Four Factor Analysis
JELD-WEN, Inc.
Klamath Falls, Oregon

Prepared by:

JELD-WEN Environmental Engineering
3250 Lakeport Blvd.
Klamath Falls, OR 97601
(541) 850-2650

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1. INTRODUCTION

The Clean Air Act (CAA) amendments of 1977 set a national goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. There are 156 specific areas across the United States, known as Class I areas subject to the Regional Haze Rule (RHR) established in 1999. Class I areas are defined under the CAA as parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence as of August 7, 1977.

Under 40 CFR 51.308, RHR, states must set goals to provide reasonable progress towards achieving natural visibility conditions for Class I areas and must take in to consideration the following when establishing a reasonable progress:

(A) Under 40 CFR 51.308(d)(1)(i)(A) – *Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*

(B) Under 40 CFR 51.308(d)(1)(i)(B) – *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

States are currently in the second planning period for the natural regional haze efforts. The second planning phase has a few notable differences from the first planning phase. The most notable difference is distinguishing the difference between "natural" and "anthropogenic" sources. The Western Regional Air Partnership (WRAP) in coordination with the U.S. Environmental Protection Agency (EPA) will compare anthropogenic source contributions against natural background concentrations using a Photochemical Grid Model (PGM).

Under 40 CFR 51.308(d)(3)(iv), *"The State must identify all anthropogenic sources of visibility impairment considered by the State in developing its long-term strategy. The State should consider major and minor stationary sources, mobile sources, and area sources."* To accomplish this for major stationary sources, the Oregon Department of Environmental Quality (ODEQ) reviewed 2017 emission inventory data for Title V sources and current Plant Site Emission Limits established in Title V permits and screened each facility's potential impact on visibility in Class I areas using a "Q/d" analysis, where "Q" is the magnitude of emissions that could impact ambient visibility, and "d" is the distance of a facility to a Class I area. The "Q" values are comprised of potential NO_x, SO_2, and PM_{10} potential emissions. Based on a "Q/d" value greater than 5, 32 facilities were identified by ODEQ.

As part of the RHR second planning phase ODEQ is requiring Oregon manufacturing sites, who's Q/d > 5 on a potential basis, to perform a 'four factor' analysis to assess impacts to Class 1 Wilderness Areas under the Oregon Regional Haze program. According the ODEQ, "The 'four factor' analysis involves assessing potential emission controls technologies against four statutory factors: (1) The cost of control, (2) Time necessary to install controls, (3) Energy and non-air quality impacts, and (4) Remaining useful life."

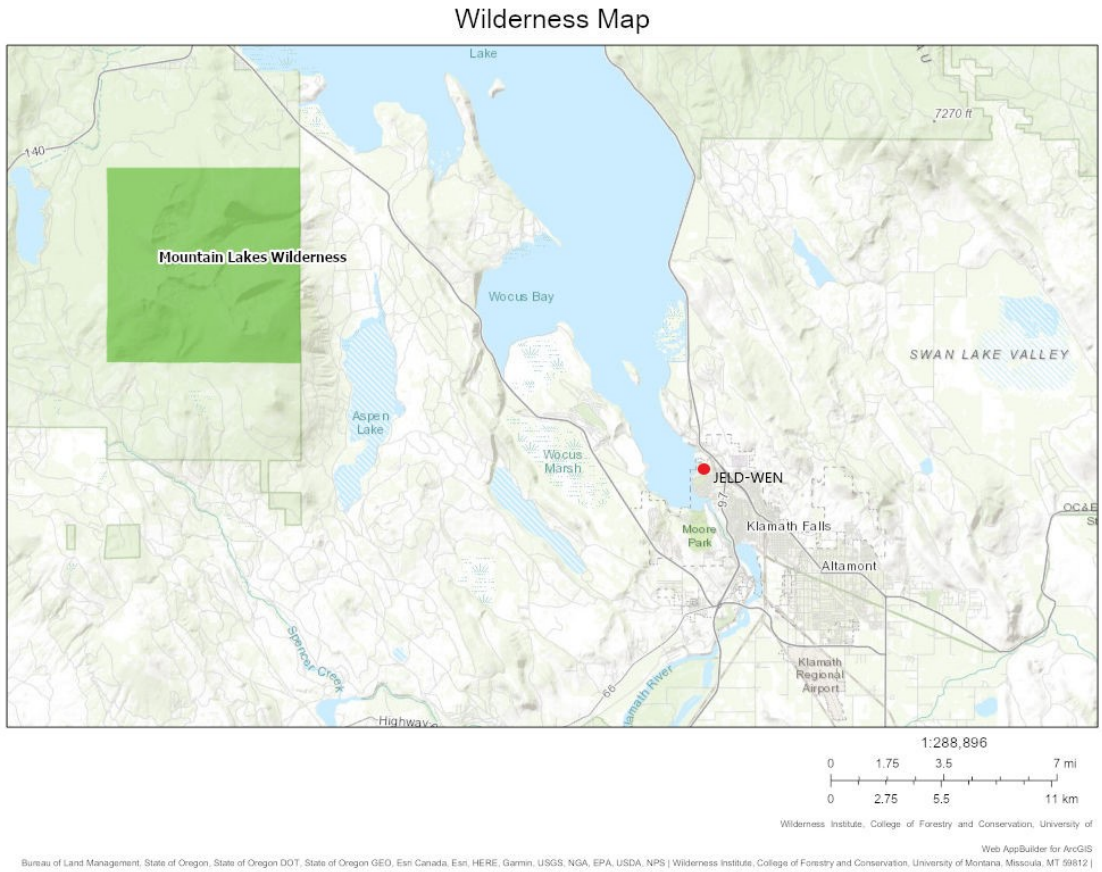
As directed by ODEQ, JELD-WEN, Inc. (JELD-WEN) offers the following four factor analysis for its manufacturing facilities, located on the Klamath Falls Campus, in Klamath Falls, Oregon. The campus operates under Title V permit no. 18-0006.

2.1 LACK OF CONTRIBUTION DUE TO PREVAILING WINDS

Contributions to visibility impairment is a critical factor when selecting sources to perform a four-Factor Analysis and establishing realistic progress goals for Class I areas. It appears though the Oregon Department of Environmental Protection (ODEQ) did not consider, actual contribution to visibility impairment, when selecting sources for the four-factor Analysis as evidenced by the selection of JELD-WEN to perform a four-factor analysis.

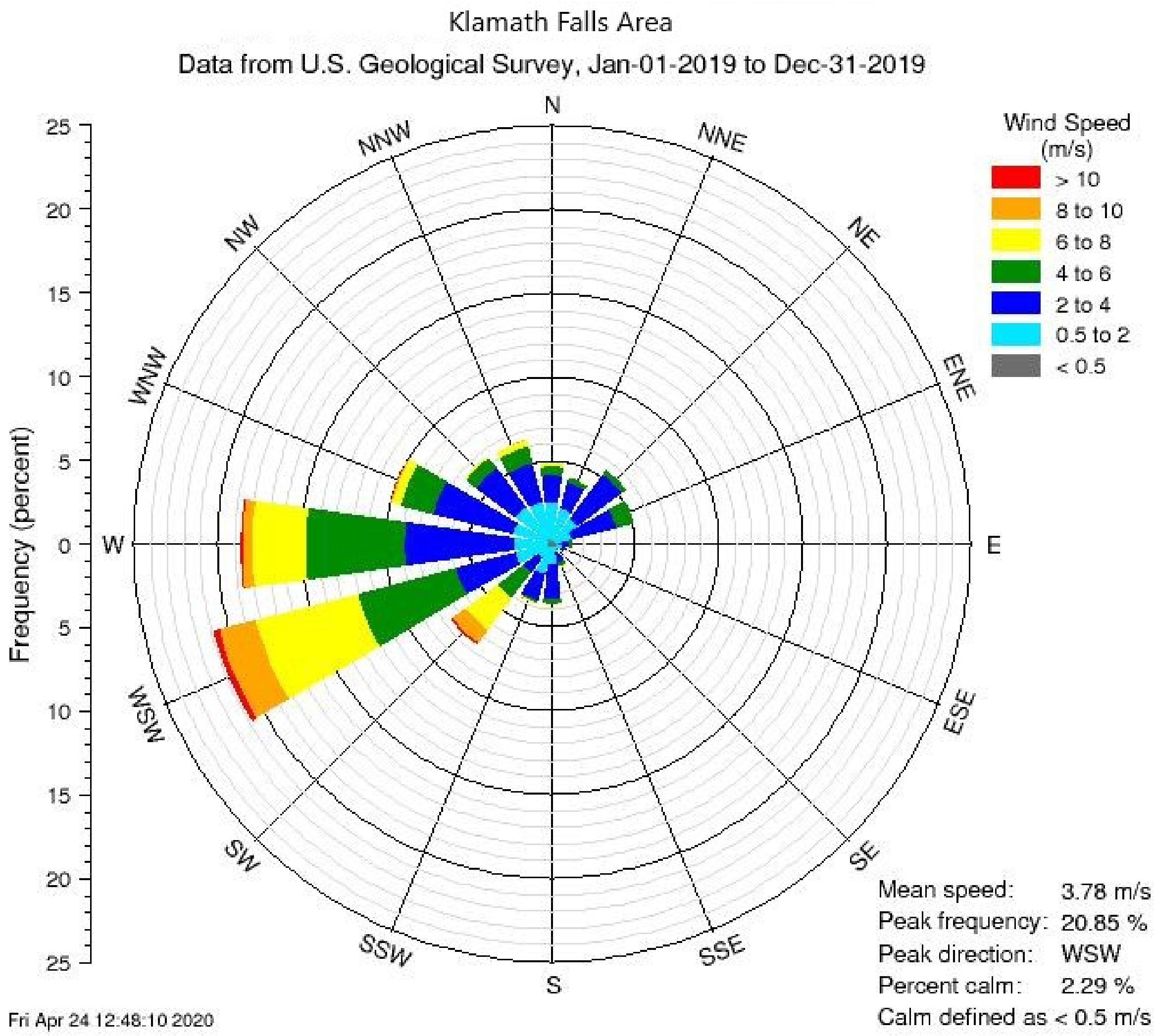
In the case of JELD-WEN's Klamath Falls complex, the emission sources are located in the opposite direction from the Class I area, with respect to the prevailing winds. In Figure 2-2 below, the meteorological data identifying the prevailing winds around the JELD-WEN's Klamath Falls Campus can be used to estimate the facility's impact on the Class 1 area. As noted, the winds predominately blow from the west to the east. Based upon this data, it is unlikely the emissions from the JELD-WEN Klamath Falls Campus contribute to the regional haze at the Mountain Lakes Wilderness Class I area.

FIGURE 2-1: MOUNTAIN LAKES WILDERNESS AREA LOCATION MAP



As shown in the figure above, the JELD-WEN Klamath Falls Campus is located east-southeast of the Mountain Lakes Wilderness Class I area. As represented in Figure 2-2, the prevailing winds can be used to estimate the facility's potential impact on the Mountain Lakes Wilderness Class I Area. The 2019 meteorological data from the U.S. Geological website shows that winds over the JELD-WEN Klamath Falls Campus blows toward the Mountain Lakes Wilderness Area less than 1% of the time. Based off the infrequent amount of time the wind blows from the JELD-WEN Klamath Falls Campus toward the Mountain Lakes Wilderness, it is unlikely that the facility's potential emissions impact visibility at the Class I Area. When balancing retrofit costs and visibility improvements, ODEQ should consider emissions from this facility are unlikely to contribute to regional haze at the Mountain Lakes Wilderness Area.

FIGURE 2-2: KLAMATH FALLS AREA METEOROLOGICAL DATA, 2019 WIND ROSE



2.2 LACK OF CONTRIBUTION TO VISIBILITY IMPAIRMENT DUE TO SMALL UNIT INSIGNIFICANT EMISSIONS

2.2.1 SO_2 EMISSIONS:

Certain JELD-WEN Klamath Falls Campus' combustion units emit SO_2. Table 2.2-1 provides each of the emission units; the associated BTU rating, and potential to emit, as submitted to ODEQ, in the 2017 Title V permit renewal application.

TABLE 2.2-1: SO_2 POTENTIAL EMISSIONS

Emission Unit	Rating (MMBtu/hr)	Potential Emissions (TPY)
Wood Fired Boiler	73	3.0
Natural Gas Boiler	26.84	0.4
Biofilter (From Fiber Dryer)	19.8	0.05
Paint Booth NG Oven	6.0	0.07
Fiber Building Heat	2 units @ 4.167 each	0.04 (total)
Package NG Boiler	1.6	1.78E-02

OAR 340-200-0020(23) provides a list of categorically insignificant activities as regulated pollutant emitting activities principally supporting the source or the major industrial group. As shown in Table 2.2-1, the Package NG Boiler meets the definition of categorically insignificant activity under OAR 340-200-0020(23)(c). Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and meeting the definition of categorically insignificant activity, no further analysis should be necessary to evaluate SO_2 emissions from the Package NG Boiler. Therefore, JELD-WEN need not assess any control technologies for this emissions unit.

The de minimis level for SO_2 specified under OAR 340-200-0020(39) is 1 ton per year. As shown in Table 2.2-1 above, the Natural Gas Boiler, Biofilter (From Fiber Dryer), Paint Booth NG Oven, and Fiber Building Heat meet the de minimis emissions level under OAR 340-200-0020(39). Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and meeting the de minimis emissions level for 1 ton per year, no further analysis should be necessary to evaluate SO_2 emissions from the Natural Gas Boiler, Biofilter (From Fiber Dryer), Paint Booth NG Oven, and Fiber Building Heat. Therefore, JELD-WEN need not assess any control technologies for these emission units.

2.2.2 PM_{10} EMISSIONS:

The Klamath Falls Campus PM_{10} emissions are associated with woodworking operations, combustion devices, and painting operations. Table 2.2-2 below, shows each of the emission units, and the potential to emit as submitted in the 2017 Title V permit renewal application.

TABLE 2.2-2: PM_{10} POTENTIAL EMISSIONS

Emission Unit	Potential Emissions (TPY)
Wood Fired Boiler	4.1
Natural Gas Boiler	0.4
Lumber Kilns	3.0
Storage Piles	4.7
Cyclone A	2.4
Cyclone D	0.8
Target Box: Silo G	0.2
Target Box: Silo H	1.1
Target Box: Silo I	0.7

Target Box: Silo L	0.3
Shaker Baghouse	2.8E-02
Fiber South Baghouse	0.1
Fiber Main Baghouse	0.1
Line 1 Former Baghouse	2.0E-02
Line 2 Former Baghouse	2.0E-02
Cyclone Z	4.8E-03
Target Box: Silo S	0.8
Truck Bins	1.3
Biofilter	2.16E-01
Paint Booth NG Oven	0.1
Fiber Prime Line	5.0
Fiber Building Heat	0.04
Veneer Dryer	6.0E-03
Dehumidification Kilns	0.8
Package Boiler	1.71E-02
Millwork Manufacturing	5.39E-03
Engineering Emissions	1.33

OAR 340-200-0020(39) lists the de minimis emission level for regulated pollutants. The de minimis level for PM_{10} is 1 ton per year. As shown in table 2.2-2 above, the Natural Gas Boiler, Cyclone D, Target Box: Silo G, Target Box: Silo I, Target Box: Silo L, Shaker Baghouse, Fiber South Baghouse, Fiber Main Baghouse, Line 1 Former Baghouse, Line 2 Former Baghouse, Cyclone Z, Target Box: Silo S, Biofilter, Pain Booth NG Oven, Fiber Building Heat, Veneer Dryer, Dehumidification Kilns, Package Boiler, and the Millwork Manufacturing emissions meet the de minimis emissions level under OAR 340-200-0020(39). Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and meeting the de minimis emissions level for 1 ton per year, no further analysis should be necessary to evaluate PM_{10} emissions from the Natural Gas Boiler, Cyclone D, Target Box: Silo G, Target Box: Silo I, Target Box: Silo L, Shaker Baghouse, Fiber South Baghouse, Fiber Main Baghouse, Line 1 Former Baghouse, Line 2 Former Baghouse, Cyclone Z, Target Box: Silo S, Biofilter, Pain Booth NG Oven, Fiber Building Heat, Veneer Dryer, Dehumidification Kilns, Package Boiler, and the Millwork Manufacturing. Therefore, JELD-WEN need not assess any control technologies for these emission units.

2.2.3 NO_X EMISSIONS:

The Klamath Falls Campus facility NO_x emissions are associated with combustion units. Table 2.2-3 below, shows each of the emission units, and the potential to emit as submitted in the 2017 Title V permit renewal application.

TABLE 2.2-3: NO_X POTENTIAL EMISSIONS

Emission Unit	Potential Emissions (TPY)
Wood Fired Boiler	56.2
Natural Gas Boiler	8.5
Biofilter (from Fiber Dryer)	4.89
Paint Booth NG Oven	1.28
Fiber Building Heat	0.74
Package Boiler	0.34

OAR 340-200-0020(39) lists the de minimis emission level for regulated pollutants. The level for NOx is 1 ton per year. As shown in table 2.2-3 above, the Fiber Building Heat and Package Boiler emissions meet the de minimis emissions level under OAR 340-200-0020(39). Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and meeting the de minimis emissions level for 1 ton per year, no further analysis should be necessary to evaluate NO_x emissions from the Fiber Building Heat and Package Boiler. Therefore, JELD-WEN need not assess any control technologies for these emission units.

2.2.4 AGGREGATE INSIGNIFICANT:

The Klamath Falls Campus facility operates several emissions units that fall under the definition of aggregate insignificant activities. Table 2.2-4 below, shows each of the aggregate insignificant emission units.

TABLE 2.2-3: AGGREGATE INSIGNIFICANT UNITS

Emission Unit
2000 EGEN 80 KW 107 HP (Emergency Generator)
2003 EGEN 150 KW 214 HP (Emergency Generator)
2006 EGEN 125 KW 175 HP (Emergency Generator)
2005 Fire Pump 188 HP
Cyclone C (Baghouse C-C)
Cyclone D (Baghouse D-D)
Pneumatic conveyor: milling operations (Baghouse K)
Pneumatic conveyor: milling operations (Baghouse WK)

Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and meeting the aggregate insignificant definition, no further analysis should be necessary to evaluate emissions from the units listed in Table 2.2-3. Therefore, JELD-WEN need not assess any control technologies for these emission units.

JELD-WEN operates several sources potentially subject to the Oregon Regional Haze Four Factor Analysis. Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1), emission sources located on the Klamath Falls Campus with a potential-to-emit of less than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) are not evaluated under the four factor analysis. The units meeting this criterion are too small to control the specified emissions. A search of the RBLC database did not provide information on additional controls for the emission units. Each source meeting the 10 lb/hr and 5 tpy criteria and not listed in Section 2 are listed in Table 3.0-1.

TABLE 3.0-1. PTE EMISSIONS SMALL EMISSION SOURCES

Emission Source	Pollutant	lbs/hr	TPY
Cyclone A	PM_{10}	1.36E-07	2.4
Target Box: Silo H	PM_{10}	6.04E-08	1.1
Lumber Kilns	PM_{10}	0.8	3.0
Truck Bins	PM_{10}	6.0E-08	1.3
Storage Piles	PM_{10}	1.07	4.7
Biofilter	PM_{10}	4.96E-02	2.2E-01
Biofilter	NO_x	1.12	4.89
Paint Booth NG Oven	NO_x	0.29	1.28
Fiber Prime Line	PM_{10}	0.52	4.98
Engineering Emissions	PM_{10}	6.39E-04	1.33

3.1 COMPONENTS THOMAS LUMBER EMISSIONS

The Components Thomas Lumber Manufacturing facility located on the JELD-WEN Klamath Falls Campus emits NO_x, SO_2, and PM_{10} from its manufacturing operations. The emission units associated with the Components Thomas Lumber Manufacturing facility are evaluated below.

3.1.1 NATURAL GAS BOILER

The Natural Gas Boiler operated by the Components Thomas Lumber facility is rated at approximately 52.5 MMBtu/hr heat input and produces a nominal 40,000 lbs-steam/hr to operating devices on the Klamath Falls Campus. The boiler is equipped with a low-NO_x burner and flue gas recirculation system, which results in reduced emissions of NO_x compared to uncontrolled natural gas boilers. Therefore, the low NOx burner is considered best available control and since emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) and as shown in Tables 2.2-1 and 2.2-2, the SO_2 and PM_{10} emissions from the Natural Gas Boiler meet the definition of de minimis emissions, no further analysis should be necessary to evaluate emissions from the Natural Gas Boiler. Therefore, JELD-WEN need not assess any control technologies for this emission unit.

3.1.2 WOOD-FIRED BOILER

JELD-WEN uses a Wood-Fired Boiler to provide steam to operating units across the JELD-WEN Klamath Falls Campus. The fuel cell boiler is rated at 72.5 MMBtu/hr heat input and produces a nominal 50,000 lbs-steam/hr. The boiler burns hogged wood waste and the particulate matter emissions are controlled by a multiclone and an electrostatic precipitator (ESP).

3.1.2.1 SO_2 EMISSIONS

The Wood-Fired Boiler has a potential-to-emit SO_2 emissions of 0.70 lbs per hour and 3 tons per year. Because emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1), emission sources located on the Klamath Falls Campus with a potential-to-emit of less than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) are not evaluated under the four factor analysis.

3.1.2.2 PM_{10} EMISSIONS

The Wood-Fired Boiler has a potential-to-emit PM_{10} emissions of 0.95 lbs per hour and 4.1 tons per year. The Wood-Fired Boiler already uses an ESP to control particulate matter, which is considered BACT. However; since emissions from JELD-WEN's Klamath Falls Campus are not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1), emission sources located on the Klamath Falls Campus with a potential-to-emit of less than 10 pounds per hour (lb/hr) and 5 tons per year (tpy) are not evaluated under the four factor analysis.

3.1.2.3 NO_X EMISSIONS

The NO_x potential-to-emit emissions for the Wood-Fired Boiler is 56.2 tons per year. The Wood-Fired Boiler uses both resinated and non-resinated wood as a fuel source. Nitrogen is inherently contained in fuels and in the air and does not react at low temperatures. Nitrogen oxides are a by-product of combustion and during combustion, the high temperatures cause the nitrogen and oxygen in the air to react and form NO_x. The amount of NO_x formed is dependent on many factors including the type of fuel combusted, temperature, and residence time of the air. There are two types of NO_x associated with the Wood-Fired Boiler, there are: Thermal NO_x and Fuel NO_x. Thermal NO_x formation has a positive correlation with temperature. Fuel NO_x is the result of nitrogen contained in organic fuels releasing and reacting with oxygen. There are two types of potential controls for the Wood-Fired Boiler: Combustion modification and post-combustion NO_x controls. Combustion modifications are changes to one or more controllable variables in the combustion process itself, such as temperature and residence time. Post-combustion NOx controls use add-on control technologies to decrease the amount of formed NO_x before the combustion air is released to the atmosphere.

3.1.2.3.1 COMBUSTION MODIFICATION

Boiler Tuning/Optimization

One method of combustion modification to control NO_x from boilers is by performing tuning of the boiler combustion controls, also known as optimization. The air to fuel ratio for combustion is analyzed and adjusted to ensure the boiler has efficient combustion and better performance. The optimization for efficient combustion results in lower NO_x emissions.

The JELD-WEN Wood-Fired boiler is subject to the Industrial, commercial, and institutional boilers MACT regulations listed under 40 CFR Part 63, Subpart JJJJJJ. Under the 40 CFR 63.11223(a) and (b), the Wood-Fired boiler is subject to conducting a tune-up of the boiler biennially and under 40 CFR 63.11201(b) follow the work practices provided in Table 2(6) of the rule.

3.1.2.3.2 POST-COMBUSTION NO_X CONTROLS

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) removes NO_x by injecting urea, ammonia or another reducing agent into the flue gas. The reagent reacts with NOx to form nitrogen gas (N_2) and water. SNCR systems can reduce NOx emissions by 30 to 60 percent. Retro-fitting the Wood-Fired Boiler with an SNCR system is technically feasible; however, as discussed in Section 4, the installation is economically infeasible.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) removes NO_x by injecting reducing agent, typically ammonia, into the flue gas; however, SCR utilizes a catalyst. The catalysis lowers the activation energy needed for the reaction of NOx and ammonia for form nitrogen gas (N_2) and water. As a result, SCRs are only appropriate for boilers with flue gas temperatures of 470 to 1000 degrees F. The flue gas from the Wood-Fired boiler exceeds the temperature limit recommended for using a SCR as an add-on control, making the control technically infeasible and not discussed in Section 4.

4. Cost of Compliance

According to the EPA Control Cost Manual, there are five steps associated with evaluating the control cost effectiveness:

1. Obtain the facility parameters and regulatory options;
2. Control system design;
3. Size control system;
4. Estimate costs of individual components; and
5. Estimate capital and annual costs of entire system.

4.1 Cost Effectiveness

The cost effectiveness to control the NOx emissions from the Wood-Fired Boiler located on the JELD-WEN Klamath Falls Campus is shown in the sections below. The calculation spreadsheets used for the cost effectiveness are from EPA's cost control website and can be found in Appendix A.

4.1.1 Retrofit Wood-Fired Boiler with SCR - Urea

Tables 4.1-1 through 4.1-3 show the input parameters, design parameters, and the cost effectiveness of retrofitting the Wood-Fired Boiler with a SNCR – Urea system.

TABLE 4.1-1. DESIGN INPUTS

Data Inputs

Data on combustion unit:

Is the combustion unit a utility or industristal boiler?	Industrial	What type of fuel is burned?	Wood
Is the SNCR for a new boiler or retrofit of an existing boiler?	Retrofit	Reagent Used	Urea
Retrofit difficulty factor	1.00		

Maximum heat input rate (Q_B)=	72.5	MMBtu/hr	Sulfur content (%S) =	0.05	percent by weight
Fuel higher heating value (HHV) =	8,249	Btu/lb*	Ash Content (%Ash) =	1.82	percent by weight
Maximum Actual Annual Fuel consumption (M_{actual}) =	76,995,817	lbs/yr			
Net plant heat input rate (NPHR) =	16	MMBtu/MW	*HHV listed is on a Dry Basis.		

Proposed SNCR design parameters:

Number of days the SNCR operates (t_{SNCR})	365	Days	Plant Elevation (h) =	5000	Feet above sea level
Inlet NOx Emissions (NOx_{in}) to SNCR	0.226	lb/MMBtu			
Outlet Nox Emissions (NOx_{out}) from SNCR	0.1582	lb/MMBtu			
Estimated Normalized Stoichiometric Ration (NSR)	1.53		* The NSR for a urea system is calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).		
Concentration of reagent as stored (C_{stored})	50	Percent			
Density of reagent as stored (p_{sol})	71	lb/ft3			
Concentration of reagent injected (C_{inj})	50	Percent	(Typically 50% for Urea and 10% for Ammonia)		
Number of days reagent is stored ($t_{storage}$)	60	days	*Reagent supply storage before next delivery		
Estimated equipment life (n)	10	Years			

Proposed SNCR cost data:

Desired dollar-year	2018				
CEPCI for Desired dollar-year	616.5		499.6	2006 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent	Based on Federal Reserve highest rate		
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu			
Reagent ($Cost_{reag}$)	1.66	$/gallon			
Water ($Cost_{water}$)	0.006	$/gallon			
Electrity ($Cost_{elect}$)	0.1038	$/kWh			
Ash Disposal (wood-fired boiler only) ($Cost_{ash}$)	61	$/ton			

TABLE 4.1-2. DESIGN PARAMETERS

Design Parameters

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	From Data Input	72.5	MMBtu/hr	
Maximum Actual Annual Fuel Consumption (M_{actual}) =	From Data Input	76,995,817	lbs/Year	
Maximum Annual Fuel Consumption (M_{fuel}) =	(Q_B * 1.0E6 Btu/MMBtu * 8760)/HHV =	76,995,817	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.6		*Equation 1.6, Chapter 1 of the Air Pollution Control Cost Manual
Total System Capacity Factor (CF_{total}) =	(M_{actual}/M_{fuel}) * (t_{SNCR}/365) =	1.00	fraction	*Equation 1.7, Chapter 1 of the Air Pollution Control Cost Manual
Total operating time for the SNCR (t_{op}) =	CF_{total} * 8760 =	8,760	hours	*Equation 1.11, Chapter 1 of the Air Pollution Control Cost Manual
Nox Removal Efficiency (EF) =	(NOx_{in}-NOx_{out})/NOx_{in} =	30	percent	*Equation 1.10, Chapter 1 of the Air Pollution Control Cost Manual
NOx removed per hour =	NOx_{in} * EF * Q_B =	4.92	lb/hr	*Equation 1.12, Chapter 1 of the Air Pollution Control Cost Manual
Total NOx removed per year =	(NOx_{in} * EF * Q_B * t_{op}) / 2000 =	21.53	tons/year	*Equation 1.11, Chapter 1 of the Air Pollution Control Cost Manual
SO2 Emission Rate =	(%S/100) * (64/32) * 1E6 / HHV =	0.12	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia / P =	1.20		*Equation 1.22, Chapter 1 of the Air Pollution Control Cost Manual
Atmospheric pressure at facility elevation above sea level (P) =	2116 *[(59-(0.00356*h)+459.7)/518.6)$^{5.256}$ * (1/144) =	12.24	psia	*Equation 1.23, Chapter 1 of the Air Pollution Control Cost Manual
Retrofit Factor (RF) =	From Data Input	1.00		

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW_R) =		60.06	g/mole
			Density (p_{sol}) =	71	lb/gallon

Parameter	Equation	Calculated Value	Units	
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} * Q_B * NSR * MW_R) / (MW_{NOx} * SR_T) = (where SR_T =1 for NH3; 2 for Urea)	16.35	lb/hr	*Equation 1.18, Chapter 1 of the Air Pollution Control Cost Manual
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{stored} =	32.71	lb/hr	*Equation 1.19, Chapter 1 of the Air Pollution Control Cost Manual
Reagent Volume Flow Rate (q_{sol}) =	(m_{sol} * 7.4805)/p_{sol} =	3.45	gal/hr	*Equation 1.20, Chapter 1 of the Air Pollution Control Cost Manaul
Estimated tank volume for reagent storage (Vol_{tank}) =	q_{sol} * $t_{storage}$ * 24 hours/day =	5,000	gallons (rounded to nearest 100 gallons)	*Equation 1.21, Chapter 1 of the Air Pollution Control Cost Manual

Capital Recovery Factor:

Parameter	Equation	Calculated Value	Units	
Capital Recovery Factor (CRF) =	i (1 +i)^n / (1+ i)^n - 1 = Where n = Equipment life and i= Interest Rate	0.1279		*Equation 1.55, Chapter 1 of the Air Pollution Control Cost Manual
Electricity Consumption (EP) =	(0.47 * NOx_{in} * NSR * Q_B)/NPHR =	0.74	kW/hour	*Equation 1.42, Chapter 1 of the Air Pollution Control Cost Manual
Water Consumption (q_W) =	(m_{sol}/Density of Water) * ((C_{stored}/C_{inj})-1) =	0.00	gallons/hour	*Equation 1.44, Chapter 1 of the Air Pollution Control Cost Manual
Additional Fuel required to evaporate water in injected reagent ($delta_{Fuel}$) =	(Hv * $m_{reagent}$ * ((1/C_{inj})-1))/1,000,000 =	0.01	MMBtu/hour	*Equation 1.47, Chapter 1 of the Air Pollution Control Cost Manual
Additional ash produced due to increased fuel consumption ($delta_{Ash}$) =	($delta_{Fuel}$ * %Ash * 1E6)/HHV =	0.03	lb/hour	*Equation 1.50, Chapter 1 of the Air Pollution Control Cost Manual

TABLE 4.1-3. COST ANALYSIS

Cost Analysis				
Total Capital Investment (TCI)				
For Fuel Oil and Natural Gas-Fired Boilers:	$TCI = 1.3 * (SNCR_{cost} + BOP_{cost})$			*Equation 1.28 or 1.35, Chapter 1 of Air Pollution Control Cost Manual
For Wood Fired Boilers (with Economizer) :	$TCI = 1.3 * (SNCR_{cost} + APH_{cost} + BOP_{cost})$			*Equation 1.31, Chapter 1 of Air Pollution Control Cost Manual (for coal-fired boilers)
For Wood Fired Boilers (without Economizer) :	$TCI = 1.3 * (SNCR_{cost} + BOP_{cost})$			*Equation 1.28 or 1.35, Chapter 1 of Air Pollution Control Cost Manual (for gas-fired boilers)
Capital cost for the SNCR ($SNCR_{cost}$) =	$1,288,345	in 2018 dollars		
Air Pre-Heater Costs (APH_{cost}) =	$0	in 2018 dollars		*No economizer
Balance of Plant Costs (BOP_{cost}) =	$744,817	in 2018 dollars		
Total Capital Investment (TCI) =	**$2,643,110.63**	in 2018 dollars		
SNCR Capital Costs ($SNCR_{cost}$)				
For Wood Fired Boiler:	$SNCR_{cost} = 14800 * Q_B * ELEVF * RF$			*Based on Figure 1.2, Chapter 1 of Air Pollution Control Cost Manual and adjusted for CEPCI
SNCR Capital Costs ($SNCR_{cost}$) =	$1,288,345	in 2018 dollars		
Balance of Plant Costs (BOP_{cost})				
For Wood Fired Boiler:	$BOP_{cost} = 320{,}000 * (0.1 * Q_B)^{0.33} * (NOx\ removed/hr)^{0.12} * BTF * RF$			
Balance of Plant Costs (BOP_{cost}) =	$744,817	in 2018 dollars		
Annual Costs				
Total Annual Cost (TAC):	TAC = Direct Annual Costs + Indirect Annual Costs			
Direct Annual Costs (DAC) =	Annual Maintenance Cost + Annual Reagency Cost + Annual Electricty Cost + Annual Water Cost + Annual Fuel Cost + Annual Ash Cost			
Annual Maintenance Cost =	1.5% * TCI	$39,646.66	in 2018 dollars	*Equation 1.39, Chapter 1 of Air Pollution Control Cost Manual
Annual Reagent Cost =	$q_{sol} * Cost_{reag} * t_{op}$	$50,110.57	in 2018 dollars	*Equation 1.40, Chapter 1 of Air Pollution Control Cost Manual
Annual Electricity Cost =	$EP * Cost_{elect} * t_{op}$	$669.25	in 2018 dollars	*Equation 1.43, Chapter 1 of the Air Pollution Control Cost Manual
Annual Water Cost =	$q_W * Cost_{water} * t_{op}$	$0.00	in 2018 dollars	*Equation 1.46, Chapter 1 of the Air Pollution Control Cost Manual
Annual Delta Fuel Cost =	$delta_{fuel} * Cost_{fuel} * t_{op}$	$243.68	in 2018 dollars	*Equation 1.49, Chapter 1 of the Air Pollution Control Cost Manual
Annual Delta Ash Cost =	$delta_{ash} * Cost_{ash} * t_{op} /2{,}000$	$8.68	in 2018 dollars	*Equation 1.51, Chapter 1 of the Air Pollution Control Cost Manual
Direct Annual Costs (DAC) =		$90,678.84		
Indirect Annual Costs (IDAC) =	Administrative Charges (AC)+ Capital Recovery (CR)			*Equation 1.52, Chapter 1 of the Air Pollution Control Cost Manual
Administrative Charges (AC) =	3% * Annual maintenance cost	$1,189.40	in 2018 dollars	*Equation 1.53, Chapter 1 of the Air Pollution Control Cost Manual
Capital Recovery (CR) =	CRF * TCI	$338,053.85	in 2018 dollars	*Equation 1.54, Chapter 1 of the Air Pollution Control Cost Manual
Indirect Annual Costs (IDAC) =		$339,243.25		
Total Annual Cost (TAC) =	DAC + IDAC	$429,922.09		*Equation 1.56, Chapter 1 of the Air Pollution Control Cost Manual
Cost Effectiveness ($/ton) =	**TAC / NOx removed per year**	**$19,968.62**	in 2018 dollars	*Equation 1.57, Chapter 1 of the Air Pollution Control Cost Manual

As shown in Table 4.1-3 and Appendix A, the cost effectiveness to retrofit the Wood-Fired Boiler with a SCR-Urea system is $19,968.62 per ton of NO_x removed per year (in 2018 dollars). Thus, making the retrofit not economically feasible. The cost effectiveness coupled with emissions from JELD-WEN's Klamath Falls Campus not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) makes retrofitting unnecessary.

4.1.2 RETROFIT WOOD-FIRED BOILER WITH SNCR – AMMONIA

Tables 4.2-1 through 4.2-3 show the input parameters, design parameters, and the cost effectiveness of retrofitting the Wood-Fired Boiler with a SNCR – Ammonia system.

TABLE 4.2-1. DESIGN INPUTS

Data Inputs				
Data on combustion unit:				
Is the combustion unit a utility or industristal boiler?	Industrial		What type of fuel is burned?	Wood
Is the SNCR for a new boiler or retrofit of an existing boiler?	Retrofit		Reagent Used	Ammonia
Retrofit difficulty factor	1.00			
Maximum heat input rate (Q_B)=	72.5	MMBtu/hr	Sulfur content (%S) =	0.05 percent by weight
Fuel higher heating value (HHV) =	8,249	Btu/lb*	Ash Content (%Ash) =	1.82 percent by weight
Maximum Actual Annual Fuel consumption (M_{actual}) =	76,995,817	lbs/yr		
Net plant heat input rate (NPHR) =	16	MMBtu/MW	*HHV listed is on a Dry Basis.	
Proposed SNCR design parameters:				
Number of days the SNCR operates (t_{SNCR})	365	Days	Plant Elevation (h) =	5000 Feet above sea level
Inlet NOx Emissions (NOx_{in}) to SNCR	0.226	lb/MMBtu		
Outlet Nox Emissions (NOx_{out}) from SNCR	0.1582	lb/MMBtu		
Estimated Normalized Stoichiometric Ration (NSR)	1.53		* The NSR for a urea system is calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).	
Concentration of reagent as stored (C_{stored})	29.4	Percent		
Density of reagent as stored (p_{sol})	56	lb/ft3		
Concentration of reagent injected (C_{inj})	50	Percent	(Typically 50% for Urea and 10% for Ammonia)	
Number of days reagent is stored ($t_{storage}$)	60	days	*Reagent supply storage before next delivery	
Estimated equipment life (n)	10	Years		
Proposed SNCR cost data:				
Desired dollar-year	2018			
CEPCI for Desired dollar-year	616.5		499.6 2006 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent	Based on Federal Reserve highest rate	
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu		
Reagent ($Cost_{reag}$)	0.293	$/gallon		
Water ($Cost_{water}$)	0.006	$/gallon		
Electrity ($Cost_{elect}$)	0.1038	$/kWh		
Ash Disposal (wood-fired boiler only) ($Cost_{ash}$)	61	$/ton		

TABLE 4.2-2. DESIGN PARAMETERS

Design Parameters						
Parameter	**Equation**	**Calculated Value**	**Units**			
Maximum Annual Heat Input Rate (Q_B) =	From Data Input	72.5	MMBtu/hr			
Maximum Actual Annual Fuel Consumption (M_{actual}) =	From Data Input	76,995,817	lbs/Year			
Maximum Annual Fuel Consumption (M_{fuel}) =	(Q_B * 1.0E6 Btu/MMBtu * 8760)/HHV =	76,995,817	lbs/Year			
Heat Rate Factor (HRF) =	NPHR/10 =	1.6		*Equation 1.6, Chapter 1 of the Air Pollution Control Cost Manual		
Total System Capacity Factor (CF_{total}) =	(M_{actual}/M_{fuel}) * (t_{SNCR}/365) =	1.00	fraction	*Equation 1.7, Chapter 1 of the Air Pollution Control Cost Manual		
Total operating time for the SNCR (t_{op}) =	CF_{total} * 8760 =	8,760	hours	*Equation 1.11, Chapter 1 of the Air Pollution Control Cost Manual		
Nox Removal Efficiency (EF) =	(NOx_{in}-NOx_{out})/NOx_{in} =	30	percent	*Equation 1.10, Chapter 1 of the Air Pollution Control Cost Manual		
NOx removed per hour =	NOx_{in} * EF * Q_B =	4.92	lb/hr	*Equation 1.12, Chapter 1 of the Air Pollution Control Cost Manual		
Total NOx removed per year =	(NOx_{in} * EF * Q_B * t_{op}) / 2000 =	21.53	tons/year	*Equation 1.11, Chapter 1 of the Air Pollution Control Cost Manual		
SO2 Emission Rate =	(%S/100) * (64/32) * 1E6 / HHV =	0.12	lbs/MMBtu			
Elevation Factor (ELEVF) =	14.7 psia / P =	1.20		*Equation 1.22, Chapter 1 of the Air Pollution Control Cost Manual		
Atmospheric pressure at facility elevation above sea level (P) =	2116 *[(59-(0.00356*h)+459.7)/518.6)$^{5.256}$ * (1/144) =	12.24	psia	*Equation 1.23, Chapter 1 of the Air Pollution Control Cost Manual		
Retrofit Factor (RF) =	From Data Input	1.00				
Reagent Data:						
Type of reagent used	Ammonia	Molecular Weight of Reagent (MW_R) =			17.03	g/mole
			Density (p_{sol}) =		56	lb/gallon
Parameter	**Equation**	**Calculated Value**	**Units**			
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} * Q_B * NSR * MW_R) / (MW_{NOx} * SR_T) = (where SR_T =1 for NH3; 2 for Urea)	9.27	lb/hr	*Equation 1.18, Chapter 1 of the Air Pollution Control Cost Manual		
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{stored} =	31.54	lb/hr	*Equation 1.19, Chapter 1 of the Air Pollution Control Cost Manual		
Reagent Volume Flow Rate (q_{sol}) =	(m_{sol} * 7.4805)/p_{sol} =	4.21	gal/hr	*Equation 1.20, Chapter 1 of the Air Pollution Control Cost Manaul		
Estimated tank volume for reagent storage (Vol_{tank}) =	q_{sol} * $t_{storage}$ * 24 hours/day =	6,100	gallons (rounded to nearest 100 gallons)	*Equation 1.21, Chapter 1 of the Air Pollution Control Cost Manual		
Capital Recovery Factor:						
Parameter	**Equation**	**Calculated Value**	**Units**			
Capital Recovery Factor (CRF) =	i $(1+i)^n$ / $(1+i)^n$ - 1 = Where n = Equipment life and i= Interest Rate	0.1279		*Equation 1.55, Chapter 1 of the Air Pollution Control Cost Manual		
Electricity Consumption (EP) =	(0.47 * NOx_{in} * NSR * Q_B)/NPHR =	0.74	kW/hour	*Equation 1.42, Chapter 1 of the Air Pollution Control Cost Manual		
Water Consumption (q_W) =	(m_{sol}/Density of Water) * ((C_{stored}/C_{inj})-1) =	-1.56	gallons/hour	*Equation 1.44, Chapter 1 of the Air Pollution Control Cost Manual		
Additional Fuel required to evaporate water in injected reagent ($delta_{Fuel}$) =	(Hv * $m_{reagent}$ * ((1/C_{inj})-1))/1,000,000 =	0.01	MMBtu/hour	*Equation 1.47, Chapter 1 of the Air Pollution Control Cost Manual		
Additional ash produced due to increased fuel consumption ($delta_{Ash}$) =	($delta_{Fuel}$ * %Ash * 1E6)/HHV =	0.02	lb/hour	*Equation 1.50, Chapter 1 of the Air Pollution Control Cost Manual		

TABLE 4.2-3. COST ANALYSIS

Cost Analysis				
Total Capital Investment (TCI)				
For Fuel Oil and Natural Gas-Fired Boilers:	TCI = 1.3 * ($SNCR_{cost}$ + BOP_{cost})			*Equation 1.28 or 1.35, Chapter 1 of Air Pollution Control Cost Manual
For Wood Fired Boilers (with Economizer) :	TCI = 1.3 * ($SNCR_{cost}$ + APH_{cost} + BOP_{cost})			*Equation 1.31, Chapter 1 of Air Pollution Control Cost Manual (for coal-fired boilers)
For Wood Fired Boilers (without Economizer) :	TCI = 1.3 * ($SNCR_{cost}$ + BOP_{cost})			*Equation 1.28 or 1.35, Chapter 1 of Air Pollution Control Cost Manual (for gas-fired boilers)
Capital cost for the SNCR ($SNCR_{cost}$) =	$1,288,345	in 2018 dollars		
Air Pre-Heater Costs (APH_{cost}) =	$0	in 2018 dollars		*No economizer
Balance of Plant Costs (BOP_{cost}) =	$744,817	in 2018 dollars		
Total Capital Investment (TCI) =	**$2,643,110.63**	in 2018 dollars		
SNCR Capital Costs ($SNCR_{cost}$)				
For Wood Fired Boiler:	$SNCR_{cost}$ = 14800 * Q_B * ELEVF * RF			*Based on Figure 1.2, Chapter 1 of Air Pollution Control Cost Manual and adjusted for CEPCI
SNCR Capital Costs ($SNCR_{cost}$) =	$1,288,345	in 2018 dollars		
Balance of Plant Costs (BOP_{cost})				
For Wood Fired Boiler:	BOP_{cost} = 320,000 * $(0.1 * Q_B)^{0.33}$ * $(\text{NOx removed/hr})^{0.12}$ * BTF *RF			
Balance of Plant Costs (BOP_{cost}) =	$744,817	in 2018 dollars		
Annual Costs				
Total Annual Cost (TAC):	TAC = Direct Annual Costs + Indirect Annual Costs			
Direct Annual Costs (DAC) =	Annual Maintenance Cost + Annual Reagency Cost + Annual Electricty Cost + Annual Water Cost + Annual Fuel Cost + Annual Ash Cost			
Annual Maintenance Cost =	1.5% * TCI	$39,646.66	in 2018 dollars	*Equation 1.39, Chapter 1 of Air Pollution Control Cost Manual
Annual Reagent Cost =	q_{sol} * $Cost_{reag}$ * t_{op}	$10,815.36	in 2018 dollars	*Equation 1.40, Chapter 1 of Air Pollution Control Cost Manual
Annual Electricity Cost =	EP * $Cost_{elect}$ * t_{op}	$669.25	in 2018 dollars	*Equation 1.43, Chapter 1 of the Air Pollution Control Cost Manual
Annual Water Cost =	q_W * $Cost_{water}$ * t_{op}	-$81.86	in 2018 dollars	*Equation 1.46, Chapter 1 of the Air Pollution Control Cost Manual
Annual Delta Fuel Cost =	$delta_{fuel}$ * $Cost_{fuel}$ * t_{op}	$138.19	in 2018 dollars	*Equation 1.49, Chapter 1 of the Air Pollution Control Cost Manual
Annual Delta Ash Cost =	$delta_{ash}$ * $Cost_{ash}$ * t_{op} /2,000	$4.92	in 2018 dollars	*Equation 1.51, Chapter 1 of the Air Pollution Control Cost Manual
Direct Annual Costs (DAC) =		$51,192.53		
Indirect Annual Costs (IDAC) =	Administrative Charges (AC)+ Capital Recovery (CR)			*Equation 1.52, Chapter 1 of the Air Pollution Control Cost Manual
Administrative Charges (AC) =	3% * Annual maintenance cost	$1,189.40	in 2018 dollars	*Equation 1.53, Chapter 1 of the Air Pollution Control Cost Manual
Capital Recovery (CR) =	CRF * TCI	$338,053.85	in 2018 dollars	*Equation 1.54, Chapter 1 of the Air Pollution Control Cost Manual
Indirect Annual Costs (IDAC) =		$339,243.25		
Total Annual Cost (TAC) =	DAC + IDAC	$390,435.78		*Equation 1.56, Chapter 1 of the Air Pollution Control Cost Manual
Cost Effectiveness ($/ton) =	**TAC / NOx removed per year**	**$18,134.59**	in 2018 dollars	*Equation 1.57, Chapter 1 of the Air Pollution Control Cost Manual

As shown in Table 4.2-3 and Appendix A, the cost effectiveness to retrofit the Wood-Fired Boiler with a SCR-Ammonia system is $18,134.59 per ton of NO_x removed per year (in 2018 dollars). Thus, making the retrofit not economically feasible. The cost effectiveness coupled with emissions from JELD-WEN's Klamath Falls Campus not expected to impact visibility in the Mountain Lakes Wilderness Class I Area based on the predominant wind direction (see Section 2.1) makes retrofitting unnecessary.

5.1 WOOD-FIRED BOILER

5.1.1 GOOD COMBUSTION PRACTICES

Good combustion practices are already employed at the Wood-Fired boiler. There is no further time needed for compliance to assess this control technology.

5.1.2 ADDITION OF CONTROLS

JELD-WEN estimates that approximately 3 years, after EPA approves ODEQs regional haze SIP, will be needed to budget, design, procure, and install the control equipment from the time the facility is required to add controls. JELD-WEN believes this is a reasonable to since MACT standards typically allow three years for compliance and NO_x controls require significant time for engineering, construction, and facility preparedness.

6.1 WOOD-FIRED BOILER

6.1.1 GOOD COMBUSTION PRACTICES

There are no anticipated energy or non-air impacts imposed by continuing to employ good combustion practices.

6.1.2 ADDITION OF CONTROLS

Post-combustion NO_x controls impact energy use for the boiler. The additional of an SNCR system will reduce the thermal efficiency by using thermal energy in the reaction of NO_x and the reagent. The control system also requires the installation of fans, compressors, injection equipment, and related processes that will utilize energy. The increase in electrical energy required for the control system and thermal energy will increase both the indirect and direct Greenhouse Gas Emissions associated with the Wood-Fired Boiler.

7. Remaining Useful Life for Affected Sources

7.1 Wood-Fired Boiler

The remaining useful life of a boiler varies greatly depending on the age of the boiler, size of the unit, maintenance frequency, and other factors. The useful of most industrial, commercial, and institutional boilers is 10 – 30 years. The Wood-Fired Boiler located on the Klamath Falls Campus utilizes an ESP to control particulate matter emissions. Based on recommended operation and maintenance the useful like of the ESP exceeds that of the Wood-Fired Boiler. There is not a specific life expectancy listed in any industrial publication on the actual life of an ESP. Therefore, JELD-WEN believes the ESP will exceed the 30-year life expectancy of the Wood-Fired Boiler. JELD-WEN utilized recommended operation and maintenance for both the Wood-Fired Boiler and the ESP.

The table below presents the Potential to Emit (PTE) emissions for NO_x, SO_2 and PM_{10} as represented in the Title V permit renewal application submitted in 2017.

TABLE 7-1. PTE EMISSIONS

Emission Source	Pollutant	lbs/hr	TPY
Wood Fired Boiler	NO_x	16.8	56.2
	SO_2	0.70	3.0
	PM_{10}	0.95	4.1
Natural Gas Boiler	NO_x	1.3	8.5
	SO_2	0.07	0.4
	PM_{10}	0.07	0.4
Biofilter	NO_x	1.12	4.89
	SO_2	0.05	0.05
	PM_{10}	0.05	0.2
Paint Booth NG Oven	NO_x	0.29	1.28
	SO_2	0.02	0.07
	PM_{10}	0.01	0.1
Building Heat	NO_x	0.41	0.74
	SO_2	0.02	0.04
	PM_{10}	0.02	0.04
Package Boiler	NO_x	0.08	0.34
	SO_2	4.08E-3	0.02
	PM_{10}	3.92E-3	0.02
Lumber Kilns	PM_{10}	0.8	3.0
Storage Pile	PM_{10}	1.07	4.7
Baghouses	PM_{10}	5.4E-3	6.7
Truck Bins	PM_{10}	6.0E-8	1.3
Prime Line	PM_{10}	0.52	5.0
Veneer Dryer	PM_{10}	1.5E-3	6.0E-3
Dehumidification Kilns	PM_{10}	3.53E-2	0.8
Millwork Manufacturing	PM_{10}	1.08E-6	5.39E-3
Engineering Emissions	PM_{10}	6.39E-4	1.33

The table below compares the current permit limits and proposed facility wide limits. Based on the predominant wind direction emissions from the JELD-WEN Klamath Falls Campus are inconsequential for regional haze purposes and a change in the Title V permit plant site emission limits is not necessary. The complete potential-to-emit calculations and calculation methodologies are attached in Appendix B.

TABLE 7-2. PERMIT LIMIT EMISSIONS

Pollutant	Current Permit Limit Emissions *(tons/yr)	Proposed Facility-Wide Emissions (tons/yr)	Change in Emissions (tons/yr)
PM_{10}	30	30	0
NOx	73	73	0
SO2	39	39	0

*Based on draft Title V permit renewal.

9. Conclusion

Based on a comprehensive review of the emissions units located at the JELD-WEN Klamath Falls Campus, JELD-WEN has determined good combustion practices for the Wood-Fired Boiler is the only technically feasible NO_x control option. In addition, based on the predominant wind direction emissions from the JELD-WEN Klamath Falls Campus are inconsequential for regional haze purposes. Therefore, retrofitting the Wood-Fired Boiler would be uneconomical and unnecessary for improving visibility.

APPENDIX A

COST ANALYSIS

APPENDIX B

EMISSIONS CALCULATIONS

RBLC Database Search Results

Draft Title V Permit