Attachment 1:

Compressor Station No. 3 – Four Factor Analysis

This attachment includes the four factor analysis for Compressor Station No. 3.

Four-Factor Analysis for Compressor Station No. 4

Northern Border Pipeline Company's Compressor Station No. 3 is located in Roosevelt County, Montana and operates under MDEQ permit number OP2974-12. MDEQ has requested a "four factor" analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). This document provides the four factor analysis based on the MDEQ letter dated March 14, 2019, and discussion in a related March phone conversation between NBPL and MDEQ. The four factor analysis considers application of NOx control on the facility combustion turbine, and the analysis follows EPA's draft guidance document[1] and standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document.

CS3 includes a simple cycle natural gas-fired combustion turbine rated at 38,000 horsepower (hp) at ISO conditions. The turbine drives a natural gas compressor. The turbine includes a low NOx lean premixed combustion burner, as designated by "DLE" (i.e., "dry low emissions") in model number for the unit, described in the permit as a Cooper Rolls Coberra 6562 DLE Compressor Turbine. DLE is the nomenclature used for second generation combustor NOx controls that replaced water / steam injection (i.e., DLE replaced "wet" emission controls). The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time. With DLE technology in place, water or steam injection is not a candidate NOx control technology for the turbine.

DLE technology provides low emissions. For example, EPA's update to the Turbine New Source Performance Standard (NSPS) in 2006 based the emission standard on lean premixed combustion technology. The only potential option for a further decrease in NOx emission is adding selective catalytic reduction (SCR) for post-combustion exhaust control. In addition, turbines burning pipeline quality natural gas have inherently low sulfur dioxide (SO_2) emissions.

Regarding SO_2 emissions, the permit information and annual emission calculations are based on an assumption of 2 grains sulfur per 100 SCF. That is based on natural gas pipeline tariff maximum values and actual sulfur content is much lower, perhaps by an order of magnitude. Even at the tariff-based value, annual SO_2 emissions are 5 tons per year or less. Actual emissions are likely less than 1 TPY. Because SO_2 emissions are very low from units firing pipeline quality natural gas, no additional discussion of SO_2 emissions is included in this analysis.

<u>Factor #1 – NOx Emissions Controls and Control Cost</u>

[1] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

As noted above, the pollutant of concern for the natural gas-fired turbine is nitrogen oxides (NOx). The facility turbine already includes the low NOx burner technology available from the manufacturer, thus additional combustion-based controls are not available. Lean premixed combustion (i.e., "DLE") is a second-generation technology that replaced water / steam injection, so water/steam injection is not applicable for this unit. The remaining options are post-combustion control. As discussed briefly below, the only add-on control technology that can be reviewed for application to a combustion turbine is selective catalytic reduction (SCR). Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for SCR.

Other post-combustion NOx control options are not applicable for combustion turbines. For example, "non-selective catalytic reduction" (NSCR) is a technology to reduce NOx emissions, but that technology only applies to reciprocating engines where the air-to-fuel ratio (AFR) is controlled so that there is no excess combustion air (i.e., exhaust O_2 levels are close to zero). At these conditions, species such as ammonia naturally occur in the combustion exhaust and those species participate in reactions to reduce NOx. This combustion configuration and AFR is not applicable to combustion turbines. Another technology, "selective non-catalytic reduction" (SNCR) employs similar "ammonia + NOx" chemistry, with ammonia injected at higher temperatures to reduce NOx without the use of a catalyst. In contrast, similar chemistry occurs with SCR technology, but a catalyst is required for reactions to occur because the exhaust temperature is cooler. SNCR has been applied in limited cases to large boilers (e.g., utility scale electric generating units), where the boiler configuration provides ample residence time at an exhaust temperature of about 1700 ^{o}F. A very specific temperature range and residence time within that range is required for SNCR to function. Neither the temperature or residence time is available in a combustion turbine, thus SNCR is not applicable to turbines. SCR is the only potential technology, and an SCR control cost analysis follows.

SCR control cost analysis

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers, and a case study for retrofit application showed significant problems, system re-engineering, and ultimately revisions to permit limits. However, rather than providing a detailed assessment of technical feasibility, the SCR cost analysis is presented to assess economic feasibility. The analysis primarily relies on Control Cost Manual methods and related EPA support documentation. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual (CCM) supplement that updated the SCR chapter[2] of the CCM was used to estimate the capital cost.

Table 1 presents the cost details and the source for specific itemized cost elements. In addition to the SCR capital cost, an important assumption for the analysis is the estimate of *actual* NOx emissions. The current and anticipated ongoing operation of the turbine at CS3 is lower than full load due to capacity requirements for the system. Based on operations for about 18 months through early 2019, average operation load was 24,000 hp. This is based on data from days the unit operated from June 2017 through mid-February 2019. The projection of actual emissions should be used as the best estimate of ongoing operation and associated NOx emissions. Primary assumptions for the analysis include:

[2] "Chapter 2, Selective Catalytic Reduction," EPA update to Control Cost Manual, Table 2.1b (May 2016).

- A capital cost of $4,250,000 to achieve 75% reduction in NOx; based on Chapter 2 of the Control Cost Manual[3] with the cost adjusted to 2018 using the consumer price index (CPI). The Control Cost Manual Table 2.1b information for SCR cost ($ per kilowatt) is interpolated as approximately $100 per kilowatt for a 28.3 MW unit. This cost basis is estimated because the three unit sizes included in the table (2, 12, and 80 MW) are not similar to the CS3 unit size. The CPI adjustment is a factor of 1.5
- Anticipated average operating load for future operations of 24,000 hp (63% of ISO rated load). This is based on average operating load from June 2017 through mid-February 2019 (over 20 months). Operation during this period is anticipated to be consistent with future operations based on pipeline system demand. Load has been marginally higher in the past, but future operation is anticipated to be similar to or lower than recent operation.
- The permit indicates a guaranteed heat rate of 7,038 Btu/hp-hr (Low heating value based). For a high heating value basis (consistent with NOx emission factors), the heat rate would be approximately 7,750 Btu/hp-hr. With standard operation at less than full load, this is rounded up to 8,000 Btu/hp-hr for calculating the NOx emission rate in pounds per hour (lb.hr). Thus, the fuel rate is approximately 192 MMBtu/hr.
- Baseline (pre-SCR) NOx emissions are based on a best estimate of actual emissions. The NOx emission rate used is 0.117 lb/MMBtu. This value has been used for annual emission estimates based on a compliance test in 2003. In more recent years, the average value from 18 portable analyzer tests conducted at full load from May 2012 through September 2018 is 0.1156 lb/MMBtu. In more recent years and projecting forward, a lower load is anticipated, and that operation would result in *lower* NOx emissions from the DLE-equipped unit. Thus, the assumed pre-SCR emission rate is a reasonable, conservatively high estimate.
- From the previous bullets, the NOx emission rate prior to SCR control is 22.5 lb/hr (i.e., 0.117 lb/MMBtu x 192 MMBtu/hr).
- Capital cost recovery is based on a twenty-year life and interest rate of 5.25% (consistent with the current prime rate). Longer life is not appropriate for catalytic systems which typically have a warranty of no longer than five years. It would be reasonable to assume a shorter life for capital recovery, and the twenty-year life is conservatively high.
- Annual operating hours have varied from year to year, but operation in the last year is anticipated to be representative of future operations. Annual operating hours were 6,835 in 2017 and 2,113 in 2018. For 2019, the turbine has operated only 181 hours through May. Relatively low operations similar to 2018 and 2019 are expected in the future, but for the cost evaluation, 4,500 annual operating hours was assumed based on the average of 2017 and 2018 operating hours (4,474 hours).
- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.
- Reagent cost is based on a conservatively low-cost estimate of $550 per ton for ammonia and a molar ratio (NOx / NH_3) of 1.1. The ammonia cost is based on information available on-line from the U.S. Department of Agriculture[4] for the cost of ammonia.

[3] "Chapter 2, Selective Catalytic Reduction," EPA update to Control Cost Manual, Table 2.1b (May 2016). Cost based on cost estimate presented in Table 2.1b for 12 MW unit.

[4] Anydrous ammonia price fluctuates; $550 per ton is within range (and towards the low end of the range) in recent years. For example, see U.S. DOA worksheet Table 7 at: https://www.ers.usda.gov/data-products/fertilizer-use-and-price/ and figures at: https://www.michfb.com/MI/Farm_News/Content/Crops/Adjusting_nitrogen_plans_based_on_fertilizer_prices_trends/

The resulting NOx control cost is estimated to be $37,750 per ton. NBPL believes this significantly exceeds a reasonable cost threshold. If MDEQ disagrees, NBPL requests an opportunity for additional discussion to review several assumptions and further refine the analysis.

Factor #2 – Time Necessary for Compliance

Retrofitting SCR would require a timeline of three years or more. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A schedule up to five years could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

Factor #3 – Energy and Non-Air Environmental Impacts

SCR for NOx results in a fuel penalty and requires use of electricity to drive reagent pumps. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. SCR would also introduce other air impacts – e.g., ammonia emissions (which are a particulate precursor).

Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of twenty years for SCR. A twenty-year lifetime exceeds typical estimates for emission control analysis presented in a U.S. Department of Energy (DOE) report[5] and control technology analysis in EPA regulations and regulations from other states, and greatly exceeds the technology warranty. The turbine life is much longer and not limited if standard maintenance requirements are followed.

Summary

In summary, the four factor analysis indicates a NOx cost effectiveness of $37,750 per ton for SCR. Several conservative assumptions tend to lower this cost. If alternatives were assumed that decreased parameters such as hours of operation, and average load, the cost per ton would increase. In addition, there are questions about technological feasibility for retrofitting SCR to an existing compressor driver turbine, especially when the unit will typically operate at a reduced load. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia emissions), and other factors (e.g., catalyst disposal, ammonia transportation and use). NBPL recommends no further control requirements for Compressor Station No. 3.

[5] "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines," Department of Energy, Prepared by ONSITE SYCOM Energy Corporation under Contract No. DE-FC02-97CHIO877 (November 1999).

Table 1. Rolls Royce Cobrerra DLE Turbine Selective Catalytic Reduction NOx Control Cost Effectiveness.

NOx Control Cost Effectiveness Estimate

Engine Manufacturer	Cooper-Rolls
Model No.	Cobrerra 2648S Avon
Engine Type	
Fuel Used	Natural Gas
Emissions Control	SCR
Combustion Control Purpose	NOx
Target Reduction	75%

Color Legend
User Data / Information Input Cell
"Cumulative" Cost Cell for Primary Categories
Cost Effectiveness ($ / ton)

				Comments
1 Engine Design Conditions				**Comments**
Power Output	24000	(hp)	(ISO rating 38,000 hp)	Anticpated average annual horsepower for future operations
Engine Exhaust Temperature		(F)		*optional input*
Engine Exhaust Rate		(lb/hr)		*optional input*
Gas Volume		(dscfm)		*optional input*
2 Full Load Engine Exhaust Composition:				**Comments**
Oxygen (O_2)		(vol. %)		*optional input*
Carbon Dioxide (CO_2)		(vol. %)		*optional input*
Water (H_2O)		(vol. %)		*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)		*optional input*
Nitrogen (N_2)		(vol. %)		*optional input*
NOx	22.5	lb/hr	0.117 (lb/MMBtu)	NOx emissions - Full Load emission factor for DLE (2003 test)
	50.54	(NOx TPY pre-SCR)		
3 Engine Parameters				**Comments**
Total Operating Hours per Season	4500	(hrs)	51% utilization	
4 Final Exhaust Gas Composition				**Comments**
Oxides of Nitrogen (NOx)	5.6	lb/hr	0.029 (lb/MMBtu)	Assume 75% reduction for unit equipped with DLE combustion
5 Economic Parameters				**Comments**
Source of Cost Data	see Analysis			Analysis primarily relying on EPA Cost Manual
Direct Costs		**Cost Formula**		**Comments**
Control Equipment and Auxiliary Equipment	$4,250,000	(A)		Based on EPA control cost manual ($100/kw; adjust to 2018$)
Instrumentation	$85,000	~~(0.1*A)~~		Default is 0.1*A; use lower value from example (improved flow control)
Sales Taxes	$130,050	(0.03*(A+instrumentation))		3% Sales Tax in this example
Freight	$212,500	(0.05*A)		Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$4,677,550**	PEC		
6 Direct Installation Costs		**Cost Formula**		**Comments**
Foundations and Supports	$374,200	(0.08*PEC)		Calculated Cost using EPA Control Cost Manual
Handling and Erection	$654,860	(0.14*PEC)		Calculated Cost using EPA Control Cost Manual
Electrical	$187,100	(0.04*PEC)		Calculated Cost using EPA Control Cost Manual
Piping	$93,550	(0.02*PEC)		Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	$46,780	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Painting	$46,780	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP		As required
Buildings	$0	Bldg		As required
Total Installation Cost (TIC)	**$1,403,270**			

Table 1 (continued).

	Total Direct Costs (PEC+TIC)	**$6,080,820**				
7	**Indirect Costs**		**Cost Formula**			**Comments**
	Engineering	$467,755	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Construction and field expenses	$233,878	(0.05*PEC)			Calculated Cost using EPA Control Cost Manual
	Contractor fees	$467,755	(0.10*PEC)			Calculated Cost using EPA Control Cost Manual
	Start-up	$93,551	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
	Performance test	$46,776	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
	Contingencies	$140,327	(0.03*PEC)			Calculated Cost using EPA Control Cost Manual
	Total Indirect Costs (IC)	**$1,450,041**	(0.31*PEC)			
8	**Capital Cost Summary**					**Comments**
	Total Direct Capital Costs (DC)	$6,080,820				
	Total Indirect Capital Costs (IC)	$1,450,041				
	Total Capital Investment (TCI)	**$7,530,861**				
9	**Direct Annual Costs**		**Cost Formula**			**Comments**
	Operator Labor	$12,500	nominal cost			0.5 hr/shift; example from similar EPA analysis
	Supervisor Labor	$1,875				15% of operator
	Operating Materials - ammonia	$11,301				estimate of materials - annual ammonia at $550 per ton; 1.1 molar ratio
	Maintenance - Labor	$12,500	nominal cost			0.5 hr/shift; rate example from EPA
	Maintenance - Materials	$5,000	nominal cost			Engineering Estimate
	Catalyst maintenance / replacement	$425,000				Engineering Estimate (10% of Cap Cost)
	Testing and QA/QC	$20,000				Engineering estimate - Annual test; reagent controller QA
	Electricity	$5,000				from PA DEP TSD
	Total Direct Annual Costs	**$493,176**				
10	**Indirect Annual Costs**		**Cost Formula**	**Capital Recovery Factor**		**Comments**
	Overhead	$19,125	(0.6*(OL+SL+ML+MM))			
	Administrative Charges	$150,617	(0.02*TCI)			Engine ACT Document
	Property Taxes	$75,309	(0.01*TCI)			Engine ACT Document
	Insurance	$75,309	(0.01*TCI)		**CRF**	
	Capital Recovery	$617,531	CRF[TCI]		0.082	Factor for costs annualized over 20 years at 5.25% interest.
	Total Indirect Annual Costs	**$937,890**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)	
11	**Summary**					**Comments**
	Total Direct Annual Operating Costs	$493,176				
	Total Indirect Annual Operating Costs	$937,890				
	Total Annual Costs	$1,431,066		$60	$ per hp	
	Incremental Annual Costs Over Baseline	$1,431,066				
12	**Annual Emissions Reduction Over Baseline**					**Comments**
	Oxides of Nitrogen (NOx)	37.91	(Tons)			
	Cost Effectiveness ($/Ton)					**Comments**
	Oxides of Nitrogen (NOx)	$37,751				