CANALGENERATING

SANDWICH, MA

September 18, 2020

Mr. Glenn Keith
Director Air and Climate Programs
Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108

Re: Canal Generating LLC
9 Freezer Road
Sandwich, MA
Regional Haze Rule – Four Factor Analysis Delivery by USPS

Dear Mr. Keith

In response to the July 9, 2020 letter from the Department regarding the implementation of the US Environmental Protection Agency's implementation of the Regional Haze Rule, attached please find the *Four-Factor Analysis* for Canal Generating LLC, Unit 1. As required, the attached evaluates emission reduction measures for nitrogen oxides, sulfur dioxides and particulate matter based on cost of compliance, time, energy and non-air quality impacts of compliance and remaining useful life of the Unit.

If after reviewing the attached you have any questions, or require additional information, please contact Leslie Alden at 508-833-5362 or by e-mail at leslie.alden@canal-gen.com.

Sincerely,

Jeffrey Araujo
Plant Manager

Attachment

Cc: L. Alden
M. Wolman, MassDEP, via e-mail
S. Pickering, MassDEP, via e-mail
T. Cushing, MassDEP, via e-mail
E. Bystrom, MassDEP, via e-mail
J. Paino, MassDEP, via e-mail

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Four Factor Analysis
Canal Unit 1

Canal Generating Station
Sandwich, MA

September 2020

Prepared for:

Canal Generating LLC
9 Freezer Road
Sandwich, MA 02563

Prepared by:

Tetra Tech, Inc.
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Boston, MA 02109

TETRA TECH

TABLE OF CONTENTS

LIST OF TABLES

APPENDICES

ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
%	percent
AGT	Algonquin Gas Transmission, LLC
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CMR	Code of Massachusetts Regulations
CPA	Comprehensive Plan Approval
ESP	electrostatic precipitator
ISO-NE	Independent System Operator – New England
kW	kilowatts
LAER	Lowest Achievable Emission Rate
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/MW-hr	pounds per megawatt-hour
lbs	pounds
LNB	low-NO_x burners
MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic Northeast Visibility Union
MassDEP	Massachusetts Department of Environmental Protection
MMBtu/hr	million British thermal units per hour
MW	megawatt
MW-hr	megawatt-hour
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
OAQPS	Office of Air Quality Planning and Standards
PM	particulate matter
RBLC	RACT/BACT/LAER Clearinghouse
SCR	selective catalytic reduction
SDA	spray dry absorber
SO_2	sulfur dioxide

Acronyms/Abbreviations	Definition
the Station	Canal Generating Station
ULSD	ultra-low sulfur distillate
USEPA	United States Environmental Protection Agency
AP-42	Compilation of Air Pollutant Emission Factors

1.0 INTRODUCTION

The Regional Haze Rule (40 CFR 51.308) was promulgated in 1999 with the objective to restore visibility to natural conditions in 156 specific areas in the United States; these areas are known as Class I Federal areas. Pursuant to 40 CFR 51.308(f)(2), states that are anticipated to cause or contribute to impairment of visibility in Class I Federal areas, are required to implement reasonable emission reduction measures to reduce visibility impairment. Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I Federal areas. Massachusetts is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), in which the member states are working collaboratively to develop emission reduction measures to address visibility impairment in nearby Class I Federal areas. MANE-VU Includes Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Northern Virginia, and the suburbs of Washington, D.C. On August 25, 2017, MANE-VU issued a *Statement of The Mid-Atlantic/Northeast Visibility Union (MANE-VU) States Concerning A Course of Action Within MANE-VU Toward Assuring Reasonable Progress For The Second Regional Haze Implementation Period* (the Statement), in which participating states committed to pursue six emission reduction strategies to meet the requirements of the Second Implementation Period of the Regional Haze Rule from 2018 through 2028. One of these six emission reduction strategies requires emission sources modeled by MANE-VU with a potential for 3.0 Mm^{-1} or greater visibility impact at any Class I area, perform a four-factor analysis for reasonable installation or upgrade to emission controls. The MANE-VU modeling identified Canal Generating Station (the Station) Unit 1 (Unit 1) as having a maximum modeled visibility impact of 3.0 Mm^{-1} at a Class I area based on 2015 data. Therefore, a four-factor analysis is required for Unit 1 in accordance with the Statement. The Massachusetts Department of Environmental Protection (MassDEP) sent a letter to the Station dated July 9, 2020 requesting a four factor analysis for Unit 1 by September 18, 2020 to evaluate emission reduction measures for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) in accordance with 40 CFR 51.308(f)(2) and consistent with United States Environmental Protection Agency (USEPA) guidance.

In accordance with the requirements of 40 CFR 51.308(f)(2)(i), an analysis to evaluate and determine the emission reduction measures necessary to make reasonable progress includes the following four factors:

1. costs of compliance;
2. time necessary for compliance;
3. energy and non-air quality environmental impacts of compliance; and
4. remaining useful life of the emission source.

This document provides the four-factor analysis prepared in accordance with 40 CFR 51.308(f)(2)(i) as well as applicable guidance from USEPA and MANE-VU.

2.0 EMISSION REDUCTION MEASURES

Unit 1 is a Babcock & Wilcox boiler that fires No.6 fuel oil, with a permitted maximum sulfur content of 0.5 percent by weight, (wt%) as the sole operational fuel, with No.2 fuel oil as a startup/ignition fuel. Unit 1 has an approximate maximum heat input rate of 5,083 million British thermal units per hour (MMBtu/hr) and a generating capacity of approximately 560 (net) megawatts (MW). Unit 1 is equipped with low-NO_x burners (LNB), overfire air ports, flue gas recirculation (FGR), and Selective Catalytic Reduction (SCR) for the control of NO_x emissions. PM emissions are controlled by an Electrostatic Precipitator (ESP).

The emission controls installed on Unit 1 are necessary to achieve compliance with the applicable emission limits under 310 CMR 7.29 and air plan approvals issued pursuant to 310 CMR 7.02. The governing NO_x, SO_2, and PM emission limits for Unit 1 are summarized below in Table 2-1.

Table 2-1: Summary of Unit 1 Emission Limits

Pollutant	Limit	Averaging Period	Applicable Requirement
NO_x	1.5 lbs/MW-hr (net) 3.0 lbs/MW-hr (net) 0.28 lbs/MMBtu 0.15 lb/MMBtu[1]	Rolling 12-Months Monthly Calendar Day Calendar Day	310 CMR 7.29 310 CMR 7.29 4B97052 310 CMR 7.19(4)(b)3.b.
SO_2	3.0 lbs/MW-hr (net) 6.0 lbs/MW-hr (net)	Rolling 12-Months Monthly	310 CMR 7.29
PM	0.02 lbs/MMBtu	Three 60-minute test run average	Approval No. 4B94178

[1] Applies if Unit 1 annual capacity factor exceeds 10% averaged over a three year period (310 CMR 7.19(1)(d)).

In recent years Unit 1 has operated with low capacity factors, well below the 10% referenced in 310 CMR 7.19(1)(d). Given its fuel mix, the Independent System Operator New England's (ISO-NE's) capacity mix, as well as ISO-NE's initiatives on energy security, it is not expected that Unit 1's capacity factor will deviate significantly in future years.

The NO_x and PM emission limits are readily met through the use of the installed emission controls. The sulfur content of No. 6 oil is limited to 0.5 wt% in accordance with 310 CMR 7.05 but the facility purchases 0.3 wt% sulfur No. 6 oil to meet the 6.0 lbs/MW-hr monthly, 3.0 lbs/MW-hr rolling 12-month SO_2 limit applicable under 310 CMR 7.29.

USEPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (08/20/2019) provides the following examples of emission control measures that States should consider during the Second Implementation Period of the Regional Haze Rule (2018 through 2028):

- Emission reductions through improved work practices.
- Retrofits for sources with no existing controls.
- Upgrades or replacements for existing, less effective controls.
- Year-round operation of existing controls.
- Fuel mix with inherently lower SO_2, NO_x, and/or PM emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.
- Operating restrictions on hours, fuel input, or product output to reduce emissions.

40 CFR 51, Appendix Y (Guidelines for BART Determinations Under the Regional Haze Rule) documents procedures for conducting a Best Available Retrofit Technology (BART) evaluation and identifying available retrofit

emission control techniques. Available retrofit control options include "air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." In accordance with 40 CFR 51 Appendix Y applicable retrofit control alternatives are identified from the following resources:

- USEPA's Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
- New Source Performance Standards (NSPS);
- State and Local BACT Guidelines;
- Control technology vendors;
- Federal/State/Local New Source Review (NSR) permits;
- Environmental consultants; and
- Technical journals, reports and newsletters, air pollution control seminars; and

The USEPA's guidance for the Second Implementation Period and BART procedures under 40, CFR 51, Appendix Y were used to evaluate emission reduction measures for NO_x, SO_2, and PM from Unit 1.

2.1 NITROGEN OXIDES

A review of the RBLC did not identify any utility scale oil fired electric generating unit (EGU's) permitted in the last 30 years. Unit 1 is equipped with LNBs, overfire air ports, FGR, and SCR for the control of NO_x emissions. There are no other add-on controls commercially available to reduce NO_x emissions from Unit 1. Therefore, this combination of controls was determined to be the most stringent controls available for the reduction of NO_x emissions from an oil fired steam EGU.

NSPS Subpart Da is applicable to new and modified EGUs and imposes a NO_x limit of 0.76 lb/MW-hr (net) on No. 6 oil fired boilers. This limit is more stringent than the 1.5 lbs/MW-hr rolling 12-month limit required to comply with 310 CMR 7.29. The MassDEP's Top Case BACT guidelines do not provide a NO_x limit for No. 6 oil fired boilers. No other sources of information were identified that imposed a NO_x emission limit from a No. 6 oil fired EGU below the applicable limits under 310 CMR 7.29.

Inherently lower-emitting processes/practices would include a switch to a lower emitting fuel such as natural gas. The Facility is located on the tail end of the Algonquin Gas Transmission (AGT) line "G" lateral and has a transport contract for 75,000 MMBtu per day on its supply lateral. The Facility does not have any transport contracts across the main portion of the "G" lateral. The facility relies on 3rd parties who own transport across the "G" to release gas and transport capacity upstream of its supply lateral when heating loads are not in excess of transport capacity. Gas supply and transport across the "G" lateral is often restricted upstream of the Facility, particularly during cold weather, and its supply lateral is unable to supply either of the existing units. The Facility's existing natural gas fired emission units, Unit 2 rated at 5,973 MMBtu/hr and Unit 3 rated at 3,323 MMBtu/hr, individually have the capacity to meet or exceed the transport contract's daily delivery volume limit. The Plan Approval issued for Unit 3 (Application No. SE 16 015) includes conditions under which the unit can be fired on ultra low sulfur distillate oil (ULSD) in the event that natural gas cannot be delivered to account for the supply limits of the AGT "G" lateral. Given the natural gas capacity of Units 2 and 3 and the natural gas supply limits of the AGT "G" lateral to the Station, conversion of Unit 1 to natural gas is not technically feasible.

Conversion to distillate oil may achieve some reductions in NO_x as distillate oil may contain a lower fuel bound nitrogen content than No. 6 oil but the reduction is uncertain. As Unit 1 is equipped with the most stringent emission controls available for the reduction of NO_x, any reduction in emissions achieved by distillate oil firing would be further reduced as compared to No. 6 oil. As 40 CFR 51, Subpart Y notes that it is not USEPA's intent to direct States to switch fuel types and any reduction in emissions from distillate oil is likely to be small, therefore, conversion to distillate oil firing was eliminated as a control option.

The *MANE-VU Regional Haze Consultation Report* (07/27/2018) recommended that "Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NO_x and/or SO_2 controls -

ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions." The governing NO_x emission limits for Unit 1 are 3.0 lbs/MW-hr on a monthly average and 1.5 lbs/MW-hr on a rolling 12-month average. As a retrofit to an older EGU, the NSPS Subpart Da limit for new units is not technically achievable for Unit 1.

USEPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (08/20/2019) recommends for units equipped with Continuous Emissions Monitoring System, a limit based on a 30-day averaging period. The NO_x emissions achievable by Unit 1 over a 30-day averaging period are dependent upon the number of operating days and hours during that period. During a 30-day period with only a few hours of operation, meeting a limit below the existing 310 CMR 7.29 limit of 3.0 lbs/MW-hr (monthly average) would be problematic due to the emissions that occur during startup. The SCR does not reach its minimum operating temperature until approximately 200 MW and emissions prior to SCR operation are above the existing 310 CMR 7.29 limits. Any limit lower than the existing 310 CMR 7.29 limits are likely to require additional runtime hours for the sole purpose of lowering the NO_x emissions to meet a permit limit. This would result in additional NO_x emissions that would not have otherwise occurred and be counterproductive towards the goal of reducing visibility at Class 1 areas.

The facility is subject to the MassDEP's Reasonably Available Control Technology (RACT) regulations for NO_x emissions under 310 CMR 7.19. A 2018 revision to this regulation incorporated a NO_x limit of 0.15 lb/MMBtu (calendar day average) that is applicable to Unit 1 if it operates at an annual capacity factor greater than 10 percent averaged over any consecutive three year period. Unit 1 has operated at a capacity factor below 10% each year beginning in 2010 and is forecast to continue to operate below a 10% capacity factor. Should Unit 1 exceed this capacity factor and the 0.15 lb/MMBtu limit become applicable, the Station would operate Unit 1 to comply with this limit. Compliance with the NO_x RACT limit would reflect a reduction in NO_x emissions of 50 percent or greater from the existing 310 CMR 7.29 monthly limit of 3.0 lbs/MW-hr, but as stated above, if additional operating hours are required to achieve the outcome, overall emissions will not be reduced.

At current and expected dispatch of Unit 1, limited runtime hours would make it difficult if not impossible to achieve NO_x emissions below the current 310 CMR 7.29 limits due to emissions that occur during startup prior to operation of the SCR. Should Unit 1 operate at a capacity factor that triggers the NO_x RACT limit of 0.15 lb/MMBtu (calendar day average), the higher capacity factor would allow for increased hours with the SCR in operation and result in a reduction in NO_x emissions of at least 50 percent below the 310 CMR 7.29 limits. The existing 310 CMR 7.29 and RACT limits reflect the achievable NO_x emissions by Unit 1.

The NSPS Subpart Da limit of 0.76 lb/MW-hr (net) is not technically feasible for Unit 1, which is currently equipped with the most stringent NO_x emission controls available.

2.2 SULFUR DIOXIDE

A review of the RBLC did not identify any utility scale oil fired EGU's permitted in the last 30 years. NSPS Subpart Da is applicable to new and modified EGUs and imposes a SO_2 limit of 1.2 lb/MW-hr (net) on No. 6 oil fired boilers. This limit is more stringent than the 6.0 lbs/MW-hr monthly and 3.0 lbs/MW-hr rolling 12-month limit required to comply with 310 CMR 7.29. The MassDEP's Top Case BACT guidelines do not provide a NO_x limit for No. 6 oil fired boilers. No other sources of information were identified that imposed a SO_2 emission limit from a No. 6 oil fired EGU below the applicable limits under 310 CMR 7.29.

Unit 1 complies with the applicable SO_2 limits under 310 CMR 7.29 by firing low-sulfur No. 6 oil, averaging emissions with Unit 2, and using Acid Rain allowances for offsets on a 3 to 1 ratio, as necessary. The No. 6 oil has a sulfur content below the current limit of 0.5 wt% under 310 CMR 7.05. One of the six emission reduction strategies in MANE-VU's Statement is for States to limit the sulfur content of No. 6 oil to 0.3-0.5 wt%. The MassDEP has satisfied this criteria with a fuel sulfur limit of 0.5 wt% for No. 6 oil under 310 CMR 7.05.

Inherently lower-emitting processes/practices would include a switch to a lower emitting fuel such as natural gas, distillate oil, or a lower sulfur No. 6 oil. As discussed in Section 2.1, conversion to natural gas is not technically feasible. The next most lower emitting practice would be the conversion to ultra low sulfur diesel (ULSD) with a maximum sulfur content of 0.0015 wt%. The conversion of Unit 1 to ULSD is technically feasible. The next most lower emitting practice would be to fire lower sulfur No. 6 oil, which is also technically feasible.

Add-on controls that could reduce SO_2 emissions would be a packed bed wet scrubber or a spray dry absorber (SDA). The retrofit of Unit 1 with these add-on controls is considered technically feasible for this analysis. An SDA is less expensive than a packed bed wet scrubber and more suitable for a retrofit installation and is therefore selected for further consideration in this analysis. An SDA to achieve the NSPS limit of 1.2 lb/MW-hr (net) is considered technically feasible.

2.3 PARTICULATE MATTER

A review of the RBLC did not identify any utility scale oil fired EGU's permitted in the last 30 years. NSPS Subpart Da is applicable to new and modified EGUs and imposes a PM limit of 0.097 lb/MW-hr (net) on No. 6 oil fired boilers.

Unit 1 is equipped with an ESP to meet the applicable PM limit in its plan approval of 0.02 lbs/MMBtu. Firing low sulfur No.6 oil also helps to reduce PM emissions.

Inherently lower-emitting processes/practices would include a switch to a lower emitting fuel such as natural gas or distillate oil. As discussed in Section 2.1, conversion to natural gas is not technically feasible. The next most lower emitting process would be the conversion to ultra low sulfur diesel (ULSD) with a maximum sulfur content of 0.0015 wt%. The conversion of Unit 1 to ULSD is technically feasible.

Add-on controls that could reduce PM_2 emissions would be replacement of the ESP with a more efficient fabric filter. The retrofit of Unit 1 with a fabric filter is considered technically feasible for this analysis. A fabric filter to achieve the NSPS limit of 0.097 lb/MW-hr (net) is considered technically feasible.

3.0 COST OF COMPLIANCE

The USEPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (08/20/2019) recommends that states follow the source type recommendations in the USEPA' Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual to determine cost estimates for emission control measures, as applicable. The August 20, 2019 USEPA guidance document instructs that control costs incurred from applying a control measure to a source consider the incremental cost from existing controls. Costs are to be expressed in terms of dollars per ton of pollutant reduced on an annual basis based upon the expected life of the emission control measure of the emission source, whichever is shorter. Per USEPA's guidance, when considering baseline emissions for the cost to control evaluation, "estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period."

Following is a presentation of the cost of compliance for the emission reduction measures described in Section 2.0.

3.1 NITROGEN OXIDES

The conclusion of Section 2.1 is that Unit 1 is currently equipped with all technically feasible emission controls. With these emission controls, the existing emission limits under 310 CMR 7.29 and NO_x RACT reflect the achievable controlled NO_x emissions, dependent upon the operating capacity factor of Unit 1. The cost of compliance would include additional ammonia injection should the NO_x RACT limit become applicable but no additional capital expenditures would be required. The cost of compliance is considered insignificant as no additional emission controls are available.

3.2 SULFUR DIOXIDE

The conclusion of Section 2.2 is that the conversion to ULSD, conversion to lower sulfur No. 6 oil, and retrofit with a SDA are technically feasible. The immediate cost for the conversion from No. 6 oil to ULSD is the increased fuel cost. A review of refiner prices of petroleum products to end users published by the U.S. Energy Information Administration (EIA) in Petroleum Marketing Monthly (August 2020), shows that ULSD has been $0.50 per gallon or higher than No. 6 oil since 2010, excluding the recent oil market turbulence during the current coronavirus global pandemic. Table 3-1 summarizes the properties of each fuel and shows that each gallon of ULSD fired in lieu of No. 6 oil will result in an SO_2 reduction of 0.0448 lbs. The cost of compliance, based upon $0.50 of increased cost per 0.0448 lbs of SO_2 controlled, is over $22,000 per ton. The heat content of ULSD is approximately 8% lower than No. 6 oil and conversion to ULSD would result in a similar reduction in the generating output of Unit 1 in addition to an estimated 6.6 MW decrease (net) output due to an increase in parasitic load to operate the SDA, which would cost the Station several million dollars per year in lost generating and capacity payments. Additional costs of compliance would include burner modifications or replacement, fuel tank conversion costs, and fuel pump replacement. Based on the cost of conversion of 2 onsite tanks to ULSD during 2018-2019, which included the addition of secondary liners and secondary floors to account for the different fuel properties, it is estimated that tank conversion alone for three No. 6 oil tanks would be between $7.5 and $9 million. Changes to burners and the control system would add additional, significant cost.

Table 3-1: SO_2 Cost of Compliance – Conversion to ULSD

Parameter	No. 6 Oil	ULSD
SO_2 Emission Rate (lb/MMBtu)	0.33[1]	0.0015
MMBtu/gal	0.150	0.138
SO_2 Emission Rate (lb/gal)	0.0450	0.00207

[1]Equivalent to existing annual emission limit 3.0 lbs/MW-hr and 9.077 MMBtu/MW-hr (560MW at 5,083 MMBtu/hr)

The cost of compliance for an SDA was determined in accordance with the procedures found in the OAQPS Control Cost Manual, Section 5, Chapter 1 (July 2020 draft). The cost procedures are based upon the retrofit of a coal fired EGU but would apply as the costing factors are based upon uncontrolled emission rates and generating output. The cost of compliance is based upon uncontrolled SO_2 emissions of 3 lbs/MW-hr (net), consistent with the current 310 CMR 7.29 limit, and a controlled emission rate of 1.2 lb/MW-hr (net) based upon the applicable limit under NSPS Subpart Da for a new oil fired EGU. The cost to control uses baseline emissions calculated using a capacity factor of 25 percent. As discussed in Section 2.1, Unit 1 has operated at a capacity factor below 10% each year beginning in 2010 and is forecast to continue to operate below a 10% capacity factor. USEPA's guidance state's that an estimate of a source's 2028 emissions can be based upon the source's operation and emissions during a representative historical period. As Unit 1 has operated below a 10% capacity factor for the past decade, using a 25% capacity factor for the baseline emissions is conservative.

No. 6 oil with a maximum sulfur content of 0.3 wt% is commercially available and represents a 40 percent reduction in SO_2 emissions from the current sulfur limit of 0.5 wt%, equivalent to a reduction of 0.03 pounds of SO_2 per gallon. Canal has contacted its fuel supplier and determined that the cost differential between the two fuels is between $0.12 and $0.19 per gallon. The cost of compliance, based upon $0.15 of increased cost per 0.030 lbs of SO_2 controlled, is $10,000 per ton. No additional costs would be incurred for the conversion to 0.3 wt% No. 6 oil.

Table A-1 in Appendix A summarizes the costs for a retrofit SDA and the cost of compliance is $21,200 per ton. This cost of control is based upon a 25% capacity factor, which is very conservative given recent and projected utilization of Unit 1.

3.3 PARTICULATE MATTER

The conclusion of Section 2.3 is that the conversion of ULSD and the retrofit with a fabric filter are both technically feasible.

The immediate cost for the conversion from No. 6 oil to ULSD is the increased fuel cost, which is $0.50 per gallon as described in Section 3.2. Table 3-2 summarizes the properties of each fuel and shows that each gallon of ULSD fired in lieu of No. 6 oil will result in a PM reduction of 0.0058 lbs (uncontrolled). The cost of compliance, based upon $0.50 of increased cost per 0.0058 lbs of PM reduced prior to the ESP, is over $170,000 per ton. Taking into account the ESP, the pounds reduced per gallon would be smaller and the cost to control would be significantly higher. The heat content of ULSD is approximately 8% lower than No. 6 oil and conversion to ULSD would result in a similar reduction in the generating output of Unit 1, which would cost the Station several million dollars per year in lost generating and capacity payments. Additional costs of compliance would include burner modifications or replacement, fuel tank conversion costs, and fuel pump replacement.

Table 3-2: PM Cost of Compliance – Conversion to ULSD

Parameter	No. 6 Oil	ULSD
PM Emission Rate (lb/MMBtu)	0.0417[1]	0.0145[1]
MMBtu/gal	0.150	0.138
PM Emission Rate (lb/gal)	0.0078	0.0020

[1] Uncontrolled emission rate from AP-42, Section 1.3, Table 1.3-1 at 0.5 wt% sulfur.

The cost of compliance for a fabric filter was determined in accordance with the procedures found in the OAQPS Control Cost Manual, Section 6, Chapter 1 (December 1998). The cost procedures are based upon a new fabric filter. The cost of compliance is based upon a baseline emission rate of 0.02 lbs/MMBtu and a controlled emission rate of 0.097 lb/MW-hr (net) based upon the applicable limit under NSPS Subpart Da for a new oil fired EGU. The cost of compliance uses baseline emissions calculated using a capacity factor of 25 percent consistent with the SDA cost of compliance in Section 3.2.

Table A-2 in Appendix A summarizes the cost of compliance for a fabric filter is $32,200 per ton in 1998 dollars; taking into account inflation, actual costs are estimated to be over $50,000 per ton.

4.0 TIME NECESSARY FOR COMPLIANCE

4.1 NITROGEN OXIDES

There are no technically feasible additional air pollution control measures that are available for the reduction in NO_x from Unit 1. With these emission controls, the existing emission limits under 310 CMR 7.29 and NO_x RACT reflect the achievable controlled NO_x emissions, dependent upon the operating capacity factor of Unit 1.

4.2 SULFUR DIOXIDE

The Facility purchases No. 6 oil with a sulfur content compliant with the 310 CMR 7.05 limit of 0.5 wt%. Unit 1 can fire 0.3 wt% sulfur No. 6 oil without any modifications and this change could be implemented immediately. Detailed engineering evaluations were not performed to determine the time necessary for compliance for the conversion to ULSD or the installation of a SDA as the cost of compliance for these emission reduction measures presented in Section 3.2 are not reasonable and detailed engineering evaluations with a schedule to complete were determined to be unwarranted. Facility personnel estimate that the time to convert to ULSD would be approximately 18 months and retrofit with an SDA 18-30 months depending on approval timelines from the various permitting entities.

4.3 PARTICULATE MATTER

Detailed engineering evaluations were not performed to determine the time necessary for compliance for the conversion to ULSD or the installation of a fabric filter as the cost of compliance for these emission reduction measures presented in Section 3.3 are not reasonable and detailed engineering evaluations with a schedule to complete were determined to be unwarranted. Facility personnel estimate that the time to convert to ULSD would be approximately 18 months and retrofit with a fabric filter 18-24 months depending on approval timelines from the various permitting entities.

5.0 ENERGY AND NON-AIR IMPACTS

Per USEPA guidance, characterizing the energy and non-air environmental impacts involves assessing the impact of a control measure on energy consumption and the generation of solid wastes and wastewater. USEPA recommends that States focus their analysis on direct energy consumption at the source rather than indirect energy inputs.

5.1 NITROGEN OXIDES

There will be no energy or non-air impacts as Unit 1 is equipped with the most stringent NO_x emission controls and there are no further emission reduction measures available.

5.2 SULFUR DIOXIDE

Conversion to 0.3 wt% sulfur No. 6 oil or ULSD would not increase energy consumption at the Station or have any non-air impacts.

Installation of an SDA would result in a heat rate penalty of approximately 1 percent, meaning that annual fuel throughput would be increased by 1 percent to generate an equivalent output when the unit is not at base load as well as causing a permanent de-rate of the facility output due to increased parasitic load. Table A-1 in Appendix A shows that an SDA would consume 6.6 MW-hr of electricity per operating hour, require 61 million gallons of water, and generate 3,700 tons of waste annually at a capacity factor of 25 percent.

5.3 PARTICULATE MATTER

Conversion to ULSD would not increase energy consumption at the Station or have any non-air impacts.

Installation of a fabric filter would result in a heat rate penalty of approximately 0.5 percent, meaning that annual fuel throughput would be increased by 0.5 percent to generate an equivalent output. Table A-1 in Appendix A shows that a fabric filter would consume 1 MW-hr of electricity and generate 52 tons of waste annually at a capacity factor of 25 percent.

6.0 REMAINING USEFUL LIFE

Unit 1 has an in-service date of July 1968, achieving 52 years of operation. There is currently no planned retirement date for Unit 1. An independent engineer's condition assessment was completed for Unit 1 in December 2019. The report identified two technical issues which can lead to an unpredicted end-of-life for an older steam generating facility; these issues are catastrophic failure of a major component and prohibitive costs to address major mechanical or electrical deficiencies. The condition assessment report concluded that Unit 1 was in good condition and failure of a major component or major mechanical or electrical deficiencies were not expected in the foreseeable future.

Based upon the current operating condition of Unit 1, it is expected to operate for the foreseeable future until such point when it becomes uneconomical to maintain and operate. This date cannot be accurately estimated but it is reasonable to assume it will occur after the end of the Second Implementation Period in 2028.

7.0 RECOMMENDATION

This four factor analysis demonstrates that it is not technically feasible to convert Unit 1 to natural gas firing, the cost of compliance for the conversion to ULSD is not reasonable, and the cost of compliance for retrofit with more efficient controls is not reasonable. The recent NO_x RACT regulation imposes a lower NO_x limit if Unit 1 operates at a capacity factor over 10%; below this operating level the existing limits under 310 CMR 7.29 reflect the NO_x reductions that are achievable. The PM emissions from Unit 1 are already highly controlled, meeting a limit of 0.02 lb/MMBtu. This rate is 33% below the applicable Maximum Achievable Control Technology (MACT) limit of 0.03 lb/MMBtu established for oil fired EGU's under the National Emission Standards for Hazardous Air Pollutants Subpart UUUUU. Further reductions in PM emissions from Unit 1 are not considered reasonable.

A 40 percent reduction in allowable SO_2 emissions can be achieved through the purchase of 0.3 wt% sulfur No. 6 oil. The cost of compliance for this conversion is estimated to be $10,000 per ton of SO_2 controlled based upon the fuel price differential. This cost is above the MassDEP's BACT threshold for SO_2 emissions of $4,000 to $6,000 per ton. Given the projected low utilization of Unit 1, the cost of compliance for conversion to 0.3 wt% sulfur No. 6 oil would be considered not reasonable. However, as noted in the MANE-VU Regional Haze Consultation Report (July 2018), "sulfates from SO_2 emissions remain the primary driver behind visibility impairment in the region". For this reason, Canal will commit to purchasing 0.3 wt% No. 6 fuel oil following the depletion of the current fuel inventory.

Unit 1 is highly controlled with very low emissions of NO_x, SO_2, and PM as compared to similar sized EGUs. At current and projected utilization of Unit 1, further reductions in emissions would be limited. Should Unit 1 operate at a higher capacity factor in the future, the NO_x RACT regulation would require over a 50 percent reduction from the 310 CMR 7.29 limits. Furthermore, Canal will commit to purchasing 0.3 wt% No. 6 fuel oil following the depletion of the current fuel inventory. The reduction in fuel oil sulfur content, along with the existing emission controls and governing regulations, impose reasonable control of NO_x, SO_2, and PM from Unit 1.

8.0 REFERENCES

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APPENDIX A: COST-TO-CONTROL CALCULATIONS

TABLE A-1
CANAL GENERATING STATION - UNIT 1
ECONOMIC ANALYSIS - SPRAY DRYER ABSORBER

Control System Economic Life (yrs):	20		**Annual Operating Hours:**	2,190	
Interest Rate:	7.00%		**Pollutant controlled:**	SO_2	
Capital Recovery Factor (CRF):	0.0944		**Removal Efficiency:**	60%	To Meet NSPS Subpart Da Limit

OPERATING PARAMETERS			**ANNUAL COSTS**	
			Direct Operating Costs	
Baseline Emission Rate:	3.0	lb/MW-hr	Annual Maintenance Cost (Eq. 1.45)	$3,107,710
	1,680	lb/hr	Operating Labor (1 FT employee @ $50/hr w/ benefits, Eq. 1.46)	$104,000
	1,840	tpy	Reagent Cost (Lime Cost $50/ton, Eq. 1.47)	$79,247
Rated Heat Input (MMBtu/hr):	5,083	MMBtu/hr	Waste Disposal Cost (Cost $35/ton, Eq. 1.48)	$127,918
Rated Generating Capacity (MW)	560	MW	Electricity Cost ($25/MW-hr, Eq. 1.49)	$362,396
Net Plant Heat Rate (NPHR [MMBtu/MW-hr]):	9.077	MMBtu/MW-hr	Water Cost ($1/kgal, Eq. 1.50)	$61,571
Heat Rate Factor (Eq. 1.6):	0.9077			
SO_2 Emission Rate:	0.331	lb/MMBtu		
Lime Consumption (Qlime, Eq. 1.33):	0.7237	tph	**Total Direct Annual Costs (DAC)**	**$3,842,843**
Water Consumption (Qwater, Eq. 1.34):	28.11	kgph		
Waste Generation (Qwaste, Eq. 1.35):	1.669	tph	**Indirect Operating Costs**	
Power (P, Eq. 1.36):	6,619	kW-hr		
			Administration Cost (Eq. 1.52)	$40,413
			Capital Recovery Cost (Eq. 1.53)	$19,556,392
CAPITAL COSTS			**Total Indirect Annual Costs (IAC)**	**$19,596,805**
Absorber Island Cost (ABScost, Eq. 1.41)	$54,421,762		**Total Annual Cost = DAC + IAC**	**$23,439,647**
Reagent and Waste Equipment Cost (BMFcost, Eq. 1.42)	$24,662,868			
Balance of Plant Cost (BMPcost, Eq. 1.43)	$80,285,137		**SO_2 Reduction (tons/yr)**	**1,104**
Total Capital Investment (TCI, Eq. 1.37)	**$207,180,697**		**Cost to Control ($/ton)**	**$21,236**

NOTES: All cost estimates from OAQPS Cost To Control Manual, Section 5.2, Chapter 1 (July 2020 draft)

TABLE A-2
CANAL GENERATING STATION - UNIT 1
ECONOMIC ANALYSIS - PULSE JET FABRIC FILTER

Control System Economic Life (yrs):	20	
Interest Rate:	7.00%	
Capital Recovery Factor (CRF):	0.0944	
Annual Operating Hours:	2,190	
Pollutant controlled:	PM	
Removal Efficiency:	47%	

OPERATING PARAMETERS		
Baseline Emission Rate:	0.182	lb/MW-hr
	102	lb/hr
	111	tpy
Rated Heat Input (MMBtu/hr):	5,083	MMBtu/hr
Rated Generating Capacity (MW)	560	MW
Net Plant Heat Rate (NPHR [MMBtu/MW-hr]):	9.077	MMBtu/MW-hr
Heat Rate Factor (Eq. 1.6):	0.9077	
PM Emission Rate:	0.020	lb/MMBtu
Exhaust Flow Rate	1,100,000	ACFM
Total System Pressure Drop	5.0	"H_2O
DESIGN PARAMETERS		
Gas to Cloth Area (Table 1.1, Fly Ash, Felt Fabric	5.0	fpm
Cloth Area (ACFM / Gas to Cloth Area)	220,000	ft^2
Number of Bag Cages (8" D bags, 10' cages)	10,504	
PURCHASED EQUIPMENT COSTS		
Housing Cost (Figure 1.8)	$1,578,167	
Insulation Cost (Figure 1.8)	$491,641	
Bag Cost (Table 1.8, $0.50/ft^2)	$341,000	
Cage Cost (Table 1.8, 500 cage lots)	$149,323	
Purchased Equipment Cost (PEC)	$2,560,131	
Instrumentation (0.10 PEC)	$256,013	
Sales Tax (0.0625 PEC)	$160,008	MA Tax
Freight (0.05 PEC)	$128,007	
Total Purchased Equipment Cost (TPEC)	**$3,104,158**	

INSTALLATION COSTS				
Foundation (0.04 TPEC)				$124,166
Handling & erection (0.50 TPEC)				$1,552,079
Electrical (0.08 TPEC)				$248,333
Piping (0.01 TPEC)				$31,042
Insulation for ductwork (0.07 TPEC)				$217,291
Painting (0.04 TPEC)				$124,166
Engineering (0.10 TPEC)				$310,416
Construction and field expense (0.20 TPEC)				$620,832
Contractor fees (0.10 TPEC)				$310,416
Start-up (0.01 TPEC)				$31,042
Performance test (0.01 TPEC)				$31,042
Contingencies (0.03 TPEC)				$93,125
Total Capital Investment (TCI)				**$6,798,107**
ANNUAL COSTS				
Direct Annual Costs (DAC)				
Operating Labor (2hrs/shift; 3 shifts/day; 360 days; $50/hr)				$108,000
Supervisor Labor (15% of operating labor)				$16,200
Maintenance Labor (1hrs/shift; 3 shifts/day; 360 days)				$54,000
Maintenance Materials (100% of Maintenance Labor)				$54,000
Replacement parts, bags (Eq. 1.13)				$258,241
Electricity	2,180	MW-hr/yr	(Eq. 1.14 @ $25/MW-hr)	$54,504
Compressed Air	2200	cfm	(2cfm/kACFM @ $0.25/kcfm)	$72,270
Waste	52	tpy	($35/ton)	$1,814
Indirect Annual Costs				
Overhead (60% of sum of Op. and Maint labor and materials)				$139,320.0
Admin, Property Tax, and Insurance (4% of TCI)				$271,924
Capital Recovery Cost (CRF * TCI)				$641,693
Total Annual Cost = DAC + IAC				**$1,671,966**
PM Reduction (tons/yr)				**52**
Cost to Control ($/ton)				**$32,254**

NOTES: All cost estimates from OAQPS Cost To Control Manual, Section 6, Chapter 1 (December 1998)