VIA E-mail (kendal.stegmann@deq.ok.gov)

August 20, 2020

Ms. Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Re: Regional Haze Four-Factor Analysis; Western Farmers Electric Cooperative; Hugo Power Plant Unit 1

Dear Ms. Stegmann:

The enclosed report is provided in response to your July 1, 2020 request for a regional haze four-factor analysis for Western Farmers Electric Cooperative's Hugo Power Plant Unit 1.

If you have any questions regarding this submittal, please contact me by phone at (405) 249-5440 or by e-mail at g_butcher@wfec.com.

WESTERN FARMERS ELECTRIC COOPERATIVE

Gerald Butcher

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Environmental Health & Safety Supervisor

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REGIONAL HAZE RULE FOUR-FACTOR REASONABLE PROGRESS ANALYSIS

Western Farmers Electric Cooperative
Hugo Electric Generating Plant

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Project 203701.0016

TABLE OF CONTENTS

LIST OF TABLES

1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Western Farmers Electric Cooperative (WFEC) in response to the July 1, 2020 "Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program" (the July 1, 2020 request) from the Oklahoma Department of Environmental Quality (the ODEQ). Per the request, this report provides a four-factor analysis of potential control measures for sulfur dioxide (SO_2) emissions from WFEC's Hugo Electric Generating Plant (Hugo) Unit 1.

The Hugo Unit 1 electric generating unit (EGU) is a wall-fired dry-bottom boiler that burns sub-bituminous coal. It has a nominal power output rating of 446 megawatts (MW) and a heat input capacity of 4,600 million British thermal units per hour (MMBtu/hr). It is equipped with an electrostatic precipitator (ESP) for particulate matter (PM) emission control.

In this report, the following specific technical and economic information is provided for each emissions reduction option considered for Hugo Unit 1, in accordance with instructions in the request:

- Technical feasibility
- Achievable emissions reductions
- Time necessary for implementation[1]
- Remaining useful life[1]
- Energy and non-air quality environmental impacts[1]
- Costs of implementation[1]

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[1] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 51.308(f)(2)(i).

2. SO_2 EMISSION REDUCTION OPTIONS

This report addresses the following three (3) SO_2 emission reduction options as potentially feasible add-on controls based on a review of the numerous regional haze analyses (both for Best Available Retrofit Technology [BART] assessments and first and second planning period reasonable progress analyses) that have been conducted throughout the U.S. and especially in EPA Region 6 and Oklahoma:

- Wet Flue Gas Desulfurization (WFGD),
- Dry Flue Gas Desulfurization (DFGD), and
- Dry Sorbent Injection (DSI).

2.1 Technical Feasibility

WFGD, DFGD, and DSI are technically feasible control options for Hugo Unit 1.

2.2 Control Effectiveness

Table 2-1 summarizes the controlled emission rates for the technically feasible SO_2 emissions reduction options. The controlled emission rates for WFGD and DFGD were taken from the EPA's March 2011 Technical Support Document for the Oklahoma Regional Haze SIP and FIP[2] (herein referred to as "the 2011 TSD"), which states at B-14: "EPA concluded that installation of DFGD could achieve a 0.06 lb/mmBtu SO2 emission limit or the installation of WFGD could achieve a 0.04 lb/mmBtu SO2 emission limit at all six BART units."[3] The controlled emission rate for DSI was taken from the October 2012 Settlement Agreement for the Public Service Company of Oklahoma (PSO) Northeastern Plant[4] (herein referred to as "the Northeastern Settlement Agreement"), which states at 10: "...install and operate a dry-sorbent injection system...PSO will achieve...a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis."

The Northeastern Units 3 and 4 (as they existed prior to the Northeastern Settlement Agreement), at 470 MW each, are assumed for the purposes of this report to be representative of Hugo Unit 1.

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options

SO_2 Emissions Reduction Option	Controlled Emission Rate (lb/MMBtu)
WFGD	0.04
DFGD	0.06
DSI	0.4

[2] Kordzi, Joe; Snyder, Erik; Feldman, Michael; Belk, Ellen; and Carbo-Lugo, Agustin, *Technical Support Document for the Oklahoma Regional Haze State Implementation Plan and Federal Implementation Plan*, March 2011.

[3] The "six BART units" referred to by EPA were Oklahoma Gas & Electric's (OG&E's) Muskogee Generating Station units 4 and 5, OG&E's Sooner Generating Station units 1 and 2, and Public Service of Oklahoma's (PSO's) Northeastern Generating Station units 3 and 4.

[4] Parties to the Settlement Agreement included PSO, the Oklahoma Secretary of Environment, the ODEQ, the EPA, and the Sierra Club, and it was executed on or about October 17, 2012.

2.3 Emission Reductions

A baseline period of January 1, 2018 through December 31, 2019 is proposed as reasonable representation of 2028 operations and emissions. Monthly operations and emissions for this baseline period are presented in Table 2-2.[5]

Table 2-2. Baseline Operations and SO_2 Emissions

Year-Month	Operating Time (Hours)	Heat Input (MMBtu/month)	SO_2 Emissions (ton/month)	Average of Hourly SO_2 Emission Rates (lb/MMBtu)
2018-1	677.75	2,698,420.4	795.0	0.583
2018-2	650.30	2,312,446.8	645.6	0.556
2018-3	210.60	713,646.1	183.6	0.513
2018-4	276.42	882,253.7	226.4	0.518
2018-5	535.63	1,913,496.0	448.4	0.458
2018-6	720.00	2,851,567.6	656.0	0.459
2018-7	643.41	2,512,090.6	569.0	0.444
2018-8	744.00	2,823,401.9	666.2	0.471
2018-9	268.81	898,078.4	223.1	0.478
2018-10	0	0	0	0
2018-11	107.26	255,912.1	57.2	0.451
2018-12	744.00	2,865,207.7	647.2	0.452
2019-1	193.64	627,753.3	140.8	0.396
2019-2	108.88	269,552.5	60.9	0.385
2019-3	312.57	1,099,963.4	257.7	0.458
2019-4	0	0	0	0
2019-5	138.49	406,460.8	85.0	0.375
2019-6	409.67	1,386,407.2	315.0	0.435
2019-7	133.46	319,152.0	72.7	0.407
2019-8	385.06	1,115,265.3	259.4	0.445
2019-9	446.58	1,330,211.6	320.0	0.479
2019-10	78.70	276,196.2	72.1	0.524
2019-11	95.05	245,004.7	56.5	0.412
2019-12	0	0	0	0

The average of monthly operating time during the baseline is 328.35 hours/month. This monthly value is annualized (i.e., multiplied by 12) to 3,940 hours/year, which is equivalent to a 0.45 capacity factor[6] (or capacity utilization). Correspondingly, the annualized averages of monthly heat input values and SO_2 emissions are 13,901,244 MMBtu/yr and 3,379 tons per year (tpy), respectively.

The average of month-by-month – for months during which the unit operated – average hourly SO_2 emission rates is 0.462 lb/MMBtu. Applying this emission rate to the baseline heat input gives a baseline emission rate of 3,211 tpy. This value, which is slightly (approximately five percent) less than the actual

[5] Based on EPA's Air Markets Program Data, https://ampd.epa.gov/ampd, queried on July 9, 2020.

[6] This method of calculating capacity factor, based on hours of operation only, is used for consistency with the 2011 TSD, Appendix C *Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4* by Dr. Phyllis Fox, Ph.D., P.E.

average of total mass emissions for 2018 and 2019, is taken to be representative of 2028 emissions assuming operation during each month of the year at the 0.45 capacity factor. Moreover, this is the method with which controlled emission rates based on lb/MMBtu limits must be calculated, and it is the method used by EPA in the 2011 TSD to calculate baseline emissions.

Table 2-3 presents the baseline emission rate and the controlled emission rates and emission reduction potentials for each of the technically feasible SO_2 emissions reduction options.

Table 2-3. Baseline Emission Rates and Controlled Emission Rates for SO_2 Emissions Reduction Options

SO_2 Emissions Reduction Option	Baseline SO_2 Emission Rate (tpy)	Controlled SO_2 Emission Rate (tpy)	SO_2 Emissions Reduction (tpy)
WFGD	3,211	278	2,933
DFGD		417	2,794
DSI		2,780	431

2.4 Time Necessary for Implementation

Five (5) years, counting from the effective date of an approved determination, would be needed for implementing either the WFGD or DFGD options. This is consistent with the compliance timeframes allowed for in the 2011 TSD (at 51 - 52). 3.5 years would be needed for implementing DSI. This is consistent with the compliance timeframes in the Northeastern Settlement Agreement. Assuming an EPA approval date for the ODEQ's regional haze second planning period (2PP) SIP of December 31, 2022, anticipated implementation dates would be January 1, 2028 for WFGD or DFGD and July 1, 2026 for DSI.

2.5 Remaining Useful Life

WFEC has no plans to shut down or cease burning coal at Hugo Unit 1. Therefore, a remaining useful life (RUL) value of 30 years is assumed based on information presented for DFGD and WFGD the 2011 TSD (at Appendix C).

2.6 Energy and Non-air Quality Environmental Impacts

All the SO_2 emissions reduction options under consideration demand increased power usage, and they generate solid waste that must be managed. The FGD options also require increased freshwater usage, and the WFGD option generates large volumes of wastewater that must be managed/treated.

2.7 Costs

Table 2-4 summarizes the total annual costs (capital recovery plus annual operations and maintenance (O&M) costs) for each SO_2 emission reduction option as estimated in the subsections below and presents the associated cost effectiveness based on the emission reduction values from Table 2-3.

Table 2-4. Cost Effectiveness of SO_2 Emissions Reduction Options at Hugo

SO_2 Emissions Reduction Option	Total Annual Cost ($/year)	Cost Effectiveness ($/ton)
WFGD	24,819,997	8,462
DFGD	22,919,263	8,203
DSI	17,670,253	41,003

2.7.1 DFGD

For the purposes of this report, costs estimates for DFGD are taken from the 2011 TSD, Appendix C *Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4* by Dr. Phyllis Fox, Ph.D., P.E. (herein referred to as the "EPA/Fox Calculations") at 34 - 38 and 57 - 58. Figure 2-1 presents images of the CAPITAL COST SUMMARY and INPUTS portions of EPA/Fox Calculations.

Figure 2-1. EPA/Fox Calculations – DFGD ("Fox" Column) (1 of 2)

APPENDIX 2
Revised Cost Effectiveness Analysis for Flue Gas Desulfurization at Northeastern Units 3 & 4[204]

		Trinity[a]	Fox	Section
10	**CAPITAL COST SUMMARY**			
12	Purchased Equipment Cost (PEC)	547,080,000	249,100,000	
13	Landfill Construction	25,000,000	25,000,000	
15	TOTAL CAPITAL INVESTMENT (TCI)	**572,080,000**	**274,100,000**	
51	**INPUTS**			
52	DFGD Capital Cost ($/kW)	582	265	
53	Net Rating (MW)	940	940	
54	Landfill costs estimated by AEP ($)	25,000,000	25,000,000	
55	Estimated Lime Usage (ton/yr)	30,893	30,893	
56	Lime Cost ($/ton)	200	200	
57	Estimated Electricity Usage (kW/hr)	6,900	6,900	
58	Cost of Electricity ($/kW)	0.05	0.05	
59	SO2 Removal Rate	0.83	0.91	
60	Water (gal/MMBtu)		4.25	
61	Water Cost ($1.40/1000 gal)		1.40	
62	Solids Generated (lb solids/lb SO2)		5	
63	Solids Disposal Cost ($/ton)		5	
64	Baseline emissions (lb SO2/MMBtu)	0.90	0.90	
65	Annual Average Firing Rate (MMBtu/hr)	4,775	4,775	
66	Capacity Factor	0.85	0.85	
67	Capital Recovery Factor	0.1019	0.0806	
68	Interest Rate	0.08	0.07	
69	Scrubber Lifetime (yr)	20	30	

(a) 5/30/08 Trinity Report, Appx. F, BART Economic Analysis for DFGD (SO2).
Modified to replace $555/kW with $582/kW, based on 1/19/10 ODEQ BART Report, Table 11.

The total capital cost (TCI) in the EPA/Fox Calculations was based on a cost ratio of $265/kilowatt (kW). This cost ratio is approximately half of the actual expected cost for a DFGD based on data compiled by the

Energy Information Administration (EIA) and based on WFEC's and Trinity's knowledge of other DFGD projects. Nevertheless, because the resulting cost effectiveness values are already clearly infeasible, additional refinement to this estimate is not pursued at this time.[7]

Using the $265/kW ratio, the TCI for Hugo Unit 1, at 446 MW, is $118,190,000. The EPA/Fox Calculations used a 2009 basis. Scaling to a 2019 basis using Chemical Engineering Plant Cost Index (CEPCI) values[8] results in a TCI for Hugo Unit 1 of $137,575,062. Again, this value severely undervalues the actual expected costs for a DFGD installation at Hugo Unit 1.

Using the EPA/Fox Calculations' capital recovery factor (CRF) of 0.0806 – based on 30 years at 7 % interest and which has been used dozens if not hundreds of times by EPA in previous determinations – the estimated annualized capital cost is $11,086,679 (2019 basis). Table 2-5 summarizes the annual capital cost estimation.

Table 2-5. Estimation of Annual Capital Cost at Hugo

Variable	Value	Notes
Cost Ratio from EPA/Fox Calculations	$265/kW	2009 basis
Hugo Unit 1 Capacity	446 MW or 446,000 kW	None
Estimated TCI for Hugo Unit 1	$118,190,000	2009 basis
	$137,575,062	2019 basis
CRF	0.0806	30 years, 7 %
Annual Capital Cost at Hugo Unit 1	$11,086,679	2019 basis

Annual operations and maintenance (O&M) costs for Hugo Unit 1 were also taken from the EPA/Fox Calculations. Figure 2-2 presents an image of the ANNUAL COST SUMMARY portion of EPA/Fox Calculations.

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[7] WFEC reserves the right and the time to complete a site-specific control cost study if it is determined that any controls are to be installed at Hugo Unit 1.

[8] From https://www.chemengonline.com/pci-home (subscription required) as of July 24, 2020:

Year:	2009	2016	2019
CEPCI:	521.9	541.7	607.5

Figure 2-2. EPA/Fox Calculations – DFGD ("Fox" Column) (2 of 2)

ANNUAL COST SUMMARY		
DIRECT OPERATING COST		
Lime Injection	6,178,600	6,178,600
Operating Electricity	3,022,200	3,022,200
Water		423,100
FGD Waste Disposal		727,981
Bag & Cage Replacement		572,000
Fixed O&M		4,116,350
TOTAL DIRECT COST (DC)	**9,200,800**	**15,040,232**
INDIRECT OPERATING COSTS		
Administrative Charges (2% TCI)	11,441,600	5,482,000
Insurance (1% TCI)	5,720,800	28,781
Property Taxes (1% TCI)	5,720,800	2,329,850
Capital Recovery (CRFxTCI)	58,267,612	22,088,733
TOTAL INDIRECT COST (IC)	**81,150,812**	**29,929,364**
TOTAL ANNUALIZED COST (DC+IC)	90,351,612	44,969,595

Table 2-6 summaries how the EPA/Fox Calculations for Northeastern were extrapolated for Hugo.

Table 2-6. Annual O&M Costs for DFGD at Hugo

O&M Cost Variable	EPA/Fox Calculations for Northeastern		Hugo Unit 1	Notes Regarding Differences
	Both Units	One Unit		
Fixed O&M	4,116,350	2,058,175	2,395,749	Escalated from 2009 to 2019
Indirect O&M	5,482,000	2,741,000	2,751,501	Escalation of TCI
Lime	6,178,600	3,089,300	3,089,300	None
Water	423,100	211,550	165,428	Hugo Unit 1 heat input (3,528 MMBtu/hr) and capacity factor (0.45)
FGD Waste Disposal	727,981	363,991	69,855	Hugo Unit 1 emission reduction from Table 2-3
Bag & Cage Replacement	572,000	286,000	665,817	Escalated from 2009 to 2019
Auxiliary Power	3,022,200	1,511,100	1,511,100	None
Property Taxes	2,329,850	1,164,925	1,169,388	Escalation of TCI
Insurance	28,781	14,390	14,445	Escalation of TCI
Total O&M Costs	22,880,862	11,440,431	11,832,584	None

Therefore, the estimated total annual costs (annualized capital + total O&M) for the DFGD option for Hugo Unit 1 is $22,919,263/yr.

2.7.2 WFGD

Based on information in the EPA/Fox Calculations, at 47 – 48, all costs for WFGD are estimated at 9 percent greater than the DFGD costs. Therefore, the estimated total annual costs for the WFGD option for Hugo Unit 1 is $24,819,997/yr.

2.7.3 DSI

The total capital cost for DSI are taken from the ODEQ's June 20, 2013 SIP revision, Appendix II, Item 03 *Supplemental BART Determination Information, American Electric Power – Northeastern Power Plant* (herein referred to as the "EPA-Approved DSI Calculations") which was approved by EPA on March 7, 2014.[9] Figure 2-3 presents an image of the CAPITAL COSTS portion of the EPA-Approved DSI Calculations.

Figure 2-3. EPA-Approved DSI Calculations ("Cost Estimate Based on EPA's..." Column) (1 of 2)

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	Cost Estimate Based on EPA's Control Cost Manual (One Unit)	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment Cost (EC), including instrumentation	--	$49,883,940	$49,883,940
Sales Tax	3% of EC [b]	$0 [h]	$0 [h]
Freight	5% of EC [b]	$0 [h]	$0 [h]
Purchased Equipment Costs (PEC)		***$49,883,940***	***$49,883,940***
Direct Installation Costs			
Foundations and supports	6% of PEC [b]	$2,993,036	$11,433,582
Handling and erection	40% of PEC [b]	$19,953,576	$12,705,233
Electrical	1% of PEC [b]	$498,839	$8,181,380
Piping	5% of PEC [b]	$2,494,197	$9,536,419
Insulation for ductwork	3% of PEC [b]	$1,496,518	$3,181,956
Painting	1% of PEC [b]	$498,839	$1,232,111
Direct Installation Costs (DIC)		***$27,935,006***	***$46,270,680***
Other Direct Costs			
Site Preparation Costs (SPC)	--	$10,849,305	$10,849,305
Buildings Costs (BC)	--	$5,204,446	$5,204,446
Landfill Construction	--	$0 [i]	$0 [i]
Other Direct Costs (ODC)		***$16,053,751***	***$16,053,751***
Total Direct Capital Costs (DC = PEC + DIC + ODC)		***$93,872,698***	***$112,208,371***
Indirect Capital Costs			
Engineering	10% of PEC [b]	$4,988,394	$24,202,634
Construction and field expenses	10% of PEC [b]	$4,988,394	$8,977,897
Contractor fees	10% of PEC [b]	$4,988,394	$280,800
Start-up	1% of PEC [b]	$498,839	$3,562,477
Performance test	1% of PEC [b]	$498,839	$514,443
Contingencies	3% of PEC [b]	$1,496,518	$13,676,183
Total Indirect Capital Costs (IC)		***$17,459,379***	***$51,214,433***
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		***$111,332,077***	***$163,422,804***

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[9] 79 FR 12954-12957.

The TCI included a total direct capital cost value of $93,872,698 (2016 basis), which escalates to $105,275,362 (2019 basis), and an indirect capital cost value of $17,459,379 (not escalated), for an estimated TCI of $122,734,742 (2019 basis) for Hugo Unit 1.

Using the same CRF as for DFGD, 0.0806, the estimated annualized capital cost for the DSI option for Hugo Unit 1 is $9,890,751.

Annual O&M costs for Hugo Unit 1 were also taken from the EPA-Approved DSI Calculations. Figure 2-4 presents an image of the OPERATING COSTS portion of the EPA-Approved DSI Calculations.

Figure 2-4. EPA-Approved DSI Calculations ("Cost Estimate Based on EPA's..." Column) (2 of 2)

OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)			
Operating Labor ($14.24/hour) [d]	8 hr/shift, 3 shifts/day [c]	$124,742	$997,939
Operating Labor Supervision	15% of op. labor [c]	$18,711	$0
Maintenance Labor ($14.24/hour) [d]	2 hr/shift, 3 shifts/day [c]	$31,186	$0
Maintenance materials	100% of maint. labor [c]	$31,186	$407,800
Fixed O&M Costs		*$205,825*	*$1,405,739*
Other Direct Operating Costs (e.g., utilities)			
Sorbent (22,776 tons/yr, $230/ton, Avg. CU) [e,f]	--	$3,500,257	$3,500,257
Electricity (5,696 kW/yr, $0.05588/kW, Avg. CU) [f]	--	$1,862,726	$1,862,726
Water (zero cost)	--	$0	$0
Waste Disposal (zero cost)	--	$0	$0
Bag and Cage Replacement (9,424 bags/cages;... ...$114 & 3-yr cycle for bag; $29 & 6-yr cycle for cages)	--	$403,661	$403,661
Other Direct Operating Costs		*$5,766,644*	*$5,766,644*
Total Direct Operating Costs (DOC)		*$5,972,469*	*$7,172,383*
Indirect Operating Costs			
Overhead	60% of O&M [c]	$0 [j]	$0 [j]
Property tax	1% of TCI [c]	$946,323 [j]	$1,389,094 [j]
Insurance	1% of TCI [c]	$11,690 [j]	$17,159 [j]
Administration	2% of TCI [c]	$2,226,642	$3,268,456
Capital Recovery (10 years, 7 %) (CRF_{10})	0.1424 of TCI	$15,851,183	$23,267,731
Capital Recovery (30 years, 7 %) (CRF_{30})	0.0806 of TCI	--	--
Total Indirect Operating Costs (IOC)		*$19,035,837*	*$27,942,440*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		*$25,008,306*	*$35,114,823*

Table 2-7 summaries how the EPA-Approved DSI Calculations for the Northeastern units were extrapolated for Hugo.

Table 2-7. Annual O&M Costs for DSI at Hugo

O&M Cost Variable	Northeastern (One Unit)	Hugo Unit 1	Notes Regarding Differences
Operating Labor	$124,742	$124,742	None
Op. Labor Supervision	$18,711	$18,711	None
Maintenance Labor	$31,186	$31,186	None
Maintenance Materials	$31,186	$31,186	None
Sorbent	$3,500,257	$2,356,240	Hugo Unit 1 capacity factor (0.45)
Electricity	$1,862,726	$1,253,916	Hugo Unit 1 capacity factor (0.45)
Bag & Cage Replacement	$403,661	$452,694	Escalated from 2016 to 2019
Property Tax	$946,323	$1,043,245	Escalation of TCI
Insurance	$11,690	$12,887	Escalation of TCI
Administration	$2,226,642	$2,454,695	Escalation of TCI
Total O&M Costs	9,157,124	$7,779,502	None

Therefore, the estimated total annual costs (annualized capital + total O&M) for the DFGD option for Hugo Unit 1 is $17,670,253/yr.

3. CONCLUSIONS

WFEC and Trinity have developed this four-factor analysis based on the best information available during the timeline allowed by the ODEQ's July 1, 2020 request and in accordance with ODEQ and EPA guidance and EPA-approved/used methods. The analysis results, especially for the fourth factor, which shows estimated costs of compliance of greater than $8,000/ton for all options, demonstrates that no SO_2 emissions controls are feasible for Hugo Unit 1. WFEC requests the ODEQ's concurrence with this conclusion.