RACT Evaluation Report – Bountiful City Light and Power – Power Plant

UTAH $PM_{2.5}$ SIP RACT

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2014

State of Utah
GARY R. HERBERT
Governor
GREG BELL
Lieutenant Governor

Department of
Environmental Quality
Amanda Smith
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-AN101200003-13

March 7, 2013

Allen Johnson
Bountiful City Light and Power
198 S 200 W
Bountiful, UT 84010

Dear Mr. Johnson:

Re: Approval Order: R307-401-12, Reduction in Air Contaminants Change - Replacement of Generator and Removal of Fuel Tank
Project Number: N10120-0003

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:kw

cc: Mike Owens
Davis County Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: R307-401-12, Reduction in Air Contaminants Change - Replacement of Generator and Removal of Fuel Tank

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

APPROVAL ORDER NUMBER

DAQE-AN101200003-13

Date: March 7, 2013

Bountiful City Light and Power
Power Plant

Source Contact:
Allen Johnson Engineer
Phone: (801) 298-6072
Email: ajohnson@bountifulutah.gov

Bryce C. Bird
Director

Abstract

On June 28, 2012 Bountiful City Light and Power (BCL&P) submitted a notification of two changes in equipment which are covered by R307-401-12, Reduction in Air Contaminants. The changes in question involve the removal of a fuel storage tank and the replacement of an emergency generator with a lower rated model. No change in annual emissions is anticipated and PTE emission totals will remain as follows (all values are tons per year): PM_{10} 36.9, $PM_{2.5}$ (a subset of PM_{10}) 36.9, NO_x 160.0, SO_2 6.7, CO 112.8, VOC 14.7.

BCL&P is located in Davis County which is a maintenance area for ozone and a non-attainment area for $PM_{2.5}$. BCL&P is also defined as a contributing source in the Salt Lake County portion of the PM_{10} SIP.

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:**
Bountiful City Light and Power 198 S 200 W Bountiful, UT 84010	Power Plant 253 S 200 W Bountiful, UT 84010

UTM coordinates: 425450 m Easting, 4526400 m Northing, UTM Zone 12
SIC code: 4911 (Electric Services)

Section I: GENERAL PROVISIONS

I.1 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.2 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.3 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 two-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. [R307-415-6a]

I.4 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.5 The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]

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

I.7 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]

Section II: SPECIAL PROVISIONS

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

II.A.1 **Power Generation Facility**

II.A.2 **IC #8: Engine No. 8**
Dual fuel internal combustion (IC) engine rated at 6,800 kW with an electronic air to fuel ratio controller

II.A.3 **GT #1: Gas Turbine**
5.3 MW gas turbine Fired on Natural gas only, low NO_x technology equipped

II.A.4 **Misc. Fuel Tanks**
Diesel fuel tanks. Two 20,000 gallon tanks.

II.A.5 **GT #2: Gas Turbine**
SOLAR TITAN 130 - 13.5 MW (nameplate rating) natural gas-fired turbine/generator set with oxidation catalyst

II.A.6 **GT #3: Gas Turbine**
SOLAR TITAN 130 - 13.5 MW (nameplate rating) natural gas-fired turbine/generator set with oxidation catalyst

II.A.7 **Emergency Generator**
Olympian G250LG GenSet natural gas-fired IC engine

II.B Requirements and Limitations

II.B.1 **Conditions on Permitted Source**

II.B.1.a All internal combustion engines and turbine stacks shall be vented vertically without any obstruction to upward momentum during operation. Each engine and turbine shall be equipped with a kWh meter. [R307-401-8]

II.B.1.b Visible emissions shall be no greater than 10 percent opacity except for 15 minutes at start-up, 15 minutes at shutdown and during permitted straight fuel oil operation. When straight fuel oil is used, visible emissions shall be no greater than 20 percent opacity except for operation not exceeding 3 minutes in any hour.

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. For internal combustion engines the test shall be conducted semiannually to determine the compliance with the 10 percent opacity limit. When a period of straight fuel oil use exceeds 24 hours, a 40 CFR Part 60, Appendix A, Method 9 test shall be conducted at least once during each period to determine compliance with the 20 percent opacity limit. Records of observation shall be maintained, and shall include date, time, engine number and observed opacity. [R307-401-8]

II.B.1.c Annual emissions from the entire plant shall not exceed the following amounts:

PM_{10}	36.9 tons per rolling 12-month period
SO_2	6.7 tons per rolling 12-month period
NO_x	160.0 tons per rolling 12-month period
CO	112.8 tons per rolling 12-month period
Non-Methane VOC	14.7 tons per rolling 12-month period

Compliance to the above annual emission limitations shall be determined by recording the amount of kilowatt hours generated by each engine on a monthly basis. The kilowatt hours produced by the natural gas fired turbines and each engine shall be multiplied by the appropriate emission factors as shown below:

For PM_{10}, SO_2 and VOC, the emission factors shall be derived from manufacturers data sheets. Emission factors from NO_x and CO shall be derived from the most recent emission test results.

The following equation shall be used to calculate one month emissions in order to get the rolling 12-month emission from each engine/turbine:

(kW-hrs/month)(g/kW-hr)(1 lb/453.59 g)(1 ton/2000 lbs) = tons/month emissions

Combined emissions shall be the sum of emissions from each natural gas fired turbine and each internal combustion engine. To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the tenth day of each month using data from the previous 12 months. Power production shall be determined by examination of monthly power production records. [R307-401]

II.B.1.d The sulfur content of any fuel oil or diesel burned shall not exceed 15 ppm. Certification of fuels shall be either by BCL&P's own testing or certification from the fuel marketer. If directed the sulfur content of any fuel oil burned shall be determined by ASTM Method D2880-71 or D-4294-89, or EPA-approved equivalent. Records of fuel supplier's test report on sulfur content or fuel certification shall be available on-site for each load delivered. [R307-401-8]

II.B.1.e At least 30 days prior to conducting any emission testing required under any part of UAC, R307, the owner or operator shall notify the Director of the date, time and place of such testing and, if determined necessary by the Director, the owner or operator shall attend a pretest conference. 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. The pretest conference shall include representation from the owner/operator, the tester, and 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. [R307-165]

II.B.2 **Conditions on Engine #8**

II.B.2.a Engine #8 shall be equipped with an hour meter. [R307-150]

II.B.2.b The owner/operator shall use natural gas as the primary fuel in engine #8. Distillate fuel oil #1 or #2, or a combination of #1 and #2, may be used only: during a 15 minute start up and 15 minute shut down period; backup fuel during periods of natural gas curtailment; for maintenance firings; for break-in firing; for system electrical power outages; and as pilot fuel. Pilot fuel is used to ignite the gaseous portion of the fuel charge. Natural gas curtailment is defined as period when the natural gas provider/supplier imposes a curtailment or interruption of service, and the curtailment is involuntary and beyond the control of the owner/operator. Records of fuel oil pumped to the day tank shall be maintained, and shall include date, gallons of oil, and engine number. [R307-401-8]

II.B.2.c The hours of operation of engine #8 shall not exceed 1600 hours per year. Operating time shall be determined by a log book and the hour meter. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. [R307-401-8]

II.B.2.d Engine #8 shall be retested to verify the emissions factors for NO_x and CO after every 800 operating hours, or at least once every 24 months. Emission testing for NO_x and CO shall be performed using 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E (for NO_x) and 40 CFR 60, Appendix A, Method 10 (for CO) or through use of a portable monitoring system approved by the Director or an assigned representative.

Compliance with this limitation shall be determined by maintaining a record of operation based over a 24 month period. After engine #8 has been tested due to the 800 hour or 24 month limitation, a new 24 month or 800 hour period shall be started.The emission factors shall be expressed in grams per kilowatt hour (g/kW-hr).

The emission factor shall be determined by following equation:

(g/kW-hr) = [(1.194 x 10^7) x (PPMv NO_x) x flow rate (scf/hr) / (engine output at test condition kW)] / 453.59 g/lb

Where scf means standard cubic feet at standard condition of 68 degree F and 14.7 psia.

For the testing with portable analyzer a Conditional Test Method CTM-034 protocol or an equivalent shall be used. Equivalency shall be determined by the Director. [R307-165]

II.B.3 **Conditions on Natural Gas-Fired Turbines**

II.B.3.a The owner/operator shall use only natural gas in each turbine. [R307-401-8]

II.B.3.b GT #2 and GT #3 shall each be equipped with an oxidation catalyst. [R307-401-8]

II.B.3.c Each turbine shall comply with the monitoring and testing requirements of 40 CFR 60.334 and 60.335. For sulfur content monitoring owner/operator may develop custom schedules for determination of the values in accordance with 40 CFR 60.334(i)(3). Nitrogen monitoring can be waived for pipeline quality natural gas, since there is no fuel-bound nitrogen and since the fuel nitrogen does not contribute appreciably to NO_x emissions [USEPA Memo, August 14, 1987]. [40 CFR 60 Subpart GG]

II.B.3.d Emissions to the atmosphere shall not exceed the following rates and concentrations:

GT #1 (5.3 MW Turbine) Exhaust Stack

Pollutant	g/kW-hr
NO_x	0.6
CO	0.6

GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack

Pollutant	Concentration at 15% O_2	lb/hr (at 64° F reference temp)
NO_x	15 ppm	7.5
CO	15 ppm	7.5

The sample location shall conform to 40 CFR 60. Appendix A, Method 20. The volumetric flow rate and NO_x emission rate shall be determined by 40 CFR 60, Appendix A, Method 20. The CO emission rate shall be determined by 40 CFR 60, Appendix A, Method 10. Each turbine shall be tested for NO_x and CO emissions at least once per year. [R307-165]

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), Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
NSPS (Part 60), GG: Standards of Performance for Stationary Gas Turbines
NSPS (Part 60), JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
NSPS (Part 60), KKKK: Standards of Performance for Stationary Combustion Turbines
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Title V (Part 70) major source

PERMIT HISTORY

This AO is based on the following documents:

Is Derived From	Source Submitted NOI dated June 28, 2012
Replaces	DAQE-AN010120002-10 dated September 15, 2010

ADMINISTRATIVE CODING

The following information is for UDAQ internal classification use only:

Davis County
CDS A
MACT (Part 63), Nonattainment or Maintenance Area, Title V (Part 70) major source, PM_{10} SIP / Maint Plan, NSPS (Part 60),

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

Company: Bountiful City Light and Power- F
Site ID: 10120
Project: PM10 SIP
Date: 3/16/2015

County FIPS	Category NAICS	NAICS	SIC	Site ID
11	3	221119	4911	10120
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Power Plant

Site Name	Comp ID	Process ID	Process Code	Component Description
Bountiful City Light and Power- Power Plant	3622	1	a	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	3622	2	b	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	4241	1	a	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4241	2	b	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4243	1	a	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4243	2	b	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4245	1	a	I. C., Dual Fuel Engine #5
Bountiful City Light and Power- Power Plant	4245	2	b	I. C., Dual Fuel Engine #5
Bountiful City Light and Power- Power Plant	4247	1	a	I. C., Dual Fuel Engine #6
Bountiful City Light and Power- Power Plant	4247	2	b	I. C., Dual Fuel Engine #6
Bountiful City Light and Power- Power Plant	4249	1	a	I. C., Dual Fuel Engine #8
Bountiful City Light and Power- Power Plant	4249	2	b	I. C., Dual Fuel Engine #8
Bountiful City Light and Power- Power Plant	171807	1	a	Turbine
Bountiful City Light and Power- Power Plant	175407	1	a	Unit #3 Cooling Tower

Site Name	Comp ID	Process ID	Process Code	Component Description
Bountiful City Light and Power- Power Plant	3622	1	a	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	3622	2	b	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	4241	1	a	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4241	2	b	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4243	1	a	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4243	2	b	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4245	1	a	I. C., Dual Fuel Engine #5
Bountiful City Light and Power- Power Plant	4245	2	b	I. C., Dual Fuel Engine #5

Bountiful City Light and Power- Power Plant	4247	1	a	I. C., Dual Fuel Engine #6
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Bountiful City Light and Power- Power Plant	177505	1	a	Turbine
Bountiful City Light and Power- Power Plant	177506	1	a	Turbine
Bountiful City Light and Power- Power Plant	175405	1	a	Unit #1 Cooling Tower
Bountiful City Light and Power- Power Plant	175406	1	a	Unit #2 Cooling Tower
Bountiful City Light and Power- Power Plant	175407	1	a	Unit #3 Cooling Tower

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Bountiful City Light and Power- Power Plant	175407	1	a	Unit #3 Cooling Tower

Site Name	Comp ID	Process ID	Process Code	Component Description
Bountiful City Light and Power- Power Plant	3622	1	a	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	3622	2	b	I. C., Dual Fuel Engine #2
Bountiful City Light and Power- Power Plant	4241	1	a	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4241	2	b	I. C., Dual Fuel Engine #3
Bountiful City Light and Power- Power Plant	4243	1	a	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4243	2	b	I. C., Dual Fuel Engine #4
Bountiful City Light and Power- Power Plant	4245	1	a	I. C., Dual Fuel Engine #5
Bountiful City Light and Power- Power Plant	4245	2	b	I. C., Dual Fuel Engine #5
Bountiful City Light and Power- Power Plant	4247	1	a	I. C., Dual Fuel Engine #6
Bountiful City Light and Power- Power Plant	4247	2	b	I. C., Dual Fuel Engine #6
Bountiful City Light and Power- Power Plant	4249	1	a	I. C., Dual Fuel Engine #8
Bountiful City Light and Power- Power Plant	4249	2	b	I. C., Dual Fuel Engine #8
Bountiful City Light and Power- Power Plant	171807	1	a	Turbine
Bountiful City Light and Power- Power Plant	175407	1	a	Unit #3 Cooling Tower

Material or Fuel	Component SCC	Stack					
		ID	Height	Diameter	Temp	Flow	Area
Natural Gas	20100202	1681	44.75	1.08	655	61.39	0.916088
Distillate Oil (No. 2)	20100102	1681	44.75	1.08	655	61.39	0.916088
Natural Gas	20100202	1682	44.75	1.08	657	56.33	0.916088
Distillate Oil (No. 2)	20100102	1682	44.75	1.08	657	56.33	0.916088
Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
Distillate Oil (No. 2)	20100102	1683	44.75	1.08	718	40.89	0.916088
Natural Gas	20100202	1684	44.75	1.08	703	42.78	0.916088
Distillate Oil (No. 2)	20100102	1684	44.75	1.08	703	42.78	0.916088
Natural Gas	20100202	1685	44.75	2.1	772	172	3.463606
Distillate Oil (No. 2)	20100102	1685	44.75	2.1	772	172	3.463606
Natural Gas	20100202	1686	50	3.42	833	317.5	9.186331
Distillate Oil (No. 2)	20100102	1686	50	3.42	833	317.5	9.186331
Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Cooling Water	30600701	926284	10	0	72	0	0

Material or Fuel	Component SCC	Stack					
		ID	Height	Diameter	Temp	Flow	Area
Natural Gas	20100202	1681	44.75	1.08	655	61.39	0.916088
Distillate Oil (No. 2)	20100102	1681	44.75	1.08	655	61.39	0.916088
Natural Gas	20100202	1682	44.75	1.08	657	56.33	0.916088
Distillate Oil (No. 2)	20100102	1682	44.75	1.08	657	56.33	0.916088
Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
Distillate Oil (No. 2)	20100102	1683	44.75	1.08	718	40.89	0.916088
Natural Gas	20100202	1684	44.75	1.08	703	42.78	0.916088
Distillate Oil (No. 2)	20100102	1684	44.75	1.08	703	42.78	0.916088

Natural Gas	20100202	1685	44.75	2.1	772	172	3.463606
Distillate Oil (No. 2)	20100102	1685	44.75	2.1	772	172	3.463606
Natural Gas	20100202	1686	50	3.42	833	317.5	9.186331
Distillate Oil (No. 2)	20100102	1686	50	3.42	833	317.5	9.186331
Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Natural Gas	20100201	178802	50	6.25	935	3852.32	30.68
Natural Gas	20100201	178803	50	6.25	935	3852.32	30.68
Cooling Water	30600701	926282	10.00	0.003	72	0.00	0.000000
Cooling Water	30600701	926283	10.00	0.003	72	0.00	0.000000
Cooling Water	30600701	926284	10.00	0.003	72	0.00	0.000000

Material or Fuel	Component SCC	Stack					
		ID	Height	Diameter	Temp	Flow	Area
Natural Gas	20100202	1681	44.75	1.08	655	61.39	0.916088
Distillate Oil (No. 2)	20100102	1681	44.75	1.08	655	61.39	0.916088
Natural Gas	20100202	1682	44.75	1.08	657	56.33	0.916088
Distillate Oil (No. 2)	20100102	1682	44.75	1.08	657	56.33	0.916088
Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
Distillate Oil (No. 2)	20100102	1683	44.75	1.08	718	40.89	0.916088
Natural Gas	20100202	1684	44.75	1.08	703	42.78	0.916088
Distillate Oil (No. 2)	20100102	1684	44.75	1.08	703	42.78	0.916088
Natural Gas	20100202	1685	44.75	2.1	772	172	3.463606
Distillate Oil (No. 2)	20100102	1685	44.75	2.1	772	172	3.463606
Natural Gas	20100202	1686	50	3.42	833	317.5	9.186331
Distillate Oil (No. 2)	20100102	1686	50	3.42	833	317.5	9.186331
Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Cooling Water	30600701	926284	10	0.003	72	0	0

Material or	Component	Stack

Fuel	SCC	ID	Height	Diameter	Temp	Flow	Area
Natural Gas	20100202	1681	44.75	1.08	655	61.39	0.916088
Distillate Oil (No. 2)	20100102	1681	44.75	1.08	655	61.39	0.916088
Natural Gas	20100202	1682	44.75	1.08	657	56.33	0.916088
Distillate Oil (No. 2)	20100102	1682	44.75	1.08	657	56.33	0.916088
Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
Distillate Oil (No. 2)	20100102	1683	44.75	1.08	718	40.89	0.916088
Natural Gas	20100202	1684	44.75	1.08	703	42.78	0.916088
Distillate Oil (No. 2)	20100102	1684	44.75	1.08	703	42.78	0.916088
Natural Gas	20100202	1685	44.75	2.1	772	172	3.463606
Distillate Oil (No. 2)	20100102	1685	44.75	2.1	772	172	3.463606
Natural Gas	20100202	1686	50	3.42	833	317.5	9.186331
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Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Cooling Water	30600701	926284	10	0.003	72	0	0

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		ID	Height	Diameter	Temp	Flow	Area
Natural Gas	20100202	1681	44.75	1.08	655	61.39	0.916088
Distillate Oil (No. 2)	20100102	1681	44.75	1.08	655	61.39	0.916088
Natural Gas	20100202	1682	44.75	1.08	657	56.33	0.916088
Distillate Oil (No. 2)	20100102	1682	44.75	1.08	657	56.33	0.916088
Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
Distillate Oil (No. 2)	20100102	1683	44.75	1.08	718	40.89	0.916088
Natural Gas	20100202	1684	44.75	1.08	703	42.78	0.916088
Distillate Oil (No. 2)	20100102	1684	44.75	1.08	703	42.78	0.916088
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Distillate Oil (No. 2)	20100102	1685	44.75	2.1	772	172	3.463606
Natural Gas	20100202	1686	50	3.42	833	317.5	9.186331
Distillate Oil (No. 2)	20100102	1686	50	3.42	833	317.5	9.186331
Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Cooling Water	30600701	926284	10	0.003	72	0	0

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Natural Gas	20100202	1683	44.75	1.08	718	40.89	0.916088
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Distillate Oil (No. 2)	20100102	1686	50	3.42	833	317.5	9.186331
Natural Gas	20100201	20550	50	3.5	902.6	334.72	9.621128
Cooling Water	30600701	926284	10	0.003	72	0	0

	Location							
Velocity	Lat	Long	Hrs/Day	Days/Wk	Wks/Yr	Hrs/Yr	% Jan	% Feb
67.01	40.885289	-111.8849	0	0	0	0	0	21.32
67.01	40.885289	-111.8849	0	0	0	0	0	21.32
61.49	40.885289	-111.8849	24	7	52	2	0	100
61.49	40.885289	-111.8849	0	0	0	0	0	100
44.63	40.885289	-111.8849	24	7	52	2	0	100
44.63	40.885289	-111.8849	0	0	0	0	0	100
46.7	40.885289	-111.8849	24	7	52	2	0	100
46.7	40.885289	-111.8849	0	0	0	0	0	100
49.66	40.885289	-111.8849	0	0	0	0	0	100
49.66	40.885289	-111.8849	0	0	0	0	0	100
34.56	40.885289	-111.8849	24	7	52	12	0	21.89
34.56	40.885289	-111.8849	0	0	0	0	0	21.89
34.79	40.885289	-111.8849	24	7	52	34	0	21.32
0	40.885289	-111.8849	24	7	16	2688	0	21.89

	Location							
Velocity	Lat	Long	Hrs/Day	Days/Wk	Wks/Yr	Hrs/Yr	% Jan	% Feb
67.01	40.885289	-111.8849	0	0	0	0	0	0
67.01	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0

49.66	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.79	40.885289	-111.8849	24	7	52	2500	19.75	3.33
125.6	40.885289	-111.8849	24	7	52	8760	19.75	3.33
125.6	40.885289	-111.8849	24	7	52	8760	19.75	3.33
0.00	40.88529	-111.8849	24	7	52	2500	0.00	0.38
0.00	40.88529	-111.8849	24	7	52	8760	16.54	6.33
0.00	40.88529	-111.8849	24	7	52	8760	0.00	0.00

	Location							
Velocity	**Lat**	**Long**	**Hrs/Day**	**Days/Wk**	**Wks/Yr**	**Hrs/Yr**	**% Jan**	**% Feb**
67.01	40.885289	-111.8849	0	0	0	0	0	0
67.01	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.79	40.885289	-111.8849	24	7	52	2500	19.75	3.33
0	40.885289	-111.8849	24	7	52	8760	0	0

	Location	

Velocity	Lat	Long	Hrs/Day	Days/Wk	Wks/Yr	Hrs/Yr	% Jan	% Feb
67.01	40.885289	-111.8849	0	0	0	0	0	0
67.01	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.79	40.885289	-111.8849	24	7	52	2500	19.75	3.33
0	40.885289	-111.8849	24	7	52	8760	0	0

	Location							
Velocity	Lat	Long	Hrs/Day	Days/Wk	Wks/Yr	Hrs/Yr	% Jan	% Feb
67.01	40.885289	-111.8849	0	0	0	0	0	0
67.01	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.79	40.885289	-111.8849	24	7	52	2500	19.75	3.33
0	40.885289	-111.8849	24	7	52	8760	0	0

	Location							
Velocity	Lat	Long	Hrs/Day	Days/Wk	Wks/Yr	Hrs/Yr	% Jan	% Feb
67.01	40.885289	-111.8849	0	0	0	0	0	0
67.01	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
61.49	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
44.63	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
46.7	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
49.66	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.56	40.885289	-111.8849	0	0	0	0	0	0
34.79	40.885289	-111.8849	24	7	52	2500	19.75	3.33
0	40.885289	-111.8849	24	7	52	8760	0	0

Temporal Operating Information

% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	6.93	0	32.97	15.27	23.51	0	0	0
0	6.93	0	32.97	15.27	23.51	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	48.87	0	29.24	0	0	0
0	0	0	48.87	0	29.24	0	0	0
0	6.93	0	32.97	15.27	23.51	0	0	0
0	0	0	48.87	0	29.24	0	0	0

Condensables included

Temporal Operating Information

% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0

0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0.12	0.62	1.11	11.36	24.81	23.33	7.30	0.74	0.00
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0.00	0.00	1.36	16.58	39.41	34.81	5.82	1.58	0.00
0.02	0.00	0.00	19.81	29.17	20.62	7.47	0.00	0.01
0.00	0.00	0.00	25.70	37.86	26.75	9.69	0.00	0.00

Temporal Operating Information

% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0	0	0	25.7	37.86	26.75	9.69	0	0

Temporal Operating Information

% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0	0	0	25.7	37.86	26.75	9.69	0	0

Temporal Operating Information								
% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0	0	0	25.7	37.86	26.75	9.69	0	0

Temporal Operating Information								
% Mar	% Apr	% May	% Jun	% Jul	% Aug	% Sep	% Oct	% Nov
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0.12	0.62	1.11	11.36	24.81	23.33	7.3	0.74	0
0	0	0	25.7	37.86	26.75	9.69	0	0

2011 Actual Emissions (tons/yr)						
PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0.0894	0.0894	0.0155	0.3183	0.0751	0.1636	0.0000

	Permit	2011 Actual Emissions						
% Dec	Status	PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0	Yes	0	0	0	0	0.000000	0	0
0	Yes	0	0	0	0	0.000000	0	0
0	Yes	0.000134	0.000134	0.00051	0.030225	0.002428	0.007708	0
0	Yes	0.000022	0.000022	0.000083	0.00493	0.000396	0.001257	0
0	Yes	0.000118	0.000118	0.000452	0.018918	0.002153	0.010441	0
0	Yes	0.000022	0.000022	0.000085	0.003539	0.000403	0.001953	0
0	Yes	0.000127	0.000127	0.000485	0.018231	0.002308	0.011452	0
0	Yes	0.000011	0.000011	0.00004	0.00152	0.000192	0.000955	0
0	Yes	0	0	0	0	0.000000	0	0
0	Yes	0	0	0	0	0.000000	0	0
0	Yes	0.003006	0.003006	0.011476	0.186517	0.054650	0.100504	0
0	Yes	0.000415	0.000415	0.001586	0.025773	0.007552	0.013888	0
0	Yes	0.001376	0.001376	0.000772	0.028604	0.005055	0.01545	0
0	Yes	0.084122	0.084122			0.000000		

2019 True-Up Emissions (tons/yr)						
PM10	PM2.5	SO2	NOx	VOC	CO	NH3
35.75	33.85	6.66	100.00	18.76	12.00	0.00

Does the 2019 True-Up Include Growth?	No

	Permit	2019 True-Up Emissions						
% Dec	Status	PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00

0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	No	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.53	Yes	1.75	1.75	0.69	10.70	0.30	0.38	0.00
7.53	Yes	15.75	15.75	2.99	44.65	9.23	5.81	0.00
7.53	Yes	15.75	15.75	2.99	44.65	9.23	5.81	0.00
0.06	Yes	0.50	0.10	0.00	0.00	0.00	0.00	0.00
0.03	Yes	1.00	0.25	0.00	0.00	0.00	0.00	0.00
0.00	Yes	1.00	0.25	0.00	0.00	0.00	0.00	0.00

Projection years below do not have the additional rows which have been a

2019 Projected Emissions (tons/yr)						
PM10	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**NH3**
2.7500	2.0000	0.6900	10.7000	0.3000	0.3800	0.0000

	Permit	**2019 Projected Emissions**						
% Dec	**Status**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**NH3**
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
7.53	Yes	1.75	1.75	0.69	10.7	0.3	0.38	0
0	Yes	1	0.25	0	0	0	0	0

2024 Projected Emissions (tons/yr)						
PM10	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**NH3**
2.7500	2.0000	0.6900	10.7000	0.3000	0.3800	0.0000

	Permit	**2024 Projected Emissions**

% Dec	Status	PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
7.53	Yes	1.75	1.75	0.69	10.7	0.3	0.38	0
0	Yes	1	0.25	0	0	0	0	0

2028 Projected Emissions (tons/yr)						
PM10	PM2.5	SO2	NOx	VOC	CO	NH3
2.7500	2.0000	0.6900	10.7000	0.3000	0.3800	0.0000

	Permit	2028 Projected Emissions						
% Dec	Status	PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
7.53	Yes	1.75	1.75	0.69	10.7	0.3	0.38	0
0	Yes	1	0.25	0	0	0	0	0

2030 Projected Emissions (tons/yr)						
PM10	PM2.5	SO2	NOx	VOC	CO	NH3

2.7500	2.0000	0.6900	10.7000	0.3000	0.3800	0.0000

	Permit	2030 Projected Emissions						
% Dec	Status	PM10	PM2.5	SO2	NOx	VOC	CO	NH3
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
0	No	0	0	0	0	0	0	0
7.53	Yes	1.75	1.75	0.69	10.7	0.3	0.38	0
0	Yes	1	0.25	0	0	0	0	0

Benzene	Chlorine	HCl
0.0000	0.0000	0.0000

Benzene	Chlorine	HCl	
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00
			0.00

Benzene	Chlorine	HCl
0.00	0.00	0.00

This is a PTE validation - all projection years should be held flat, with no growth.

Benzene	Chlorine	HCl	
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00

0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.40
0.00	0.00	0.00	0.75
0.00	0.00	0.00	0.75

Verify that these rows have been added ar (or have been renamed) versus the rows i projection years listed below this point.

ıdded above. These rows have been highlighted

Benzene	Chlorine	HCl
0.0000	0.0000	0.0000

Benzene	Chlorine	HCl	
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.75

Benzene	Chlorine	HCl
0.0000	0.0000	0.0000

Benzene	Chlorine	HCl	
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.75

Benzene	Chlorine	HCl
0.0000	0.0000	0.0000

Benzene	Chlorine	HCl	
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.75

Benzene	Chlorine	HCl

0.0000	0.0000	0.0000

Benzene	**Chlorine**	**HCl**	
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.00
0	0	0	0.75

nd have not been included
ncluded in each of the

RACT EVALUATION REPORT
BOUNTIFUL CITY LIGHT AND POWER – POWER PLANT

1.0 INTRODUCTION AND FACILITY DESCRIPTION

1.1 Facility Identification

Name: Bountiful City Light and Power – Power Plant
Address: 253 South 200 West, Bountiful, Utah, Davis County
Owner/Operator: Bountiful City Light and Power
UTM coordinates: 425,450 East 4,526,400 North Zone 12

1.2 Facility Process Summary

Bountiful City Light and Power (BCLP) operates a power plant consisting of two 13.5 MW natural gas-fired turbines, one 5.3 MW natural gas-fired turbine, and one 250 kW natural gas-fired emergency generator. There are also three small cooling towers. The power plant is operated as a peaking and supplemental power plant to provide electrical power to municipal power customers in and around the City of Bountiful. The plant is defined as a Title V major source located in Davis County, and within the Salt Lake City $PM_{2.5}$ nonattainment area.

An Approval Order (AO) for the two 13.5 MW turbines was issued in September 2010, the AO for the emergency generator was issued March 2013. Aside from the emergency generator, operation of the plant is dependent on local demand and cost of utility power. With the exception of the dual fuel IC engine generator, all equipment is fired exclusively on natural gas.

1.3 Facility Criteria Air Pollutant Emissions Sources

As previously discussed the facility contains the following emission sources:
5.3 MW LoNOx natural gas-fired turbine (GT #1)
13.5 MW LoNOx natural gas-fired turbine (GT #2)
13.5 MW LoNOx natural gas-fired turbine (GT #3)
250 kW natural gas-fired emergency generator (Em Gen)
Cooling Tower #1
Cooling Tower #2
Cooling Tower #3

1.4 RACT Cut-off Threshold

A RACT cut-off threshold was established generally for all facilities based on Utah Division of Air Quality’s (DAQ) existing small source exemption rule R307-401-9. This rule exempts sources of pollution with emissions less than 5.0 tpy from permitting requirements. Therefore, sources with baseline actual emissions which fall below this threshold could be exempted from evaluation under this general establishment.

However, BCLP is a municipal power plant which operates both as a peaking plant and as part of the general municipal power generator network which means it operates well below its established allowable (permitted) emissions. Even though emission source GT #1 has baseline actual emissions below 5 tpy, potential emissions from this source are demonstrably higher. This source will also be included for evaluation.

The cooling towers and emergency generator have potential (allowable) emissions which remain below the 5 tpy threshold. These sources will not be included for evaluation.

Cooling towers: PM10 < 0.1 tpy, PM2.5 < 0.1 tpy
Em Gen: PM10 < 1.0 tpy, PM2.5 < 1.0 tpy, NOx < 1.0 tpy, SO2 < 1.0 tpy, VOC < 1.0 tpy.

2.0 RACT Evaluation

2.1 Natural Gas-fired Turbines

Rather than evaluating the three turbines individually, DAQ has chosen to evaluate all three turbines as a group. Each of the turbines is described below in greater detail.

GT #1 is the smallest of the three turbines located at the facility. It is also the oldest, having been installed several years prior to the two larger turbines. Currently the turbine is equipped with inherent low-NOx burner design, and is fired exclusively on natural gas.

2008 actual emissions for this turbine were less than 1 tpy for each of the pollutants in question. Potential emissions in approximate tpy for this turbine are as follows:
PM_{10} = 1.2, $PM_{2.5}$ = 1.2, NOx = 13.3, SO_2 < 1.0, VOC = 2.3

GT #2 and GT #3 are identical units. Permitted in 2010, the units have inherent low-NOx burner design, and are fired exclusively on natural gas. They are also equipped with catalytic oxidation control devices to reduce emissions of CO to 15 ppm, with a related VOC reduction of approximately an equal amount, although at the time of installation, they were required for CO BACT without regard to the specific level of VOC reduction obtained.

Since these units were not installed until late 2010/early 2011, no baseline 2008 actual emissions for these two units could be established. Individual potential emissions for these two units are as follows (per turbine):
PM_{10} = 15.75, $PM_{2.5}$ = 15.75, NOx = 39.65, SO_2 < 1.0, VOC = 9.23

To begin with only add-on controls for the turbines will be evaluated. A separate section which discusses total equipment replacement will follow.

<u>$PM_{2.5}$</u>

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. 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.

<u>SO_2</u>

Available Control Technology

Similarly, no additional add-on control technology has been identified by DAQ that can further reduce emissions of SO_2 from combustion turbines. Pipeline quality natural gas is inherently low in sulfur. Total potential annual emissions from all three combustion turbines are less than 2 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 combustion turbines – 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. Currently the two larger 13.5 MW turbines have oxidation catalysts installed, as these were required as CO BACT as part of the requirements in the 2010 initial AO to construct and operate the turbines. The smaller 5.3 MW turbine does not currently have an oxidation catalyst installed.

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

As the two larger 13.5 MW turbines already have oxidation catalysts installed, and these units control VOC emissions to approximately 15 ppm, an evaluation of oxidation catalysts for the combustion turbines at BCLP will be conducted in two parts:

Part One – Additional/Greater Control on the 13.5 MW Turbines

To determine if a greater level of control is possible on the two 13.5 MW turbines, DAQ investigated the current level of VOC control available with oxidation catalysts in this turbine size range. New turbines can achieve as low as 2 ppm VOC emissions, but these are large mainline baseload units with much higher temperatures and specifically designed oxidation catalyst systems and greater inlet loading. For turbines in this size range, CO oxidation catalysts typically reduce CO emissions to the range of 15 ppm. VOC emissions roughly match CO emissions, but oxidation catalysts for a turbine of this size are designed for a CO emission rate rather than a VOC emission rate. Aiming for a lower CO emission rate of perhaps 9 ppm requires a higher stack temperature. This will require the burning of more fuel.

Increased heat requires that the turbines be operated more often, or requires that some supplemental heating is supplied to the oxidation catalyst to increase oxidation efficiency. Increased fuel burning to reduce VOC emissions is counter-productive. Attempting to reduce VOC emissions below 15 ppm is environmentally infeasible.

Part Two – Add-on Oxidation Catalyst on the 5.3 MW Turbine

The 5.3 MW turbine falls into a similar size range to the 13.5 MW turbines. Therefore an add-on oxidation catalyst which reduces CO and VOC emissions down to the 15 ppm range is technically feasible. DAQ then needs to evaluate whether the addition of an oxidation catalyst is economically viable.

The 5.3 MW turbine has a VOC PTE of approximately 2.3 tpy. This is based on a potential operation of 8760 hours of operation. Expected operation, based on actual operation of past years' use is closer to 1800 hours per year. This leads to actual reported VOC emissions of less than 1 tpy. The cost for an oxidation catalyst on this turbine is estimated at nearly $100,000 installed. Assuming an at best control efficiency of 70% control, this would yield a total reduction of 1.8 tpy. Annualizing this cost, and dividing by the total tons reduced, gives an at best RACT "cost" of 10,000 $/ton. Going with the more reasonable value of less than 1 tpy, the RACT "cost" increases to a much higher $36,000 or more $/ton amount.

Selection of RACT Controls

Keeping the existing oxidation catalysts on the two 13.5 MW turbines is obvious. Owing to the extremely high RACT cost for adding an oxidation catalyst on the smaller turbine, the addition of an oxidation catalyst is not justified. No additional add-on controls are 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 (GCP – 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.

Technically Infeasible RACT Controls

Low emission combustion controls would require a redesign of the existing equipment. As this source is a municipal power plant, it is subject to the funding requirements of the City of Bountiful. Therefore, direct replacement of the existing equipment is considered economically infeasible (although please see the RACT analysis for Direct Replacement of Existing Equipment located below).

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

The remaining three control methodologies are then ranked in terms of control effectiveness.

1. SCR
2. SNCR
3. GCP

BCLP has indicated that the manufacturer of the 13.5 MW turbines has guaranteed specific emission rates based on pre-set back pressure, flow velocities, compression rations, ignition sequencing and other factors, and that placing “end of pipe” emission controls would invalidate these guarantees. This would substantially increase the annualized cost of both SCR and SNCR control options. Maintenance costs would increase by the amount required to offset the cost of the guarantees, as well as any additional costs associated with the breach of contract. These would need to be included with the regular annualized costs of merely installing and operating the SCR or SNCR systems.

Secondly, BCLP is land limited. All available space is currently occupied by existing equipment. BCLP needed to remove five existing IC engines in 2010 in order to make room for the two new turbine generators. If additional add-on control equipment is to be installed, BCLP will need to obtain additional footprint space, or else build some sort of superstructure to house this equipment, which will greatly increase the initial cost, as well as require the securing of construction/building permits, proper zoning, etc.; all of which also increases the overall cost.

Finally, both SCR and SNCR require ammonia injection, which generates ammonia slip – a source of particulate emissions. Direct particulate emissions are of greater impact on the attainment demonstration than NOx emissions. Although the exact ratio is subject to

debate depending on numerous factors; in general, the prevention of direct particulate emissions is good – especially for a relatively small reduction in NOx emissions.

While the exact cost for installation of either an SCR or SNCR unit has not been determined, at best a retrofit SCR unit would be about 50% effective in controlling NOx emissions. The turbines do not generate the high concentration, high temperature exhaust required for maximum high-efficiency SCR units to operate. Retrofit units would be placed into the exhaust stream as space allows, not as optimal temperature and mixing requirements would dictate.

BCLP is space limited and received specific performance guarantees that would be negated should add-on emission controls be installed. As BCLP did not evaluate SCR for the three turbines, costs and potential emission reductions are estimated. However, BCLP did supply information demonstrating that significant additional work to the site would need to be performed to provide space for the SCR or SNCR systems, and some extrapolation of this information could generate a best case estimate. This estimate still places use of SCR at $12,500/ton for at most only 25 tons NO_X reduced. SNCR, would achieve far lower NO_X reductions for similar (or higher) cost.

However, the "cost" for either of these options is deceptive, as the installation of either control system would require a demolition of the existing structure; temporary, but significant, long-term removal of the turbines while a new structure was erected; reinstallation of the turbines, control systems, exhaust systems, sampling and testing, etc.. During this period, BCLP would not be providing power under its contract, would not be available for emergency power, and because of municipal bonding issues would likely not have any reductions available prior to the 2019 projection year.

Selection of RACT Controls

Based on the above evaluation, add-on SCR or SNCR controls are not economically or technically justified. The remaining control methodology, GCP is therefore recommended.

2.3 Replacement of Equipment

The final control option is to outright replace GT #1. This available control option would involve replacing the emission unit with an equivalent, but lower emitting more modern unit.

<u>Emission Reductions</u>

Available Control Technology

Direct replacement of an emission unit is an available control option.

Technically Infeasible RACT Controls

N/A – Direct replacement of an emission unit is technically feasible.

Evaluation and Ranking of Technically Feasible RACT Controls

BCLP is a municipal power plant, and therefore subject to the funding concerns of the City of Bountiful. Funding would require issuing new bonds for the replacement of little used, existing equipment.

Selection of RACT Controls

Based on the above evaluations, replacement of existing equipment is not economically justified. No changes are recommended.

3.0 Conclusion- Emissions Reduction through RACT implementation

The summary of all the above RACT evaluations is that no changes to the existing control methodologies at BCLP are recommended. No reductions in actual or potential emissions are expected.

4.0 Startup / Shutdown

In order to minimize emissions generated during startup and shutdown of the combustion turbines, BCLP has a defined emission minimization plan. The plan is similar in scope to those at all the smaller municipal power generation facilities, and consists of two main components: defining the periods which constitute startup and shutdown, and limiting the total duration of those periods on a daily basis.

As most startup and/or shutdown periods are of very short duration, standard stack testing cannot be used to obtain emission totals when operating in these modes. Similarly, requiring use of expensive, expanded operating range CEM equipment to obtain emission information is of limited use when the ultimate goal is emission reduction through limiting the total amount of time the turbines are operating in these modes.

5.0 Implementation Schedule

As an update to its original submission in March of 2013, BCLP submitted new information dated April 25, 2014. In this most recent submission, BCLP demonstrated that IC #8 has been permanently retired from service at the plant, leaving only the three combustion turbines as main power generators. This RACT review has been updated with respect to this information. The combustion turbines have been installed and operational since 2012, with no changes in operation or controls since installation.

6.0 References

Bountiful City Light and Power Major Point Source RACT Evaluation – dated March 1, 2013
Bountiful City Light and Power PM2.5 Sip Process Next Steps – dated April 25, 2014
Fairbanks Morse Engine emission estimations
Caterpillar performance estimates
Solar Titan performance estimates

RACT Evaluation Report – Bountiful City Light and Power – Power Plant

UTAH $PM_{2.5}$ SIP RACT

Salt Lake City Nonattainment Area

Supporting Information