Apex·CAES

Apex Compressed Air Energy Storage, LLC
3200 Southwest Freeway • Suite 2210
Houston, TX 77027
www.apexcaes.com

October 12, 2012

VIA EMAIL

Melanie Magee
United States Environmental Protection Agency, Region VI
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Subject: Response to EPA Completeness Comments
Application for Greenhouse Gas PSD Permit
APEX Bethel Energy Center
Tennessee Colony, Anderson County, Texas

Dear Ms. Magee:

This letter is in response to Carl E. Edlund's request for additional information regarding the application for Greenhouse Gas PSD Permit for the APEX Bethel Energy Center located in Tennessee Colony, Anderson County, Texas.

Please find attached our responses to the requested information. If you have any questions or concerns with the information provided, please contact Ashley Campsie with CH2M HILL at 720-286-1236 or ashley.campsie@ch2m.com or myself at 713-963-8104 or stephen.naeve@apexcaes.com.

Sincerely,

Stephen W. Naeve

Stephen Naeve
Chief Operating Officer

Enclosure

cc: Mike Wilson, TCEQ Air Permits Division Director
Ashley Campsie, CH2M HILL
Peter Barth, CH2M HILL

EPA Completeness Comments

APEX Bethel Energy Center, Tennessee Colony, Anderson County, Texas

Application for Greenhouse Gas Prevention of Significant Deterioration Permit

EPA Question 1

Please provide supplemental data on the process flow diagram that identifies all GHG emission units with corresponding emission source numbers (EPNs), i.e., fugitive and maintenance, startup and shutdown emissions.

APEX Response 1

We have revised the process flow diagram (PFD) to include the following EPNs on the diagram:

- Fugitive emissions from the fuel gas conditioning process (FIN/EPN: FUG1)
- Fugitive emissions from the fuel gas metering station (FIN/EPN: FUG1)
- Fugitive emissions from components at the combustion process (FIN/EPN: FUG1)
- Fugitive SF_6 emissions at the six (6) circuit breakers (FIN/EPN: FUG1)
- Fugitive emissions at the aqueous ammonia storage and distribution, ammonia only (FIN/EPN: FUG1)
- Startup emissions at turbine train A (FIN: TURBSUA, EPN: TURBASTK)
- Startup emissions at turbine train B (FIN: TURBSUB EPN: TURBBSTK)
- Shutdown emissions at turbine train A (FIN: TURBSDA, EPN: TURBASTK)
- Shutdown emissions at turbine train B (FIN: TURBSDB EPN: TURBBSTK)
- Maintenance emissions from opening fuel gas line (FIN/EPN: MAINT1)

EPA Question 2

What are the proposed monitoring requirements for the combustion turbines operating parameters? How will the air/fuel ratio be assured during operation of the combustion turbine, i.e, alarms, alerts, continuous monitoring, etc? Will O_2 or $C0_2$ analyzers be utilized? What will be the target ratio? Please provide more details of what operating parameters will be monitored to ensure good combustion. On page 5-8 of the permit application, the proposed BACT output based limit is 4773 BTU/kWh and 558 lb CO_2/MWh. What is the company's proposed compliance monitoring methodology for this limit? Please provide a proposed maintenance and inspection schedule. To maintain the combustion efficiency, the burner maintenance will be included in the preventive maintenance program and burners will be inspected while in service. Please provide details concerning the preventive maintenance on burners, frequency and how it will be monitored and recorded. How often will burners be inspected while in service? How will this be ensured? What is the company's proposed monitoring requirements to ensure the heat recovery efficiency in Table 5-2 on page 5-7 for the recuperator is being met? What will alert onsite personnel of problems?

APEX Response 2

As stated in the application in Section 2.6, APEX is proposing to monitor the quantity of fuel combusted by the turbines in order to calculate CO_2 emissions, net heat rate (BTU/kWh) in conjunction with kWh produced, and lb CO_2 per MW-hr on a rolling 365 day period. This represents direct demonstration of compliance with the BACT limitations and therefore monitoring of other operating parameters is not needed to demonstrate compliance.

Regarding the "target" air-fuel ratio, Table 6, provided in response to Question 7, shows air and fuel flow rates at various points in the turbo expander load range. At 100% load, the quantity of air represents approximately 2.77

times the stoichiometric requirements. Air-fuel ratio of the turbo-expanders will be controlled by monitoring the turbine inlet temperature at the combustor exit. A secondary measurement will be based on the apparent fuel-air ratio based on the inlet air mass flowmeter, and the HP and LP fuel gas flowmeters. Both means of determining and controlling the fuel-air ratio will be in continuous operation while the turbo-expanders are in operation.

For the High Pressure combustors, the exit temperature is measured at the combustor exit, just ahead of the stage 1 turbine nozzles. Temperatures are monitored in 4 locations around the arc of admission, averaged to determine the overall inlet temperature, and compared to the inlet air temperature to calculate the fuel-air ratio. These temperatures are monitored continuously, and their output is fed back to the fuel controls to maintain a constant 540C turbine inlet temperature.

For the Low Pressure combustors, the turbine inlet temperature is too high at 1600F (872C) for reliable direct temperature measurement. The turbine inlet temperature is therefore determined by measuring the exhaust temperature at 9 locations around the exhaust diffuser exit. The turbine flowpath delta T is a known function of mass air flow and pressure ratio, which is then added to the averaged exhaust temperature to obtain turbine inlet temperature. The turbine inlet temperature is compared to the high pressure expander exhaust temperature to determine temperature rise and air-fuel ratio in the low pressure combustors.

In addition to the direct temperature measurements, mass airflow and mass fuel flows to both sets of combustors are measured and monitored by the plant control and data logging systems. Sufficient discrepancy between fuel-air ratios based on the temperature measurements and those based on air and fuel mass flow measurements will trigger an alert to the operators.

With regard to the suggestion that burners well be inspected while in service, we offer the following comments. Fossil fuel fired boilers frequently operate such that furnace pressure in the burner zone is slightly negative in comparison to atmospheric pressure. Under such circumstances, ports can be installed in the burner zone, allowing an operator to open the port and visually inspect the flame. The burners for the APEX Bethel Energy Center will operate at a pressure of approximately 800 psia for the HP combustors, and 265 psia for the LP combustors (at maximum rated output). Under these circumstances, inspection of the burners while in service is impractical and unsafe.

Regarding the burner maintenance and inspection schedule, please see the following maintenance schedule provided by Dresser-Rand (Table 1 and Table 1A). APEX will follow the Dresser-Rand maintenance schedule, for the combustors, burners and turbo expanders. Please note that this schedule is subject for revision by Dresser-Rand.

With regard to measures to demonstrate performance of the recuperator, air and exhaust gas temperatures will be measured upstream and downstream of the recuperator as a means of identifying any performance deficiency in the recuperator. Temperatures found to be outside the desired range will trigger an alert to operators.

EPA Question 3

On page 5-2 of the permit application, the individual GHG emission rates that are presented in Table 5-1 do not add up to total emissions. Please explain the discrepancies.

APEX Response 3

The 456,319 t/yr provided in Table 5-1 for the two (2) expansion turbine trains is CO_2 emission, not CO_2 equivalent (CO_2e) emissions. The CO_2e emissions for the two (2) expansion turbine trains is 458,769 t/yr CO_2-e (including normal, startup, and shutdown operating conditions). We have provided the corrected page 5-2 and associated Table 5-1 in the attachments.

EPA Question 4

Beginning on page 5-4 of the permit application, the cost estimates provided for the Carbon Capture and Storage (CCS) appear to rely on the August 20I0 report entitled "Report of the Interagency Task Force on Carbon Capture and Storage." Since BACT is a case-by-case determination, please provide site-specific facility data to evaluate and eliminate CCS from consideration. This material should contain detailed information on the quantity and concentration of CO_2 that is in the waste stream and the equipment for capture, storage and transportation. Please include cost of construction, operation and maintenance, cost per pound of CO_2 removed by the technologies evaluated and include the feasibility and cost analysis for storage or transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with such a removal system, including any details regarding increased GHG emissions if CCS was installed.

APEX Response 4

As concluded from the BACT analysis presented in Section 5 of the application, CCS is not considered technically feasible for the Bethel Energy Center and hence the application did not include a site specific analysis of the cost of CCS. However at EPA's request, a supplementary analysis of CCS costs has been completed and is summarized below.

I. Facility Information

As requested, site specific Bethel Energy Center information is presented in order to comprehensively evaluate the cost of CCS as a CO_2 reduction technology for the Bethel Energy Center. Table A below provides an estimate of CO_2 quantity and concentration in the Bethel Energy Center flue gas over the rated load range for each combustion turbine.

TABLE 1
CO_2 Quantity and Concentration

LOAD	STACK FLOWRATE (acfm)	CONCENTRATION CO_2 (%)	QUANTITY CO_2 (LB/SEC)
100% of Rated Output	452,569	3.5	1,351
75 % of Rated Output	344,042	3.4	985
50% of Rated Output	232,590	3.2	607
25% of Rated Output	167,291	2.8	389
11% of Rated Output	98,650	1.7	141

II. Cost Analysis

Estimates for the Bethel Energy Center CCS were prepared utilizing two primary sources: 1) vendor information, and 2) published cost estimating information.

Carbon Capture Cost Estimate

Information was requested from a major carbon capture system vendor to include carbon capture system preliminary design, budgetary pricing, and operational details for the Bethel Energy Center. The following flue gas information was utilized as a basis of design over the anticipated operating range:

Flow rate: ~ 99,000 to 453,000 actual cubic feet per minute per unit (40 MMSCF/hr maximum instantaneous total for both units)
Temperature: 210 to 230 degrees F
CO_2 concentration: 1.7 to 3.5%
CO_2 target removal rate: 90%

The estimated annual CO_2 emissions at maximum yearly fuel usage for both trains at the Bethel Energy Center are 445,104 tons per year (excluding startup and shutdown operating conditions) based on a federally enforceable combined fuel limit. With an estimated 90% reduction from the carbon capture system, the total captured CO_2 will be a maximum of approximately 400,594 tons per year.

The vendor response included information for a post combustion amine scrubbing system. The design flue gas flow rate was based on 40 MMSCF/hr, which is based on the maximum total flue gas flow rate from two units. The scrubber system design is capable of recovering approximately 69.9 tons of CO_2 per hour (609,550 tons per year) at maximum capacity, but will be effectively limited to the 400,594 tons per year based on federally enforceable fuel limits.

Vendor Information

The following information is summarized from the vendor response for a carbon capture amine scrubber system.

Major Equipment List

There are three major categories of equipment included with the scrubber system; 1) flue gas pretreatment, 2) CO_2 absorption, and 3) solvent regeneration.

Flue gas pretreatment—Since the flue gas temperature from the combustion turbine is too high to be fed directly into the CO_2 absorber; the flue gas must first be cooled through the use of a heat exchanger.

CO2 Absorption –The CO_2 absorber is a packed column where the flue gas is first treated in the CO_2 absorption section in the lower absorber section, and treated flue gas then passes through a water wash located in the upper section before exiting the absorber and being exhausted to atmosphere. The CO_2-rich solvent from the absorber is pumped to the regenerator.

Solvent Regeneration—The regenerator is also a packed column where the CO_2 is removed from the rich solvent with the use of steam. The rich solvent is stripped of CO_2, regenerated to a lean solvent, and returned to the CO_2 absorber. The CO_2 product gas stream is available for recovery or compression required for transport.

CO_2 Compression---In preparation for transport either to storage or enhanced oil recovery (EOR) applications, the CO_2 must be dehydrated and compressed to a supercritical phase which corresponds to a pressure of up to approximately 2,200 psi. This compression is required to minimize transport pipe diameter and avoid two-phase flow in the pipe.

Cost Estimate

The carbon capture vendor provided an indicative installed cost estimate for the CO_2 capture equipment plus the CO_2 compression and dehydration equipment, which was $230 million.

Parasitic Power Estimate and Heat Rate Impact

The vendor also provided the following indicative estimates for equipment power consumption:

- CO_2 capture and recovery equipment---4.85 MW
- CO_2 compression and dehydration equipment---6.40 MW

Utility requirements:

- Nominal process steam requirement---180,000 lb/hr @ 50 psig and 360 F
- Process cooling water requirement --- 975 gpm makeup

A requirement for approximately 200 MMBtu/hr of steam energy, which would require the installation of an on-site auxiliary boiler to provide the steam. Assuming a 70% boiler conversion efficiency, an approximate 300 MMBtu/hr auxiliary boiler would be required.

The current Bethel Energy Center net heat rate is 4,390 Btu/kWh (HHV) at maximum load. Allowing for the impact of the power and steam requirements for the carbon capture, compression, and dehydration equipment, the resultant Bethel Energy Center net heat rate would be increased by approximately 26% to 5,534 Btu/kWh (HHV).

New Heat Rate Adjustment = (Original Heat Input +Additional Heat Input)/ (Original net power output-Reduction in net power output)

(1,390 MMBtu/hr + 300 MMBtu/hr)/(316,676 kW -11,250kW) = 5,534 Btu/kWh

Carbon Transport and Storage

Estimates for the Bethel Energy Center carbon transport and storage were primarily derived from the referenced information below.

Transport Piping Size

Table 1 in Reference 1 below provides an estimated pipeline size based on CO_2 flow rate. With the calculated maximum CO_2 flow rate of approximately 402,000 tons per year, the estimated pipeline diameter is 6 inches.

CO_2 Transport Pipeline Boosting Compression Cost Estimate

From Reference 2, estimated capital cost of boosting compression can range from $3.5 to $6 million per MW of booster compression power installed which includes capital and power costs over the lifetime of the installation. This boosting compression is to overcome pipeline pressure drop associated with the CO_2 mass flow, and is in addition to the compression required to change the captured CO_2 to a "supercritical" temperature and pressure in preparation for transport. However, since the estimated length of transport pipeline is assumed to be less than 40 miles, no boosting compression costs are anticipated for the Bethel Energy Center.

Any cooling water or associated equipment required for CO2 compression process has not been included in the cost and therefore would be additive to the values presented below.

Transport Piping Cost Estimate

Also from Reference 1, 2007 CO_2 pipeline construction cost is estimated by the equation below;

LCC = a * D * L * (2007 Index)

LCC = Land Construction Cost
a = $33,853
D = pipeline diameter in inches (estimated 6 inches for Bethel Energy Center)
L = pipeline length in miles

Calculations result in approximately $200K per mile for a 6-inch pipeline in 2007$.

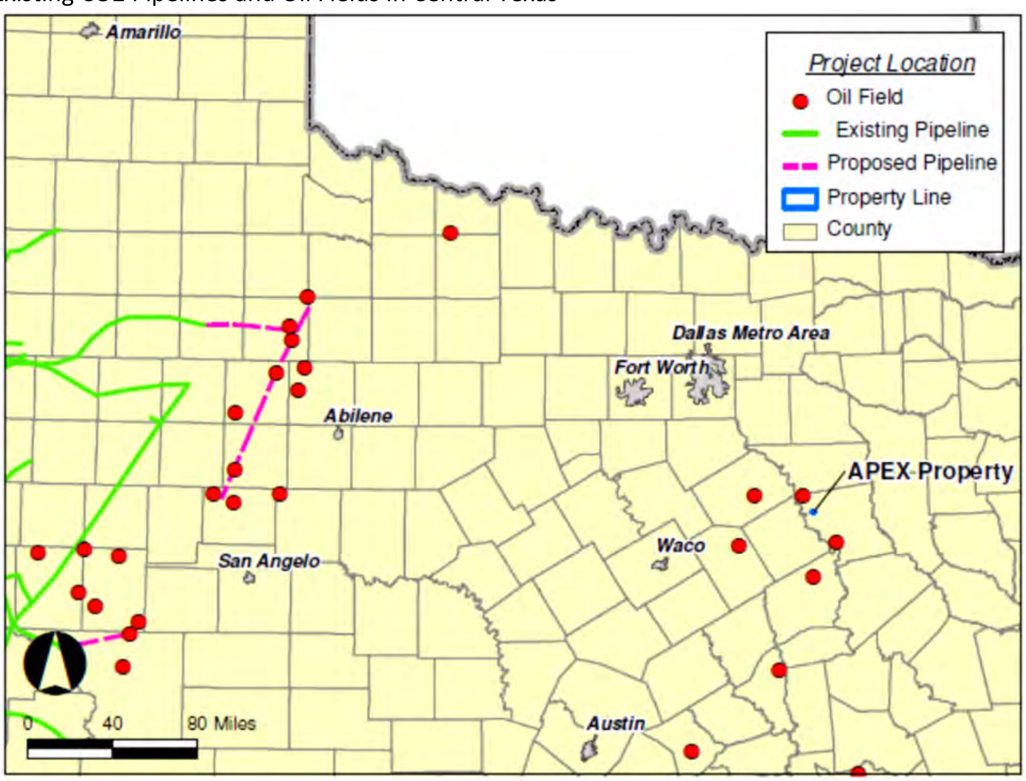
This equation can be utilized to estimate the Bethel Energy Center transport piping cost by comparing to the 232-mile Greencore CO_2 pipeline project from Wyoming to Montana. The Greencore project consists of a 20-inch pipeline, and is estimated to cost $275 to $325 million to complete (Reference 8) or approximately $1.2 to $1.4 million per mile in 2012$. Using the LCC equation above and scaling the 20-inch Greencore project cost per mile to the Bethel Energy Center 6-inch pipeline, the result is $420K per mile.

Using Reference 1 Table 3.1, construction conditions can significantly impact overall pipeline costs; with highway or railroad crossing costs resulting in 3 times base case cost, and populated areas having a 15 times base case cost effect. The Greencore project is being installed in relatively open terrain in Wyoming and Montana, and also includes a long distance economy of scale. The Bethel Energy Center project is located in a higher population density area with greater infrastructure. Therefore, utilizing a conservatively low 2 X base cost adjustment, installed pipeline costs for the Bethel Energy Center is estimated at $800K per mile.

In summary, the transport piping construction estimated at approximately $800K per mile for a 6-inch pipeline.

From Figure 1 below, the Bethel Energy Center is located in proximity of several oil fields generally to the south of Dallas/Ft. Worth, TX and to the east of Waco, TX, which are potential sites for CO_2 EOR projects. Making the assumption that these oil fields are suitable for injection, and further assuming the Bethel Energy Center can negotiate supply contracts with oil producers, transport piping costs were calculated using the distance from the Bethel Energy Center to the closest oil field. The approximate distance from the Bethel Energy Center to these sites is as far as 40 miles. Using the calculated cost per mile estimate from above, the piping cost for the Bethel Energy Center to the potential EOR sites would be approximately $32 million.

FIGURE 1
Existing CO2 Pipelines and Oil Fields In Central Texas



Reference: Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: East and Central Texas, U.S. DOE, February 2006

TABLE 2
Vendor CCS Information

Parameter	Carbon Capture Vendor	Source
Installed Capital Cost	$230 million	Vendor
Parasitic Power Consumption (Scrubber + compression/dehydration)	11.25 MW	Vendor
Annual Scrubber O&M Costs	$12 million	Estimated at 4% of capital cost (Ref.6)
Pipeline Installed Cost	$32 million	Estimate Above
Pipeline O&M Costs	$1.6 million	Estimated at 5% of capital cost (Ref. 2)
Booster Compression Lifetime Costs	0	Assumed No Booster Compression Required
Net Bethel Energy Center Heat Rate Impact	Increased by 26 % to 5,534 Btu/kWhr	Calculation

The following control cost table presents the calculation of the annual cost of CCS for the Bethel Energy Center utilizing a Capital Cost Recovery Factor of 0.1205 which is based on a weighted cost of capital of 11.6%. The cost of capital is derived assuming a cost of equity of 20% interest and cost of debt of 6% interest, with a 40/60 equity to debt ratio. The equipment life was assumed to be 30 years.

Control Costs for Carbon Capture
APEX
Bethel Energy Center

Capital Cost Recovery Factor=0.1205
11.6% Pre-tax Cost of Capital, 30 year equipment life

Carbon Capture	
Installed Capital Cost	$230,000,000
Annual Scrubber O&M Costs	$9,200,000
Pipeline Installed Cost	$32,000,000
Pipeline O&M Costs	$1,600,000
Subtotal Annual Equipment Cost	$42,371,000
Annual Cost of Lost Generation (@0.05 $/kwh)	$4,927,500
Annual Cost of Process Steam (@ $10/1000 lb)	$15,768,000
Total Annual Cost	$63,066,500

III. Safety, Operational, and Environmental Impacts of CCS

Safety and Environmental Impacts

Implementing CCS systems may cause several health and safety concerns (Reference 4). Some of the associated risks are listed below:

- CO_2 capture and transport system leaks resulting in concentrations of greater than 7-10% may cause threat to human and animal life.
- Inadvertent leaks from EOR applications or underground storage caverns can accumulate and pose risk of asphyxiation to humans and animals. When released in significant quantities, CO_2 can accumulate in low areas and closed spaces since it is heavier than air.
- Injection of CO_2 in underground storage formations which are close to aquifers can lead to water contamination due to the formation of carbonic acid.
- Production of amine is energy intensive and can leak from the scrubber system. (Reference 5)
- Long term effects of underground storage are unknown.

While not specifically a safety or environmental issue there are several other issues of concern. The transport and storage of CO2 raises questions of changes of ownership. These issues can also involve accounting and liability issues between both public and private sector entities. While this analysis assumes that the captured CO2 will be utilized for EOR operations, similar ownership concerns would apply for all underground storage options.

Also, surface acreage needed for the CO_2 capture process is not available in proximity to the CAES expansion trains. The proposed site has numerous spacing constraints due to the location on the site of existing pipelines, an existing natural gas storage cavern well, an existing natural gas processing unit, electric distribution and transmission lines, and easements for two additional natural gas storage cavern wells, as well as the current siting for the facility, auxiliary equipment, facility tie-ins and related storm water controls. The site is bordered on the north and east by highways. Existing natural gas storage operations control the surface across both of these roads. A single landowner controls the land to the south of the site. Apex has attempted to purchase this property, but the owner has no interest in selling. This leaves one direction to look for additional land - where land ownership is fragmented, encumbered by pipelines and electric transmission/interconnection facilities, and separated from the site by an ephemeral stream.

These considerations would result in a sub-optimum location for the CCS related equipment, with an adverse impact on the cost of the facility.

Impact on Net GHG Emissions

While a carbon capture system such as the amine scrubber reviewed above claims CO_2 removal efficiency of 90%, there are significant parasitic power requirements associated with operation of the scrubber system. For the Bethel Energy Center, the heat rate is increased by approximately 26%, due to the net power output being diminished by 11.25 MW of parasitic load and the significant process steam requirements. Because less power is being generated by the Bethel Energy Center, this power must be replaced with purchases from other generation facilities. Assuming the secondary generation facility CO2 emission rate meets the new NSPS requirement of 1,000 lb CO_2/MWhr, the additional GHG produced to replace the CCS lost generation is approximately 30,797 tpy based on an 62.5% capacity factor.

The steam requirement necessitates the installation of a nominal 300 MMBtu/hr auxiliary boiler. Given this heat input for natural gas, and a 62.5% capacity factor, the calculated CO_2 emissions due to steam generation is 95,995 tpy. The cost of an auxiliary boiler was not included in this analysis, and it was assumed that the cost of on-site steam generation would be $10/1,000 lb of steam.

In order to calculate the net CO_2 reduction from carbon capture system, the following equation was used:

Net CO_2 reduction = Captured CO_2 – Energy penalty-related CO_2 emissions (Reference 5)

Net CO_2 reduction=

400,594 tpy – (30,797 tpy + 95,995 tpy)

Net CO2 reduction= 273,802 tpy

Estimated Bethel Energy Center CCS Cost

The cost per net ton of CO_2 removed is:

Annual Cost/Net CO_2 Reduction

$63,066,500 /273,802tpy = 230 $/ton of CO_2 removed

This cost is significantly higher than other GHG mitigation options and is economically infeasible for the following reasons.

- The estimated CCS capital cost of $230MM would increase the total project capital costs by nearly 70% from $350MM to $580MM and make the project economically infeasible.
- The estimated annual cost of $230/ton removed is over 10 times higher than the ADAGE projected 2020 allowance trading value of $22/ton.

REFERENCES

1) Carbon Management GIS: CO_2 Pipeline Transport Cost Estimation, MIT, June 2009.

2) CO_2 Transportation Cost Calculations; Canadian Clean Power Coalition, March 2011.

3) Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: East and Central Texas, U.S. DOE, February 2006.

4) Health and Safety Risks of Carbon Capture and Storage, John Fogarty, MD, MPH and Michael McCally, MD, PhD, American Medical Association, January 2010.

5) Carbon Dioxide Capture and Storage Issues – Accounting and Baselines Under The United Nations Framework Convention on Climate Change (UNFCCC), IEA Information Paper, May 2004.

6) CO2 Capture & Storage, IEA Energy Technology Essentials ETE01, December 2006.

7) CO_2 Pipeline Infrastructure: An analysis of global challenges and opportunities, elementenergy, April 2010.

8) Work Nears on Pipeline to Carry CO2 to Wyoming, Montana Oil Fields, Billings Gazette, July 2011.

EPA Question 5

On page 5- 10 of the permit application, it states that "In addition to the combustion sources planned for the Bethel Energy Center, there are natural gas emissions from leaking piping components, which include methane and CO_2 emissions and sulfur hexafluoride (SF_6) circuit breakers". The identified control technologies for fugitive emission are a formal Leak Detection and Repair (LDAR) Program and a Comprehensive Equipment Maintenance

Program. APEX is proposing a comprehensive equipment maintenance program that will include "periodic" inspect ions for leaks using auditory, visual, and olfactory (AVO) methods to find leaks. Leaks will be repaired in a "reasonable" amount of time. Please provide supplemental data that discusses in detail the specifics of the proposed comprehensive maintenance program, inspection and repair schedule. What is the proposed monitoring and recordkeeping strategy for this program? In addition, please provide a 5-step BACT analysis for fugitives that include a comprehensive evaluation of alternative technologies for detection and repair to minimize leaks or other LDAR programs considered to reduce methane fugitive emissions and a basis for elimination. The technologies could include, but are not limited to, the following:

- Installing leakless technology components to eliminate fugitive emission sources;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Designing and constructing facilities with high quality components and materials of construction;
- Monitoring of flanges for leaks;
- Using a lower leak detection level for components

APEX Response 5

We have attached a revised section 5.7 Fugitive Emissions BACT for GHGs to address the above requests. A 5-step BACT analysis has been included that addresses potential technologies. In addition, a detailed description of the proposed Comprehensive Equipment Maintenance Program has been included.

EPA Question 6

APEX proposes a natural gas generator. The generator will operate during emergencies for backup power generation. Please provide benchmark comparison efficiency and design data for the emergency generator to existing or similar sources.

APEX Response 6

The generator selected to provide emergency backup power has non-selective catalytic reduction (NSCR) add-on controls. It was the only unit found in the market designed for natural gas fuel and capable of providing the necessary output for back-up power, while meeting the very low NO_x emissions objectives established for the project. The table below provides information on a similar sized gas fired unit from another manufacturer, offering a slightly better heat rate. The annual CO_2e emissions difference between the two units is approximately 1.1 tons per year. The unit selected by APEX Bethel Energy Center, prior to add-on non-selective catalytic reduction (NSCR) controls, provides lower NO_x and VOC emissions than the Waukesha counterpart. With the addition of NSCR controls, the NO_x, VOC, and CO emissions are substantially lower. Thus, the criteria pollutant emissions reductions were determined to be an acceptable trade-off, with more overall benefit to the environment, than a slightly better efficiency (Btu/bhp-hr) with the Waukesha unit.

TABLE 5
Emergency Generator Efficiency and Design Data

	Selected Generator Caterpillar G3516SITA	Similar Generator Waukesha VHP7100G
kW (bhp)	740(1053)	725(1025)
Btu/bhp-hr	7391	7223
Fuel use (scf/hr)	8600	8181

EPA Question 7

Please provide supplemental technical data to support basis or rationale for the example calculations provided in Appendix A for the turbines. Please provide data for the combustion turbine generators that includes heat load and efficiency data that was selected. (This information can be graphically represented). Please provide supplemental information as a basis to support the heat rates used in the emission calculations in the Appendix. Please provide the rationale that indicates operating these turbines at the heat loads used in the calculations is energy efficient as BACT.

APEX Response 7

The following table provided by the manufacturer shows operating parameters (including heat rate) across the probable range of CAES expander train unit output. Heat rate varies as a function of load on the machine, with the maximum efficiency achieved at full load. APEX has chosen to accept a limitation in annual fuel use as a means of ensuring that criteria pollutant emissions (principally NOx) remain below minor source permitting thresholds. Because firing rate (on a Btu/kWhr basis) and NOx emission (on a lbs/mmBtu basis) vary across the load range, APEX calculated the amount of fuel to be consumed on an annual basis to produce less than 40 tons per year of NOx. This annual fuel consumption is stipulated in the TCEQ construction permit, and represents a federally enforceable limit for the facility. APEX will install NOx CEMS on CAES trains (EPN stacks TURBASTK and TURBBSTK) to demonstrate compliance with the NOx emission limits in the TCEQ standard permit. The CEMS will be installed and operated in accordance with the Acid Rain Program as specified in 40 CFR Part 75.

Maximum annual GHG emissions for the facility are commensurate with this federally enforceable annual fuel limit.

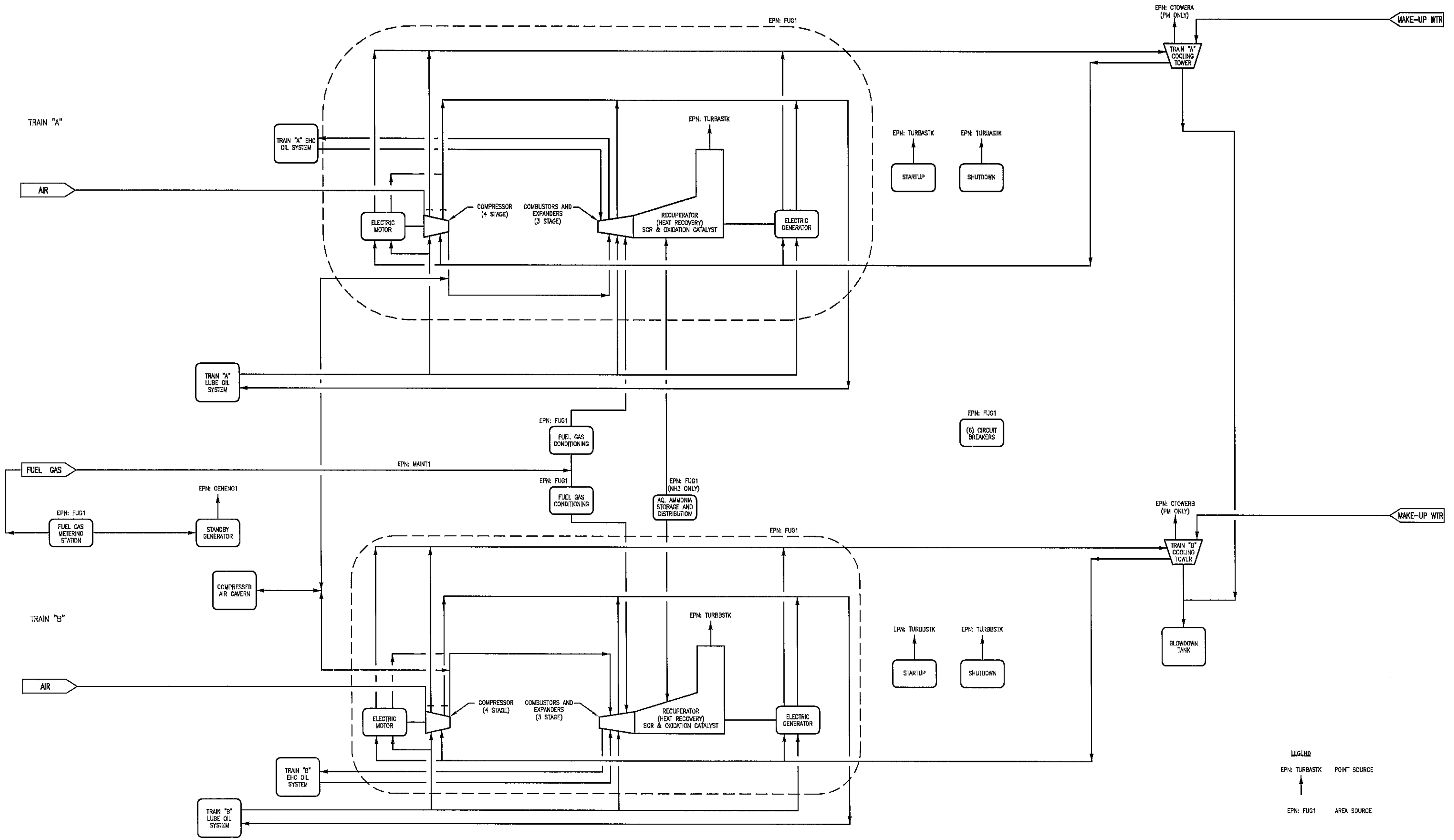
TABLE 6
Turbo-expander Operating Parameters Across Output Range

	11% Load	15% Load	25% Load	25% Load	50% Load	75% Load	100% Load
Air Flow Per Train (lb/sec)	88	100	145	145	200	300	400
Gas Flow Per Train(lb/sec)	0.836	1.295	2.235	2.324	3.636	5.905	8.099
Water Inj Per Train (lb/sec)	0	0	0	0.930	1.454	2.362	3.240
Exhaust Flow (lb/sec)	88.836	101.295	147.235	148.253	205.090	308.267	411.388
Output Per Train (KW)	15,033	24,529	43,071	43,369	69,351	114,516	158,338
Heat Rate (BTU/kWhr) (HHV)	4773	4531	4453	4599	4499	4425	4390

As stated in the application, the heat rate for the Bethel Energy Center turbo expanders is lower than the only other CAES installations operating worldwide. Attached is a figure showing a comparison of the manufacturer's design heat rate across the load range for the Bethel Energy Center and the McIntosh CAES facility. This demonstrates that the Bethel Energy Center represents BACT for GHG emission for CAES technology.

Heat Rate Comparison

Process Flow Diagram



REV	DATE	BY	DESCRIPTION	CHK	ENGR	APPR	CLIENT
A	06/21/12	JH	ISSUE FOR PERMIT APPLICATION				

MUSTANG PROCESS AND INDUSTRIAL, INC.

Apex·CAES

PROJECT NO: 20406N		
DESIGNED BY:		
DRAWN BY: SDG	05MAY2012	
CHECKED BY:		
APPROVED BY:		
SCALE: NTS	DATE	

COMPRESSES AIR ENERGY STORAGE (CAES)

CAES OVERALL PROCESS FLOW DIAGRAM

DRAWING NO: PFD-001 REV: A

Maintenance Schedule
(Table 1 and 1A)

Table 1. Dresser-Rand Model EA-418 Turbo-Expander Maintenance Schedule

Component	Dresser Rand Recommended Maintenance Activity				Component Replacement			
	Estimated Repair Turn-Around[1]	Borescope Inspect	Hot Gas Path Inspect-Repair Interval[2]		Replacement Lead Time	Repair/Replacement Interval[4]		
	Weeks	Starts	Starts	EOH (Hours)[3]	Weeks	Minor Repair	Major Repair	Retire
Combustion Liners	6	750	1500	24000	18	72000	na	144000
Transition Pieces	12	750	1500	24000	26	72000	na	144000
Fuel Nozzles	6	750	1500	24000	18	72000	na	144000
Stage 1 Nozzles	26	750	1500	24000	80	48000	96000	144000
Stage 2 Nozzles	26	750	1500	24000	80	72000	na	144000
Stage 3 Nozzles	26	750	1500	24000	80	96000	na	na
Stage 4 Nozzles	26	750	1500	24000	80	96000	na	na
Stage 1 Buckets	20	750	1500	24000[5]	80	72000	na	144000
Stage 2 Buckets	20	750	1500	24000[5]	80	72000	na	144000
Stage 3 Buckets	20	750	1500	24000	80	72000	na	144000
Stage 4 Buckets	20	750	1500	24000	80	72000	na	144000

Notes:

(1) Dependent on the type of repair; time given is guideline only. (Based on most complex repair option)

(2) Whichever comes first.

(3) EOH Calculation:

Starts -	Emergency Start (<10 Min)	50 EOH
	Fast Start (=10 < 15 Min)	25 EOH
	Normal Start(>15 Min)	15 EOH
Operating Hours -	1600°F TIT	EOH = 1 X actual fired hours
	1550°F TIT	EOH = .75 X actual fired hours
	</=1500°F TIT	EOH = .5 X actual fired hours
	Part load hours	EOH = 1 X (actual output/rated output)

(4) Replacement Intervals are guideline only. Individual part replacement intervals depend on HGPI & repair history. Consult D-R Engineering

Table 1A. Dresser-Rand Model 6T CAES High Pressure Turbo-Expander Maintenance Schedule

Component	Dresser Rand Recommended Maintenance Activity				Component Replacement	
	Estimated Repair Turn-Around[1]	Borescope Inspect	Gas Path Inspect-Repair Interval[2]		Replacement Lead Time	Replacement Interval[4]
	Weeks	Starts	Starts	EOH[3] (hrs)	Weeks	Starts/EOH
Combustion Liners	6	750	1500	24000	18	4500/72000
Fuel Nozzles	6	750	1500	24000	18	4500/72000
Stage 1 Nozzles	26	750	1500	24000	30	9000/144000
Stage 2 - 6 Nozzles	26	NA	1500	24000	30	9000/144000
Stage 1 Buckets	12	750	1500	24000	30	9000/144000
Stage 2 - 6 Buckets	12	NA	1500	24000	30	9000/144000
Rotor	20	NA	1500	24000	60	9000/144000[5]

Notes:

(1) Dependent on the type of repair; time given is guideline only. (Based on most complex repair option)

(2) Whichever comes first.

(3) EOH Calculation Starts: 15 hours/start (power-gen or compressor start using expanders)

Operating Hours: ≥ 1000oF TIT EOH = 1.0 X actual hours

<1000°F TIT EOH = .75 X actual hours

(4) Intervals are guideline only. Actual intervals depend on results of GPI & repair history.

(5) Rotor may be debladed, and rebladed for continued service, dependent on inspection results. Consult D-R Engineering.

Corrected Page 5-2 and Table 5-1

To determine CO_2e emissions, mass flows of each individual gas emitted are multiplied by the appropriate Global Warming Potential (GWP) as referenced to the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report, and the results are summed.

The expansion turbine combustors will be fired with pipeline-quality natural gas, and complete combustion will result in water and CO_2 byproducts. However, incomplete combustion will result in some unburned natural gas or CH_4 emissions. Additionally, due to the presence of nitrogen in the combustion air, some small quantities of N_2O will also be emitted.

The standby generator engine will be fired with natural gas, again resulting in CO_2 emissions from oxidation of the fuel, minor quantities of CH_4 emissions resulting from incomplete combustion, and N_2O emissions from conversion of nitrogen from the atmosphere and fuel.

Fugitive emissions from equipment leaks consist of hydrocarbons, including CH_4, CO_2, and SF_6, which may be used as an insulating gas for high-voltage equipment and circuit breakers.

In addition, equipment maintenance activities may emit GHG during equipment purging prior to inspection and repairs. These emissions will consist primarily of CH_4 and other hydrocarbons.

Table 5-1 represents potential sources and estimated quantities of GHG emissions from the Bethel Energy Center equipment.

TABLE 5-1
Bethel Energy Center Estimated GHG Emissions by Equipment Category

Equipment/Activity	Description	Total CO_{2e} Emissions (t/yr)
Two (2) Expansion Turbine Trains	Maximum Heat Input Each 695.1 MMBtu/hr Higher Heating Value (HHV)**	**458,769** (including normal, startup, and shutdown operating conditions)
Fugitive Equipment Leaks	Weight percent of methane in gas stream 90.7 percent	**248**
One (1) Natural Gas-Fired Emergency Generator	Maximum Heat Input 7.78 MMBtu/hr	**23**
Facility Maintenance Activities	Emissions during purging of equipment prior to maintenance	**85**
Total		**459,125**

*** design maximum heat input to turbines was adjusted upward by 3% to account for equipment degradation between overhauls.*

5.3.1 GHG BACT Analysis Assumptions

During the completion of GHG BACT analysis, the following assumptions were made:

1. Table 5-1 presents the estimated Bethel Energy Center GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, N_2O, and SF_6. The Bethel Energy Center is not expected to emit HFCs or PFCs because these manufactured gases are primarily used as cooling, cleaning, or propellant agents.

2. From the GHG emissions inventory presented in Appendix B, the relative quantities of CH_4, N_2O, and SF_6 total only approximately 2806 tpy of CO_2e, or less than 0.61 percent of total CO_2e emissions. Due to the extremely small contribution of these three constituents to the total GHG emissions, the Bethel Energy Center GHG BACT analysis only included the five-step process for CO_2 emissions.

3. Installation of low NO_X burners with water injection and an SCR system for NO_X emissions reduction, and an oxidation catalyst for control of CO and VOCs for each expansion turbine train will be required to meet the

Revised Section 5.7 Fugitive Emissions BACT for GHGs

5.7 Fugitive Emissions BACT for GHGs

In addition to the combustion sources planned for the Bethel Energy Center (BEC), there are hydrocarbon emissions from leaking piping components, which include methane emissions and sulfur hexafluoride (SF_6) leaks from circuit breakers. Although this is a small source with an estimated 248 tpy CO_2e or 0.05% of the total site emissions, for completeness, fugitive emissions are addressed in this BACT analysis. The GHG calculations for this source are located in Appendix B.

Step 1: Identify All Control Technologies

The available control technologies for process fugitive emissions are as follows

- Use of a Leak Detection and Repair (LDAR) Program using traditional FID or newer IR camera technology;
- A Comprehensive Equipment Maintenance Program;
- Installing leakless technology components to eliminate fugitive emission sources;
- Designing and constructing facilities with high quality components and materials of construction; and,
- Using a lower leak detection level for components.

Step 2: Eliminate Technically Infeasible Options Effectiveness

Use of LDAR

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions from components in natural gas service. The traditional LDAR program using an FID will not detect SF_6. An IR camera can detect leaks of SF_6 if calibrated for SF_6; therefore, a LDAR program using IR camera technology is a technically feasible option for SF_6 leaks.

Use of a Maintenance Program

A comprehensive equipment maintenance program is a technically feasible option for controlling process fugitive GHG emissions from components in natural gas service.

Installing Leakless Technology

APEX BEC will be using welded piping where possible. Other components such as flanges and valves inherently cannot be leakless. Since the facility cannot be constructed, operated or maintained without the use of flanges and valves, installing leakless technology is technically infeasible for controlling process fugitive GHG emissions.

Designing and Constructing with High Quality Components

Designing and constructing with high quality components is technically feasible for controlling process fugitive emissions from components in natural gas service and SF_6.

Lower Detection Levels

Using lower detection levels for components is technically feasible for controlling process fugitive emissions from components in natural gas service and SF_6 in conjunction with a LDAR program.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible GHG control technologies for the Bethel Energy Center are "LDAR", "Maintenance Program", "High Quality Components" and "Lower Detection Levels".

Step 4: Evaluate most effective controls and document results

LDAR

There are varied levels of stringency in LDAR programs for controlling volatile organic compound (VOC) emissions. However, due to the extremely small amount of GHG emissions from the fugitive sources, an LDAR program would not be considered for control of GHG emissions alone but in conjunction with an already existing LDAR program. This evaluation does not compare the effectiveness of different levels of LDAR programs.

Although technically feasible, the use of an LDAR program to control the small amount of GHG emissions from the fugitive sources at the Bethel Energy Center is not cost effective.

Based on an estimate from an LDAR company, assuming that this site would be similar to a smaller gas plant subject to 40 CFR Part 60, Subpart KKK with around 600 quarterly components to monitor the cost would be as follows:

- $16,000 for the first year, which includes tagging and initial monitoring
- $12,000 for annual monitoring

Control costs are evaluated based on cost effectiveness calculated as annual cost per ton of pollutant removed. Additional costs would be incurred for multiple calibrations of the IR camera if used to also detect leaks of SF_6 which have not been included. Based on this cost estimate, APEX believes the use of an LDAR or LDAR like program would be cost effective for the Bethel Energy Center. The comprehensive equipment maintenance program will have similar reduction percentages and costs can be rolled into normal operations without additional capital. APEX suggests the comprehensive equipment maintenance program will be more cost effective. Therefore, an LDAR program can be eliminated based on economic feasibility.

TABLE 5-4
Control Cost for LDAR at the Bethel Energy Center

Capital Cost Recovery Factor	0.1205 (annual 11.6% pre-tax cost of capital, equipment life 30 years)
Total Capital Cost	$16,000
Total Annual Operating Cost	$12,000
Annualized Equipment Cost	$1,928
Total Annual Cost	$13,928
PTE CO_2e (ton/yr)	248.0
CO_2e Removal (ton/yr)	79.1
Cost per ton of CO_2e removed ($/ton)	$176.10

Maintenance Program

Due to LDAR being cost prohibitive, a more reasonable choice for size and equipment at the Bethel Energy Center would be to apply a comprehensive equipment maintenance program. The cost of this program would be rolled into the normal operation and maintenance of the facility.

The comprehensive maintenance program will include periodic inspections for leaks using auditory, visual and olfactory (AVO) methods to find leaks. Elements of the program include at a minimum the following:

- Monthly walkthroughs using AVO to identify leaks.
- First attempt to repair within 5 days and repair or replace within 15 days.
- Exceptions for components that require a process unit shut down or waiting on parts to repair or replace.
- Records of leaks and repairs shall be kept and made available upon request.

High Quality Components

APEX will use high quality components and materials for design and construction of the Bethel Energy Center. The cost of implementing this will be included in the cost of construction.

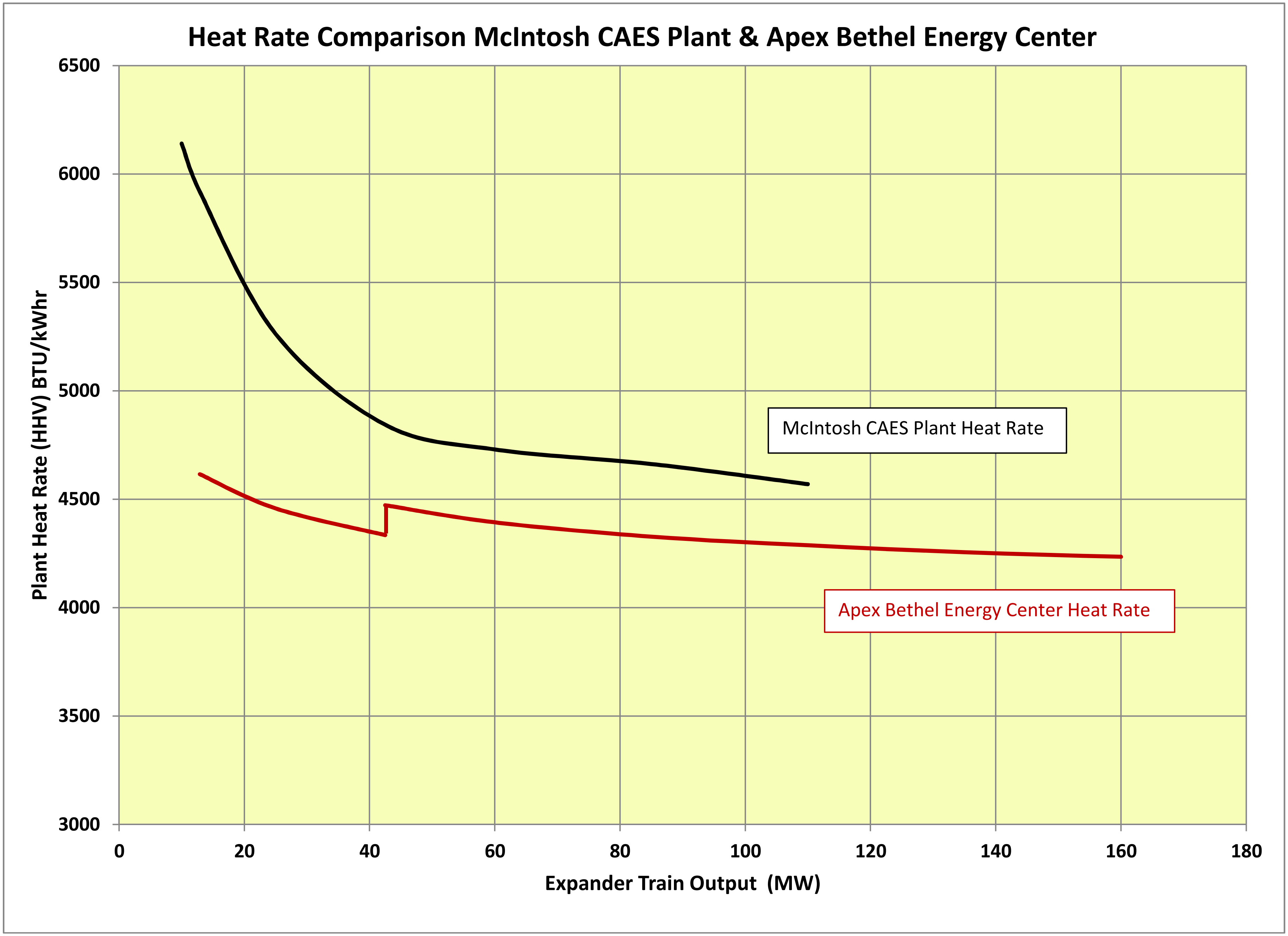
Lower Detection Levels

Lower detection levels are associated with an LDAR program with a leak definition. The comprehensive maintenance program detailed above does not have a leak definition and the LDAR program has been removed as not cost effective. Therefore, this approach is cost prohibitive as part of an LDAR program.

Step 5: Select BACT

Based on the above analysis, BACT is determined to be a comprehensive equipment maintenance program using AVO and the installation of high quality components.

Heat Rate Comparison



*Both heat rates depicted above do not include the 3% degradation as described in the Bethel Energy Center application