056	94.470	721.415	91.878	0.263	0.000	0.000

2028 Projected Emissions						
NOx	VOC	CO	NH3	Benzene	Chlorine	HCl

89.61703	47.1931	360.1475	45.92045	0.131201	0	0	0.000
89.61703	47.1931	360.1475	45.92045	0.131201	0	0	0.000
0.663878	0.036736	0.557605	0.020992	1.31E-05	0	0	0.000
0.489381	0.027552	0.41066	0.015744	1.31E-05	0	0	0.000
0	0	0	0	0	0	0	8.397
0.58647	0.017056	0.133825	0	0.000138	0	0	0.000
0.082657	0.002624	0.018368	0	1.97E-05	0	0	0.000

2030 Projected Emissions (tons/yr)						
NOx	**VOC**	**CO**	**NH3**	**Benzene**	**Chlorine**	**HCl**
189.028	98.629	753.178	95.923	0.274	0.000	0.000

2030 Projected Emissions							
NOx	**VOC**	**CO**	**NH3**	**Benzene**	**Chlorine**	**HCl**	
93.56267	49.27091	376.004	47.94222	0.136978	0	0	0.000
93.56267	49.27091	376.004	47.94222	0.136978	0	0	0.000
0.693108	0.038354	0.582156	0.021916	1.37E-05	0	0	0.000
0.510927	0.028765	0.42874	0.016437	1.37E-05	0	0	0.000
0	0	0	0	0	0	0	8.767
0.612291	0.017807	0.139717	0	0.000144	0	0	0.000
0.086296	0.00274	0.019177	0	2.05E-05	0	0	0.000

e included for any projection years.

This table has had four (4) rows added to it. These rows have been highlighted in yellow.

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Amanda Smith
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-AN130310012-15

March 13, 2015

Bill Lawson
PacifiCorp Energy
1407 W. North Temple, Suite 310
Salt Lake City, UT 84116

Dear Mr. Lawson:

Re: Approval Order: Update to Correct Description of Listed Equipment
Project Number: N13031-0012

The attached document is the Approval Order for the above-referenced project. Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is John Jenks, who may be reached at (801) 536-4459.

Sincerely,

Bryce C. Bird
Director

BCB:JJ:jc

cc: Mike Owens
Utah County Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: Update to Correct Description of Listed Equipment

Prepared By: John Jenks, Engineer
Phone: (801) 536-4459
Email: jjenks@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN130310012-15

Date: March 13, 2015

PacifiCorp Energy
Lake Side Power Plant

Source Contact:
Bill Lawson
Phone: (801) 220-4581
Email: bill.lawson@pacificorp.com

Bryce C. Bird
Director

Abstract

PacifiCorp Energy (PacifiCorp) submitted a request dated September 4, 2014, to revise its AO for the Lake Side Power Plant (DAQE-AN0130310010-11) to more accurately describe the nameplate ratings for three listed pieces of equipment, specifically: Auxiliary Boiler #1, Auxiliary Boiler #2, and the Fuel Dew Point Heater. These items are not being modified in any way; however, the descriptions listed in the most recent AO do not precisely match the actual nameplate rating of the equipment as installed. In order to avoid confusion, PacifiCorp has requested that these listings be updated to match the actual nameplate ratings.

No other changes in equipment, emissions, or conditions shall occur as a result of this project.

This air quality AO authorizes the project with the following conditions and failure to comply with any of the conditions may constitute a violation of this order. This AO is issued to, and applies to the following:

Name of Permittee:	**Permitted Location:**
PacifiCorp Energy 1407 W. North Temple, Suite 310 Salt Lake City, UT 84116	Lake Side Power Plant 1825 N Pioneer Lane Vineyard, UT 84058

UTM coordinates: 436,000 m Easting, 4,464,500 m Northing, UTM Zone 12
SIC code: 4911 (Electric Services)

Section I: GENERAL PROVISIONS

I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]

I.2 The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401. [R307-401]

I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]

I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the five-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five (5) years. [R307-415-6b]

I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6 The owner/operator shall comply with UAC R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

II.A.1 **Lake Side Power Plant**
Permitted Source

II.A.2 **CT #1 and #2**
Two (2) natural gas-fired dry low-NO_x, combined cycle turbines, each with 150 foot stack (as measured from the base of the stack)

II.A.3 **HRSG #1 and #2**
Two (2) Heat Recovery Steam Generators, each equipped with low NO_x duct burner - 184 MMBtu/hr

II.A.4 **Block #1 SCR**
Two (2) Selective Catalytic Reduction (SCR) systems with ammonia injection, one for each turbine/HRSG set

II.A.5 **Block #1 CO Catalysts**
Two (2) CO catalysts, one for each turbine/HRSG set

II.A.6 **Block #1 Steam Turbine**
One (1) steam turbine

II.A.7 **Auxiliary Boiler #1**
One (1) natural gas-fired 62.765 MMBtu/hr (nameplate rating) auxiliary boiler with 50 ft. boiler stack (as measured from the base of the stack)

II.A.8 **Cooling Tower #1**
One (1) 10 Cell mechanical draft evaporative cooling tower with drift elimination

II.A.9 **CT #3 and #4**
Two (2) natural gas-fired dry low-NO_x, combined cycle turbines, each with 150 foot stack (as measured from the base of the stack)

II.A.10 **HRSG #3 and #4**
Two (2) Heat Recovery Steam Generators, each equipped with low NO_x duct burner approximately 400 MMBtu/hr

II.A.11 **Block #2 SCR**
Two (2) Selective Catalytic Reduction (SCR) systems with ammonia injection, one for each turbine/HRSG set

II.A.12 **Block #2 CO Catalysts**
Two (2) CO catalysts, one for each turbine/HRSG set

II.A.13 **Block #2 Steam Turbine**
One (1) steam turbine

II.A.14 **Auxiliary Boiler #2**
One (1) natural gas-fired 57.6 MMBtu/hr (nameplate rating) auxiliary boiler with 60 ft. boiler stack (as measured from the base of the stack)

II.A.15 **Cooling Tower #2**
One (1) 16 Cell mechanical draft evaporative cooling tower with drift elimination

II.A.16 **Fuel Dew Point Heater**
One (1) 4.76 MMBtu/hr (nameplate rating) fuel dew point heater

II.A.17 **Emergency Generator**
Two (2) approximately 1,500 hp diesel-fired emergency generators

II.A.18 **Fire Pump**
One (1) 290 hp diesel-fired fire pump

II.A.19 **Water Treatment**
Water treatment and storage facilities

II.A.20 **Ammonia Storage and Handling**
Aqueous ammonia storage and handling equipment

II.A.21 **Miscellaneous Equipment**
CT lube oil vent system, maintenance shop vent system, machining and welding operations, etc.

II.A.22 **Lake Side Block #1**
Lake Side Block #1 consists of CT #1 and #2, associated HRSGs, control equipment, auxiliary boiler and cooling tower: includes Block #1 CO Catalysts, Auxiliary Boiler #1, CT #1 and #2, Block #1 Steam Turbine, HRSG #1 and #2, Block #1 SCR, Cooling Tower #1

II.A.23 **Lake Side Block #2**
Lake Side Block #2 consists of CT #3 and #4, associated HRSGs, control equipment, auxiliary boiler and cooling tower: includes HRSG #3 and #4, Block #2 CO Catalysts, CT #3 and #4, Block #2 Steam Turbine, Cooling Tower #2, Block #2 SCR, Auxiliary Boiler #2

II.A.24 **Additional Equipment**
Fuel treatment, fire suppression, water treatment, ammonia storage and other misc. equipment: includes Emergency Generator, Fire Pump, Ammonia Storage and Handling, Miscellaneous Equipment, Water Treatment, Fuel Dew Point Heater

II.B Requirements and Limitations

II.B.1 **<u>Conditions on Permitted Source</u>**

II.B.1.a The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system on each of the HRSG stacks. The owner/operator shall record the NO_x and CO emissions. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B. The NO_x monitor shall comply with 40 CFR 75, Appendix A and B.

All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed prior to placing the affected source in operation. These devices shall be certified within 90 days of achieving full load, not to exceed 180 days after startup.

Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. [R307-170]

II.B.1.b Visible emissions shall not exceed the following values:

All natural gas combustion exhaust stacks - 10% opacity
All other emission points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. [R307-401-8]

II.B.2 **Conditions on Lake Side Block #1**

II.B.2.a The owner/operator shall use natural gas as fuel in the combustion turbines, duct burners and auxiliary boiler. [R307-401-8]

II.B.2.b Emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: Auxiliary Boiler #1

Pollutant	Limitations	Averaging Period
PM_{10}	0.01 lb/MMBtu	3-hour
NO_x	0.017 lb/MMBtu	3-hour
CO	0.037 lb/MMBtu	3-hour

Source: Each Turbine/HRSG Stack (at Block #1)

Pollutant	Limitations	Averaging Period
PM_{10}	10.8 lb/hour (0.01 lb/MMBtu)	30-day rolling average
NO_x	2.0 ppmvd at 15% O_2 (14.9 lb/hr)*	3-hour
CO	3.0 ppmvd at 15% O_2 (14.1 lb/hr)*	3-hour

* Under steady state operation.

[R307-401-8]

II.B.2.c Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

Emissions Point	Pollutant	Status	Frequency
HRSG Stacks	$PM_{10}/PM_{2.5}$	*	$
	NO_x	*	#
	CO	*	#
Auxiliary Boilers	PM_{10}	*	%
	NO_x	*	%
	CO	*	%

Testing Status (To be applied to the sources listed above)

* Initial compliance testing has been completed. If an existing source is modified, a compliance test is required on the modified emission point that has an emission rate limit.

$ Test every year or testing may be replaced with parametric monitoring if approved by the Director

% Test every five (5) years or testing may be replaced with parametric monitoring if approved by the Director

Compliance shall be demonstrated through use of a Continuous Emissions Monitoring System (CEM) as outlined in Condition II.B.1.c. The Director may require testing at any time.

[R307-165]

II.B.2.d For all emissions testing the following shall apply:

Notification:

The Director shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Director.

The source test protocol shall be approved by the Director prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Director.

Sample Location:

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by EPA and acceptable to the Director. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

Volumetric Flow Rate:

40 CFR 60, Appendix A, Method 2 or EPA Test Method No. 19 "SO_2 Removal & PM, SO_2, NO_x Rates from Electric Utility Steam Generators" or other testing methods approved by EPA and acceptable to the Director.

PM_{10}:

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a and 202, or other testing methods approved by EPA and acceptable to the Director. All particulate captured shall be considered PM_{10}. The back half condensables shall be used for compliance demonstration as well as for inventory purposes.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by EPA and acceptable to the Director. The back half condensables shall also be tested using the method specified by the Director. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

$PM_{2.5}$:

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a and 202, or other testing methods approved by EPA and acceptable to the Director. All particulate captured shall be considered $PM_{2.5}$.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be

explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by EPA and acceptable to the Director. The back half condensables shall also be tested using the method specified by the Director. The portion of the front half of the catch considered $PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

NO_x:

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by EPA and acceptable to the Director.

CO:

40 CFR 60, Appendix A, Method 10, or other testing methods approved by EPA and acceptable to the Director.

Calculations:

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director, to give the results in the specified units of the emission limitation. [R307-165]

II.B.2.e Compliance with the 3-hour NO_x and CO emission limitations specified in Condition II.B.2.b shall not be required during short-term excursions, limited to a cumulative total of 160 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the Owner/Operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NO_x and CO concentrations exceed 2.0 ppmv and 3.0 ppmv, dry @ 15% O_2, respectively. Transient load conditions include the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling
2. Rapid combustion turbine load changes
3. Initiation/shutdown of HRSG duct burners
4. Provision of Ancillary Services and Automatic Generation Control

During periods of transient load conditions, the NO_x concentration shall not exceed 25 ppmv and the CO concentration shall not exceed 50 ppmv, dry @ 15% O_2. All NO_x and CO emissions during these events shall be included in all calculations of annual mass emissions as required by this permit. [R307-401-8]

II.B.2.f Steady state operation means all periods of combustion turbine operation, except for periods of startup and shutdown as defined below, and periods of transient load conditions as defined in Condition II.B.2.e. Startup is defined as the period beginning with turbine initial firing until the unit meets the ppmvd emission limits in the first table of Condition II.B.2.b for steady state operation. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine. Startup and shutdown events shall not exceed 613.5 hours per turbine per rolling 12-month period and are counted toward the applicable annual emission limitations. Total startup and shutdown events shall not exceed 14-hours per turbine in any one calendar day, commencing at midnight. Emissions during startup and shutdown periods shall be counted toward the applicable annual emission limitations. [R307-401-8]

II.B.3 **Conditions on Lake Side Block #2**

II.B.3.a The owner/operator shall use natural gas as fuel in the combustion turbines, duct burners and auxiliary boiler. [R307-401-8]

II.B.3.b Emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: Auxiliary Boiler #2

Pollutant	Limitations	Averaging Period
$PM_{10}/PM_{2.5}$	0.01 lb/MMBtu	3-hour
NO_x	0.017 lb/MMBtu	3-hour
CO	0.037 lb/MMBtu	3-hour
VOC	0.006 lb/MMBtu	3-hour

Source: Each Turbine/HRSG Stack (at Block #2)

Pollutant	Limitations	Averaging Period
$PM_{10}/PM_{2.5}$	14 lb/hour (with duct firing)	30-day rolling average
NO_x	2.0 ppmvd at 15% O_2 (18.1 lb/hr)*	3-hour
CO	3.0 ppmvd at 15% O_2 (16.6 lb/hr)*	3-hour
VOC	2.8 ppmvd at 15% O_2*	3-hour

* Under steady state operation.

[R307-401-8]

II.B.3.c Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

Emissions Point	Pollutant	Status	Frequency
HRSG Stacks	$PM_{10}/PM_{2.5}$	*	$
	NO_x	*	#
	CO	*	#
	VOC	*	&
Auxiliary Boilers	$PM_{10}/PM_{2.5}$	*	%
	NO_x	*	%
	CO	*	%
	VOC	*	%

Testing Status (To be applied to the sources listed above)

* Initial compliance testing is required. The initial test date shall be performed as soon as possible and in no case later than 180 days after the start up of a new emission source, an existing source without an AO, or the granting of an AO to an existing emission source that has not had an initial compliance test performed. If an existing source is modified, a compliance test is required on the modified emission point that has an emission rate limit.

$ Test every year or testing may be replaced with parametric monitoring if approved by the Director

& Test every two (2) years or testing may be replaced with parametric monitoring if approved by the Director

% Test every five (5) years or testing may be replaced with parametric monitoring if approved by the Director

Compliance shall be demonstrated through use of a Continuous Emissions Monitoring System (CEM) as outlined in Condition II.B.1.c. The Director may require testing at any time.

[R307-165]

II.B.3.d For all emissions testing the following shall apply:

Notification:

The Director shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Director.

The source test protocol shall be approved by the Director prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Director.

Sample Location:

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by EPA and acceptable to the Director. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

Volumetric Flow Rate:

40 CFR 60, Appendix A, Method 2 or EPA Test Method No. 19 "SO_2 Removal & PM, SO_2, NO_x Rates from Electric Utility Steam Generators" or other testing methods approved by EPA and acceptable to the Director.

$PM_{10}/PM_{2.5}$:

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a and 202, or other testing methods approved by EPA and acceptable to the Director. All particulate captured shall be considered $PM_{10}/PM_{2.5}$. The back half condensables shall be used for compliance demonstration as well as for inventory purposes.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by EPA and acceptable to the Director. The back half condensables shall also be tested using the method specified by the Director. The portion of the front half of the catch considered $PM_{10}/PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

NO_x:

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by EPA and acceptable to the Director.

CO:

40 CFR 60, Appendix A, Method 10, or other testing methods approved by EPA and acceptable to the Director.

Calculations:

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director, to give the results in the specified units of the emission limitation. [R307-165]

II.B.3.e Compliance with the 3-hour NO_x and CO emission limitations specified in Condition II.B.3.b shall not be required during short-term excursions, limited to a cumulative total of 160 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the Owner/Operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NO_x and CO concentrations exceed 2.0 ppmv and 3.0 ppmv, dry @ 15% O_2, respectively. Transient load conditions include the following:

1. Initiation/shutdown of combustion turbine inlet air-cooling
2. Rapid combustion turbine load changes
3. Initiation/shutdown of HRSG duct burners
4. Provision of Ancillary Services and Automatic Generation Control

During periods of transient load conditions, the NO_x concentration shall not exceed 25 ppmv and the CO concentration shall not exceed 50 ppmv, dry @ 15% O_2. All NO_x and CO emissions during these events shall be included in all calculations of annual mass emissions as required by this permit. [R307-401-8]

II.B.3.f Steady state operation means all periods of combustion turbine operation, except for periods of startup and shutdown as defined below, and periods of transient load conditions as defined in Condition II.B.3.e. Startup is defined as the period beginning with turbine initial firing until the unit meets the ppmvd emission limits in the first table of Condition II.B.3.b for steady state operation. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine. Startup and shutdown events shall not exceed 553.6 hours per turbine per rolling 12-month period. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day, commencing at midnight.

Emissions of NO_x from either Block #2 CT/HRSG unit (CT #3 or #4) shall not exceed 130 lb/hr during startup or shutdown operations.

Emissions of CO from either Block #2 CT/HRSG unit (CT #3 or #4) shall not exceed 3,000 lb/hr during startup or shutdown operations. [R307-401-8]

II.B.3.g Total CO_2e emissions from Lake Side Block 2 shall not exceed 950 lb/MWh(g) on a 12-month rolling average basis. Hourly heat input for each turbine and the HSRG will be obtained from the data submitted to the Acid Rain database and summed over the appropriate 12-month period. This total heat input will then be multiplied by an emission factor of 121.723 lb CO_2e/MMBtu to obtain the total CO_2e emissions during the 12-month period. The 12-month gross generation for each turbine and HSRG will be obtained from the data reported to the Acid Rain database. This hourly generation will be summed over the twelve-month period to obtain the total gross generation. The CO_2e per MWH(g) value is calculated by dividing the 12-month total CO_2e emissions by the 12-month total gross generation. [R307-401-8]

II.B.4 **Conditions on Additional Equipment**

II.B.4.a Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, and for regular maintenance and testing. Records documenting generator usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage. [R307-401-8]

II.B.4.b The owner/operator shall use a combination of #1 or #2 fuel oil or diesel fuel in the emergency generators and fire pump.

The sulfur content of any #2 fuel oil or diesel fuel burned shall not exceed 0.0015 percent by weight. Sulfur content shall be determined by ASTM Method D-4294-89, or approved equivalent. Certification of fuels shall be either by the owner/operator's own testing or test reports from the fuel marketer or supplier. For purposes of demonstrating compliance with this limitation, the owner/operator may obtain the above specifications by testing each purchase of fuel in accordance with the required methods; by inspection of the specifications provided by the vendor for each purchase of fuel; or by inspection of summary documentation of the fuel sulfur content from the vendor; provided that the above specifications are available from the vendor for each purchase if requested. [R307-401-8]

Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

NSPS (Part 60), A: General Provisions
NSPS (Part 60), Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), GG: Standards of Performance for Stationary Gas Turbines
NSPS (Part 60), IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
NSPS (Part 60), KKKK: Standards of Performance for Stationary Combustion Turbines
MACT (Part 63), YYYY: National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Title IV (Part 72 / Acid Rain)
Title V (Part 70) major source

PERMIT HISTORY

This AO is based on the following documents:

Is Derived From	Source Submitted NOI dated September 4, 2014
Supersedes	AO DAQE-AN0130310010-11 dated May 4, 2011

ADMINISTRATIVE CODING

The following information is for UDAQ internal classification use only:

Utah County
CDS A
NSR, Nonattainment or Maintenance Area, Title V (Part 70) major source, Title IV (Part 72 / Acid Rain), Title V (Part 70), Major HAP source, NSPS (Part 60), MACT (Part 63), PSD,
API#: (No size assigned)

ACRONYMS

The following lists commonly used acronyms and associated translations as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CMS	Continuous monitoring system
CO	Carbon monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
FDCP	Fugitive dust control plan
GHG	Greenhouse Gas(es) - 40 CFR 52.21 (b)(49)(i)
GWP	Global Warming Potential - 40 CFR Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/HR	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds

RACT EVALUATION REPORT
Lake Side Power Plant

1.0 INTRODUCTION AND FACILITY DESCRIPTION

1.1 Facility Identification

Name: Lake Side Power Plant
Address: 1825 N Pioneer Lane, Vineyard, Utah, Utah County
Owner/Operator: PacifiCorp Energy
UTM coordinates: 4,464,500 m Northing, 436,000 m Easting, Zone 12

1.2 Facility Process Summary

The Lake Side Power Plant is a natural gas-fired electric generating plant consisting of four combined-cycle turbines, four heat recovery steam generators with duct burners, two auxiliary boilers, two cooling towers, one dew point heater, two diesel-fired emergency generators, and one diesel-fired fire pump. The plant is located in Utah County, which is part of the Provo, Utah $PM_{2.5}$ nonattainment area.

The plant is a Phase II acid rain source and a major source for PM_{10}/$PM_{2.5}$, NOx, CO, VOC, HAP and GHG emissions. The source (Block #1) was originally permitted as a PSD source and a PM10 non-attainment area major source. When Block #2 was added in 2011, this modification was permitted as a PSD major modification, as well as a PM10 nonattainment area major modification. Therefore, analysis of LAER was required on both occasions for the facility's PM_{10} and NOx emissions; analysis of BACT was required for all other emissions.

At the time of installation for both Block #1 and Block #2, BACT/LAER for the turbines was dry low-NOx burners, SCR and oxidation catalysts. The auxiliary boilers were fitted with dry low-NOx burners. The diesel equipment is required to operate on ultra-low sulfur diesel. The cooling towers have high-efficiency drift elimination.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #1
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #2
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #3
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #4
One heat recovery steam generator, low-NOx duct burner, 184 MMBtu/hr – HRSG #1
One heat recovery steam generator, low-NOx duct burner, 184 MMBtu/hr – HRSG #2
One heat recovery steam generator, low-NOx duct burner, 400 MMBtu/hr – HRSG #3
One heat recovery steam generator, low-NOx duct burner, 400 MMBtu/hr – HRSG #4

Two (2) selective catalytic reduction systems with ammonia injection – Block #1 SCR
Two (2) selective catalytic reduction systems with ammonia injection – Block #2 SCR
Two (2) CO oxidation catalysts – Block #1 OxyCat
Two (2) CO oxidation catalysts – Block #2 OxyCat
One (1) natural gas-fired 61.2 MMBtu/hr auxiliary boiler – Aux Boiler #1
One (1) natural gas-fired 61.2 MMBtu/hr auxiliary boiler – Aux Boiler #2
Two (2) 1,500 hp diesel generators – Em Gen #1, #2
One (1) 3.67 MMBtu/hr diesel-fired fuel dew point heater – Heater #1
One (1) 290 hp diesel-fired fire pump – Pump #1
Cooling Towers #1, #2

1.4 RACT Cut-off Threshold

A RACT cut-off threshold was established generally for all facilities based on Utah DAQ's existing small source exemption rule R307-401-9. This rule exempts sources of pollution with emissions less than 5 tpy from permitting requirements. Therefore, sources with baseline actual emissions which fall below this threshold could be exempted from evaluation under this general establishment.

At the PacifiCorp Lake Side facility, this cutoff threshold applies to both auxiliary boilers, both emergency generators, the fuel dew point heater, the fire pump, and the cooling towers. Therefore, these emission units will not be evaluated for RACT. Nearly 100% of the emissions from the Lake Side facility are associated with the combustion turbines and associated HRSG units.

2.0 RACT Evaluation

2.1 Combustion Turbines

The four combustion turbines (CTs) are each operated as combined-cycle units fired exclusively on pipeline quality natural gas. Although the HRSGs at Block #2 are designed with significantly more duct firing, the general function of both power blocks is identical. The CT provides primary power generation by spinning a generator directly. The excess heat is captured by the HRSG and the steam spins a steam turbine/generator for additional power generation. Supplemental heat can be supplied by duct firing in the HRSG.

Although identified as separate units, each CT and associated HRSG vent through a single stack and emissions from both units are controlled simultaneously with the same equipment. Since all four CT/HRSG combinations operate identically, UDAQ has chosen to treat these as a single group for purposes of RACT analysis.

The 2008 true-up emissions from all four CT/HRSGs were as follows:

$PM_{2.5}$ = 165.9 tons
SO_2 = 31.5 tons
NOx = 213.5 tons
VOC = 107.0 tons

These values were taken from the 2008 true-up emission spreadsheet, rather than the 2008 baseline emissions. Although this varies from the standard process used for most other sources, this is because the Lake Side facility only existed as Block #1 in 2008. The second two CT/HRSG units were not permitted until 2011 and so no recording of actual emissions could have been possible. To reconcile this discrepancy, UDAQ used a standard procedure of assuming 90% of PTE for all previously unpermitted equipment when such equipment was included in the true-up spreadsheet.

$PM_{2.5}$

Available Control Technology

No additional add-on control technology has been identified by DAQ that can further reduce direct particulate emissions from natural gas combustion in a turbine generator or HRSG. All particulate generated from natural gas combustion is considered to be PM 1. Typical add-on control devices – such as fabric filtration, electrostatic precipitation, or cyclonic separation – have extremely limited effectiveness in such an environment.

Since no additional available controls have been identified for the control of particulate emissions, the only remaining control is the default "no control" option of exclusive firing on pipeline quality natural gas.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT controls

No additional control required. Combustion of pipeline quality natural gas as fuel for control of particulate emissions is recommended as RACT.

SO_2

Available Control Technology

Similarly, no additional add-on control technology has been identified by DAQ that can further reduce emissions of SO_2 from CT/HRSGs. Pipeline quality natural gas is inherently low in sulfur. Total potential annual emissions from all four CT/HRSGs are less than 25 tpy of SO_2.

Most sulfur control technologies require the use of some sort of acid reducing agent such as lime slurry or limestone injection. This leads to residual solid or liquid waste which requires subsequent disposal. The remaining control techniques rely on reducing emissions of particulates and allowing any residual sulfur to be captured with the particulate. With so little SO_2 (or particulate) being generated in the first place, further reductions of SO_2 using either active or passive control techniques are therefore next to impossible.

Technically Infeasible RACT Controls

N/A – no additional controls identified.

Evaluation and Ranking of Technically Feasible RACT Controls

N/A – no additional controls identified.

Selection of RACT Controls

No additional control required. Combustion of pipeline quality natural gas as fuel for control of SO_2 emissions is recommended as RACT.

VOC

Available Control Technology

Only one add-on control technology has been identified by DAQ to reduce emissions of VOC from CT/HRSGs – the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust stream prior to the final stack, so that emissions of CO and VOC can be further oxidized to CO_2 and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics.

All four CT/HRSGs at the Lake Side facility have oxidation catalysts installed as these were required as CO/VOC BACT as part of the requirements of the PSD AOs to construct and operate the turbines.

Technically Infeasible RACT Controls

N/A – oxidation catalysts are technically feasible; therefore this section does not apply.

Evaluation and Ranking of Technically Feasible RACT Controls

The oxidation catalysts installed on the CT/HRSGs on Block #1 bring the CO emission rate down to 3 ppm and 14.1 lbs/hr per turbine/HRSG stack (both limits on a 3-hour average at steady state operation). While VOC emissions are not specifically limited, it is assumed that VOC emissions on a ppm basis are similar to CO emissions.

The oxidation catalysts on Block #2 have specific VOC limits of 2.8 ppmvd from each turbine/HRSG stack, again on a 3-hour average.

Selection of RACT controls

Retention of the existing oxidation catalyst systems for control of VOC emissions is recommended as RACT.

<u>NOx</u>

Available Control Technology

The following technologies have been identified as potential control methodologies for control of NOx emissions: good combustion practices (no additional controls, but proper operation of existing equipment); low emission combustion (LEC); selective non-catalytic reduction (SNCR); and selective catalytic reduction as potential NOx emission control technologies.

The CTs installed at the Lake Side facility are based on the Frame 7FA, which are inherently low-NOx burner design. These CTs are the standard in power generation and are now in their third generation of burner design.

Technically Infeasible RACT Controls

N/A – the turbines are LEC by design, using dry low-NOx combustors.

Selective non-catalytic reduction is the simple injection of ammonia into the exhaust stream. This is technically feasible.

Selective catalytic reduction is the same, although with the addition of a catalyst bed to facilitate reduction at a lower exhaust stream temperature. This is also technically feasible.

Evaluation and Ranking of Technically Feasible RACT Controls

As the turbines are already LEC by design, the remaining two controls would ordinarily then be ranked by control effectiveness. However, the Lake Side facility turbines already have SCR systems installed. They were installed as LAER as part of the requirements for the both the original NSR AO to construct and operate as well as the NSR major modification in 2011. SCR systems have long been acknowledged as achieving the greatest degree of control of NOx on natural gas-fired turbine sources.

The NOx emissions from Lake Side Block #1 are limited by the AO to 2 ppm and 14.9 lbs/hr for each CT/HRSGs stack (both limits on a 3-hour average at steady state operation). Block #2 is similar at 2 ppm and 18.1 lb/hr for each CT/HRSGs stack (both limits on a 3-hour average at steady state operation). The only difference is the extra mass resulting from the increased duct firing taking place on Block #2.

Selection of RACT Controls

Retention of the existing SCR systems for each of the CT/HRSGs to control NOx emissions is recommended as RACT.

3.0 Conclusion- Emissions Reduction through RACT implementation

The summary of all the above RACT evaluations is that no changes in control or control systems will take place at the Lake Side facility. The Lake Side facility is currently at RACT.

4.0 Startup / Shutdown

As a combination mainline/peaking power generation station, the Lake Side facility has implemented a defined startup/shutdown emission minimization plan. This plan is fully defined through permitting, although certain specific requirements have been included in the Part H.13 limitations for the facility. The plan consists of the following:

Defining that “steady state operation” does not include periods of “startup”, “shutdown” or “short-term transient load excursions”

Including definitions of those three terms as they apply to the facility

Limiting the duration of those events on an annual basis, and for startup and shutdown on a daily basis

Providing a limit for NOx emissions during transient load excursions

These items are provided separately for Blocks #1 and #2 as the two blocks are slightly different in power production potential; but the concept and execution of the plan is the same in both cases.

5.0 Implementation Schedule

The Lake Side facility is currently at RACT. All controls are in place and both production Blocks #1 and #2 are now in operation. No implementation schedule is required.

6.0 References

PacifiCorp Energy $PM_{2.5}$ SIP Major Point Source RACT Documentation – Lake Side Power Plant
PacifiCorp Energy PM2.5 SIP Process, PacifiCorp Energy Gadsby and Lake Side Plants – dated April 30, 2014

RACT Evaluation Report –Lake Side Power Plant

UTAH $PM_{2.5}$ SIP RACT

Provo, Utah Nonattainment Area

Supporting Information