From:	Isaac Jackson
To:	Dec Air Comment
Cc:	Dan Gavora; Shayne Coiley; Ed Stevenson; Kathleen Hook; Josh Van Horn; Stringham, Stephen D CIV (US); "fred.o.sandgren.civ@mail.mil"
Subject:	Doyon Utilities Serious SIP BACT Analysis Comments [CO 19-067]
Date:	Friday, July 26, 2019 12:46:04 PM
Attachments:	DU Serious SIP BACT Comments 7.26.19_CO_19_067.pdf

Attached find comments on the proposed Serious SIP for Fairbanks area PM 2.5 regarding the proposed BACT analysis of Doyon Utilities emission units permitted under AQ1121TVP02 Rev 2.

Any questions contact Isaac Jackson at (907) 455-1547 or ijackson@doyonutilites.com .

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July 26, 2019

Cindy Heil
Alaska Department of Environmental Conservation
Division of Air Quality
555 Cordova St
Anchorage, AK 99501

Re: Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright US Army Garrison and Doyon Utilities

Dear Ms. Heil:

Doyon Utilities, LLC (DU) provides the enclosed comments addressing the proposed Best Available Control Technology (BACT) assessment that the Alaska Department of Environmental Conservation (ADEC) has prepared for Doyon Utilities' Fort Wainwright Privatized Utilities. DU has limited this review and comment effort to those emissions units that are owned and operated by DU and that are included in Title V Permit AQ1121TVP02, Revision 2. DU has not provided comments addressing emissions units that are owned and operated by the US Army Garrison.

On May 23, 2018, DU provided comments addressing the preliminary BACT documents. On May 10, 2019, ADEC opened the official public comment period for the proposed BACT. The comments and information included in the materials accompanying this letter are directed to the proposed BACT in accordance with ADEC's invitation for public comment.

The attached comments (Attachment 1) identify a number of concerns with the proposed BACT. The following concerns are particularly important to note:

- The preliminary SIP identifies US Army Garrison Fort Wainwright as the owner of the Central Heat and Power Plant on Fort Wainwright. However, DU owns and operates the CHPP. DU's responsibilities as owner and operator are reflected in regulation by the Regulatory Commission of Alaska (CPCN #725); environmental permits with ADEC (most recently AQ1121TVP02); easement by the U.S. Army Corps of Engineers; and a 50-year contract between DU and the Department of Defense.
- The preliminary SIP proposes DSI as SO_2 BACT. DU notes that the basis for this proposal is reliance on a cost model that is not appropriate for the size of the boilers, and appears to be premised on other incorrect or unsupported assumptions. As noted in DU's comments,

DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at the CHPP's Wainwright six boilers. DU's estimate is twice the ADEC cost estimate. The proposed SO_2 controls are not economically feasible.

- The CHPP baghouse $PM_{2.5}$ BACT emission limits are provided without supporting rationale, may not be appropriate as $PM_{2.5}$ emission limits, and/or may not be achievable.
- The preliminary $PM_{2.5}$ BACT analysis for the material handling of the coal handling emissions units (EUs 7a, 7b, 7c, 51a, 51b, and 52) are unclear and may not be achievable with current configuration.
- The preliminary SIP does not reflect a generator asset transfer of several generator engines from DU to the Army in late December 2018. See Attachment 2 for a copy of this notification.

DU confirms its commitment to working with ADEC to address any questions or issues that our foregoing comments may raise. Please contact Kathleen Hook at khook@doyonutilities.com if you have any questions or would like to further discuss any specific comments.

Best Regards,

Shayne Coiley

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

cc: S. Koessel, DLA Energy
S. Stringham, Utility Chief, FWA Garrison
F. Sandgren, COR, FWA Garrison
D. Burgess, COR, FWA Garrison
P. Marvin,COR FWA Garrison

Attachment 1 Doyon Utilities' Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright Privatized Utilities Dated May 10, 2019

Attachment 2 DU correspondence dated December 31, 2018 notifying ADEC of a generator asset transfer from DU to the Army at Ft Wainwright

CO 19-067

Attachment 1

Doyon Utilities' Comments Addressing the Proposed Best Available Control Technology Determination for Fort Wainwright Privatized Utilities Dated May 10, 2019

On May 10, 2019, ADEC published proposed the Serious State Implementation Plan ("Serious SIP" or "SIP"). The SIP proposed amendments to 18 AAC 50.030 that would adopt the new section in Volume II, Section III.D.7: Fairbanks North Star Borough (FNSB) Fine Particulate Matter (PM-2.5). Interested parties and members of the public were invited to submit comment to the SIP.

Doyon Utilities, LLC (DU) herein submits comments addressing the documents that will revise the State Air Quality Control Plan. DU specifically comments on the following elements of the proposed SIP revisions:

- Amendments to State Air Quality Control Plan Volume II: III.D.7.7 Control Strategies, Draft, May 10, 2019. [Referred to below as "proposed SIP document."]
- "Fort Wainwright US Army Garrison and Doyon Utilities BACT Documents" in the Draft Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.7.07, May 10, 2019. [Referred to below as "proposed BACT Determination."]

<u>General Comments</u>

1. Section 7.7.8.3 of the proposed SIP document states incorrectly that the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) emissions units "are operated by a private utility company, Doyon Utilities, LLC (DU) and owned by the US Army Garrison Fort Wainwright."

   The Central Heat and Power Plant (CHPP) was owned and operated by the Department of Defense until formally transferred to Doyon Utilities on August 15, 2008. Prior to transfer, Department of Defense solicited proposals for privatization of the CHPP and other electric and steam utility assets. DU was the successful bidder and signed a 50-year contract on September 28, 2007 to become the new owner and operator. For more than ten years, Doyon Utilities has owned and operated the plant under the economic jurisdiction of the Regulatory Commission of Alaska Certificate of Public Convenience and Necessity #725. Under the regulated model, DU recovers operating and capital costs through rates established by the RCA. In addition to economic regulation, DU is subject to environmental regulation as well. DU has held a series of air permits from ADEC for the emissions units in the CHPP. The Army does not maintain a physical presence at any of DU's facilities, nor is the Army responsible for day to day operational discussions. As the customer who pays for utility services via tariff rates, the Army is interested in compliance issues of DU's facilities.

2. Section 7.7.8.3 of the proposed SIP document and Tables A and B of the proposed Best Available Control Technology (BACT) Determination do not reflect the asset transfer of several generator engines from DU to the Army in late December 2018. The documents identify those engines as DU emissions units instead of Army garrison emissions units. DU submitted a notification of these changes to the Alaska Department of Environmental Conservation (ADEC) on December 31, 2018. See Attachment 2 for a copy of this notification.

3. In some instances, the proposed SIP document and the underlying proposed BACT Determination are inconsistent with respect to applicable emissions limits and other requirements. Because both documents will become part of the SIP, please ensure that these two documents are internally consistent and clearly state which requirements are applicable to each emissions unit. DU has attempted to address specific inconsistencies in the subsequent comments.

BACT for Nitrogen Oxides (NO_X)

In Section 7.7.8.3.1 of the proposed SIP document, ADEC states that "the NO_X controls proposed in this section are not planned to be implemented." In the event that the U.S. Environmental Protection Agency (EPA) does not approve the precursor demonstration as justification not to require NO_X controls, DU provides the following comments on the proposed NO_X BACT determination and associated SIP requirements.

4. If NO_X BACT is required, the proposed BACT for the CHPP coal-fired boilers, Emissions Units 1 through 6, is selective catalytic reduction (SCR). The proposed emission limit is 0.060 pounds per million British thermal units (lb/MMBtu) averaged over three hours. The proposed SIP document and supporting proposed BACT Determination do not provide engineering design data supporting this emission limit for these boilers. How did ADEC determine that this emission limit was appropriate? The calculation of the emission limit is based on a 90 percent reduction in NO_X emissions compared to the baseline. A 90 percent reduction is the typical maximum reduction that can be expected from the use of SCR. However, no specific engineering information is presented to support the conclusion that a 90 percent NO_X emission reduction is achievable for the DU CHPP boilers, particularly in light of the economic analysis discrepancies, addressed below.

5. The economic analysis spreadsheet[1] is a cost model offered to support the SCR BACT determination. The cost model was developed by Sargent & Lundy (S&L) but does not appear to be an appropriate model for costs pertaining to the DU CHPP boilers. Additionally, the inputs to the cost model may not be appropriate or adequate to properly determine costs.

   DU reviewed the cost effectiveness model and supporting documentation. The validity of the model cannot be confirmed based on the information that ADEC made available in the public record. From what is available in the public record, DU can note three assumptions in the model that do not look appropriate as applied to DU.

   - ADEC assumed that the model is valid for a plant the size of DU's CHPP.
     - The S&L SCR Cost Development Methodology[2] white paper dated January 2017 addresses several caveats which are not identified or addressed in the draft BACT Determination. The white paper states that "the costs for retrofitting a plant smaller than 100 megawatts (MW) increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units." The draft BACT Determination does not

[1] 2019-05-10-adec-calculated-scr-economic-analysis-for-wainwright.xlsm
[2] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

appear to adjust for the expected increased costs for retrofitting smaller plants such as the DU CHPP. DU's CHPP boilers each have a maximum heat input rate of 250 MMBtu/hr which is an equivalent maximum input of approximately 75 MW. The DU CHPP boilers have an output significantly less than 100 MW. As a result, as noted in the S&L white paper, the cost model should have been adjusted for size; because the adjustment was not made, the cost model would underestimate emissions control costs for EUs 1 through 6.
    - The S&L white paper states that older units typically have limited space in which to add an SCR reactor and associated ductwork, and that the existing fans may not be sufficient to overcome the added pressure drop. The proposed BACT determination does not discuss these concerns. Whether the cost model as applied by ADEC accounts for these issues is unclear. DU readily confirms there would be significant design confirms for physical space and fan capacity if the boilers were to be retrofitted with SCR.

- The proposed BACT Determination assumes that multiple boilers can accurately be modeled using a totaled heat input in a single spreadsheet.
    - The S&L white paper states that "a combined SCR for small units is not a feasible option." Each boiler requires a single, dedicated SCR reactor due to the needed heat recovery.
    - Review of the spreadsheet provided by ADEC, reflects the proposed BACT considers EUs 1 thorough 6 as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities necessary to independently operate six boilers. The actual installation will require six separate trains of reagent processing and transport equipment. Each train contains a various feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit.

- ADEC assumed that the model is valid for a heat and power plant.
    - No information is available addressing the type of plant on which the S&L spreadsheet is based. It appears S&L assumed that the plant is a single power generation unit. However, a combined heat and power (CHP) plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. DU is unable to confirm that the direct annual costs can be accurately modeled for an installation such as the DU's EUs 1 through 6 by using the S&L spreadsheet.

6. Section 3.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 Code of Federal Regulations (CFR) 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of Permit AQ1121TVP02, Revision 2 and 40 CFR

60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

7. Please include a statement in Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable NO_X emission standard in 40 CFR 60 Subpart IIII.

8. Section 3.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of Permit AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

9. Section 7.7.8.3.1 of the proposed SIP document states that BACT for NO_X emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable NO_X emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable NO_X emission standard in that rule.

10. Table 3-11 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical NO_X emission limit. Section 7.7.8.3.1 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

BACT for Fine Fraction Respirable Particulate Matter (PM-2.5)

11. Section 7.7.8.3.2 of the proposed SIP document and Section 4.1 of the proposed BACT Determination establish a PM-2.5 emission limit for EUs 1 through 6 of 0.006 pounds per million British thermal units (lb/MMBtu). ADEC has not provided a sound rationale for this determination and the PM-2.5 BACT emission limit. DU does not have PM-2.5 source test data for these boilers and is concerned that this limit may be unreasonably low, restrictive, and not achievable as a practical matter.

    - **The basis for this limit is a source test for a different air pollutant.** The PM-2.5 BACT limit of 0.006 lb/MMBtu is based on one source test run from a three-run test conducted on EU 1 at

Fort Wainwright in April 2017. This source test was an EPA Method 5 test, which measures filterable particulate matter (PM). PM includes all filterable particulate matter regardless of size. PM-2.5 includes filterable particulate matter with a nominal aerodynamic diameter of 2.5 microns or less. PM-2.5 also includes all condensable matter while PM does not include any condensable matter. The proposed BACT Determination states that the lowest PM-2.5 emission rate listed in the RBLC (RACT BACT LAER Clearinghouse database) is 0.012 lb/MMBtu. The BACT emission limit being imposed is an order of magnitude less than the lowest emission rate cited in the RBLC. No rationale or supporting engineering data are provided to justify this low emission limit, or to explain the reasons ADEC believes the limit is achievable.

- **The basis for this limit is one source test run on one boiler.** Relying on one run from one source test is an inappropriate method to establish an emission limit for any purpose. While DU appreciates that ADEC was attempting to select the worst-case run, using data from one run instead of the source test result is not appropriate or standard practice.

- **If ADEC wished to rely on source testing to establish PM-2.5 limits for the coal-fired boilers, ADEC should have conducted or requested source testing for PM-2.5 emissions while adequate time was available to do so.** Neither Section 7.7 of the proposed SIP document nor the underlying proposed BACT Determination explain the reasons the PM source test result is representative of the PM-2.5 emission rate. If the assumption is being made that PM-2.5 emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported (with source test results) to confirm that compliance with the limit can be achieved. Otherwise, please explain the rationale for selecting a PM-2.5 emission rate of 0.006 lb/MMBtu as the PM-2.5 BACT emission limit for EUs 1 through 6.

- In comments dated May 23, 2018, DU noted that the appropriateness of using a filterable PM emission limit to establish a PM-2.5 BACT limit had not been established. These comments were submitted to address the preliminary BACT Determination issued by ADEC in March 2018. ADEC does not appear to have considered this information in reaching the BACT determination. DU is requesting clarification from ADEC regarding whether the previously submitted information listed below was included in the BACT evaluation. If yes, DU is requesting clarification with respect how the information was considered. If no, DU is requesting clarification with respect to the reasons the information was not considered.

- During review of these proposed SIP elements, DU reviewed a spreadsheet file "Fbks_PtSrcs_2013-2019_Episode_Inventories_ToSLR.xlsm," described by Trinity Consultants as "A version of our comprehensive point source episodic EI calculation spreadsheet with 2013-2019 EI data. This spreadsheet references facility specific spreadsheets with hourly episodic emission or fuel/throughput rates from the original 2008 episodes." In that spreadsheet, DU noted that ADEC and Trinity appeared to use a PM-2.5 emission factor of 0.697 pounds per ton of coal (lb/ton) to calculate PM-2.5 emissions from EUs 1 through 6 in certain tables. DU calculated this emission factor from data in Tables 1.1-5 and 1.1-6 in AP-42. The emission factor has been used to calculate potential assessable PM-2.5 emissions for EUs 1 through 6 in the two most recent Title V permit renewal applications (submitted in May 2013 and April 2019). The spreadsheet also includes tabs that show much lower PM-2.5 emission rates. DU is requesting clarification regarding the method used to calculate those lower rates and which emissions factors were used. BACT limits must be achievable in practice. As a result, DU requests that ADEC revisit the PM-2.5 BACT analysis using the appropriate available information to establish a PM-2.5 BACT limit that is well-supported with respect to being technically and economically feasible as well as achievable as a practical matter.

- The proposed SIP includes PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance. EUs 7a and 7c have been source tested previously but certain modification to the test method were needed due to space constraints. DU does not know whether the configurations of EUs51 and 51b are conducive to conducting a PM2.5 source test.

12. Section 4.3 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in large diesel-fired engines. (Specifically, this comment addresses privatized EU 8, the backup generator engine at the CHPP.)
    - In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.
    - Step 2 states that all control technologies identified are technically feasible to control particulate emissions from large diesel-fired engines. DU notes that the use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
    - Step 3 does not address the use of ULSD.
    - Step 5(d) requires the use of ULSD, with no supporting rationale or cost analysis.

    Please make appropriate revisions to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engine. Specifically, the sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engine. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 CFR 60 Subpart IIII.

13. Section 4.3 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for large diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

14. Please include a statement in Section 4.3 of the proposed BACT Determination and Section 7.7.8.3.2 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable PM emission standard in 40 CFR 60 Subpart IIII.

15. Section 4.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

16. Table 4-9 in Section 4.4 of the proposed BACT Determination includes a PM-2.5 BACT limit of 0.03 grams per kilowatt-hour (g/kW-hr) for EUs 29a and 31a. This limit appears to reflect the EPA Tier 4 final PM emission standard. EUs 29a and 31a are both certified to EPA Tier 4 interim standards. The applicable Tier 4 interim PM standard is 0.3 g/kW-hr. Please revise Table 4-9 to reflect the appropriate emission limit for these Tier 4 interim-certified engines.

17. Section 4.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(b), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

18. Section 4.4 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in small diesel-fired engines.
    - Step 1 does not identify the use of low sulfur fuel or ULSD an available emission control technology.
    - Step 3 ranks low sulfur fuel in the list of technically feasible control technologies. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
    - Step 5(a) requires the use of ULSD, with no supporting rationale or cost analysis.

    Please make appropriate revisions to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the SO_2 BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

19. Section 4.4 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for small diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

20. Section 7.7.8.3.2 of the proposed SIP document states that BACT for PM-2.5 emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable PM-2.5 emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable PM emission standard in that rule. (The rule does not include PM-2.5 emission standards.)

21. Table 4-9 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical PM-2.5 emission limit. Section 7.7.8.3.2 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

BACT for SO_2

22. In Section 5.1 of the proposed BACT Determination, Table 5.3 specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be $20,673 per ton SO_2 removed and $21,211 per ton SO_2 removed, respectively. Although not explicitly stated, the proposed BACT Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While DU has not evaluated the cost estimates for these control technologies, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

    The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the proposed BACT Determination states at a capital cost of $14.5 million has a cost effectiveness of $10,329 per ton SO_2 removed. DU is concerned that the analysis is based on unsupported assumptions and use of a cost model that may not be appropriate for the size of the boilers.

    As a result, DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at DU's CHPP six boilers. B&V was selected not only because of their experience performing engineering services on projects in Alaska for electric utilities and the US military, but the fact that they are familiar with the CHPP as a result of a 2017/2018 Heat and Energy Study.

B&V used 0.25% coal sulfur content, assumed a building enclosure for all pieces of equipment, including the silos due to the cold Fairbanks temperatures, and developed capital costs for two different types of sorbent. Trona capital costs are less expensive than sodium bicarbonate, but ongoing operation costs are higher due to the higher sorbent injection rate and cost of sorbent delivery to Fairbanks. With the addition of owner costs, DU estimates that depending on the selected sorbent selection, initial capital costs can range between $26.1 and $31.6 million. This far exceeds ADEC's estimate of $14.5 million. DU's estimate is twice the ADEC cost estimate, and believes that SO_2 controls are not economic feasible.

In addition to the B&V analysis, DU provides the following comments on the SIP DSI analysis;

- Cost Model Validity: The economic analysis spreadsheet[3] containing the cost-effectiveness calculations for the proposed SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
    - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
    - Applicable number of boilers (single unit or multi-boiler installation);
    - Applicable size range;
    - Equipment included in the Total Purchased Cost (TPC) calculation;
    - On-site bulk storage capacity;
    - A basis for selecting a "Retrofit factor" other than "1.0"; and
    - Data and other information used to develop and support the equations used in the spreadsheet.

  Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible given the information that ADEC has made available in the public record. The concerns are rooted in three assumptions made by ADEC in preparing the cost model.

- ADEC assumed that the model is valid for a plant the size of DU's Wainwright CHPP.
    - The calculation for "Base Module" cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on "Cost data for several DSI systems." No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information gives some indication of the applicable range. Specifically, the equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at DU's Wainwright CHPP is 1.5 tph,

[3] 2019-05-10-adec-calculated-so2-economic-analysis-fort-wainwright-locked.xlsx

these boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.

- The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
  - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
  - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills, feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. DU notes that the Retrofit Factor reflects a difficult retrofit in an attempt to account for this additional complexity.
  - DU also notes that adjusting the analysis to reflect the retrofit of one CHPP boiler (operated at full-load for 8,760 hr/yr) results in a cost-effectiveness value of greater than $35,000 per ton of SO_2 removed. That cost-effectiveness value is significantly greater than the $10,329 per ton removed presented in Section 5.1, Table 5-3 of the BACT Determination (Appendix III.D.7.07, pdf page 357 of 2309). BACT analyses are typically prepared for each emissions unit at a facility. While "grouping" emissions units is not necessarily unreasonable, a BACT analysis prepared for a group of emissions units must be proper and realistic. The S&L cost model does not appear to properly capture the emission control costs for EUs 1 through 6 as a group.
  - The sorbent feed rate currently calculated for EUs 1 through 6 is very low. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.

- ADEC assumed that the model is valid for a heat and power plant.
  - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are

evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the DU EUs 1 through 6 by using the S&L spreadsheet.

- The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The SIP uses two different SO_2 emission rates. The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

  1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
  = 0.691 lb SO_2/MMBtu

  The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant discrepancy in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the proposed SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the proposed BACT Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6.

If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

23. In Section 5.1 of the proposed BACT Determination, the proposed requirement for the coal sulfur content to be no greater than 0.2 weight percent is not evaluated using the five-step BACT process, or even identified as an available control technology in Step 1. (All coal mined at the Usibelli Coal Mine meets the definition of "low sulfur coal," which is coal with a sulfur content of less than one percent sulfur. The low sulfur coal is considered in Step 1(d).) The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of Permit AQ1121TVP02, Revision 2.) Imposing this limit without first preparing a proper BACT analysis is not appropriate. If this requirement is to be imposed as a limit without a proper BACT analysis to justify the limit, then the limit should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

    DU does not agree that the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether this assumption is valid and feasible. The 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. Step 1(d) of the proposed BACT Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

    DU does not procure coal used in the DU CHPP, but is expected to support the Department of Defense's preference to maintain a 90 day coal stockpile in the interests of energy security for Fort Wainwright. The existing 90 day coal storage pile at the CHPP includes coal with a variety of sulfur contents because coal is added to and removed from the pile over a period of years. The sulfur content of the coal pile is not certain to be less than 0.2 weight percent throughout the pile. If the final BACT requirements specify a coal sulfur content less than that currently specified contractually between the Army and Usibelli Coal Mine, please provide a limit to require that any future deliveries of coal meet the sulfur content specification as opposed to limiting the sulfur content of all coal being combusted at the DU CHPP. The coal pile at the DU CHPP is primarily an emergency storage pile and use of that stockpiled coal should not be restricted.

    The Serious SIP was silent on how the sulfur content of coal was to be reported or considered within a regulatory context. The standard operating permit condition should remain the same and that facilities continue to have available the sulfur content of each shipment of fuel.

24. Section 5.1 of the proposed SIP document appears to present language for a possible compliance order by consent (COBC) between ADEC and FWA that would impose requirements on the DU CHPP emissions units. The document does not explain how (or whether) a COBC between ADEC and the Army would ultimately apply to DU or the DU-owned emissions units. The language in the proposed COBC does not distinguish between the entire CHPP and EUs 1-6, and addresses the

additional BACT for the large diesel-fired engines or the source testing or the PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance

25. Section 7.7.8.3.3 of the proposed SIP document is unclear as to whether the 0.2 weight percent sulfur limit is a BACT limit or proposed as a requirement in the COBC, or both. If the 0.2 weight percent sulfur limit is intended to be a BACT limit, a BACT analysis was not prepared for this control technology. The underlying BACT determination document does not include a BACT limit requiring the use of coal with a sulfur content less than 0.2 weight percent.

26. Section 5.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(d), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

27. Section 5.4 in the proposed BACT determination for small diesel-fired engines, specifically Step 5(c), requires maintaining good combustion practices. The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 in Section 5.4, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at another stationary source. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

28. Section 5.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Attachment 2

DU correspondence dated December 31, 2018 notifying ADEC of a generator asset transfer from DU to the Army at Ft Wainwright

DOYON UTILITIES LLC

714 Fourth Avenue, Suite 100 • Fairbanks, AK 99701
PO Box 74040 • Fairbanks, AK 99707
Phone (907) 455-1500 • Fax (907) 455-6788

December 31, 2018

Alaska Department of Environmental Conservation
Air Permits Program
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99801-1800

SUBJECT: Notification of Asset Transfers from the Fort Wainwright (Privatized Emission Units) to the U.S. Army Garrison Fort Wainwright

Doyon Utilities, LLC (DU) is submitting this letter to notify the Alaska Department of Environmental Conservation (ADEC) about the ownership transfer of emissions units previously held by DU to the U.S. Army Garrison Fort Wainwright (Army-FWA).

DU holds Permit No. AQ1121TVP02, Revision 2, for the Fort Wainwright (Privatized Emission Units) portion of the stationary source (DU-FWA). This Permit covers infrastructure, including emissions units, which is owned and operated by DU. Emissions units covered by DU's permits include 16 units identified on Table 1, which accompanies this letter. On December 28, 2018, ownership of these emission units was transferred from DU to the U.S. Army Garrison Fort Wainwright (Army-FWA) through a Bill of Sale and related easement executed between DU and the U.S. Army Corps of Engineers. As of December 29, 2018, the emission units listed in Table 1 are no longer under the ownership or control of DU.

The emission units, listed in Table 1, are now under the ownership of Army-FWA. The Army-FWA currently holds Permit No. AQ0236TVP03, Revision 2. As agreed in a meeting on April 20, 2017 with ADEC and Army-FWA, until DU's Permit No. AQ1121TVP02 is renewed, DU compliance reports will itemize the transferred emissions units, but will reflect that the units have been transferred to the Army-FWA under its Permit. The Army will be responsible for compliance of and reporting for these units under its Permit. It should be noted that Army-FWA submitted a permit revision application to accept ownership and control of these emission units on November 27, 2017. Accordingly, ADEC should contact Army-FWA with questions or concerns about these units.

Sincerely,

Ed Stevenson

Ed Stevenson
VP of Operations

cc: Patrick Dunn, ADEC – Anchorage
Eric Dick, DPW – Fort Wainwright
Kathleen Hook, DU- Fairbanks
Shayne Coiley, DU- Fairbanks
Courtney Kimball, SLR – Fairbanks

CO 18-125

Table 1. Emission Units Transferred from DU Ownership to the U.S. Army Garrison Fort Wainwright

AQ1121TVP02 Rev. 2 EU ID	EU Name	EU Description	Rating/Size	Installation Date
10	Emergency Generator Engine	Building 1060	762 hp	2010
11	Emergency Generator Engine	Building 1060	762 hp	2010
12	Emergency Generator Engine	Building 1193	82 hp	2002
13	Emergency Generator Engine	Building 1555	587 hp	2008
15	Emergency Generator Engine	Building 2117	1,059 hp	2005
16	Emergency Generator Engine	Building 2117	212 hp	2005
17	Emergency Generator Engine	Building 2088	176 hp	2007
18	Emergency Generator Engine	Building 2296	212 hp	2005
19	Emergency Generator Engine	Building 3004	71 hp	2007
20	Emergency Generator Engine	Building 3028	35 hp	1976
21	Emergency Generator Engine	Building 3407	95 hp	2001
24	Emergency Generator Engine	Building 3703	50 hp	1993
25	Emergency Generator Engine	Building 5108	18 hp	2011
26	Emergency Generator Engine	Building 1620	68 hp	2003
27	Emergency Generator Engine	Building 1054	274 hp	2010
28	Emergency Generator Engine	Building 4390	274 hp	2010