DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit AQ0417MSS03 Preliminary – September 10, 2010
Rescinds Permits AQ0417CPT05, Rev. 2 and AQ0417MSS01, Rev. 2

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0417MSS04 to the Permittee listed below.

Operator and Permittee:	**B.P. Exploration (Alaska), Inc.** 900 E. Benson Blvd. P.O. Box 196612 Anchorage, AK 99519-6612
Owner:	B.P. Exploration (Alaska), Inc.
Stationary Source	Badami Development Facility
Location:	UTM Zone 6, Northing: 7782.6 km; Easting: 496.4 km
Physical Address:	North Slope, Alaska
Permit Contact:	Alison D. Cooke, (907) 564-4838
Project:	Extend Restart Period and Replace Emergency Generator Unit ID 421

This project is classified under 18 AAC 50.508(6) for revising or rescinding the terms and conditions of a Title I permit. The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50.

This permit authorizes the Permittee to operate under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 9 except as specified in this permit.

The Permittee shall operate under the terms and conditions of this minor permit upon issuance.

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John F. Kuterbach
Manager, Air Permits Program

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Section 1. Emission Unit Inventory

1. **Inventory.** Emission units listed in Table 1 have specific monitoring, record keeping, or reporting conditions in this permit. Except as noted elsewhere in the permit the information in Table 1 is for information purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any applicable minor or construction permit requirements.

Table 1: Minor Permit Emission Unit Inventory[1]

EU ID	Description	Make/Model	Rating/Size	Fuel Type	Max Operation
Other Emission Units					
417	Diesel Tank	Unknown	15,000 bbl	Diesel	8,760 hr/yr
418	Methanol Tank	Unknown	450 bbl	Methanol	8,760 hr/yr
419	Glycol Skid Heater	Unknown	1.05 MMBtu/hr	Diesel	8,760 hr/yr
420	Generator	Cummins KTTA50-G2	1,855 hp	Diesel	800,000 gal/yr
421a	Generator	Cummins QSK50-G4	1,971 hp	Diesel	
Stationary Emission Units					
500	Turbine	Solar Mars 90	11,862 kW	Natural Gas	8,760 hr/yr
501	Turbine	Solar Mars 90	11,862 kW	Natural Gas	8,760 hr/yr
502	Incinerator, Waste Combustion	Therm-Tec G-12	1.6 MMBtu/hr 85 lb/hr	Propane/Natural Gas/Waste	8,760 hr/yr
503	Production Heater	NATCO	34 MMBtu/hr	Natural Gas	8,760 hr/yr
504	Miscible Injection Heater	NATCO	14.87 MMBtu/hr	Natural Gas	8,760 hr/yr
505	TEG Reboiler	NATCO	1.34 MMBtu/hr	Natural Gas	8,760 hr/yr
507	Flare-Pilot Flare-Purge Flare-Assist	Unknown	0.1652 MMscf/hr[a]	Natural Gas	8,760 hr/yr
	Flare-Produced Gas	Unknown	20 MMscf/day 152 MMscf/yr	Natural Gas	Other[b]
508	110 barrel TEG Storage Tank	Unknown	110 bbl	N/A	8,760 hr/yr
509	Emergency Generator Engine	Unknown	430 hp	Diesel	500 hr/yr
Portable Equipment					
422	Smart Ash Incinerator	Smart Ash 100-A (on storage pad)	0.035 tons/hr	Oily Waste	8,760 hr/yr
601	Light Plants	Unknown	12.1 hp	Diesel	8,760 hr/yr
602	Light Plants	Unknown	12.1 hp	Diesel	8,760 hr/yr
607	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	8,760 hr/yr
608	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	8,760 hr/yr
611	Heaters-Indirect fire heaters	Unknown	1 MMBtu/hr	Diesel	8,760 hr/yr
612	Heaters-Indirect fire	Unknown	1 MMBtu/hr	Diesel	8,760 hr/yr

[1] Except for Unit 421a, all other emission units listed in Table 1 were authorized in previous permit actions. These emission units are listed herein because this permit is replacing the previous Title 1 permits after carrying over the permit conditions.

	heaters				
Drill Rig Equipment					
1	Rig Engines[c]	Unknown	Unknown	Diesel	8,760 hr/yr
8	Rig Boilers and Heaters[c]	Unknown	Unknown	Diesel	8,760 hr/yr

[a] Combined pilot, purge, and assist gas.
[b] The Permittee is authorized to flare up to 152 MMscf gas under "other" operations per 12 consecutive month rolling period, at a rate of no greater than 20 MMscf per day. Other indicates: the specific flare operations related to routine or non-routine maintenance and other planned events. The design rating/output is 257.9 MMscf/yr.
[c] The Permittee is authorized to operate any of the drill rigs listed in Permit AQ0455TVP01, Rev. 1.

2. **Authorization.** The Permittee is authorized to install and operate Emission Unit (EU) 421a as listed in Table 1. The Permittee shall notify the Department within seven days beginning the installation of EU 421a. The notification must indentify:

   2.1 unit number, serial/model number, and rating of the replacement unit;

   2.2 unit number, serial/model number, and rating of unit replaced;

   2.3 installation date of the replacement unit; and

   2.4 anticipated startup date of the replacement unit.

3. **Removal of Emission Unit.** The Permittee shall:

   3.1 Permanently remove existing EU 421 listed in Table 1 within 30 days of completing the installation of EU 421a; and

   3.2 Notify the Department within seven days of permanently removing the emission unit from service. The notification must indentify:

      a. emission unit ID;

      b. description of the unit;

      c. make/model number and rating;

      d. type of fuel burned;

      e. date of permanent removal from service; and

      f. specific actions taken to permanently remove from service.

Section 2. Emission Fees

4. Assessable Emissions. The Permittee shall pay to the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410(b). The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year. The quantity for which fees will be assessed is the lesser of

4.1 the stationary source's assessable potential to emit of 1,548 TPY; or

4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department**.**

5. Assessable Emission Estimates. Emission fees will be assessed as follows:

5.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Juneau, AK 99801-1795**;** the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

5.2 if no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 4.1.

Section 3. State Requirements

6. **Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EUs 419-422, 500, 501 – 505, 507, and 509 listed in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

7. **Industrial Process and Fuel-Burning Equipment Particulate Matter.** The Permittee shall not cause or allow particulate matter emitted from EUs 419-421a, 500, 501, 503 – 505, 507, and 509 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

8. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EUs 419-422, 500, 501 – 505, 507, and 509 to exceed 500 ppm averaged over three hours.

Section 4. Ambient Air Quality Standards and Increments, and Owner Requested Limits[2]

9. The Permittee shall not interfere with the attainment or maintenance of the Ambient Air Quality Standards listed in 18 AAC 50.010, and shall not cause or contribute to a violation of the maximum allowable increases (the PSD increments) listed in 18 AAC 50.020 as follows:

9.1 **Miscellaneous Provisions.** Flare natural gas quantities during the routine or non-routine maintenance activities and other planned events. The Permittee shall flare produced gas quantities no greater than 152 MMscf of natural gas during any 12 consecutive month period, at a rate of no greater than 20 MMscf per day.

9.2 **Air Quality Boundary.** Establish and maintain the ambient boundaries used in the ambient impact analysis using the following procedures:

a. Comply with the May 10, 2005 "CPF Pad Badami Unit – Public Access Control Plan" (Plan), or a subsequent written version approved by the Department that contains at least the following elements:

(i) a topographic map (or maps) that clearly shows the ambient boundaries, water bodies and Central Process Facility (CPF) pad;

(ii) ambient boundaries that are consistent with the land owner's authorization to preclude public access from the area within the boundaries;

(iii) defined methods of establishing and maintaining the boundary; and

(iv) the date of the revised Public Access Control Plan.

b. Do not revise the ambient air boundaries without Department approval. If requested by the Department, submit a revised ambient air impact analysis that demonstrates that the emission activities will not cause or contribute to ambient air violations when using the proposed boundary.

c. Submit all proposed revisions of the Plan, including the ambient boundary, to the Department's Juneau and Fairbanks offices. Do not implement any change without written Department approval.

9.3 **Fuel Sulfur Limits.**

a. Operate the natural gas-fired emission units using natural gas fuel with a hydrogen sulfide (H_2S) content not to exceed 250 parts per million by volume (ppmv).

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[2] These limits were originally established in Permit AQ0417CPT05 issued July 18, 2005 and carried over to Permit AQ0417CPT05 Rev 2.

b. Operate diesel-fired emission units using distillate fuel oil with a fuel sulfur content not to exceed 0.15 percent sulfur by weight (wt%S), except for intermittently used oil field equipment.[3]

9.4 **Fuel Volume Limits.**

a. In Emission Units 420 and 421a, burn a combined total of no more than 800,000 gallons of liquid fuel during any 12 consecutive month period.

b. In all drill rig emission units, burn a combined total of no more than 9,000 gallons per day and 950,000 gallons of liquid fuel during any 12 consecutive month period.

9.5 **Monitoring and recording.** The Permittee shall monitor and record as follows:

a. Obtain a statement or receipt from the fuel supplier certifying the total fuel sulfur content of the fuel for the diesel and gas fired emission units. If a certificate is not available from the supplier, then analyze a representative sample of the fuel to determine the sulfur content in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

b. Record the date and duration during which gas flaring occurs, and the quantity of gas flared.

c. For Emission Units 420 and 421a, install and operate for each unit a dedicated continuous engine hour monitoring system, and a dedicated fuel meter accurate to less than five percent error.

(i) Monitor and record the monthly hours of engine operation and identify the stationary source operational mode (e.g. normal operations, R warm shutdown, LT warm shutdown).

(ii) Monitor and record the monthly fuel consumption for each unit, calculate and record the 12 consecutive month combined fuel consumption.

(iii) If the fuel meter for Emission Units 420 and 421a is out of service, estimate the gallons of fuel consumed for the emission units using the hours of operations recorded in Condition 9.5c(i), assuming the 100 percent load fuel consumption rate in gallons per hour for the unit for any period during which the unit was operating. The fuel consumption rate shall be the design fuel consumption of 84.5 gallons per hour.

d. Monitor and record for each day, the quantity of the fuel combusted in drill rig emission units, combined. Calculate and record the 12 consecutive month total fuel consumption.

[3] This permit does not impose fuel sulfur restrictions on intermittently used oilfield support equipment. The Department has instead established off-permit fuel sulfur targets for these units in Policy and Procedure Number 04.02.105 (effective October 8, 2004).

9.6 **Reporting.** The Permittee shall report in the Operating Report required by the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50:

a. the fuel sulfur test results, or attach copies of vendor certification or analysis reports for fuel sulfur content in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and AAC;

b. the duration of gas flaring and the total quantity of gas flared; describe or document whether the flaring incident is considered an emergency operation, routine or non-routine maintenance operation, or other planned event;

c. for Emission Units 420 and 421a:

(i) the monthly and 12 consecutive month total fuel consumption, combined as required by Condition 9.5c(ii); and

(ii) the monthly and 12 consecutive month hours of operation, combined as required by Condition 9.5c(i); and

d. for the drill rig report, for each day, monthly, and 12 consecutive month fuel consumption for all drill rig emission units, combined.

Section 5. Limit to Avoid PSD Major Modification or a Minor Permit For Air Quality Protection[4]

10. The Permittee shall limit NO_X emissions from Emission Unit 509 listed in Table 1 to no greater than 3.3 tons per 12 consecutive months.

10.1 Keep the daily records of either hours of operation or fuel quantity. Keep the same record for each day of a calendar month. If records are fuel quantity, also keep records of the heat content of (higher heating value) of each load of fuel. (If blended, calculate the average heating value.)

10.2 Except as provided in Condition 10.3, calculate daily NOX emission by either

(i) multiplying the hours of operation times the appropriate emission factor from AP-42 Table 3.3-1; or

(ii) multiplying the gallons of fuel used times the heating value in MMBtu/gal times the appropriate emission factor AP-42 Table 3.3-1.

10.3 If approved by the Department in writing, the Permitted may substitute emission factors calculated from source test data for the same make and model of engine or from manufacturer's data to replace the AP-42 factors.

11. Before the end of each calendar month, calculate

11.1 the total NO_X emissions from Emission Unit 509 for the previous calendar month, and

11.2 the total NO_X emissions from Emission Unit 509 for the previous 12 calendar months.

12. If the 12 month total in Condition 11.2 exceeds 3.3 tons, report as excess emissions as described in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

13. Include the records and calculations required in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

[4] These conditions were originally established in Permit AQ0417MSS01 issued on June 4, 2009 to avoid minor permitting for that permit action. The limit was carried over to Permit AQ0417MSS01 Revision 1

Section 6. Best Available Control Technology[5]

14. The Permittee shall install emission or operational controls as BACT for the following equipment:

14.1 **Limits.**

a. NO_X BACT for fuel burning equipment at Badami is no post-combustion emission control with good operational practices.

(i) The Permittee shall install and operate as BACT for the following fuel burning equipment at Badami:

(A) Emission Units 500 and 501 with dry low NO_X combustion technology (SoloNOx);

(B) Emission Units 420 and 421a with variable-step fuel injection timing retard (FITR) as incorporated by the manufacturer;

(C) Emission Unit 503 with low NO_X burners/flue gas recirculation.

(D) Emission Unit 504 with conventional burner technology; and

(E) Emission Unit 505 with conventional burner technology;

(ii) The Permittee shall comply with the following NO_X emission limits. Emissions from:

(A) Emission Units 500 and 501 shall not exceed 28.4 lbNOx/hr for operation under all conditions, and shall not exceed 85 ppmv corrected to 15 percent oxygen in SoloNOx mode and at ambient temperatures above 0°F;

(B) Emission Unit 503 shall not exceed 0.095 lb NOx/MMBtu;

(C) Emission Unit 504 shall not exceed 0.12 lbNOx/MMBtu; and

(D) Emission Unit 505 shall not exceed 0.08 lbNOx/MMBtu.

b. CO BACT for fuel burning equipment at Badami is no post-combustion emission control with good operational practices. The Permittee shall comply with the following CO emission limits as representative of BACT. Emissions from:

(i) Emission Units 500 and 501 shall not exceed 50 ppmv corrected to 15 percent oxygen when operating at 100 percent load in SoloNOx mode at ambient temperatures above 0°F, 14 lb/hr when operating in SoloNOx mode and at ambient temperatures above 0°F, and 385 lb/hr for operation under all other conditions;

[5] These BACT limits were originally established in Permit AQ0417CPT05 issued July 18, 2005 and carried over to Permit AQ0417CPT05 Rev 2.

(ii) Emission Unit 503 shall not exceed 0.10 lb CO/MMBtu;

(iii) Emission Unit 504 shall not exceed 0.12 lb CO/MMBtu; and

(iv) Emission Unit 505 shall not exceed 0.15 lb CO/MMBtu.

c. Limit CO emissions from Emission Units 500 and 501 to no greater than 336 tons per 12-consecutive month period. Monitor, record according Condition 14.2a(ii), report according to Condition 14.3b.

d. SO_2 BACT for fuel burning equipment at Badami is use of low sulfur fuel with no post-combustion controls. The Permittee shall comply with the following fuel sulfur limits as representative of BACT:

(i) H_2S content of natural gas fuel shall not exceed 250 ppmv; and

(ii) sulfur content of fuel oil shall not exceed 0.15 wt%S.

e. VOC BACT for fuel burning equipment and fuel storage tanks, and water treatment processes at Badami is no controls with good operation practices. BACT for water injection tanks and slop tank is a sealed system design. The flare BACT determination is smokeless tip design. No emission limits are imposed as representing BACT.

f. PM less than 10 microns control technology (PM-10) BACT for fuel burning equipment at Badami is no controls with good operation practices. The Permittee shall comply with the following surrogate PM-10 emission limits as representative of BACT. Visible emissions from:

(i) Emission Units 420 and 421a shall not exceed:[6]

(A) 20 percent opacity for greater than three minutes in any one hour, during production activities including Normal Operations and R warm shut down; and

(B) 10 percent opacity for greater than three minutes in any one hour, during LT warm shutdown.

(ii) Emission Units 500 and 501 shall not exceed 10 percent opacity for greater than three minutes in any one hour.

(iii) All other industrial processes, incinerators, and fuel-burning equipment shall comply with the applicable State visible emission standards listed in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC50.

14.2 **Monitoring and Recordkeeping.**

a. NO_X and CO--Permittee shall monitor and record compliance as follows:

[6] Operational modes according to Condition 12 of this permit.

(i) For Emission Units 420 and 421a, evaluate and certify engine fuel injection/FITR settings no less once each calendar year by verifying or adjusting the fuel injection/FITR settings according the engine manufacturer procedures.

(ii) For Emission Units 500 and 501:

(A) Using the existing computer-based control system, monitor and record:

(1) the daily operating time (record time in minutes or decimal portions of an hour);

(2) the hourly average percentage natural gas producer (% NGP) speed (use six minute intervals to calculate the average % NGP speed for each hour of operation); and

(3) time in and out of SoLoNOx operation for each unit.

(B) For each time period that the units are operating, monitor and record the stationary source operational mode (as defined in Condition 15),

(C) Calculate and record the hourly NO_X and CO emissions for Emission Units 500 and 501 by using the hourly average percentage NGP speed (as determined in Condition 14.2a(ii)(A)(2) to determine the NO_X and CO emission factors listed in Table 2. Multiply the NO_X and CO emission factor by the hours of operation as determined in condition 14.2a(ii).

(D) On calendar month basis, calculate and record the total monthly and 12-consecutive month period NO_X and CO emission rates for each Emission Unit 500 and 501.

(E) On a calendar month basis, calculate and record the total and 12 consecutive month period NO_X and CO emission rates for Emission Units 500 and 501 combined.

b. SO_2--Conduct fuel sulfur monitoring and recordkeeping in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

c. PM--For all units except to Units 420 and 421a, conduct visible emission surveillance monitoring in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50. For Emission Units 420 and 421a, conduct visible emission surveillance monitoring in accordance with the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

(i) Except as indicated in Condition 14.2c(ii), conduct the surveillance on each unit no less than once per calendar quarter. Include the operational mode of the stationary source (e.g. normal operations, R warm shutdown, LT warm shutdown) on the surveillance form.

(ii) If four consecutive quarters show compliance with a given standard listed in Condition 14.1f(i), for a given unit, then the Permittee may reduce the frequency of visible emission observations required in Condition 14.2c(i) for that standard and that unit to no less than once per calendar year.

14.3 **Reporting.** The Permittee shall:

a. For Emission Units 420 and 421a, report fuel injection/FITR settings and the manufacturer recommended procedures and settings.

b. For Emission Unit 500 and 501 report:

(i) the monthly and 12 consecutive month hours of operation for Emission Units 500 and 501 each, as required by Condition 14.2a(ii); and

(ii) the monthly and 12 consecutive month total NO_X and CO emissions for Emission Units 500 and 501, each and the combined total as required in Condition 14.2a(ii)(B).

c. SO_2--Report fuel sulfur content as required by the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

d. PM-10--Report the results of the visible emission surveillance reports as required by the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

Section 7. Restart Project

15. General Conditions. The Badami restart project (restart period) is the period from September 9, 2005[7] to 24 months after Normal Operations are first resumed but in no case later than December 31, 2012. BPXA shall report the date that Normal Operations are first resumed in the operating report for the reporting period as described in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50.

15.1 The Badami restart project operational modes are defined as follows:

a. Recharge (R) warm shutdown operational mode is an operating mode that occurs during the restart period described in Condition 15. The R warm shutdown period is characterized by limited operation of the stationary source emission units. This operational mode is to allow the oil reservoir to recharge, and to allow exploration and development drilling under the plan of development that has been approved by the Alaska Department of Natural Resources. The Permittee shall not use Emission Units 500 or 501 with load banks to provide power for drilling these wells. Normal Operation (production) is not allowed under this mode.

b. Long Term (LT) warm shut down operational mode is am operating mode that occurs after the end of the restart period described in Condition 15, or occurs during the restart period if the Permittee has discontinued plans to return to Normal Operation during that period. The warm shut down mode is characterized by limited operating of the emission units to maintain equipment integrity. During the LT warm shutdown period the stationary source, oil, gas, and water production process is not active and the stationary source is dormant. Normal Operation (production) is not allowed under this mode.

c. Normal Operations (Production) is when the Badami Facility is operating and producing oil. During Normal Operations, the Solar Mars turbines (Units 500 and 501) are providing power generation and the Cummins generators (Units 420 and 421a) are operated for emergency back-up.

15.2 **Monitoring and Recordkeeping.** The Permittee shall

a. record date and time when the Normal Operations, R warm shutdown, and LT warm shutdown operations are started and terminated; and

b. calculate and record the 12 consecutive month period NO_X and CO emission rate in accordance with Conditions 14.2a(ii)(D) and 14.2a(ii)(E).

15.3 **Reporting.** The Permittee shall list the date and time when the Normal Operations, R warm shutdown, and LT warm shutdown as described in Condition 15 are started and terminated in the Operating Report required under the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50:

16. Operating Mode Consequences.

[7] This was the start date of the restart period per Permit AQ0417CPT05.

16.1 The Permittee shall submit to the Department a demonstration of load demand (power demand), consistent with the definition in Condition 16.2, meeting the following time requirements. The demonstration shall be submitted no later than 60 days after the end of the restart period, as described in Condition 15.

The demonstration shall be based on the stationary source operations during the restart period as set out above, include the period(s) that the stationary source is operated under a R warm shutdown regime (recharge). The demonstration must provide adequate information for determining if replacement or modification of Emission Units 500 and 501 is warranted. The demonstration shall include, but is not limited to, the follow elements:

(i) detailed description of the Badami operational modes, and related electric energy demands;

(ii) the intended usage of the electrical loads and their collective impact on the generators, including specification of lighting, electrical motor loads, and possible electrical load swings; and

(iii) if Condition 16.3 is not met, detailed description(s), technical data, emission performance data of the selected equipment as required in Condition 16.4.

16.2 For purposes of the load demand demonstration, load demand is defined as the electrical power (in kW) that is required to operate the stationary source[5] under the various operational modes during the restart period *without* electric load demand from load banks, water brakes, pump flow controls, or other loads that has the single purpose to destroy energy in order to improve the CO emission performance of the fuel fired generators.

16.3 If results from the load demand demonstration show that the Emission Units 500 and 501 are capable of operating consistently in SoloNOx[6] mode for 95 percent of the operating time, excluding startup, shut down, malfunction, maintenance, load transfer, source testing, and emergencies[7], without using artificial load demand equipment as indicated in Condition 16.3, then the Permittee is not subject to Condition 16.4. To demonstrate this capability, the Permittee must show that the 95 percent threshold has been met continuously during a substantial portion of the restart period that will be representative of future operation.

[5] "Load demand" is the "real power demand" to operate Badami, including support systems (e.g. light and power for workshops, workers housing, refrigerators, cookhouses, communications systems, laundry, etc.).
[6] Emission**s** Units 500 and 501 Solar Gas Turbines in $SoloNO_x$ means that the gas turbine NO_X emission controls are activated.
[7] The Department considers 120 minutes (two hours) operation maximum during equipment startup, and shutdown of the gas turbines.

16.4 If the results from the load demonstration do not show that the provisions of Condition 16.3 are met, then the Permittee shall submit to the Department within 45 days, after submittal of the load demand demonstration subject to Condition 16.1, a construction permit application, except as provided in Condition 16.4b. The application shall include the request for authorization for replacement of the existing combustion turbine(s) or for installation of CO emission controls on the existing combustion turbine(s).

a. The Permittee shall after the load demand demonstration and after new permit issuance and within the time specified in that new permit:

(i) Install and operate power generation equipment that is properly rated, and capable of operating for the specific application with appropriate NO_X and CO emission controls for available load demand without using artificial load demand equipment[8] as indicated in Condition 16.2, or

(ii) install post combustion CO controls; controls must be at least as stringent as

(A) selective catalytic oxidation, with a destruction efficiency as determined per Condition 16.6b on the existing emission units; and

(B) BACT as demonstrated in Condition 16.5.

b. If the stationary source does not operate in Normal Operation mode during the first 105 days after the end of restart period, the Permittee shall submit to the Department a construction permit application as identified in Condition 16.4 before resuming Normal Operation.

16.5 The Permittee shall provide within five months after the restart period, a NO_X and CO BACT analysis for Emission Units 500 and 501, or their replacements, except that a NO_X BACT analysis is not required if the Permittee demonstrates that the Condition 16.4 will be met during the future operations of Badami and the results of the power demand described in Conditions 16.1(i) and 16.1(ii) indicate that existing Emission Units 500 and 501 will be well aligned to Badami's future power needs. Any new BACT limits under this condition must be equal to or lower than the limits in Condition 16.1 of this permit. The Permittee shall conduct the analyses according to EPA's "top-down" approach in the proposed New Source Review Rule Revisions (EPA, 1990). The BACT assessments shall include, but not be limited to, the following elements:

a. cost estimates, cost proposal specific for Badami and actual cost data, cost indexed for the year that the analysis is provided;

8 This includes the use of a load-leveling device to mitigate the stationary source normal load swings in the operational load. The load leveling device is only used in specific operations where load swings are expected (e.g. start up large electro motors, electric block loads).

b. the cost elements used in the BACT cost analysis must be accompanied with copies of the original Vendor quotes, including the scope of supply, services;

c. the cost analysis to be performed according to the guidelines as set out in “EPA Air Pollution Control Cost Manual” US EPA, latest edition.

16.6 CO BACT analysis for Emission Units 500 and 501 and replacement equipment shall include but not be limited to the following CO emission control technologies;

a. Low NO_X turbine, or other available NO_X control technologies for the turbine suitable for the specific Badami operation conditions.

b. For the CO controls with catalytic controls include in the cost assessment the catalyst control strategies for 80, 85, and 90 percent long term control efficiency;

c. Cost analysis to include the vendor based data regarding operation, supervision and maintenance costs of the emission controls.

16.7 After receiving a complete BACT analysis under Condition 16.5, and any additional information the department needs to complete review, the department will issue a BACT determination.

a. If the results of the load demonstration show that the provisions of Condition 16.3 are met, the Permittee shall operate in compliance with the new BACT determination within 15 months after the date the Department issues the final determination.

b. If the results of the load demonstration show that the provisions of Condition 16.3 are *not* met, the Permittee shall operate in compliance with the new BACT determination consistent with Condition 16.4.

17. LT Warm Shutdown Mode Consequences.

17.1 The Permittee shall within 60 days after the end of the restart period, as described in Condition 15, submit to the Department a power generation demonstration that will provide the information necessary to determine if emission units re-sizing, and output optimizing is necessary in the LT warm shut down mode. The demonstration must include a detailed study regarding the power generation during the LT warm shutdown mode. The demonstration will include but is not limited to the following elements:

a. detailed description of the power demand during the LT warm shutdown, and the available fuels;

b. for each option as described in Condition 17.1e, the potential NO_X, CO, PM-10, VOC, and SO_2 emissions, and the emission performance under Badami-specific conditions (fuel, Arctic cold, and load characteristics);

c. demonstration of possible reduction of NO_X, CO, PM-10, and VOC emissions for each of the option compared to power generation with the existing emission units during the LT warm shut down.

d. for the option described in Condition 17.1e(i), the Permittee shall submit a cost analysis that includes the total cost of the conversion, based on the conversion parts costs of the new (converted parts) minus the replaced components remainder value; and

e. supply options for generating electric power during LT warm shutdown operation to include:

(i) converting one or both of the existing diesel-fired generators, Emission Units 420 and 421a, to natural gas firing or duel fuel (natural gas and diesel) firing;

(ii) installing and operating of new, appropriately sized generator(s) driven by a natural gas-fired reciprocating engine(s);

(iii) installing a new, appropriately sized generator driven by a natural gas-fired combustion turbine; or

(iv) installing some other, not yet identified, innovative technology such as a multiple micro-turbine driven generator set; fuel cell; sterling engine or wind-driven turbine generator.

17.2 **Monitoring and Recordkeeping.** The Permittee shall monitor and record the monthly operating hours for Emission Units 500 and 501 as set out in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50. Specify the reason of operation of the gas turbine.

17.3 **Reporting.** The Permittee shall list in the Operating Report required in the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50:

a. the monthly and consecutive 12-month total hours;

b. as set out the applicable operating permit issued for the source under AS 46.14.130(b) and AAC 50, dates and times when the Normal Operations, R warm shutdown, and LT warm shutdown (as described in Condition 15) are started and stopped; and

c. reason for operating Emission Units 500 and 501 in the LT warm shut down mode during the period.

17.4 If the Permittee decides to terminate the LT warm shut down operations as set out in Condition 15.1b, and start operations in modes under Conditions 15.1a or 15.1c, before starting operations in modes under Conditions 15.1a or 15.1c, the Permittee shall provide the demonstrations under Conditions 16.1 and 16.5 through 16.7. The Permittee shall comply with Conditions 16.4 and 16.7.

Table 2: Badami Restart Solar Gas Turbine NO_X and CO Emission Factors

Emission Unit	Description	Gas Turbine Load Condition (% NGP)	CO emission factor
500 – 501	Solar Mars 90 SoloNOx gas turbine	% NGP speed average hourly value	
	In SoloNOx mode		**4.7 lb/hr**
	Out SoloNOx mode	% NGP ≥ 94	4.7 lb/hr
		% NGP ≥ 90 and < 94	202.0 lb/hr
		% NGP ≥ 87 and < 90	236.0 lb/hr
		% NGP ≥ 84 and < 87	261.9 lb/hr
		% NGP < 84	385 lb/hr
			NO_X emission factor
	In and Out SoloNOx mode	All % NGP	28.4 lb/hr

Section 8. General Conditions

Standard Terms and Conditions

18. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

18.1 an enforcement action; or

18.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

19. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

20. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

21. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

22. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 9. Permit Documentation

August 31, 2010	Application addendum received to add expiration date to the Restart Project.
August 18, 2010	Meeting between BPXA, SLR-Hoefler, and the Department regarding Restart Period Extension; decision to incorporate emergency generator permit into restart extension permit.
August 6, 2010	Decision to rescind and incorporate previous permits into this permit.
July 8, 2010	Request for Information Letter sent to BPXA for emergency generator
June 21, 2010	Minor Permit application received to replace emergency generator, EU 421. Responses regarding Restart Period received.
June 17, 2010	Meeting between BPXA, Hoefler, and the Department regarding concerns for the Restart Period extension
May 21, 2010	email: Al Trbovich (Hoefler) clarifying the revision to Condition 13.XI.A of Minor Permit AQ0417MSS01, Rev. 2
March 23, 2010	Minor Permit application for Restart Period Extension received. The Department found the application complete.