INFORMATION REQUEST REFERENCE INFORMATION

Agency	Date of Request	Letter Request No.	AGDC ID No.
ADEC	12-3-2019	N/A	N/A

REQUEST:

Provide additional information to support the use of facility specific cost factors and vendor data to the EPA Cost Control Manual equations (6^{th} edition) used to evaluate cost effectiveness for Selective Catalytic Reduction. Alternatively, provide updated cost effectiveness calculations using EPA default cost factors and equations.

RESPONSE:

AGDC has reviewed the cost-effectiveness calculations and updated them based on ADEC input. The revised cost effectiveness calculations continue to demonstrate that installation of a selective catalytic reduction (SCR) system on the Gas Treatment Plant (GTP) and Liquefaction (LNG) facility turbines is not cost effective under both the procedures described in the 2002 (6th Edition) and 2019 versions (7th Edition) of the EPA Cost Control Manual. The updated results are summarized in the table below, and backup for the calculations are included in Appendix A (6th edition) and Appendix B (7th edition):

Facility	Unit	EPA 6th Edition Cost Manual ($/ton NOx Removed)	EPA 7th Edition Cost Manual ($/ton NOx Removed)
		Facility Specific Cost Factors Applied	EPA Default Calculation Tool Applied
GTP	CO_2 Compressor Turbines	$16,333	$10,941
GTP	Power Generation Turbines	$25,402	$13,428
GTP	Treated Gas Compressor Turbines	$14,200	$10,895
LNG	Compressor Turbines	$18,164	$11,241
LNG	Power Generation Turbines	$24,588	$10,904

The 6th edition cost estimates were updated as follows:

- AGDC obtained vendor quotes for the potential turbine models being considered for the Project. Appendix C to this response provides the budgetary cost quotations.
- Appendix C to this response provides back-up documentation to support the site-specific assumptions used in the cost calculations. Some of the assumptions used in prior cost effectiveness calculations have been updated based on a review of the current engineering data.

- AGDC has updated the baseline NOx assumptions used in the cost-effectiveness calculations for the compressor turbines at the LNG plant. AGDC has surveyed possible turbine vendors and determined that baseline NOx values are between 9 and 15ppmv @ 15% O_2. For the purposes of the analysis, AGDC has assumed the upper bound of the range (i.e., 15ppmv NOx), consistent with the analysis for the other GTP and LNG turbines proposed for the Project.
- Where supplemental fire is anticipated for the turbine operations, the NOx from duct fire burning has also been considered in the cost-effectiveness calculations. Duct firing is expected at the GTP CO_2 and Treated Gas Compressors.
- The controlled NOx emissions target in the cost effectiveness calculations is assumed to be 2ppmv @ 15% O_2. While this level of control has been achieved elsewhere in BACT/LAER determinations, we believe it is an aggressive level of NOx control, considering the environment where these turbines will operate. AGDC believes that 5ppmv NOx would be a more reasonable level. Nevertheless, to assure the cost effectiveness calculations are conservative, a 2ppmv NOx target was used in the analysis.

For completeness, AGDC modeled cost effectiveness using both the EPA 6th and 7th editions. However, it is important to note the 6th edition cost-effectiveness results are likely more accurate for the Alaska LNG Project than the 7th edition results, because the 7th edition has limited capability for the user to enter site specific information. Site-specific conditions for both the GTP and the Liquefaction Facility are significantly different from the 'standard' EPA model because of the increased transportation requirements to get equipment to Alaska and the operating conditions. The 7th edition cost effectiveness calculations are biased low in the following respects:

- SCR cost data for simple cycle gas turbines is based on limited vendor data collected in the 1990's for typical units expected to be installed within the contiguous United States.
- EPA vendor data does not reflect additional expenses of installing large scale equipment in Alaska including the costs of modularization of the turbines and the unique installation method on the North Slope (i.e., sea lifts to the facility locations);
- The study does not appear to leverage any other data or information that is specific to installations in the Alaska.

The cost effectiveness calculations and supporting data are attached to this response. The key assumptions used to prepare the calculations are summarized below.

GTP ASSUMPTIONS:

The key facility-specific cost factors which differ from the typical EPA factors described in the 6th edition cost effectiveness calculation method for GTP include:

Cost Category	GTP	Comments Regarding AGDC Approach
Direct Capital Costs		
Purchased Equipment Costs	---	AeriNOx Quote (1/7/2020)
Ammonia System	0%	Included in Purchased Equipment Costs
Instrumentation & Controls	0%	Included in Purchased Equipment Costs
Freight	10.7%	Updated based on ratios from the GTP estimated freight costs provided in Appendix C.
Taxes (Enter sales tax rate in "% Applied")	0%	No sales tax in Alaska.
Direct Installation Costs:		
Foundation & Supports	8.8%	50% of North Slope module pile foundations and supporting structural steel installation cost ratio Supporting information is provided in Appendix C.
Erection and Handling	31%	Includes 30% of the Structural Steel portion of the installation cost ratio and 1% of the mechanical portion. . See Appendix C.
Electrical	3.8%	50% of Electrical portion of the installation cost ratio, includes instrumentation
Piping	5.2%	10% of Piping portion of the installation cost ratio
Insulation	6.8%	30% Insulation portion of the installation cost ratio
Indirect Costs:		
Engineering & Supervision	16%	Site engineering and construction management plus North Slope engineering and construction management.
Construction and Field Expenses	0%	Did not include.
Contractor Fees	0%	Did not include.
Startup-up	0%	Did not include.
Performance Testing	0%	Did not include.

Other facility-specific costs included in the cost effectiveness evaluation for GTP:

Data Element	6th Edition Values Applied	Sources for Value
Purchased Equipment Costs	$4,100,000	January 2020 Quote - Power Generation Units
	$3,500,000	January 2020 Quote - CO2 Compression Units
	$4,100,000	January 2020 Quote – Treated Gas Compression Units
Site Preparation	$45,000	January 2020 Quote

Data Element	6th Edition Values Applied	Sources for Value
Construction and Field Expenses	$120,000	January 2020 Quote – Construction Supervision
Reagent Cost ($/gallon)	$5.67/gallon	Ammonia cost per Brenntag quote (June 15, 2015). See Appendix C.
Electricity Cost ($/kWh)	0.16	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017: https://www.eia.gov/electricity/data.php#sales
Higher Heating Value (HHV) (Btu/scf)	1077	HHV per GTP Fuel Gas specifications.

LNG ASSUMPTIONS:

The LNG facility-specific cost factors that were applied generally fall within the typical EPA factors described in the 6th edition cost effectiveness calculation method. Cost factors specifically applied for LNG cost estimates are summarized below:

Cost Category	LNG	Comments Regarding AGDC Approach
Purchased Equipment:		
Purchased Equipment Costs	---	AeriNOx Quote (1/7/2020)
Ammonia System	0%	Included in Purchased Equipment Costs
Instrumentation & Controls	0%	Included in Purchased Equipment Costs
Taxes (Enter sales tax rate in "% Applied")	0.0%	No sales tax in Alaska

Other facility-specific costs included in the cost effectiveness evaluation for LNG:

Data Element	6th Edition Values Applied	Sources for Value
Purchased Equipment Costs	$7,800,000	January 2020 Quote - Compression Units
	$4,100,000	January 2020 Quote - Power Generation Units
Site Preparation	$45,000	January 2020 Quote
Construction and Field Expenses	$120,000	January 2020 Quote – Construction Supervision
Reagent Cost ($/gallon)	$2.24/gallon	Ammonia cost based on $0.30/pound (Weekly Fertilizer Review, 4/2015)
Electricity Cost ($/kWh)	0.16	Updated electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017: https://www.eia.gov/electricity/data.php#sales
Higher Heating Value (HHV) (Btu/scf)	1087	HHV per LNG Fuel Gas specifications.

APPENDICES:

Appendix A – 6th Edition Cost Effectiveness Calculations – Facility Specific Cost Factor Analysis:

- Appendix A.1 – GTP Power Generation Turbines
- Appendix A.2 – GTP CO2 Compressor Turbines
- Appendix A.3 – GTP Treated Gas Compressor Turbines
- Appendix A.4 – LNG Power Generation Turbines
- Appendix A.5 – LNG Compressor Turbines

Appendix B – 7th Edition Cost Effectiveness Calculations – EPA Default Analysis:

- Appendix B.1 – GTP Power Generation Turbines
- Appendix B.2 – GTP CO2 Compressor Turbines
- Appendix B.3 – GTP Treated Gas Compressor Turbines
- Appendix B.4 – LNG Power Generation Turbines
- Appendix B.5 – LNG Compressor Turbines

Appendix C – Supporting Information:

- Appendix C.1 – AeriNOx SCR quote (January 2020)
- Appendix C.2 – Brentag ammonia cost quote (2015)
- Appendix C.3 – GTP Cost Estimate Basis for SCR Cost Evaluation (Confidential)

APPENDIX A - 6TH EDITION COST EFFECTIVENESS CALCULATIONS – FACILITY SPECIFIC COST FACTOR ANALYSIS

APPENDIX A.1

GTP Power Generation Turbines

ALASKA LNG

Appendix A.1 - BACT Cost Effectiveness (Main Power Generator)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
Power Gen SCR Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$4,100,000		-	A	AeriNOx Quote (1/7/2020)
Ammonia System	$0		-	B	Included in Purchased Equipment Costs
Instrumentation & Controls		$0	0%	C = 0.00 x A	Included in Purchased Equipment Costs
Freight		$459,610	11.2%	D = 0.11 x (A+B)	Cost factor based on ratios from the GTP estimate equipment to freight costs
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$4,559,610		-	PE	
Direct Installation Costs:					
Foundation & Supports		$1,504,671	33%	0.33 x PE	33% based on cost to modularize equipment.
Erection and Handling		$1,550,267	34%	0.34 x PE	34% based on NS sea lift logistics costs vs equipment costs Did not include any NS installation costs
Electrical		$0	0%	0.00 x PE	Part of Foundation and Supports
Piping		$0	0%	0.00 x PE	Part of Foundation and Supports
Insulation		$0	0%	0.00 x PE	Part of Foundation and Supports
Painting		$0	0%	0.00 x PE	Part of Foundation and Supports
Site Preparation	$45,000		-	Project-Specific	AeriNOx Quote (1/7/2020)
Total Direct Installation Cost (DI)	$3,099,939		-	DI	
Total Direct Capital Costs (DC)	**$7,659,549**		-	**DC = PE + DI**	
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$1,504,671	33%	0.33 x PE	33% based on MFS const management and Const staff, no eng costs included
Construction and Field Expenses		$0	0%	0.00 x PE	Did not include.
Contractor Fees		$0	0%	0.00 x PE	Did not include.
Startup-up		$0	0%	0.00 x PE	Did not include.
Performance Testing		$0	0%	0.00 x PE	Did not include.
Total Indirect Costs (TIC)	**$1,504,671**		-	IC	
Capital Investment:					
Project Contingency		$1,374,633.00	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$316,165.59	3%	F = 0.03 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Inventory Capital (initial reagent fill)		$10,031	-	G = [Storage Gal] x [Reagent $/gal]	See parameters below
Total Capital Investment	**$10,865,050**		-	**TCI = DC + IC + E + F + G**	

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
Power Gen SCR Cost Effectiveness Analysis

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor			-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$162,976	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$162,976	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Reagent Cost		$261,522	-	q*Cost*[op hr/yr]	See parameters below
Annual Electricity Cost		$152,882	-	See parameters below	See parameters below
Catalyst Replacement		$76,236	-	See parameters below	See parameters below
Catalyst Disposal Cost		$7,624	10%	0.100 x Cat Repl	Engineering Estimate
Fuel Penalty Costs (specify)			-		Vendor Supplied
Other Maintenance Cost (specify)			-		Vendor Supplied
Total Direct Annual Costs	**$824,215**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$195,571	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$108,650	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$108,650	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$217,301	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$630,173**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$1,546,939**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$3,001,326**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

			Reference
Uncontrolled NOx (tpy)	100.61		Calculated below
Controlled NOx Emissions (tpy)	13.41		Calculated below
NOx Reduction (tpy)	87.20		Calculated below

		Reference
Total Annual Costs	$3,001,326	Calculated above
Cost Effectiveness ($/ton/yr)	**$34,421**	OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
Power Gen SCR Cost Effectiveness Analysis

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

				Reference
Turbine heat capacity:		418.00	MMBtu/hr	
Duct burner heat capacity, if applicable:			MMBtu/hr	

NOx Emission Rates

				Reference
Turbine uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	15	ppmv @ 15% O2	Assumption for baseline/uncontrolled emissions
	or (default)		ppmv @ 15% O2	
Duct burner uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or		ppmv @ 3% O2	
	or (default)		ppmv @ 3% O2	
Controlled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	2	ppmv @ 15% O2	Most stringent limit identified as BACT

Natural Gas Properties

			Reference
HHV [Default: 1050 Btu/scf]	1077	Btu/scf	
F-factor (dry) [Default: 8710 dscf/MMBtu]		dscf/MMBtu	EPA 40 CFR Part 60 Appendix A, Method 19, Table 19-2

Operational Parameters

			Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

			Reference
Power demand:		kW	Calculated below
If power demand is not known, estimate on the basis of the parameters below:			
delta P duct [Default: 3 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
delta P catalyst (per layer) [Default: 1 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
number of layers of catalyst	2		
Calculated Power demand:	111.8	kW	OAQPS Eqn 2.48 (Section 4.2, Ch. 2)

ALASKA LNG

Appendix A.1 - BACT Cost Effectiveness (Main Power Generator)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
Power Gen SCR Cost Effectiveness Analysis

Electricity Cost [Default: 0.1572 $/kWh]	0.16	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017.

Aqueous Ammonia Costs: Enter values below or parameters to estimate.

			Reference
Aqueous ammonia cost:	$5.67	$/gallon	Ammonia cost per Brenntag quote (June 15, 2015).
Aqueous ammonia storage volume:		gallons	
or	14	days' worth	Engineering Estimate
Aqueous ammonia consumption rate:		gal/hr	
If aqueous ammonia consumption rate not known, estimate on the basis of the parameters below:			
Stored NH3 concentration [Default: 19.4%]		wt%	
NH3 solution mass flow rate (m_{sol})	40.97	lb/hr	OAQPS (Section 4.2, Ch. 2)
NH3 solution density [Default: 7.782 lb/gal]	7.782	lb/gal	Engineeering Data
Calculated Aqueous ammonia consumption rate:	5.3	gal/hr	OAQPS Eqn 2.32-2.34 (Section 4.2, Ch. 2)

Catalyst Costs:

			Reference
Initial catalyst cost:	$245,091		OAQPS (Section 4.2, Ch. 2)
Catalyst replacement frequency:	3	years	
Interest Rate	7.00%	%	ADEC Default
Annual Catalyst Replacement Cost	$76,236		OAQPS Eqn 2.51 (Section 4.2, Ch. 2)

* OAQPS refers to the EPA Air Pollution Control Cost Manual, Sixth Edition and subsequent revisions.

APPENDIX A.2

GTP CO_2 Compressor Turbines

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
CO_2 Compression SCR Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$3,500,000		-	A	AeriNOx Quote (1/7/2020)
Ammonia System	$0		-	B	Included in Purchased Equipment Costs
Instrumentation & Controls		$0	0%	C = 0.00 x A	Included in Purchased Equipment Costs
Freight		$392,350	11.2%	D = 0.11 x (A+B)	Cost factor based on ratios from the GTP estimate equipment to freight costs
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$3,892,350		-	PE	
Direct Installation Costs:					
Foundation & Supports		$1,284,476	33%	0.33 x PE	33% based on cost to modularize equipment.
Erection and Handling		$1,323,399	34%	0.34 x PE	34% based on NS sea lift logistics costs vs equipment costs Did not include any NS installation costs
Electrical		$0	0%	0.00 x PE	Part of Foundation and Supports
Piping		$0	0%	0.00 x PE	Part of Foundation and Supports
Insulation		$0	0%	0.00 x PE	Part of Foundation and Supports
Painting		$0	0%	0.00 x PE	Part of Foundation and Supports
Site Preparation	$45,000		-	Project-Specific	AeriNOx Quote (1/7/2020)
Total Direct Installation Cost (DI)	$2,652,875		-	DI	
Total Direct Capital Costs (DC)	**$6,545,225**		-	**DC = PE + DI**	
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$1,284,476	33%	0.33 x PE	33% based on MFS const management and Const staff, no eng costs included
Construction and Field Expenses		$0	0%	0.00 x PE	Did not include.
Contractor Fees		$0	0%	0.00 x PE	Did not include.
Startup-up		$0	0%	0.00 x PE	Did not include.
Performance Testing		$0	0%	0.00 x PE	Did not include.
Total Indirect Costs (TIC)	**$1,284,476**		-	IC	
Capital Investment:					
Project Contingency		$1,174,455.00	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$270,124.65	3%	F = 0.03 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Inventory Capital (initial reagent fill)		$12,327	-	G = [Storage Gal] x [Reagent $/gal]	See parameters below
Total Capital Investment	**$9,286,606**		-	**TCI = DC + IC + E + F + G**	

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
CO_2 Compression SCR Cost Effectiveness Analysis

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor			-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$139,299	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$139,299	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Reagent Cost		$321,376	-	q*Cost*[op hr/yr]	See parameters below
Annual Electricity Cost		$158,395	-	See parameters below	See parameters below
Catalyst Replacement		$93,268	-	See parameters below	See parameters below
Catalyst Disposal Cost		$9,327	10%	0.100 x Cat Repl	Engineering Estimate
Fuel Penalty Costs (specify)			-		Vendor Supplied
Other Maintenance Cost (specify)			-		Vendor Supplied
Total Direct Annual Costs	**$860,964**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$167,159	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$92,866	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$92,866	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$185,732	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$538,623**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$1,322,204**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$2,721,791**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

			Reference
Uncontrolled NOx (tpy)	141.86		Calculated below
Controlled NOx Emissions (tpy)	16.12		Calculated below
NOx Reduction (tpy)	125.74		Calculated below
Total Annual Costs	$2,721,791		Calculated above
Cost Effectiveness ($/ton/yr)	**$21,646**		OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
CO_2 Compression SCR Cost Effectiveness Analysis

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

			Reference
Turbine heat capacity:	311.00	MMBtu/hr	
Duct burner heat capacity, if applicable:	191.22	MMBtu/hr	

NOx Emission Rates

			Reference
Turbine uncontrolled NOx concentration:		lb NOx/MMBtu	
or		lb NOx/MMscf	
or	15.00	ppmv @ 15% O2	Assumption for baseline/uncontrolled emissions
or (default)		ppmv @ 15% O2	
Duct burner uncontrolled NOx concentration:	0.08	lb NOx/MMBtu	
or		lb NOx/MMscf	
or		ppmv @ 3% O2	
or (default)		ppmv @ 3% O2	
Controlled NOx concentration:		lb NOx/MMBtu	
or		lb NOx/MMscf	
or	2	ppmv @ 15% O2	Most stringent limit identified as BACT

Natural Gas Properties

			Reference
HHV [Default: 1050 Btu/scf]	1,077	Btu/scf	
F-factor (dry) [Default: 8710 dscf/MMBtu]		dscf/MMBtu	EPA 40 CFR Part 60 Appendix A, Method 19, Table 19-2

Operational Parameters

			Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

			Reference
Power demand:		kW	Calculated below
If power demand is not known, estimate on the basis of the parameters below:			
delta P duct [Default: 3 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
delta P catalyst (per layer) [Default: 1 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
number of layers of catalyst	4		
Calculated Power demand:	115.8	kW	OAQPS Eqn 2.48 (Section 4.2, Ch. 2)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
CO_2 Compression SCR Cost Effectiveness Analysis

Electricity Cost [Default: 0.1572 $/kWh]	0.16	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017.

Aqueous Ammonia Costs: Enter values below or parameters to estimate.

			Reference
Aqueous ammonia cost:	$5.67	$/gallon	Ammonia cost per Brenntag quote (June 15, 2015).
Aqueous ammonia storage volume:		gallons	
or	14	days' worth	Engineering Estimate
Aqueous ammonia consumption rate:		gal/hr	Calculated below
If aqueous ammonia consumption rate not known, estimate on the basis of the parameters below:			
Stored NH3 concentration [Default: 19.4%]		wt%	
NH3 solution mass flow rate (m_{sol})	50.35	lb/hr	OAQPS (Section 4.2, Ch. 2)
NH3 solution density [Default: 7.782 lb/gal]	7.782	lb/gal	Engineeering Data
Calculated Aqueous ammonia consumption rate:	6.5	gal/hr	OAQPS Eqn 2.32-2.34 (Section 4.2, Ch. 2)

Catalyst Costs:

			Reference
Initial catalyst cost:	$299,848		OAQPS (Section 4.2, Ch. 2)
Catalyst replacement frequency:	3	years	Vendor Supplied
Interest Rate	7.00%	%	ADEC Default
Annual Catalyst Replacement Cost	$93,268		OAQPS Eqn 2.51 (Section 4.2, Ch. 2)

* OAQPS refers to the EPA Air Pollution Control Cost Manual, Sixth Edition and subsequent revisions.

APPENDIX A.3

GTP Treated Gas Compressor Turbines

ALASKA LNG

Appendix A.3 - BACT Cost Effectiveness
Treated Gas Compressor Drivers)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
TG Compression SCR Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$4,100,000		-	A	AeriNOx Quote (1/7/2020)
Ammonia System	$0		-	B	Included in Purchased Equipment Costs
Instrumentation & Controls		$0	0%	C = 0.00 x A	Included in Purchased Equipment Costs
Freight		$459,610	11.2%	D = 0.11 x (A+B)	Cost factor based on ratios from the GTP estimate equipment to freight costs
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$4,559,610		-	PE	
Direct Installation Costs:					
Foundation & Supports		$1,504,671	33%	0.33 x PE	33% based on cost to modularize equipment.
Erection and Handling		$1,550,267	34%	0.34 x PE	34% based on NS sea lift logistics costs vs equipment costs Did not include any NS installation costs
Electrical		$0	0%	0.00 x PE	Part of Foundation and Supports
Piping		$0	0%	0.00 x PE	Part of Foundation and Supports
Insulation		$0	0%	0.00 x PE	Part of Foundation and Supports
Painting		$0	0%	0.00 x PE	Part of Foundation and Supports
Site Preparation	$45,000		-	Project-Specific	AeriNOx Quote (1/7/2020)
Total Direct Installation Cost (DI)	$3,099,939		-	DI	
Total Direct Capital Costs (DC)	**$7,659,549**		-	**DC = PE + DI**	
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$1,504,671	33%	0.33 x PE	33% based on MFS const management and Const staff, no eng costs included
Construction and Field Expenses		$0	0%	0.00 x PE	Did not include.
Contractor Fees		$0	0%	0.00 x PE	Did not include.
Startup-up		$0	0%	0.00 x PE	Did not include.
Performance Testing		$0	0%	0.00 x PE	Did not include.
Total Indirect Costs (TIC)	**$1,504,671**		-	IC	
Capital Investment:					
Project Contingency		$1,374,633.00	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$316,165.59	3%	F = 0.03 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Inventory Capital (initial reagent fill)		$17,266	-	G = [Storage Gal] x [Reagent $/gal]	See parameters below
Total Capital Investment	**$10,872,285**		-	**TCI = DC + IC + E + F + G**	

ALASKA LNG

Appendix A.3 - BACT Cost Effectiveness
(Treated Gas Compressor Drivers)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
TG Compression SCR Cost Effectiveness Analysis

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor			-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$163,084	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$163,084	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Reagent Cost		$450,161	-	q*Cost*[op hr/yr]	See parameters below
Annual Electricity Cost		$212,891	-	See parameters below	See parameters below
Catalyst Replacement		$130,613	-	See parameters below	See parameters below
Catalyst Disposal Cost		$13,061	10%	0.100 x Cat Repl	Engineering Estimate
Fuel Penalty Costs (specify)			-		Vendor Supplied
Other Maintenance Cost (specify)			-		Vendor Supplied
Total Direct Annual Costs	**$1,132,895**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$195,701	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$108,723	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$108,723	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$217,446	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$630,593**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$1,547,969**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$3,311,457**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

			Reference
Uncontrolled NOx (tpy)	200.35		Calculated below
Controlled NOx Emissions (tpy)	22.55		Calculated below
NOx Reduction (tpy)	177.80		Calculated below

Total Annual Costs	$3,311,457		Calculated above
Cost Effectiveness ($/ton/yr)	**$18,625**		OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

ALASKA LNG

Appendix A.3 - BACT Cost Effectiveness
(Treated Gas Compressor Drivers)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
TG Compression SCR Cost Effectiveness Analysis

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

	Value	Units	Reference
Turbine heat capacity:	418.00	MMBtu/hr	
Duct burner heat capacity, if applicable:	284.64	MMBtu/hr	

NOx Emission Rates

	Value	Units	Reference
Turbine uncontrolled NOx concentration:		lb NOx/MMBtu	
or		lb NOx/MMscf	
or	15.00	ppmv @ 15% O2	Assumption for baseline/uncontrolled emissions
or (default)		ppmv @ 15% O2	
Duct burner uncontrolled NOx concentration:	0.08	lb NOx/MMBtu	
or		lb NOx/MMscf	
or		ppmv @ 3% O2	
or (default)		ppmv @ 3% O2	
Controlled NOx concentration:		lb NOx/MMBtu	
or		lb NOx/MMscf	
or	2	ppmv @ 15% O2	Most stringent limit identified as BACT

Natural Gas Properties

	Value	Units	Reference
HHV [Default: 1050 Btu/scf]	1077	Btu/scf	GTP Fuel Gas Specificaiton
F-factor (dry) [Default: 8710 dscf/MMBtu]		dscf/MMBtu	EPA 40 CFR Part 60 Appendix A, Method 19, Table 19-2

Operational Parameters

	Value	Units	Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

	Value	Units	Reference
Power demand:		kW	Calculated below
If power demand is not known, estimate on the basis of the parameters below:			
delta P duct [Default: 3 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
delta P catalyst (per layer) [Default: 1 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
number of layers of catalyst	4		
Calculated Power demand:	155.7	kW	OAQPS Eqn 2.48 (Section 4.2, Ch. 2)

ALASKA LNG

Appendix A.3 - BACT Cost Effectiveness
(Treated Gas Compressor Drivers)

GTP BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Natural Gas Turbines
TG Compression SCR Cost Effectiveness Analysis

Electricity Cost [Default: 0.1572 $/kWh]	0.16	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017.

Aqueous Ammonia Costs: Enter values below or parameters to estimate.

			Reference
Aqueous ammonia cost:	$5.67	$/gallon	Ammonia cost per Brenntag quote (June 15, 2015).
Aqueous ammonia storage volume:		gallons	
or	14	days' worth	Engineering Estimate
Aqueous ammonia consumption rate:		gal/hr	
If aqueous ammonia consumption rate not known, estimate on the basis of the parameters below:			
Stored NH3 concentration [Default: 19.4%]		wt%	
NH3 solution mass flow rate (m_{sol})	70.53	lb/hr	OAQPS (Section 4.2, Ch. 2)
NH3 solution density [Default: 7.782 lb/gal]	7.782	lb/gal	Engineeering Data
Calculated Aqueous ammonia consumption rate:	9.1	gal/hr	OAQPS Eqn 2.32-2.34 (Section 4.2, Ch. 2)

Catalyst Costs:

			Reference
Initial catalyst cost:	$419,909		OAQPS (Section 4.2, Ch. 2)
Catalyst replacement frequency:	3	years	Vendor Supplied
Interest Rate	7.00%	%	ADEC Default
Annual Catalyst Replacement Cost	$130,613		OAQPS Eqn 2.51 (Section 4.2, Ch. 2)

* OAQPS refers to the EPA Air Pollution Control Cost Manual, Sixth Edition and subsequent revisions.

APPENDIX A.4

LNG Power Generation Turbines

LNG BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Power Generation Natural Gas Turbine
Power Gen SCR Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$4,100,000		-	A	AeriNOx Quote (1/7/2020)
Ammonia System	$0		-	B	Included in Purchased Equipment Costs
Instrumentation & Controls		$0	0%	C = 0.00 x A	Included in Purchased Equipment Costs
Freight		$205,000	5%	D = 0.05 x (A+B)	OAQPS (5% of PE)
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$4,305,000		-	PE	
Direct Installation Costs:					
Foundation & Supports		$430,500	10%	0.10 x PE	OAQPS (4-12% of PE)
Erection and Handling		$1,506,750	35%	0.35 x PE	OAQPS (14-50% of PE)
Electrical		$258,300	6%	0.06 x PE	OAQPS (1-8% of PE)
Piping		$344,400	8%	0.08 x PE	OAQPS (1-30% of PE)
Insulation		$86,100	2%	0.02 x PE	OAQPS (1-7% of PE)
Painting		$172,200	4%	0.04 x PE	OAQPS (1-4% of PE)
Site Preparation	$45,000		-	Project-Specific	AeriNOx Quote (1/7/2020)
Total Direct Installation Cost (DI)	$2,843,250		-	DI	
Total Direct Capital Costs (DC)	**$7,148,250**		-	**DC = PE + DI**	

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$645,750	15%	0.15 x PE	OAQPS (10-20% of PE)
Construction and Field Expenses		$430,500	10%	0.10 x PE	OAQPS (5-20% of PE)
Contractor Fees		$215,250	5%	0.05 x PE	OAQPS (0-10% of PE)
Startup-up		$43,050	1%	0.01 x PE	OAQPS (1-2% of PE)
Performance Testing		$43,050	1%	0.01 x PE	OAQPS (1% of PE)
Total Indirect Costs (TIC)	**$1,377,600**		-	IC	

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Capital Investment:					
Project Contingency		$1,278,877.50	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$196,094.55	2%	F = 0.02 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Inventory Capital (initial reagent fill)		$4,077	-	G = [Storage Gal] x [Reagent $/gal]	See parameters below
Total Capital Investment	**$10,004,899**		-	**TCI = DC + IC + E + F + G**	

LNG BACT ANALYSIS
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Alaska LNG Project
Power Generation Natural Gas Turbine
Power Gen SCR Cost Effectiveness Analysis

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor			-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$150,073	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$150,073	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Reagent Cost		$106,283	-	q*Cost*[op hr/yr]	See parameters below
Annual Electricity Cost		$188,137	-	See parameters below	See parameters below
Catalyst Replacement		$78,424	-	See parameters below	See parameters below
Catalyst Disposal Cost		$7,842	10%	0.100 x Cat Repl	Engineering Estimate
Fuel Penalty Costs (specify)			-		Vendor Supplied
Other Maintenance Cost (specify)			-		Vendor Supplied
Total Direct Annual Costs	**$680,834**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$180,088	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$100,049	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$100,049	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$200,098	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$580,284**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$1,424,472**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$2,685,591**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

			Reference
Uncontrolled NOx (tpy)	103.50		Calculated below
Controlled NOx Emissions (tpy)	13.80		Calculated below
NOx Reduction (tpy)	89.70		Calculated below
Total Annual Costs	$2,685,591		Calculated above
Cost Effectiveness ($/ton/yr)	**$29,940**		OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

LNG BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Power Generation Natural Gas Turbine
Power Gen SCR Cost Effectiveness Analysis

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

				Reference
Turbine heat capacity:		430.00	MMBtu/hr	
Duct burner heat capacity, if applicable:			MMBtu/hr	

NOx Emission Rates

				Reference
Turbine uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	15	ppmv @ 15% O2	Assumption for baseline/uncontrolled emissions
	or (default)		ppmv @ 15% O2	
Duct burner uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or		ppmv @ 3% O2	
	or (default)		ppmv @ 3% O2	
Controlled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	2	ppmv @ 15% O2	Most stringent limit identified as BACT

Natural Gas Properties

			Reference
HHV [Default: 1050 Btu/scf]	1087	Btu/scf	LNG Fuel Gas Specification
F-factor (dry) [Default: 8710 dscf/MMBtu]		dscf/MMBtu	EPA 40 CFR Part 60 Appendix A, Method 19, Table 19-2

Operational Parameters

			Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

			Reference
Power demand:		kW	Calculated below
If power demand is not known, estimate on the basis of the parameters below:			
delta P duct [Default: 3 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
delta P catalyst (per layer) [Default: 1 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
number of layers of catalyst	3		
Calculated Power demand:	137.6	kW	OAQPS Eqn 2.48 (Section 4.2, Ch. 2)

LNG BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Power Generation Natural Gas Turbine
Power Gen SCR Cost Effectiveness Analysis

Electricity Cost [Default: 0.1572 $/kWh]	0.16	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017.

Aqueous Ammonia Costs: Enter values below or parameters to estimate.

			Reference
Aqueous ammonia cost:	$2.24	$/gallon	Ammonia cost as specified in AKLNG Supporting Data (USAL-CB-SRZZZ-00-000005-500): $0.30/pound (Weekly Fertilizer Review, 4/2015)
Aqueous ammonia storage volume:		gallons	
or	14	days' worth	Engineering Estimate
Aqueous ammonia consumption rate:		gal/hr	
If aqueous ammonia consumption rate not known, estimate on the basis of the parameters below:			
Stored NH3 concentration [Default: 19.4%]		wt%	
NH3 solution mass flow rate (m_{sol})	42.15	lb/hr	OAQPS
NH3 solution density [Default: 7.782 lb/gal]	7.782	lb/gal	Engineeering Data
Calculated Aqueous ammonia consumption rate:	5.4	gal/hr	OAQPS Eqn 2.32-2.34 (Section 4.2, Ch. 2)

Catalyst Costs:

			Reference
Initial catalyst cost:	$252,127		OAQPS (Section 4.2, Ch. 2)
Catalyst replacement frequency:	3	years	
Interest Rate	7.00%	%	ADEC Default
Annual Catalyst Replacement Cost	$78,424		OAQPS Eqn 2.51 (Section 4.2, Ch. 2)

* OAQPS refers to the EPA Air Pollution Control Cost Manual, Sixth Edition and subsequent revisions.

APPENDIX A.5

LNG Compressor Turbines

LNG BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Compressor Driver Natural Gas Turbine
SCR Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$7,800,000		-	A	AeriNOx Quote (1/7/2020)
Ammonia System	$0		-	B	Included in Purchased Equipment Costs
Instrumentation & Controls		$0	0%	C = 0.00 x A	Included in Purchased Equipment Costs
Freight		$390,000	5%	D = 0.05 x (A+B)	OAQPS (5% of PE)
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$8,190,000		-	PE	
Direct Installation Costs:					
Foundation & Supports		$819,000	10%	0.10 x PE	OAQPS (4-12% of PE)
Erection and Handling		$2,866,500	35%	0.35 x PE	OAQPS (14-50% of PE)
Electrical		$491,400	6%	0.06 x PE	OAQPS (1-8% of PE)
Piping		$655,200	8%	0.08 x PE	OAQPS (1-30% of PE)
Insulation		$163,800	2%	0.02 x PE	OAQPS (1-7% of PE)
Painting		$327,600	4%	0.04 x PE	OAQPS (1-4% of PE)
Site Preparation	$45,000		-	Project-Specific	AeriNOx Quote (1/7/2020)
Total Direct Installation Cost (DI)	$5,368,500		-	DI	
Total Direct Capital Costs (DC)	**$13,558,500**		-	**DC = PE + DI**	
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$1,228,500	15%	0.15 x PE	OAQPS (10-20% of PE)
Construction and Field Expenses		$819,000	10%	0.10 x PE	OAQPS (5-20% of PE)
Contractor Fees		$409,500	5%	0.05 x PE	OAQPS (0-10% of PE)
Startup-up		$81,900	1%	0.01 x PE	OAQPS (1-2% of PE)
Performance Testing		$81,900	1%	0.01 x PE	OAQPS (1% of PE)
Total Indirect Costs (TIC)	**$2,620,800**		-	IC	
Capital Investment:					
Project Contingency		2426895	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$372,123.90	2%	F = 0.02 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Inventory Capital (initial reagent fill)		$11,035	-	G = [Storage Gal] x [Reagent $/gal]	See parameters below
Total Capital Investment	**$18,989,354**		-	**TCI = DC + IC + E + F + G**	

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Alaska LNG Project
Compressor Driver Natural Gas Turbine
SCR Cost Effectiveness Analysis

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor			-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$284,840	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$284,840	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Reagent Cost		$287,707	-	q*Cost*[op hr/yr]	See parameters below
Annual Electricity Cost		$425,728	-	See parameters below	See parameters below
Catalyst Replacement		$212,293	-	See parameters below	See parameters below
Catalyst Disposal Cost		$21,229	10%	0.100 x Cat Repl	Engineering Estimate
Fuel Penalty Costs (specify)			-		Vendor Supplied
Other Maintenance Cost (specify)			-		Vendor Supplied
Total Direct Annual Costs	**$1,516,638**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$341,808	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$189,894	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$189,894	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$379,787	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$1,101,383**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$2,703,657**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$5,321,677**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

			Reference
Uncontrolled NOx (tpy)	280.17		Calculated below
Controlled NOx Emissions (tpy)	37.36		Calculated below
NOx Reduction (tpy)	242.81		Calculated below
Total Annual Costs	$5,321,677		Calculated above
Cost Effectiveness ($/ton/yr)	**$21,917**		OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

LNG BACT ANALYSIS
6th Edition EPA Cost Control Manual

Alaska LNG Project
Compressor Driver Natural Gas Turbine
SCR Cost Effectiveness Analysis

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

				Reference
Turbine heat capacity:		1164.00	MMBtu/hr	
Duct burner heat capacity, if applicable:			MMBtu/hr	

NOx Emission Rates

				Reference
Turbine uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	15.00	ppmv @ 15% O2	Assumption for baseline/uncontrolled emissions
	or (default)		ppmv @ 15% O2	
Duct burner uncontrolled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or		ppmv @ 3% O2	
	or (default)		ppmv @ 3% O2	
Controlled NOx concentration:			lb NOx/MMBtu	
	or		lb NOx/MMscf	
	or	2	ppmv @ 15% O2	Most stringent limit identified as BACT

Natural Gas Properties

			Reference
HHV [Default: 1050 Btu/scf]	1087	Btu/scf	LNG Fuel Gas Specification
F-factor (dry) [Default: 8710 dscf/MMBtu]		dscf/MMBtu	EPA 40 CFR Part 60 Appendix A, Method 19, Table 19-2

Operational Parameters

			Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

			Reference
Power demand:		kW	Calculated below
If power demand is not known, estimate on the basis of the parameters below:			
delta P duct [Default: 3 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
delta P catalyst (per layer) [Default: 1 in H2O]			OAQPS Eqn 2.48 (Section 4.2, Ch. 2)
number of layers of catalyst	2		
Calculated Power demand:	311.4	kW	OAQPS Eqn 2.48 (Section 4.2, Ch. 2)

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Alaska LNG Project
Compressor Driver Natural Gas Turbine
SCR Cost Effectiveness Analysis

Electricity Cost [Default: 0.1572 \$/kWh]	0.16	\$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska in 2017.

Aqueous Ammonia Costs: Enter values below or parameters to estimate.

			Reference
Aqueous ammonia cost:	\$2.24	\$/gallon	Ammonia cost as specified in AKLNG Supporting Data (USAL-CB-SRZZZ-00-000005-500): \$0.30/pound (Weekly Fertilizer Review, 4/2015)
Aqueous ammonia storage volume:		gallons	Calculated below
or	14	days' worth	Engineering Estimate
Aqueous ammonia consumption rate:		gal/hr	Calculated below
If aqueous ammonia consumption rate not known, estimate on the basis of the parameters below:			
Stored NH3 concentration [Default: 19.4%]		wt%	
NH3 solution mass flow rate (m_{sol})	114.10	lb/hr	Calculated below
NH3 solution density [Default: 7.782 lb/gal]	7.782	lb/gal	Engineeering Data
Calculated Aqueous ammonia consumption rate:	14.7	gal/hr	OAQPS Eqn 2.32-2.34 (Section 4.2, Ch. 2)

Catalyst Costs:

			Reference
Initial catalyst cost:	\$682,502		OAQPS (Section 4.2, Ch. 2)
Catalyst replacement frequency:	3	years	Vendor Supplied
Interest Rate	7.00%	%	ADEC Default
Annual Catalyst Replacement Cost	\$212,293		OAQPS Eqn 2.51 (Section 4.2, Ch. 2)

* OAQPS refers to the EPA Air Pollution Control Cost Manual, Sixth Edition and subsequent revisions.

APPENDIX B – 7TH EDITION COST EFFECTIVENESS CALCULATIONS – EPA DEFAULT ANALYSIS

APPENDIX B.1

GTP Power Generation Turbines

GTP BACT ANALYSIS
7th Edition EPA Cost Control Manual

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 418 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,077 Btu/scf
HHV per GTP Fuel Gas specifications.

What is the estimated actual annual fuel consumption? 3,399,888,579 scf/Year

Enter the net plant heat input rate (NPHR) 9.486 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 46 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

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Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	1
Inlet NO_x Emissions (NOx_{in}) to SCR	0.055 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0074 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	5 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	1,578 Cubic feet
*The SRF value of 1.05 is a default value. User should enter actual value, if known.		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	590350 acfm

Notes: Inlet Nox 15 ppmv per Gas Turbine Vendor. Outlet NOx 2 ppmv per EPA.

Estimated operating life of the catalyst ($H_{catalyst}$)	26,280 hours	Gas temperature at the SCR inlet (T)	750 °F
Estimated SCR equipment life * For industrial boilers, the typical equipment life is between 20 and 25 years.	20 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	1412.32 ft^3/min-MMBtu/hour
Concentration of reagent as stored (C_{stored})	19 percent		
Density of reagent as stored (ρ_{stored})	58 lb/cubic feet		
Number of days reagent is stored ($t_{storage}$)	14 days		

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2017	
CEPCI for 2017	567.5 Enter the CEPCI value for 2017 · 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	5.670 $/gallon for 19% ammonia	Ammonia cost per Brenntag quote (June 15, 2015).
Electricity ($Cost_{elect}$)	0.1600 $/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska: https://www.eia.gov/electricity/data.php#sales
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

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SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	418	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,399,888,579	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,399,888,579	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.95		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	86.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	19.91	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	87.19	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.08		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	590,350	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	374.11	/hour	
Residence Time	$1/V_{space}$	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

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Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,578.00	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	615	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	707	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	26.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	30	feet

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Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	41	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,800	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	228.83	kW

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Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$5,952,307	in 2017 dollars

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Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$724,437	in 2017 dollars
Indirect Annual Costs (IDAC) =	$501,193	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$1,225,630	in 2017 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$29,762	in 2017 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$260,858	in 2017 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$320,732	in 2017 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$113,086	in 2017 dollars
Direct Annual Cost =		$724,437	in 2017 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,985	in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$498,208	in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$501,193	in 2017 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,225,630	per year in 2017 dollars
NOx Removed =	87	tons/year
Cost Effectiveness =	$14,056	per ton of NOx removed in 2017 dollars

APPENDIX B.2

GTP CO_2 Compressor Turbines

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Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	502.22 MMBtu/hour
What is the higher heating value (HHV) of the fuel? HHV per GTP Fuel Gas specifications.	1,077 Btu/scf
What is the estimated actual annual fuel consumption?	4,084,909,192 scf/Year
Enter the net plant heat input rate (NPHR)	11.398 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 46 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3

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Inlet NO_x Emissions (NOx_{in}) to SCR	0.06452	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0074	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	5	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	1,929	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	268183	acfm

Notes: Weighted average inlet Nox (Main Burner - 0.055 lb/MMBtu, Supplemental Firing - 0.08 lb/MMBtu) per Gas Turbine Vendor. Outlet NOx 2 ppmv per EPA.

Estimated operating life of the catalyst ($H_{catalyst}$)	26,280	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	750	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	534.00	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2017		
CEPCI for 2017	567.5	Enter the CEPCI value for 2017 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	5.670	$/gallon for 19% ammonia	Ammonia cost per Brenntag quote (June 15, 2015).
Electricity ($Cost_{elect}$)	0.1600	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska: https://www.eia.gov/electricity/data.php#sales
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

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SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	502	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	4,084,909,192	scf/Year	
Actual Annual fuel consumption (Mactual) =		4,084,909,192	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.14		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	88.6	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.70	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	125.70	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.11		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	268,183	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	139.03	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3157	Fraction

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Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,929.00	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	279	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	321	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	17.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	59	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,600	gallons (storage needed to store a 14 day reagent supply rounded to tl

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF\ x\ HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	297.52	kW

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Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,706,591	in 2017 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$872,673	in 2017 dollars
Indirect Annual Costs (IDAC) =	$564,372	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$1,437,045	in 2017 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$33,533	in 2017 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$376,057	in 2017 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$417,003	in 2017 dollars

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Annual Catalyst Replacement Cost =		$46,080 in 2017 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	
Direct Annual Cost =		$872,673 in 2017 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,030 in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$561,342 in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$564,372 in 2017 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,437,045 per year in 2017 dollars
NOx Removed =	126 tons/year
Cost Effectiveness =	$11,432 per ton of NOx removed in 2017 dollars

APPENDIX B.3

GTP Treated Gas Compressor Turbines

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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 702.64 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,077 Btu/scf
HHV per GTP Fuel Gas specifications.

What is the estimated actual annual fuel consumption? 5,715,066,295 scf/Year

Enter the net plant heat input rate (NPHR) 15.946 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 46 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 365 days

Number of days the boiler operates (t_{plant}) 365 days

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

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Inlet NO_x Emissions (NOx_{in}) to SCR	0.0651	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0074	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	5	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	2,692	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	385879	acfm

Notes: Weighted average inlet Nox (Main Burner - 0.055 lb/MMBtu, Supplemental Firing - 0.08 lb/MMBtu) per Gas Turbine Vendor. Outlet NOx 2 ppmv per EPA.

Estimated operating life of the catalyst ($H_{catalyst}$)	26,280	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	750	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	549.18	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2017		
CEPCI for 2017	567.5	Enter the CEPCI value for 2017 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	5.670	\$/gallon for 19% ammonia	Ammonia cost per Brenntag quote (June 15, 2015).
Electricity ($Cost_{elect}$)	0.1600	\$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska: https://www.eia.gov/electricity/data.php#sales
Catalyst cost ($CC_{replace}$)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	\$/hour (including benefits)*	* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

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SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	703	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	5,715,066,295	scf/Year	
Actual Annual fuel consumption (Mactual) =		5,715,066,295	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.59		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	88.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	40.58	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	177.74	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.11		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	385,879	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	143.34	/hour	
Residence Time	$1/V_{space}$	0.01	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)^*$ =	14.7	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3157	Fraction

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Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,692.00	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	402	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	462	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	21.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	16	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	83	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	11	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	3,600	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	480.91	kW

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Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$8,342,517	in 2017 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,311,798	in 2017 dollars
Indirect Annual Costs (IDAC) =	$701,397	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$2,013,195	in 2017 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$41,713	in 2017 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$531,735	in 2017 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$674,044	in 2017 dollars

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Annual Catalyst Replacement Cost =		$64,306 in 2017 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	
Direct Annual Cost =		$1,311,798 in 2017 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,129 in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$698,269 in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$701,397 in 2017 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,013,195 per year in 2017 dollars
NOx Removed =	178 tons/year
Cost Effectiveness =	$11,327 per ton of NOx removed in 2017 dollars

APPENDIX B.4

LNG Power Generation Turbines

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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 430 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,087 Btu/scf
HHV per LNG Fuel Gas specifications - RR9 - Appendix D.

What is the estimated actual annual fuel consumption? 3,465,317,387 scf/Year

Enter the net plant heat input rate (NPHR) 9.759 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 131 Feet above sea level

Elevation per RR9 - Appendix D, Section 1.1.

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0553	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0074	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	5	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	1,635	Cubic feet

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*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Notes: Inlet Nox 15 ppmv per Gas Turbine Vendor. Outlet NOx 2 ppmv per EPA.

Estimated operating life of the catalyst ($H_{catalyst}$)	26,280	hours
Estimated SCR equipment life	20	Years*
* For industrial boilers, the typical equipment life is between 20 and 25 years.		
Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Select the reagent used: Ammonia

Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	351168	acfm
Gas temperature at the SCR inlet (T)	341	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	816.67	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SCR:

Desired dollar-year	2017		
CEPCI for 2017	567.5	Enter the CEPCI value for 2017 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	2.240	$/gallon for 19% ammonia	Ammonia cost based on $0.30/pound (Weekly Fertilizer Review, 4/2015)
Electricity ($Cost_{elect}$)	0.1600	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska: https://www.eia.gov/electricity/data.php#sales
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

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SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,465,317,387	scf/Year	
Actual Annual fuel consumption (Mactual) =		3,465,317,387	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.98		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	86.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	20.61	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	90.26	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.08		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	351,168	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	214.78	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	1,635.00	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	366	ft^2

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Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	421	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.5	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	40	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	8	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	42	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,900	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	238.28	kW

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Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,062,828	in 2017 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$529,557	in 2017 dollars
Indirect Annual Costs (IDAC) =	$510,450	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$1,040,007	in 2017 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$30,314	in 2017 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$106,678	in 2017 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$333,980	in 2017 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$58,585	in 2017 dollars

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Direct Annual Cost =	$529,557 in 2017 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,992 in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$507,459 in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$510,450 in 2017 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,040,007	per year in 2017 dollars
NOx Removed =	90	tons/year
Cost Effectiveness =	$11,522	per ton of NOx removed in 2017 dollars

APPENDIX B.5

LNG Compressor Turbines

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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	1164 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,087 Btu/scf
What is the estimated actual annual fuel consumption?	9,380,533,579 scf/Year
Enter the net plant heat input rate (NPHR)	26.417 MMBtu/MW

HHV per LNG Fuel Gas specifications - RR9 - Appendix D.

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation: 131 Feet above sea level

Elevation per RR9 - Appendix D, Section 1.1.

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days
Number of days the boiler operates (t_{plant})	365 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.0553 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0074 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	2
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	5 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	4,080 Cubic feet

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*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Notes: Updated assumes inlet Nox 15 ppmv. Outlet NOx 2 ppmv per EPA.

Estimated operating life of the catalyst ($H_{catalyst}$)	26,280	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Select the reagent used: Ammonia

Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	1535885	acfm
Gas temperature at the SCR inlet (T)	970	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	1319.49	ft^3/min-MMBtu/hour

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SCR:

Desired dollar-year	2017		
CEPCI for 2017	567.5	Enter the CEPCI value for 2017 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	2.240	$/gallon for 19% ammonia	Ammonia cost based on $0.30/pound (Weekly Fertilizer Review, 4/2015)
Electricity ($Cost_{elect}$)	0.1600	$/kWh	Electricity pricing per Department of Energy, annual retail sales of electricity to industrial customers in Alaska: https://www.eia.gov/electricity/data.php#sales
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,164	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	9,380,533,579	scf/Year	
Actual Annual fuel consumption (Mactual) =		9,380,533,579	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	2.64		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	86.7	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	55.78	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	244.32	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.08		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,535,885	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	376.44	/hour	
Residence Time	$1/V_{space}$	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.6	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	4,080.00	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,600	ft^2

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Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	1,840	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	42.9	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	37	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	22	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	114	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	15	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/Reagent Density =	5,000	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	989.80	kW

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Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$11,582,176	in 2017 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,880,178	in 2017 dollars
Indirect Annual Costs (IDAC) =	$972,751	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$2,852,930	in 2017 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$57,911	in 2017 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$288,765	in 2017 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,387,308	in 2017 dollars
Annual Catalyst Replacement Cost =		$146,194	in 2017 dollars
	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$		

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Direct Annual Cost =	$1,880,178	in 2017 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,323	in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$969,428	in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$972,751	in 2017 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,852,930	per year in 2017 dollars
NOx Removed =	244	tons/year
Cost Effectiveness =	$11,677	per ton of NOx removed in 2017 dollars

APPENDIX C –SUPPORTING INFORMATION LNG COMPRESSOR TURBINES

APPENDIX C.1

AeriNOx SCR Quote (January 2020)

Lisa Kiehl

From: Loran Novacek <lnovacek@aerinox-inc.com>
Sent: Tuesday, January 7, 2020 5:08 PM
To: Joel LeBlanc
Cc: Bart Leininger; Lisa Kiehl
Subject: RE: SCR Sizing and Quote

Hi Joel,

Below is a very rough budgetary but should get you ballpark. This is for a horizontal duct from the turbine outlet flange to the top of the stack. I am assuming a 150ft stack height for now. We will need more customer requirements to pull together better pricing for the entire exhaust and SCR system. If CEMS is required we can include this in our scope since it allows us to drop our analyzer, used for closed loop control and use the CEMS for the feedback.

I am planning to be in the Houston area next week. Would you have time for a meeting?

ITEM	DESCRIPTION	BUDGETARY PRICE (USD)

001	**SCR-OXICAT SYSTEM (Per Unit)**
	▪ 1 x Ducting / SCR Housing / Silencer
	  ○ 1 Layer of SCR Catalyst with CS modules
	  ○ Ducting from Turbine Outlet to SCR
	  ○ Expansion joint at Turbine Outlet
	  ○ Ducting from SCR to Tailpipe
	  ○ Silencer / Tailpipe with Test Ports, 150ft Height
	▪ 1 x Tempering Air System (2 x Blowers)
	▪ 1 x Ammonia Injection Grid
	▪ 1 x Recycle Gas Skid, each including:
	  ○ 1 x Two-Phase Injection Lance for ammonia/air
	  ○ 1 x Static mixer
	  ○ 1 x Ventilator fan
	▪ 1 x SCR Control System with Touch-screen and PLC
	▪ 1 x Ammonia/Air Dosing Panel
	▪ 1 x Ammonia Pump Station (2 x 100% pumps)
	▪ 1 x Ammon Storage Tank, SS304
	▪ Engineering, Operation & Maintenance Documentation
		GTP TG COMP $4,100,000
		GTP ACID GC $3,500,000
		GTP LNG $4,100,000
		LNG MRC $7,800,000

002	**COMMISSIONING** **(Based on Time and Material Only – Per Unit)** Estimated 10 man-days (Per Turbine) for the commissioning of the emission control system to meet the required emissions levels, plus all travel expenses and accommodations. We can provide qualified personnel to supervise installation at the rate of $1,350 per man-day, plus all travel expenses. Commissioning time/expenses will be billed per the time and material rates.	**$45,000**
003	**CONSTRUCTION SUPERVISION** **(Based on Time and Material Only – Per Unit)** Estimated 60 man-days (Per Turbine) for the construction supervision/support of the emission control system. Includes	**$120,000**

	estimated travel expenses and accommodations. Construction supervision is based time/expenses will be billed per the time and material rates. NOT REQUIRED	

PRICE

The given prices for the SCR Emissions Control System are net prices, FCA Point of Manufacture per Incoterms 2010. All prices are in US dollars. Not included are duties, fees or taxes. Taxes will be included on each invoice unless a tax-exempt certificate is supplied.

PAYMENT

25% of the order value upon initial order;
20% of the order value with approval of engineering documents
20% of the order value upon release for manufacturing
30% of the order value with 'ready to ship' of hardware
5% of the order value after successful commissioning, not to exceed six (6) months after delivery

All payments are to be paid within 30 days after each date of invoice, net.

SCHEDULING & DELIVERY

Delivery of the drawings and technical documents is as follows:

- Preliminary Engineering Drawings – Approximately 20 weeks after receipt of a purchase order for preliminary drawings with final drawings approximately 12 weeks after customer review/approval
- Ready for Shipment of the hardware is approximately 32 weeks after engineering approval

EMISSION CONTROL SYSTEM DESIGN PARAMETERS:

Parameter	Unit	GTP TG COMP	GTP GAS COMP	GTP LNG COMP	LNG MRC
Estimated Reagent Flow Rate, Based on 19% Aqueous Ammonia, Per Turbine	GPH	8.5	5.5	8.5	14
Aqueous NH3 Tank Size	USG	15,000	10,000	15,000	25,000
Total System Backpressure Contribution (AIG + SCR + Ducting / Silencer / Tailpipe)	inH_2O	<10	<10	<10	<10
Air Consumption, Per Turbine (Based on 87 psi nominal, max 160 psi, Per ISO 1.2.4	cfm	25	15	25	25

EMISSIONS GUARANTEE & WARRANTY

Emission*	Units	Current Turbine Out	Required Stack Out*
NOx as NO_2 **	ppm @15% O_2	15	2

** based on 1 hour averaging with the turbine operating at 100% load*
***Maximum 20% volume of NOx is present as NO_2*

Not included in the scope of supply:

- Load signal from the turbine (4-20 mA or 0-5 VDC)

- Unit running signal (Digital dry contact, closed when turbine is running)
- Internet connection for remote SCR PLC access and data logging
- Ethernet connection for service requirements
- Structural and civil work necessary to complete the installation
- Aqueous Ammonia Solution (assumed to be delivered to the site)
- Heat tracing of Ammonia tank or Ammonia lines
- Air compressor for aqueous ammonia atomization (available as an option)
- Provision for electricity and connection of the power supply to the enclosure
- System integration (design and engineering) with the building structure
- Connection to the local supply and disposal network
- Platforms and other support structures not listed herein
- Any 3rd party emission certification of stack test
- Installation of all hardware
- Shipping and crating

Regards,

Loran Novacek
Chief Executive Officer

AeriNOx® Inc.
100 S. Cherry Ave, Ste 6B
Eaton, CO 80615
Main: 970-454-5639, Ext10
Cell: 970-443-3868
Email: lnovacek@aerinox-inc.com
Web: www.aerinox-inc.com

From: Joel LeBlanc <jleblanc@algcorp.com>
Sent: Friday, January 3, 2020 5:01 PM
To: Loran Novacek <lnovacek@aerinox-inc.com>
Cc: Bart Leininger <bleininger@algcorp.com>; Lisa Kiehl <lkiehl@algcorp.com>
Subject: RE: SCR Sizing and Quote

We made some updates to the data, some of which include a correction for power output. The updates are included in the attachment.

With regards to the NOx emissions requirement, the SCR outlet should meet 2 ppm NOx.

ASHWORTH LEININGER GROUP
Los Angeles • San Francisco • Houston • Denver
Joel LeBlanc, P.E. | Houston General Manager
T: 281.806.5830 | C: 346.246.8036 | F: 805.764.6011
2219 Sawdust Rd, Suite 1604, Spring, TX 77380
jleblanc@algcorp.com | www.algcorp.com

APPENDIX C.2

Brentag Ammonia Cost Quote (2015)

URS	CALCULATION SHEET	Calculation No. USAG-EC-PCCAL-00-000147
		Project No. 31409
Project Title:	Alaska LNG	Sheet No. 1 of 6
Subject/Feature:	SCR, CO, and Ammonia Costs for Pre-BACT	Rev: A

SCR Ammonia

Supplier		**Brenntag**	**Univar**	**Comments**	**Ref**
19% Aq. Ammonia	$/gal	$5.67	$3.20		1, 2
ISO Container Size	gallons	6000	5000		1, 2
Density	lb/gal	7.74	7.83	Brenntag did not supply density. Assumed value of 7.74	2
Container Weight	lb	46,440	39,150		
FOB		Prudhoe Bay Area	Anchorage		
Trucking Cost					
# Trucks		1	1		
From		Prudhoe Bay Area	Anchorage		
To		Prudhoe Bay Area	Prudhoe Bay Area		
Distance	mi	0	860	Fairbanks to Prudhoe bay is 500 miles per Ref 3.	3
Fuel Efficiency	mi/gal	4	4	Assumed average to/from site	3
Truck Cost	$/100 lb freight	$0.00	$19.92	Price for Fairbanks to Prudhoe Bay Ref 3, Escalated 2012 cost @ 3%/yr and adjusted for milage.	3
Fuel Surcharge	$/gal fuel	$0.00	$5.98	Assumed 30%	
Total Transit Cost	per container	$0	$10,370		
	$/gal	$0.00	$2.07		
Delivered Ammonia Cost	$/gal	$5.67	$5.27		

URS

CALCULATION SHEET

Calculation No. USAG-EC-PCCAL-00-000147

Project No. 31409

Project Title: Alaska LNG

Subject/Feature: SCR, CO, and Ammonia Costs for Pre-BACT

Sheet No. 2 of 6

Rev: A

SCR Catalyst

		Case A	Case B		Case C	Case D		Ref.
Reference (for turbine data)		[7]	[7]	[7]	[7]	[7]	[7]	[8]
Reference for Cost								[3]
		No heat	with heat	DLN1+	DLN1			
Gas Turbine		**LM6000**	**LM6000**	**Frame6**	**Frame6**	**Heater**	**PGT25+**	**Frame 7EA**
Drive		Power Gen	Power Gen	Mechanical	Mechanical			Mechanical
Exhaust Stream								
Mass Flow	[lb/hr]	1,135,408	1,082,488	1,291,288	1,291,288	243,609	648,000.00	2,293,200.00
Volume Flow	[ACFM]	657,282	626,647	747,520	747,520	93,493	379,037.00	1,464,659
	[SCFM]	251,314	239,600	285,816	285,816	105,688	139,688	511,156
Stack Diameter	[ft]	10	10	13	10			
SCR Catalyst Replacement Cost		$ 187,567.22	$ 178,824.94	$ 213,318.29	$ 213,318.29	$ 78,879.67	$ 104,255.47	350,000

Notes

1) Scaled costs from 2012 budgetary price for Frame 7EA [3] based on ACFM. New costs include 9% escalation to 2015 dollars as discussed in reference [5].

APPENDIX C.3

GTP Cost Estimate Basis for SCR Cost Evaluation (Confidential)

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GTP Cost Factors for SCR Cost Control Calculation

Cost Category	GTP Cost Estimate Basis Line Item (see MFS and North Slope Estimate tabs)	Cost Estimate %	AGDC Factor [1]	EPA Factor [2]	Comments Regarding AGDC Approach
Direct Capital Costs					
Instrumentation & Controls			0%	10%	Included in purchased equipment
Freight			11%	5%	
	FREIGHT TO MODULE FABRICATION SITE	10%			Freight from US Vendor to MFS
	MISC FREIGHT TO NORTH SLOPE	1%			Freight from Lower-48 to North Slope
Taxes (Enter sales tax rate in "% Applied")			0%	3%	No sales tax in Alaska.
Direct Installation Costs:					
Foundation & Supports	NS- EARTHWORK, STRUCTURAL STEEL	9%	9%	8 - 12%	50% of North Slope module pile foundations and supporting structural steel installation cost ratio
Erection and Handling	MFS -STRUCTURAL STEEL	30%	31%	14 - 40%	40% of the Structural Steel portion of the MFS installation cost ratio
	NS - MECHANICAL / HVAC EQUIPMENT	1%			Mechanical portion of the MFS installation cost ratio
Electrical	MFS- ELECTRICAL, INSTRUMENATION	4%	4%	1 - 4%	50% of Electrical portion of the MFS installatin cost ratio, includes instrumentation
Piping	MFS - PIPING	5%	5%	2%	10% of Piping portion of the MFS installation cost ratio
Insulation	MFS-INSULATION	7%	7%	1%	30% Insulation portion of the MFS installation cost ratio
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision			16%	10%	
	MFS- GENERAL CONTRACTOR CM	5%			MFS site engineering and construction management
	NS- CONTRACTOR CM @ SITE	11%			North Slope engineering and construction management
Project Contingency			15%	3%	Level IV Cost Estimate Basis contingency

1 - Cost factors updated in January 2020 based on revised evaluation of potential costs.

2 - EPA factors as described in EPA Air Pollution Control Cost Manual, 6th Edition, EPA/452/B-01-001, January 2002.

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Source Document: ***Gas Treatment Plant Class IV Estimate Optimization Phase AKLNG-4010-BBB-EST-DOC-00001(Confidential)***

CLIENT: Alaska LNG
PROJECT: Gas Treatment Plant
LOCATION: Prudhoe Bay, Alaska
JOB NO.: 31409
REV NO.: 0

DATE: 07-Jul-16
PREPARED BY: IJH / MLH
WAGE RATE (Blended): $25.18

ALASKA LNG

OPTIMIZATION PHASE - GAS TREATMENT PLANT
OVERALL MFS SUMMARY

ACCT.	DESCRIPTION	DIRECT HIRE			TOTAL	[%] COSTS	WEIGHT [ST]	WEIGHT [MT]
		HOURS	LABOR	MATERIALS				
01	DEMOLITION							
02	IMPROVEMENTS TO SITE							
03	EARTHWORK							
04	CONCRETE							
05	STRUCTURAL STEEL	31,158,788	$784,221,019	$276,495,489	$1,060,716,508	43%	111,420	100,359
06	MECHANICAL / HVAC EQUIPMENT	362,723	$8,893,708	$779,091,787	$787,985,495	32%	49,923	45,172
11	PIPING	4,993,879	$123,298,190	$114,826,059	$238,124,249	10%	31,587	28,601
12	ELECTRICAL	421,615	$10,959,269	$146,699,119	$157,658,388	6%	13,759	12,432
13	INSTRUMENTATION	225,375	$5,735,712	$58,324,827	$64,060,539	3%	1,154	1,045
14	PAINTING	84,698	$2,163,784	$10,497,706	$12,661,490	1%	1,108	998
15	INSULATION	844,154	$23,414,643	$79,739,753	$103,154,396	4%	8,048	7,117
16	ARCHITECTURAL	179,802	$5,065,259	$20,823,161	$25,888,421	1%	5,517	4,911
	DIRECT COSTS	**38,271,034**	**$963,751,585**	**$1,486,497,901**	**$2,450,249,486**	**100%**	**222,516**	**200,636**
31	GENERAL CONTRACTOR CM	846,644	$135,463,000		$135,463,000			
32	CRAFT LABOR RELATED EXPENSES				INCL. IN WAGE RATE			
33	TEMPORARY FACILITIES				INCL. IN WAGE RATE			
41	CONSTR EQUIP, TOOLS, SUPPLIES				INCL. IN WAGE RATE			
42	SMALL TOOLS & CONSUMABLES				INCL. IN WAGE RATE			
49	CONSTRUCTION CAMP (Not Included)				INCL. IN WAGE RATE			
51	STARTUP CRAFT SUPPORT ALLOWANCE				INCL. IN WAGE RATE			
22	FREIGHT TO MODULE FABRICATION SITE	10%	of Materials	$148,649,790	$148,649,790			
	INDIRECT COST	**846,644**	**$135,463,000**	**$148,649,790**	**$284,112,790**			
	TOTAL MODULE FABRICATION SHOP	**39,117,678**	**$1,099,214,585**	**$1,635,147,691**	**$2,734,362,276**			

PRIVILEGED AND CONFIDENTIAL - DO NOT RELEASE

Source Document: ***Gas Treatment Plant Class IV Estimate Optimization Phase AKLNG-4010-BBB-EST-DOC-00001(Confidential)***

ALASKA LNG

CLIENT: Alaska LNG
PROJECT: Gas Treatment Plant
LOCATION: Prudhoe Bay, Alaska
JOB NO.: 31409
REV NO.: 0

DATE: 07-Jul-16
PREPARED BY: IJH / MLH
WAGE RATE (Blended): $87.95

OPTIMIZATION PHASE - GAS TREATMENT PLANT
NORTH SLOPE SITEWORK

ACCT.	DESCRIPTION	FABRICATION (CHINA & NORTH AMERICA)			DIRECT HIRE			SPECIALTY SUBCONTRACTORS		TOTAL	[%] Costs	WEIGHT [ST]	WEIGHT [MT]
		HOURS	LABOR	MATERIALS	HOURS	LABOR	MATERIALS	HOURS	Total				
01	DEMOLITION												
02	IMPROVEMENTS TO SITE												
03	EARTHWORK	417,136	$19,509,499	$82,356,940	594,618	$52,326,431	$15,886,804	659,829	$324,191,851	$494,271,525	51%		
04	CONCRETE												
05	STRUCTURAL STEEL	410,317	$9,740,919	$5,760,672	543,342	$47,814,108	$12,096,622			$75,412,321	8%	14	13
06	MECHANICAL / HVAC EQUIPMENT				326,428	$28,725,665	$638,919			$29,364,584	3%	3,128	2,838
11	PIPING	56,066	$1,331,011	$84,565,274	219,249	$19,293,890	$13,318,545			$118,508,719	12%	520	472
12	ELECTRICAL				455,918	$40,117,666	$26,005,762			$66,123,428	7%	1,421	1,289
13	INSTRUMENATION				11,826	$849,691	$27,375,692			$28,225,383	3%	664	603
14	PAINTING				21	$1,859	$5,776			$7,635	0%	0	0
15	INSULATION				2,694	$237,031	$30,217			$267,248	0%	5	5
16	ARCHITECTURAL												
	MODULE INTERCONNECTS				1,778,464	$156,504,832				$156,504,832	16%		
	DIRECT FIELD COSTS	883,519	$30,581,428	$172,682,886	3,932,559	$345,871,173	$95,358,337	659,829	$324,191,851	$968,685,675	84%	5,753	5,220
32	CRAFT LABOR RELATED EXPENSES & INDIRECT CRAFT				1,110,073	$97,631,689	$0			$97,631,689	4%		
32	CRAFT TRAVEL						$31,067,241			$31,067,241			
41	SCAFFOLDING				705,193	$62,022,218	$6,004,627			$68,026,845	2%		
51	START-UP & COMMISSIONING				509,572	$44,817,168				$44,817,168	2%		
42	SMALL TOOLS AND CONSUMABLES									INCL. IN WAGE RATE			
41	TEMPORARY FACILITIES				1,547,992	$136,146,942	$39,466,880			$175,613,822	6%		
41	CONSTRUCTION EQUIPMENT				1,107,891	$97,439,752	$103,460,869			$200,900,621	7%		
41	CONSTRUCTION EQUIPMENT HEAVY LIFT CRANES				356,446	$31,349,625	$38,500,000			$69,849,625			
41	CRAFT BUSSING				499,846	$43,961,772	$4,500,000			$48,461,772	2%		
22	MISC FREIGHT TO NORTH SLOPE								$18,000,000	$18,000,000	1%		
22	LOGISTICS								$695,642,241	$695,642,241	25%		
51	CONTRACTOR CM @ SITE				1,758,387	$304,201,000				$304,201,000	11%		
51	CONTRACTOR CM @ ANCHORAGE				236,234	$30,237,952				$30,237,952	1%		
	INDIRECT FIELD COSTS	883,519	$30,581,428	$172,682,886	11,764,194	$1,193,679,289	$318,357,955	659,829	$1,037,834,092	$2,753,135,650	100%	2.84	