Statement of Legal and Technical Basis
Proposed Changes to 18 AAC 50
Related to Drill Rigs
And
Proposed Changes to the Drill Rig General Permit MG1 (MGP1)

November 4, 2004

Prepared by
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Summary
The department proposes to revise 18 AAC 50 to require minor permits for portable oil and gas operations. The term "portable oil and gas operation" would have a definition similar to that in 18 AAC 50 before October 1, 2004. The proposal would apply to portable oil and gas operations (drill rigs and associated equipment) with and without an associated well test flare. Air quality dispersion modeling predicts that these oil and gas drilling operations could cause or contribute to violations of ambient air quality standards, whether or not there is an associated well test flare.

While the major purpose of this public notice and rulemaking was to make changes to the Minor General Permit for Portable Oil and Gas Drilling Operations, this rulemaking also updates the adoptions by reference in 18 AAC 50.035 and 18 AAC 40.040. The adoption by reference dates have been changed to July 1, 2004, to ensure that the DEC regulations have adopted the most up-to-date versions of the federal regulations. In addition, three new National Emission Standards for Hazardous Air Pollutants for Source Categories as they apply to a Title V source have been adopted from 40 C.F.R. Part 63. These are Subpart YYYY (Stationary Combustion Turbines), Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines) and Subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters).

This notice also proposes to revise the minor general permit for portable oil and gas operations and the associated notification form. The changes include making the general permit and notification form consistent with the proposed regulations, and making the notification form consistent with the electronic version being developed for on-line permitting.

Background
In the original regulatory proposal to rewrite the air quality permit program to implement the statutory change of HB 160, the department deleted the category "fuel burning equipment with a rated capacity of 100 million btu per hour or more."[1] This category had required permits for oil and gas drilling operations with an associated well test flare because of the rated capacity such flares. In the proposal the department replaced that category with emission rate categories, and with the category "portable oil and gas operation with a flare."

Following the comment period the department refined the categories of stationary sources needing minor permits with the intention of more accurately reflecting those sources with the

[1] The proposal was in January 2004.

potential to cause violations of ambient air quality standards (the minor permit category described in AS 46.14.130(c)(1)). Some proposed categories were deleted, and others were changed. One category that was changed was for portable oil and gas operations. The regulations that were adopted before the review by the Department of Law dropped the words "with a flare" for this category. That meant that drill rigs without well test flares would also need minor permits.

Oil and gas industry representatives became concerned that they would not have adequate time to obtain permits for planned drilling that did not involve associated well test flares, and that there was inadequate public process. While the department and interested parties may disagree whether the original public notice was adequate to cover the changes to the regulation we made for the first adoption, we deleted from the final adoption, and are re-proposing, the provisions for oil and gas drill rigs.[2] We deleted the minor permit category for portable oil and gas operations, the definition of portable oil and gas operation, and the portable oil and gas operation permit by rule (PBR),[3] which could be used for an operation needing a permit because of the drill rig permit category.

Industry representatives then became concerned that they would still need minor permits for drill rigs because the potential to emit could exceed the emission rate thresholds in 18 AAC 50.502(c). Without the permit by rule, obtaining a permit might delay planned drilling operations. When the department became aware of this problem, we proposed a general minor permit for drilling operations that has the same applicability criteria and the same provisions as the permit by rule being repealed. We issued the general permit (MG1) October 11, 2004. Unlike the permit by rule, MG1 can be used regardless of whether the permit classification is based on emissions, or on a category specifically for portable oil and gas operations. Like the permit by rule, MG1 uses a notification rather than an application. An operator does not need to wait for approval from the department before operating; because the department does not issue an approval, the operator retains the responsibility to assure they qualify for the general permit so that there is no violation of the requirement to have a permit. Also like the PBR, MG1 does not expire, although authorizations to operate under it last only for the time indicated in the notification.

We are re-proposing the minor permit category for portable oil and gas operations, and the definition. We are not re-proposing the permit by rule. With MG1 in place, readopting the permit by rule would not add any benefit. We are also proposing flat emission fees. The emission fees would apply to portable oil and gas operations under a general minor permit (MG1). They are similar to those in the previous permit by rule, but are based on the current emission fee rate.

After the public comment period ends, the department will either adopt these or other provisions dealing with the same subject, without further notice, or decide to take no action on them. The language of the final regulations may be different from that of the proposed regulations.

[2] One exception is that we inadvertently did not delete the definition of "rig day" in 18 AAC 50.990. That definition relates only to the provisions specific to oil and gas drill rigs.

[3] The former 18 AAC 50.390.

Reason for the Change to the Drill Rig Category

The oil and gas permit by rule for drill rigs became effective in February 2002. To support development of that rule, the department analyzed the ambient impacts of drill rigs using computer dispersion modeling. That modeling, and other modeling done by the department for evaluation of drill rig permit applications, predicted that the ambient impact from a well test flare represents only a small part of the ambient impact from drill rigs. A flare's release height is high and the plume is hot and buoyant, so much dispersion would occur before the plume would reach ground level. The modeling predicted that the other emission units, especially the internal combustion engines, may cause impacts great enough to cause violations of ambient standards. In short, we have been using the wrong criteria for requiring permits. The drill rig itself rather than the flare would have been the appropriate category.

Drill rigs are stationary sources, and therefore subject to the permit program, because they contain fuel-burning equipment such as boilers and heaters. The internal combustion engines used with a drill rig are nonroad engines, which are not by themselves subject to stationary source permitting. But when considering the ambient impact of a stationary source, the impacts of all emissions from the source are part of the analysis. In-use restrictions are then allowed under the Clean Air Act for nonroad engines to protect ambient air quality. Such restrictions include limits on hours of operation or fuel quantity, and fuel sulfur content.

The department is relying on the same technical basis we used to support the 2002 adoption of the oil and gas permit by rule. See Attachment A of this document for a discussion of the modeling that supported the permit by rule development. The document in Attachment A discusses the potential of the drill rigs modeled to violate or contribute to violation of ambient air quality standards.

<u>Results of Modeling for Drill Rigs and for Flares Alone</u>

Table 1 shows the predicted flare contribution to ambient impacts for the drill rigs modeled to support the permit by rule. The conclusions below, consistent with EPA's *Guideline on Air Quality Models*, are based on operation at full rated capacity. The modeling for flares alone and for the entire drill rigs used meteorological data from the North Slope, Kenai Airport, and the West side of Cook Inlet.

- The highest predicted annual NO_x concentration from a well test flare is less than 1/20th of a microgram per cubic meter. The highest modeled NO_x concentration for a drill rig as a whole [not including background concentrations] is 136 $\mu g/m^3$. To calculate NO_2 from predicted NO_x concentrations we used the ambient ratio method – multiplication of the NO_x concentration by 0.75. Using the ambient ratio method, NO_2 concentrations would be less than 1/30th microgram per cubic meter for the flare alone, and 102 for the rig as a whole. The ambient NO_2 standard is 100.

- The highest predicted 24-hour ambient SO_2 concentration from a flare is less than three micrograms per cubic meter. The highest modeled SO_2 concentration for a drill rig as a whole is 1024 $\mu g/m^3$, assuming 0.5% fuel sulfur. The ambient SO_2 standard is 365.

- The highest predicted 24-hour PM-10 concentration from a flare is less than three micrograms per cubic meter. The highest modeled PM-10 concentration for a drill rig as a whole is 150 $\mu g/m^3$. The ambient PM-10 standard is 150.

Table 1
Maximum Modeled Flares

	(ug/m3) NO_X annual	SO_2 24-hour	PM-10 24-hour
North slope			
Concentration	0.024	2.7	2.6
Met data	1995	1993	1993
Kenai			
Concentration	0.043	0.52	1.78
Met data	1995	1994	1994
West Side Cook Inlet			
	0.023	0.43	1.47

These findings indicate that portable oil and gas operations for well drilling, with or without flares, have the potential to result in to violations of ambient air quality standards. Therefore, department proposes to require minor permits for these sources to implement the requirements of 40 C.F.R. 51.160 and AS 46.14.130(c)(1).

Definition of "Portable Oil and Gas Operation"
The proposal makes one change to the definition of portable oil and gas operation because the purpose of the definition has changed. The definition in effect before October 1, 2004 was intended to describe, of the drill rigs that needed permits [because they had fuel burning equip equipment > 100 MMBtu/hr], which ones could take advantage of the permit by rule of 18 AAC 50.390 to satisfy the need for a permit. That definition

> *…does not include equipment that operates at a single pad or platform, or at pads within a quarter of a mile of each other, for more than 24 consecutive months;…*

The proposed rule is intended to define what drill rigs need a permit, rather than to limit which those rigs can use a PBR to show compliance. Therefore the proposed rule does not contain the 24 month exclusion. Drill rigs that operate at one location for a long period of time are more likely to result in degradation of air quality at that location. The 24-month exclusion is contained in the minor general permit, and serves the same purpose it did for the oil and gas PBR.

The definition is otherwise unchanged.

Changes to the General Permit for Drill Rigs

The permit number is being changed from MGP1 to MG1 to conform to our new permit numbering system.

The existing general minor permit for drill rigs, MG1, uses the definition of 'portable oil and gas operation" as one of the applicability criteria for the permit. The definition used in MG1 includes the 24-month exclusion and a similar 12-month exclusion related to the non-road engine rule. The definition means that a drill rig that operates on the same pad or group of pads for more than 24 month, or that operates at the same "location," as the term is used in 40 C.F.R. 89, for 12 consecutive months or more does not meet the qualifying criteria for operating under MG1.

After 24 months, an operation would not be considered a "temporary construction activity", and would consume increment. The modeling done for this project serves as an investigation under 18 AAC 50.201 that this class of sources is capable of violating increments. So the permit is not usable for stationary sources that remain for more than 24 months because the permit does not contain provisions adequate to protect increment. If a portable internal combustion engine remains in one location, as defined in 40 C.F.R. 89.2, those engines could be considered stationary, rather than nonroad engines. They would then be subject to state emission standards. One of the purposes of a minor permit is to determine if an emission units is capable of complying with those emissions standards. The general permit does not address that determination.

Because the existing definition is different from the definition of the same term we are proposing for 18 AAC 50, we propose to amend MG1 and the associated application. To avoid possible conflict or confusion, the proposed amendment would make the definitions the same, but would rephrase the permit and application to keep all of the current qualifying criteria.

We propose to change the application form by adding more complete contact information, reformatting, and making other changes consistent with the permit. The department also intends to reformat the notification form for use with on-line permitting.

The public notice for this project also allows the department to make other changes to the general permit based on public comment received.

Fees

For this proposal we have calculated the emission fees due for a portable oil and gas drilling operation using a minor general permit under 18 AAC 50.560. The department is proposing a flat emission fee for the general permit based on maximum actual emissions for each of the two areas of the state. We are proposing a flat fee as we did for the PBR, rather than fees based on activity data specific to each drill rig and location, because Permit by Rule Workgroup members often expressed concerns about the difficulty and cost of tracking fuel use for drill rigs. We used the current rate of $12.52 per ton of pollutant, rather than $5.02 per ton used for the permit by rule. The calculations are in Attachment B.

For North Slope operations, the emission rates are based on information received from the PBR Work Group during the development of the permit by rule for portable oil and gas operations. The reported highest fuel consumption for a winter drilling season was 439,000 gallons. Consistent with fee calculation for the permit by rule, I rounded up to 500,000 gallons to account for combustion during well testing, and I allocated 75% of the fuel to diesel engines and 25% to

other fuel burning equipment. Based on rated horsepower, I further allocated the fuel used in the diesel engines to large and small engine groups, which have different emission factors.[4] The equipment considered came from the model facility I used to represent North Slope drilling operations for the ambient air quality analysis that formed the basis for the permit by rule.

For operation at a gravel pad, winter drilling fuel use and duration could be used to extrapolate to an estimate of annual consumption. However, that would result in an estimate of greater than 1.5 million gallons per year. Therefore, fees for operation at a location other than an ice pad were projected based on 1.5 million gallons per year because higher consumption would preclude use of the general permit. This is also the same method of calculation as for the permit by rule.

For emission fees for operations in other areas of the state, I used information supplied by the PBR Work Group, as well as more recent information. Before final adoption of the PBR, work group members reported that the highest annual fuel consumption at a single pad was 233,382 gallons for drilling 2 wells in 94 days. They reported that they had not drilled more than two wells at a time, and did not anticipate doing so. Therefore, the PBR fees were calculated based on three months of operation. In subsequent oral communication, a representative of an operator in the Cook Inlet area reported planning to drill up to 10 wells at one location, spanning a year of activity. For this proposal, I started with the reported fuel consumption for two wells and rounded up to 250,000 to account for combustion during well testing. I prorated emissions at 90% for the diesel engines, and 10% for other fuel burning equipment. Finally I multiplied by 5 to account for a maximum of 10 wells instead of two.

The proposed emission fees are

- $1808 for operation of a single portable oil and gas operation at one or more North Slope ice pads during a winter drilling season;

- $5424 for operation of a single portable oil and gas operation during a state fiscal year at a single location that is not a seasonal ice pad;

- for operation outside the North Slope, $5031 for operation of a single portable oil and gas operation during a fiscal year.[5]

We propose that the flat emission fee for drill rigs would take effect at the same time as the rest of these proposed regulations. However, since only a few months will remain of the current fiscal year when we anticipate this proposal to become effective, to avoid confusion the flat emission fees will only apply to new notifications under the minor general permit after the effective date.

Under regulations expected to become effective in January, 2005, minor stationary sources subject to permitting are also subject to permit administration fees.

The department specifically requests comment on the proposed emission fee provisions.

[4] Emission factors for all equipment types were from EPA's AP-42.
[5] The department could consider alternate fees based on the number of wells to be drilled, such as more than or less than a specified number of wells. Any additional wells would then need a new notification under the general permit.

ATTACHMENT A

Modeling Appendix A
From

Proposed Air Quality Regulations for Oil and Gas Temporary Operations

November 22, 2000

Modeling Appendix A

Report on Ambient Air Quality Analysis
For Oil Drilling Permit by Rule
6/23/99

PREPARED BY BILL WALKER

I performed the dispersion modeling described in this report to support adoption of a permit by rule for oil drilling. The permit by rule would replace existing permitting requirements that apply to oil drilling.

Rigs modeled

For the North Slope, I modeled the "typical" rig described in ARCO's construction permit application for their 1998-1999 winter drilling program. All building dimensions, source parameters and emission rates were taken directly from ARCO's application and are presented in Appendix A of the Modeling Protocol.

I modeled the East and West sides of Cook Inlet separately. All information input into the model was the same, except for the meteorology data sets. The same drill rigs are used on both sides of the inlet. This project does not consider drilling from platforms in the inlet.

I used the Nabors 160 rig to represent drilling on both sides of the inlet. Most of the source information came from the permit application for Anadarko, modified as described in the April 21, 1999 protocol. To complete the modeling I also needed more complete and correct information on building sizes and locations. The additional information was provided by Marathon Oil.

Pollutants modeled

I modeled NO_2 for comparison to the annual standard, and SO_2 and PM-10 for comparison to the 24 hour ambient standards. Previous modeling of similar sources has consistently shown these to be the limiting pollutants and averaging periods.

SO_2 emissions are based on a fuel sulfur of 0.25% by weight for the North Slope, and 0.5% S for Cook Inlet.

Model Selection

The department selected ISC PRIME for this project. PRIME is similar to ISCST3, except that downwash calculations have a more complete scientific basis. Subsequent verification for four facilities has shown PRIME to be more accurate than ISCST3 for those facilities.

EPA is still in the process of adopting ISC PRIME as an approved model. In the mean time EPA Region 10 will approve its use case by case as appropriate. The department intends to request approval to use it for this project. To be granted approval we must show that the characteristics of the drill rig are similar to one or more of the sources for

which the accuracy of ISC PRIME has been verified. The department is currently preparing that request.

Modeling Procedures

I used ISC PRIME to evaluate the effects of

- Full rated capacity;
- Operation at "worst real case"; and
- The use of 8 foot stack extensions at both full rated capacity and worst real case.

Full rated capacity for the NO_2 annual standard is based on a winter drilling season for the North Slope, rather than a full calendar year. It assumes continuous operation for 3 months of well drilling and one month of well testing. For the Cook Inlet, full rated capacity is based on 4800 hours of operation per year. Both of these time periods were permit limits requested in recent permit applications.

I calculated "worst real case" emissions by pro-rating emissions at full rated capacity based on fuel consumption for the equipment and averaging period.

North Slope

ARCO provided fuel consumption information to estimate worst real case. Based on recent data the highest daily fuel consumption is 6167 gallons. The highest total fuel used for a winter drilling season was 439,000 gallons. To allow a "safety margin" I used 6500 gallons per day, and 500,000 gallons per winter season.

I used two scenarios for "worst real case." Russ Douglas of Doyon Drilling provided estimates of percentage breakdowns of fuel consumption by source group for North Slope rigs operating at an average daily consumption of 3344 gallons. The worst real case 24 hour fuel consumption was almost twice that amount. For Scenario 2, I assumed that all fuel consumption was apportioned to each source group in the same proportions as the reported averages, regardless of the total quantity burned. For Scenario 1, I assumed that when the rig burned more than the average amount, the additional fuel was mostly used for drilling. I assigned 75% of the fuel in excess of 3344 gallons to the engines (excluding the camp engine), and 25% to other fuel burning equipment. I only used Scenario 2 for NO_2, since it has an annual standard.

I did two runs for each pollutant type. The first run used a rectangular receptor grid with a 25 meter spacing from the pad edge out to 400 meters from the pad center in each direction. After I verified that highest impacts were predicted toward the west, I used the following:

- Around the pad edge a single row of receptors spaced at 12.5 meters; and
- Only toward the west, grids of receptors spaced at
  - 12.5 meters extending out to 225 meters from the pad center;

- 25 meters extending out to 400 meters; and
- 50 meters extending to 800 meters

Cook Inlet

Marathon Oil provided the fuel consumption rates. Annual fuel consumption was based on drilling two wells with the Nabors 160 rig at the same pad during a 12 month period. This was 13.7% of full rated capacity. For worst real case I used 15%. The highest 24 hour fuel consumption reported was 4416 gallons per day. I used 4500 gallons for the 24 hour averaging periods. This was 53% of full rated capacity.

Vertical stack velocities are less when a source is operating at less than full rated capacity. Vertical velocity affects pollutant dispersion. In order to calculate velocities for "worst real case" emissions, I used two scenarios. For one scenario, I assumed sources were operating at 100% load all of the time they were operating, so the vertical velocity was unchanged in the model input. For the other scenario, I assumed that sources averaged 75% load during all periods of operation, and therefore used a vertical velocity that was 75% of full load velocity.

I used a receptor spacing of 12.5 meter to determine each of the highest impacts. In some cases I only used the fine grid for the single year with the highest impacts predicted with the coarser grid.

Evaluation Criteria

AS OUTLINED IN THE PROTOCOL, FOR THE NORTH SLOPE AND THE EAST SIDE OF COOK INLET I USED

- highest 2nd high for any year for 24 hour SO_2;
- highest 6th high for 5 years combined for 24 hour PM-10; and
- highest annual for NO_2 annual.

I used these criteria because 5 years of National Weather Service data, or 5 years of industry-collected data in lieu of NWS data were available. For NO_2, I used the ambient ratio method. Since no local data is available for conversion of NO to NO_2 I used the EPA default value of 75%.

Only one year of meteorological data was available for the West Side of Cook Inlet. This was industry-collected data used in lieu of National Weather Service Data. Since it is used to represent such a large area, it cannot be considered “on-site” data. I therefore used the high first high for both 24 hour standards, consistent with 40 C.F.R. 51, Appendix W and the April 21, 1999 protocol.

Background Air Quality

The background air quality data used for this project were presented in the April 21 protocol, and are shown in Table 1.

Table 1
Selected Background Concentrations

	NO_2 Annual	SO_2 24 hour	PM-10 24 hour

North Slope – remote	5.6	10	57
North Slope – near industrial facility	26[1]	13[1]	57[2]
West Cook Inlet – remote	1.9	5.2	33
West Cook Inlet – near industrial facility	13[3]	53[3]	41[4]
East Cook Inlet – remote	5.3	27	41[4]
East Cook Inlet – near industrial facility	13[3]	53[3]	41[4]

[1] CCP
[2] DS-1F
[3] Maximum value from Tesoro site.
[4] Maximum value from Phillips site.

North Slope

To represent background concentrations of NO_2, SO_2, and PM-10 for a rig which is remote from any North Slope oil production facility, I used high values from DS-F1 monitoring data. To represent background plus ambient concentrations caused by a nearby production facility, I used the pollutant monitoring data collected at CCP. Ambient standards minus the background concentrations are presented in Table 1.

Cook Inlet

For remote sites I used Beluga data for the West Side and Tesoro data on the East for NO_2 and SO_2. For remote background, the Tesoro data was screened to eliminate hours when the wind was blowing directly from Nikiski industrial facilities. Data from the Nikiski Phillips site was used for PM-10. Since it was measured daily, it could not be screened hourly to eliminate the industrial source component.

To represent background near industrial facilities, I used maximum values from Tesoro for NO_2 and SO_2, and the Phillips data for PM-10. I used the same data for sites near an industrial facility on the West Side since no data has been collected near the oil production facilities there.

To use the results of this modeling for a rig operating *at* a new or existing production facility would not be consistent with the modeling guidelines in 40 C.F.R. 51, Appendix W, and therefore would not be approvable by EPA in support of a change to the State Implementation Plan.

Results and Discussion

Because maximum impacts were associated with downwash, all predicted violations were at or near the pad edge.

North Slope

SO_2 impacts for operation at full rated capacity were predicted to exceed the 24 hour standard at and very near the pad edge. The highest predicted concentration

was 30% over the allowable concentration. Standard violations were not predicted at modeled part load.

PM-10 concentrations exceed the standard near the pad edge when the summertime background concentration is used. This is true at both full rated capacity, and part load Scenario 2. For winter months the department has accepted a background concentration of 20 :g/m^3. At this lower background concentration, violations of the 24 hour PM-10 ambient standard are not predicted.

Modeling for NO_2 at full rated capacity for three months of well drilling and one month of well testing resulted in a maximum concentration exceeding the annual NO_2 standard when the higher monitoring data for CCP is used to represent both background and a nearby facility. The combined concentration exceeds the standard by only 1 ug/m3 at the pad edge. Fuel use corresponding to full rated capacity for 3 months of drilling and 1 month of testing can be considered the maximum that can be used without violating the NO_2 ambient standard.

Since we have been provided only with exploration drilling data, we do not know what fuel is consumed by rigs operating at a single pad for a full year drilling production wells. Therefore I did not model worst real case production well NO_2 emissions. The PBR can be extended to cover drilling that lasts longer than a winter drilling season by allowing the rule to cover any activity that uses no more fuel in a year than the amount corresponding to full rated capacity for a winter season.

Table 2a North Slope Highest Predicted NO_x Concentrations				
Standard = 100 :g/m^3 NO_2				
	High NO_x Concentrations	High NO_2 Concentration (Ambient Ratio = 75%)	NO_2 With Highest Background	NO_2 With Remote Background
Full Rated Capacity	100	75	101	81
Worst Real Case – Scenario 1	na			
Worst Real Case – Scenario 2	45	34	60	40
8 Foot Stack Extension Full Rated Capacity	81	61	87	67
8 Foot Stack Extension Worst Real Case 75% vertical velocity	34	26	52	32

Table 2b North Slope Highest Predicted SO_2 Concentrations			
Standard = 365 :g/m^3 $_{SO2}$			
	High SO_2 Concentrations	SO_2 With Highest Background	SO_2 With Remote Background
Full Rated Capacity	459	472	469
Worst Real Case – Scenario 1	292	305	302
Worst Real Case – Scenario 2	276	289	286
8 Foot Stack Extension Full Rated Capacity	428	441	438
8 Foot Stack Extension Worst Real Case 75% vertical velocity	278	291	288

Table 2c North Slope Highest Predicted PM-10 Concentrations			
Standard = 150 :g/m^3 PM-10			
	High PM-10 Concentrations	PM-10 With Background	PM-10 With Background Winter Only
Full Rated Capacity	120	177	140
Worst Real Case – Scenario 1	78	135	98
Worst Real Case – Scenario 2	111	168	131
8 Foot Stack Extension Full Rated Capacity	110	167	130
8 Foot Stack Extension Worst Real Case 75% vertical velocity	74	131	94

West Side Cook Inlet

NO_2 at full rated capacity was at or a little above the standard near the pad edge. Results for operation at 15% of full load, and full load with higher stacks, were well below the standards.

SO_2 concentrations were predicted to exceed standards, with the highest about three times the standard at the pad edge for full rated capacity. Worst real case emissions were also predicted to exceed standards close to the pad edge, assuming a fuel sulfur concentration of 0.5%.

PM-10 was predicted to violate standards at full rated capacity.

East Side Cook Inlet

The only predicted ambient violations were for NO_2 at full rated capacity for 4800 hours per year.

The only differences between the East and West Cook Inlet modeling were the meteorological data sets used. Because there were 5 years of data available for the East Side, and only one year for the West, different evaluation criteria had to be used—that is high second high or high 6th high for five years v. high first high.

Table 3a West Side Cook Inlet Highest Predicted NO_x Concentrations				
Standard = 100 :g/m^3 NO_2				
	High NO_x Concentrations	High NO_2 Concentration (Ambient Ratio = 75%)	NO_2 With Highest Background	NO_2 With Remote Background
Full Rated Capacity	130.4	97.8	110.8	99.7
Worst Real Case – 75% Vertical Velocity	25.2	18.9	31.9	20.8
Worst Real Case – 100% Vertical Velocity	19.6	14.7	27.7	16.6
8 Foot Stack Extension Full Rated Capacity	22.0	16.5	29.5	18.4
8 Foot Stack Extension Worst Real Case 75% vertical velocity	4.7	3.5	16.5	5.4

Table 3b **West Side Cook Inlet** **Highest Predicted SO_2 Concentrations**			
Standard = 365 :g/m^3 SO_2			
	High SO_2 Concentrations	SO_2 With Highest Background	SO_2 With Remote Background
Full Rated Capacity	1024	1077	1029
Worst Real Case – 75% Vertical Velocity	694	747	699
Worst Real Case – 100% Vertical Velocity	543	596	548
8 Foot Stack Extension Full Rated Capacity	108	161	114
8 Foot Stack Extension Worst Real Case 75% vertical velocity	91	144	96

Table 3c **West Side Cook Inlet** **Highest Predicted PM-10 Concentrations**			
Standard = 150 :g/m^3 PM-10			
	High PM-10 Concentrations	PM-10 With Highest Background	PM-10 With Remote Background
Full Rated Capacity	150	191	183
Worst Real Case – 75% Vertical Velocity	98	139	131
Worst Real Case – 100% Vertical Velocity	80	121	113
8 Foot Stack Extension Full Rated Capacity	20	61	53
8 Foot Stack Extension Worst Real Case 75% vertical velocity	13	54	46

Table 4a East Side Cook Inlet Highest Predicted NO_x Concentrations				
Standard = 100 :g/m^3 NO_2				
	High NO_x Concentrations	High NO_2 Concentration (Ambient Ratio = 75%)	NO_2 With Highest Background	NO_2 With Remote Background
Full Rated Capacity	136	102	114.7	107
Worst Real Case – 75% Vertical Velocity	26	19	32	25
Worst Real Case – 100% Vertical Velocity	20	15	28	21
8 Foot Stack Extension Full Rated Capacity	63	47	60	52
8 Foot Stack Extension Worst Real Case 75% vertical velocity	13	10	23	15

Table 4b **East Side Cook Inlet** **Highest Predicted SO_2 Concentrations**			
Standard = 365 :g/m^3 SO_2			
	High SO_2 Concentrations	SO_2 With Highest Background	SO_2 With Remote Background
Full Rated Capacity	300	353	327
Worst Real Case – 75% Vertical Velocity	209	262	236
Worst Real Case – 100% Vertical Velocity	159	212	186
8 Foot Stack Extension Full Rated Capacity	192	245	219
8 Foot Stack Extension Worst Real Case 75% vertical velocity	131	184	158

Table 4c **East Side Cook Inlet** **Highest Predicted PM-10 Concentrations**			
Standard = 150 :g/m^3 PM-10 Compared to High 6th High over 5 Years			
	High PM-10 Concentrations	PM-10 With Highest Background	PM-10 With Remote Background
Full Rated Capacity	41	82	82
Worst Real Case – 75% Vertical Velocity	28	69	69
Worst Real Case – 100% Vertical Velocity	22	63	63
8 Foot Stack Extension Full Rated Capacity	30	71	71
8 Foot Stack Extension Worst Real Case 75% vertical velocity	20	61	61

ATTACHMENT B

EMISSION FEE CALCULATIONS

North Slope Model Drill Rigs

Based on December 1, 1998 *Revised Modeling Analysis for Mobile Exploration Drilling and Well Testing, North Slope, Alaska. ARCO Alaska, Inc.*

Maximum annual fuel consumption for a winter drilling season

500000 Gallons

Fuel source estimates:

Engines Other fuel burning equipment

For engines prorate fuel use by total horsepower above and at or below 600hp per engines

Total hp – small engines	Total hp – large engines
2055	3645

Percent of total fuel used

75%	25%	27%	48%

Emission Factors from AP-42: 3.4-1, 3.3-2, 1.3-2

North Slope

Large engines			Small engines			Other fuel burning equipment			Tpy - All Sources
240000 gallons/season			135000			125000 gallons			
32887.2 mmbtu			18499.05 small						
105239 lb nox	52.62	tpy nox	81580.81 lb nox	40.79	tpy nox	2500 lb nox	1.25	tpy nox	94.66
16443.6 lb so2	8.22	tpy so2	9249.53 lb so2	4.62	tpy so2	8875 lb so2	4.43	tpy so2	17.28
3288.72 lb PM-10	1.64	tpy PM-10	5734.71 lb PM-10	2.86	tpy PM-10	135 lb PM-10	0.067	tpy PM-10	4.58
27954.12 lb co	13.98	tpy CO	17574.10 lb co	8.78	tpy CO	625 lb co	0.31	tpy CO	23.08
2959.85 lb VOC	1.48		6659.66 lb VOC	3.32		0 lb VOC	0		4.80
Total	77.94		Total	60.39		Total	6.06		144.40
$	975.84		$	756.20		$	75.96		$1808.01 for winter drilling

$5424.02 for entire year

Not North Slope
Maximum annual fuel consumption for a winter drilling season

Based on Nabors 160 rig
250000 Gallons

Fuel source estimates

Engines	Other fuel burning equipment	For engines prorate fuel use by total horsepower above and at or below 600hp per engines	
		Total hp - small engines	Total hp - large engines
		183.58	3800
Percent of total fuel used			
90%	10%	4%	86%

Large engines		Small engines		Other fuel burning equipment		Tpy - All Sources
215000 gallons/season		10000		25000 gallons		
29461.45 mmbtu		1370.3 small				
94276.64 lb nox	47.14 tpy nox	6043.02 lb nox	3.022 tpy nox	2500 lb nox	1.25 tpy nox	51.41
14730.73 lb so2	7.37 tpy so2	685.15 lb so2	0.34 tpy so2	8875 lb so2	4.44 tpy so2	12.15
2946.15 lb PM-10	1.47 tpy PM-10	424.79 lb PM-10	0.21 tpy PM-10	135 lb PM-10	0.068 tpy PM-10	1.75
25042.23 lb co	12.52	1301.79 lb co	0.65	625 lb co	0.31	13.48
2651.53 lb VOC	1.33	493.31 lb VOC	0.25	0 lb VOC	0	1.57
	69.82		4.47		6.07	80.37
	874.19		56.01		75.97	1006.17 three months

5030.86 for entire year