

FACT SHEET

Whelan Energy Center
4520 East South Street
Hastings, Nebraska 68901

March 26, 2004

DESCRIPTION OF THE FACILITY OR ACTIVITY:

Hastings Utilities (HU) currently operates the Whelan Energy Center (WEC) with an existing 77 MW coal-fired electric generating unit (Unit 1) located approximately 3 miles east of Hastings, Nebraska on Highway 6. This original generation facility was permitted in 1977 and is currently a major source of air emissions under both the Prevention of Significant Deterioration (PSD) program and the Title V operating permits program. Its Standard Industrial Classification (SIC) code is 4911, and North American Industry Classification System (NAICS) code is 221112 for fossil fueled electric generators.

WEC is operating under a Class I operating permit issued on 05/20/1998 and a Phase II Acid Rain permit effective 01/01/2000.

The Department received a PSD Construction Permit application for "WEC Unit 2" on 10/23/2002. The proposed modification at WEC will consist of the addition of one (1) 220 MW coal-fired electric generating unit (Unit 2) with a maximum rated heat input of 2,210.5 MMBtu/hr. The unit is classified as a pulverized coal (PC) dry-bottom boiler and will primarily combust western subbituminous coal from the Powder River Basin (PRB) with a minimum heat content of approximately 8,100 Btu/lb. This is the same coal as currently being used in Unit 1. Distillate fuel oil will be used as a start-up fuel.

Other proposed modifications identified in the permit application consist of the addition of the following support equipment: a coal conveying system to transfer coal from the existing storage area to Unit 2, a 74 MMBtu/hr auxiliary boiler 2, an 800 kW diesel-fired emergency generator, and a 50-horsepower diesel-fired emergency fire pump. The auxiliary boiler will be operated only when both Unit 1 and Unit 2 main boilers are inoperative, and it will be used to provide building heat and the steam needed for startup of the main boilers. The emergency generator will be used for emergency shut down of the plant equipment. Additionally, the emergency generator and emergency fire pump will be operated approximately once per week for about one hour in order to maintain them in working order. The auxiliary boiler and emergency equipment have a proposed limit on operating hours of 400 hours per year.

HU also proposes to modify two emission limitations for the Unit 1 boiler and fuel and operational limitations for Unit 1 ancillary equipment in order to ensure compliance with relevant ambient air quality standards and allowable increment concentrations as follows:

- Particulate Matter (PM) emissions from Unit 1 shall not exceed 41.8 lb/hr (averaging time based on test method);
- Sulfur dioxide (SO₂) emissions from Unit 1 shall not exceed 1.10 lb/MMBtu. (3-hour average);
- Auxiliary boiler 1 (emission point 104) and Well B pump (106) shall be limited to 400 hours of operation annually and combustion of distillate oil with a maximum sulfur content of 0.05 percent.

TYPE AND QUANTITY OF AIR CONTAMINANT EMISSIONS ANTICIPATED:

Unit 2 will have the potential to emit nitrogen oxides (NO_x), carbon monoxide (CO), PM, particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM₁₀), SO₂, sulfuric acid mist (H₂SO₄), volatile organic compounds (VOCs), fluorides (expressed as hydrogen fluoride, HF) and hazardous air pollutants (HAP). Ancillary equipment (auxiliary boiler, emergency generator, emergency fire pump) at WEC will have the potential to emit NO_x, CO, PM/PM₁₀, SO₂, VOCs and HAPs.

Annual potential to emit calculations for the ancillary equipment are based on the proposed operational limit of 400 hours per year. Annual potential to emit calculations for Unit 2 are representative of 100 percent load firing conditions. As utility boilers are primarily used for base-load electrical generators, potential emissions were calculated based on full-time operation of 8,760 hours per year. HU has indicated that the Unit 2 cooling tower may obtain water from the Navel Ammunition Depot (NAD) superfund site east of WEC. According to the U.S. Army Corps of Engineers, Trichloroethylene (TCE), 1,1,2-Trichloroethane (TCA), and Dichloroethene (DCE) are the primary contaminants tested to be in the NAD water. The cooling towers are expected to “strip” out these chemicals from the NAD groundwater, thus serving as a treatment method for the NAD water. Emission calculations for the cooling towers assume that all contaminants in the NAD groundwater are released to the atmosphere as VOCs and HAPs. During the first year of “clean-up”, this is expected to be less than 0.37 tons/yr and decreasing in following years. Table 1 shows a summary of the potential annual emissions for this proposed project under the terms of this permit. Attachment A details the emission factors and calculations for each individual emissions point.

Table 1 – Emissions Summary

Emission Point	Unit Description	POTENTIAL ANNUAL EMISSIONS (tons/yr)								
		SO ₂	NO _x ^a	CO	VOC	PM	PM ₁₀	H ₂ SO ₄ mist	Fluorides (as HF)	Total HAPs
201	Coal Transfer	-	-	-	-	3.36	3.36	-	-	-
202	Unit #2 Boiler	1,161.8	774.6	1,452.3	38.7	174.3	174.3	3.49	3.9	20.2
203	Coal Silos	-	-	-	-	3.78	3.78	-	-	-
204	Lime Bin	-	-	-	-	0.47	0.47	-	-	-
205	Fly Ash Handling	-	-	-	-	0.58	0.58	-	-	-
206	FGD Handling	-	-	-	-	0.58	0.58	-	-	-
207	Fly Ash Bin	-	-	-	-	1.22	1.22	-	-	-
208	FGD Recycle Bin	-	-	-	-	1.22	1.22	-	-	-
209	FGD Waste Bin	-	-	-	-	1.22	1.22	-	-	-
210	Cooling Tower	-	-	-	0.37	13.5	7.7	-	-	0.37
211	Auxiliary Boiler	0.74	1.48	0.74	0.44	0.30	0.30	0.01	-	0.005
212	Emer. Gen	0.08	2.83	0.29	0.07	0.04	0.04	-	-	0.007
213	Fire Pump	0.004	0.19	0.04	0.007	0.004	0.004	-	-	negl.
	Haul Roads	-	-	-	-	20.5	4.1	-	-	-
	Coal Pile	-	-	-	-	1.4	0.7	-	-	-
Totals:		1,162.7	779.1	1,453.4	39.6	222.5	199.6	3.5	3.9	20.6

^a NO_x emissions from the Unit #2 boiler are permitted to reach 1,161.9 tons/yr during the first 18 months (@ 0.12 lb/MMBtu)

APPLICABLE REQUIREMENTS AND VARIANCES OR ALTERNATIVES TO REQUIRED STANDARDS:

A. Prevention of Significant Deterioration (PSD):

The existing WEC facility is classified as a major stationary source under the PSD program (>100 tpy). As a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input, WEC is included as one of the 28 listed source categories in 40 CFR 52.21(b)(1)(iii) that must include fugitive emissions in determining whether a proposed modification is major. PSD regulations require that all new or modified major stationary sources submit a BACT analysis and ambient air quality analysis for all criteria and other pollutants emitted over the significant emission increase thresholds listed in 40 CFR 52.21(b)(23). An 'Additional Impact Analysis' must also be conducted as required in 40 CFR 52.21(o).

Because the existing Unit 1 boiler process capacities will not be affected by the WEC Unit 2 addition, emissions from Unit 1 are not included in the emissions increase analysis. Refer to Table 2 for Significant Thresholds and PSD review applicability.

Table 2 - Estimated Potential Emissions Vs. PSD Thresholds

Regulated Pollutant	Maximum Annual Emissions (ton/yr)	PSD Significance Threshold (ton/yr)	PSD/BACT Applicability
NO _x	779	40	Yes
CO	1,453	100	Yes
PM ^a	222	25	Yes
PM ₁₀ ^a	199	15	Yes
SO ₂	1,163	40	Yes
VOC	39.6	40	No
Lead (Pb)	0.04	0.6	No
H ₂ SO ₄ mist	3.5	7	No
Fluorides (calculated as HF)	3.9	3	Yes
Total HAPs	20.6	n/a	n/a

^a PM/PM₁₀ emissions include fugitive emissions resulting from new coal handling operations

1.00 Best Available Control Technology (BACT):

Emission estimates in Table 2 indicate that WEC Unit 2 will have the potential to emit NO_x, CO, PM/PM₁₀, SO₂, and fluorides in excess of PSD significance thresholds, thus requiring the applicant to apply BACT for each emissions unit that has the potential to emit these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction, determined on a case-by-case basis, considering technical, economic, energy, and environmental factors. However, BACT cannot be less stringent than emission limits established by an applicable NSPS. Table 3 summarizes BACT for the Unit 2 boiler. Because of the low limit proposed on hours of operation (400) for the ancillary equipment (auxiliary boiler 2, emergency generator, fire water pump), BACT for these units is considered good combustion and the use of clean fuels, and were not considered further as part of the BACT analysis for WEC Unit 2.

Table 3 - Proposed Unit 2 Boiler BACT Emission Limitations.

Pollutant	Emission Limit	Control Type
SO ₂	0.12 lb/MMBtu (30-day rolling average)	Dry FGD & Fabric Filter
NO _x	0.08 lb/MMBtu (30-day rolling average)	SCR
CO	0.15 lb/MMBtu (3-hour average)	Combustion Controls

Pollutant	Emission Limit	Control Type
PM/PM ₁₀	0.018 lb/MMBtu (3-hour average)	Fabric Filter
HF	0.0004 lb/MMBtu (test method average)	Dry FGD & Fabric Filter

This Fact Sheet contains a summary of the BACT analysis submitted with the permit application. Refer to the application for complete details including the basis for the cost calculations provided in this permit document.

1.01 Top-Down BACT Analysis

The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy or environmental consideration.

A “Top-Down” BACT analysis basically consists of the following steps:

- *Identify All Control Technologies.* All control technologies for similar processes, as well as Lowest Achievable Emission Rate (LAER) technologies are included.
- *Eliminate Technically Infeasible Options.* Technologies demonstrated to be infeasible based on physical, chemical, and engineering principles are excluded from further consideration.
- *Rank Technologies By Control Effectiveness.* Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction. The ranking also includes expected emission rate, control effectiveness, energy impacts, environmental impacts (including toxic and hazardous air emissions), and economic impacts.
- *Control Technology Evaluation.* The technology ranking is evaluated and case-by-case consideration is given to energy, environmental, and economic impacts. The most effective option not rejected is chosen as BACT and is used to express an enforceable emission limitation for the affected emission unit.

1.02 Applicable Pollutants

The Unit 2 BACT analysis addresses criteria pollutant emissions of NO_x, CO, PM/PM₁₀, SO₂ and fluorides. Particulate matter limitations for utility boilers are generally expressed as total PM. PM₁₀ is a subset of PM, and therefore cannot exceed PM. In order to present a conservative analysis, the two components of particulate matter (PM/PM₁₀) are treated together and considered equal for the purpose of this analysis. The BACT analysis has been divided into sections that address each applicable pollutant individually.

1.10 SO₂ BACT Analysis

The objective of this analysis is to determine BACT for SO₂ emissions from the proposed Unit 2 boiler. Generally, there are two approaches to controlling SO₂ emissions: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO₂ from the flue gases after combustion.

SO₂ Formation. SO₂ emissions are formed from the oxidation of organic and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO₂, however, a small quantity is further oxidized to form sulfur trioxide (SO₃). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as SO_x compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash.

In solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS₂) or some other mineral sulfates. Mineral sulfates can be removed through washing or other physical cleaning. However, organic sulfur cannot be removed by physical cleaning. Because coal is solid, the use of chemical desulfurization processes can be very costly. Additionally, it is unlikely that sufficient desulfurization of coal can be accomplished to meet current SO₂ emission requirements. Therefore, some form of FGD must be considered for solid fuels.

1.11 Identification of SO₂ Control Technologies

The following paragraphs identify available FGD technologies for coal-fired boiler processes and address the feasibility of the technologies as applied to the operation of the proposed Unit 2 Boiler. FGD technologies can be divided into two main categories, regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from the flue gas and the scrubber byproducts are discarded. All of the FGD technologies considered can achieve SO₂ removal efficiencies of 90 to 95%, depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operational expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO₂ by a bed of copper oxide.

A new regenerative process that was developed as an indirect result of collaborative research with the former U.S. Bureau of Mines and the University of Minnesota is the Pahlman process. The Pahlman process is a dry removal technology that can remove multiple pollutants (NO_x and SO₂) at efficiencies greater than 99 percent. As a regenerative process, the Pahlman process purportedly reduces problems associated with waste disposal and creates a commercially valuable byproduct. In the closed-loop process, the Pahlmanite sorbent repeatedly captures NO_x and SO₂, which upon regeneration, yields raw sulfates and nitrates. The Pahlman process is new technology that has been pilot tested at several industrial sites, including smaller coal-fired electrical generating plants. However, proven technical feasibility with application to large-scale coal-fired electrical generating units, such as the proposed Unit 2 Boiler, has yet to be demonstrated. Therefore, this new regenerative technology will not be considered further in this BACT analysis.

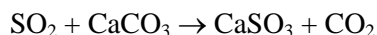
Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have lower overall costs and are simpler to operate than regenerative processes. Because the throwaway processes can achieve the same removal efficiencies as

regenerative processes and cost less, this BACT analysis for SO₂ will focus on throwaway processes and further discussion of regenerative process will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

Wet FGD

Wet scrubbing (wet FGD) systems used for SO₂ reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling. Wet FGD technology is a well-established process for removing SO₂ from flue gas. In wet scrubbers, the flue gas enters the spray tower or absorber where it is sprayed with a water slurry which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. The calcium in the slurry reacts with the SO₂ in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

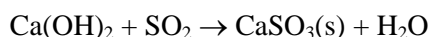


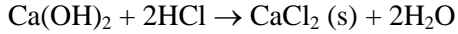
Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50% solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO₂ to SO₃ and subsequently, sulfuric acid (H₂SO₄). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensate. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages, one for fly ash removal and one for SO₂ removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO₂ absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO₂ to other absorber designs.

Dry FGD

In contrast to wet scrubbing systems, dry FGD systems (spray dryer) systems use much smaller amounts of liquid. With a spray dryer absorber system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO₂ are absorbed by the slurry mixture and react to form solid salts. The absorption process is temperature dependent and the cooler the flue gas, the more effectively the acid gases will react with the sorbents. The overall chemical reactions can be simply expressed as:





As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO₂, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO₂. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO₂¹.

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and unreacted lime, which must be sent to a particulate control device such as an electrostatic precipitator (ESP) or fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

1.12 Top-Down Ranking

The SO₂ control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 4 summarizes the control technology ranking.

Table 4 - SO₂ Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control SO₂ emissions	Available and demonstrated effective^a	In service on similar systems	Technically feasible for Unit 2	% SO₂ Reduction
Wet FGD	Yes	Yes	Yes	Yes	>90%
Dry FGD	Yes	Yes	Yes	Yes	>90%

^a Based on design and configuration of the Unit 2 Boiler.

1.13 Control Technology Evaluation

The following paragraphs present detailed evaluations of each of the feasible SO₂ control technologies. Energy, environmental and economic impacts are considered for each of the potential control technologies.

Wet FGD

As stated previously, wet FGD is a process where the flue gas from the boiler is passed through an absorber, which uses alkaline slurry to remove the SO₂ from the exhaust gas stream. There are numerous operating parameters that can affect the SO₂ removal rate of the absorber. Those parameters are: liquid-to-gas ratio, pH, gas velocity, residence time, gas distribution, scrubber design, turndown, and coal properties such as heating value, moisture content, sulfur content, ash content, and chlorine content. Another design consideration with wet FGD systems is that the flue gas exiting the absorber is saturated with water and does still contain some SO₂. These gases are highly corrosive to any downstream

¹ Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

equipment. To minimize corrosion of the downstream equipment, the gases can be reheated to temperatures above the dewpoint, or construction materials and design conditions can be selected to withstand the corrosive conditions. Both of these alternatives increase the cost of an FGD system. Reheaters can also experience operational problems ranging from acid attack on reheater components to vibration, which causes structural deterioration.

Another potential problem with wet FGD systems using lime or limestone is that calcium sulfite in the sludge settles and filters poorly. This problem can be remedied using a forced oxidation system in a designated section of the absorber or in a separate oxidation tank. This process creates calcium sulfate, which is easily filtered. The forced oxidation process also helps to prevent scale buildup by removing calcium sulfites through conversion to calcium sulfate, thus preventing calcium sulfites from oxidizing and precipitating out in the scrubber internal areas. Scaling and oxidation can also be reduced through the use of chemical inhibitors such as magnesium and dibasic acid. The necessary reduction of scaling in wet FGD equipment increases the operational cost for these systems.

Non-regenerable wet FGD processes produce a sludge waste, which must be disposed of properly. In these processes, the scrubbing liquid can be recycled or regenerated, but no useful product is obtained from the sludge. Additionally, wastewater treatment is required for the process wastewater produced by wet FGD systems.

Energy: Use of Wet FGD to control SO₂ emissions from Unit 2 will result in significant energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment as well as additional backpressure on the exhaust system that results in a slight reduction in output. Pumps and water handling equipment required for slurry preparation, as well as flue gas reheating, would consume approximately 1% of the total proposed capacity of Unit 2.

Environmental: The primary detrimental environmental effect of the Wet FGD system is the creation of waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream as well as a waste sludge that must be disposed of in a landfill.

Economic: The capital investment associated with the installation of a Wet FGD system and associated fabric filter for Unit 2 to achieve an SO₂ emission level of 0.12 lb/MMBtu during combustion of subbituminous coal is estimated at \$76,468,900. Costs were based on budgetary quotations and standard engineering estimating practices presented in the EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002. Refer to the application for additional cost analysis details.

The total annual cost to maintain a 0.12 lb/MMBtu SO₂ emission level for Unit 2 using a Wet FGD/Fabric Filter control system is estimated to be \$11,046,300. This annual cost results in a cost effectiveness for SO₂ removed of \$1,056/ton when combusting subbituminous coal (See Table 4). Note that this cost does not include wastewater treatment costs, which would make the annualized \$/ton cost of Wet FGD somewhat higher than this.

Dry FGD

In a Dry FGD system, also called a spray dryer absorber (SDA), flue gases are passed through an atomized spray of alkaline slurry. The minimal amount of moisture in the slurry is dried by the exhaust gases, which leave the absorber and are directed to a baghouse or ESP for particulate control.

Key design parameters for spray dryer design are flue gas flow rate and composition, temperature of the flue gas, alkaline stoichiometric ratio, alkaline properties, and the required removal efficiency. The most

important parameter for sizing a spray dryer is to ensure adequate residence time in the absorber to prevent wet solids at the spray dryer outlet.

SDAs are relatively simple devices with few moving parts, and thus are not prone to a lot of operational problems. The primary maintenance problem associated with spray dryers is potential plugging in the solid or slurry transport systems. However, if manufacturer suggested maintenance and inspection schedules are followed, these problems can be minimized or avoided.

Wastewater treatment is not required with a SDA system, because the water is completely evaporated in the absorber. However, a solid waste stream is created from the fabric filter baghouse. This waste can be recycled with an optional recycling system, but is more often shipped for proper disposal. Because this waste is high in lime and contains sulfur, a necessary agricultural soil supplement, there is a possibility of beneficial re-use of this by-product by farmers.

Estimated SO₂ emission rates for implementation of a Dry FGD system on Unit 2 are listed in Table 4. The emission rates incorporate the use of Dry FGD to control SO₂ emissions to 0.12 lb/MMBtu, which is approximately equivalent to 90 percent control. The NSPS for utility boilers such as the one proposed for Unit 2 requires only 70 percent control.

Energy: Use of Dry FGD to control SO₂ emissions from Unit 2 will result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment as well as additional backpressure on the exhaust system that results in a slight reduction in output. The additional electrical demand will consume approximately 0.8% of the total proposed capacity of Unit 2 according to design estimates.

Environmental: The primary detrimental environmental effect of the Dry FGD system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced can be land filled or possibly used as an agricultural soil supplement.

Economic: The capital investment associated with the installation of a Dry FGD system and associated fabric filter for Unit 2 to achieve a SO₂ emission level of 0.12 lb/MMBtu during combustion of subbituminous coal is estimated at \$24,690,700. Costs were based on budgetary quotations and standard engineering estimating practices presented in the EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

The total annual cost to maintain a 0.12 lb/MMBtu SO₂ emission level for Unit 2 using a Dry FGD/Fabric Filter control system is estimated to be \$5,179,900. This annual cost results in a cost effectiveness for SO₂ removed of \$495/ton when combusting subbituminous coal (See Table 5).

Table 5 - Summary of Emission Rates & Top-Down SO₂ BACT Analysis Costs

Emission Unit	Control Alternative	Emission Rate (Lb/MMBtu)	Emissions (lb/hr) tpy	Emissions Reduction tpy	Total Annualized Cost \$/yr	Total Cost Effectiveness \$/ton
Unit 2	Uncontrolled	1.2	(2,652) 11,618	-	-	-
Unit 2	Wet FGD	0.12	(265) 1,161	10,456.8	11,046,300	1,056
Unit 2	Dry FGD	0.12	(265) 1,161	10,456.8	5,179,900	495

1.14 Proposed SO₂ BACT Selection

Because the Wet FGD and Dry FGD can produce an equivalent level of SO₂ control for this application, and because Dry FGD has less than half the annualized cost as Wet FGD, HU proposes to use Dry FGD as BACT for SO₂ emissions from the Unit 2 boiler. Table 3 lists the SO₂ emission limitations proposed as BACT under typical operating ranges for the Unit 2 Boiler.

For short-term periods of spray dryer absorber (SDA) maintenance, higher SO₂ emissions limits are needed to allow for changeout of the SDA atomizer every 3-4 months. The atomizer changeout can be done in a matter of hours, and in normal circumstances, is not expected to affect the ability of the unit to meet the above BACT limit on a 30-day rolling average basis. However, to allow for the higher SO₂ emissions during atomizer changeout, the dispersion modeling for short term (3-hour and 24-hour) averaging periods has been done using an uncontrolled SO₂ emission rate of 1.1 lb/mmBtu. Therefore, HU requests a 3-hour average, modeling-based SO₂ limit of 1.1 lb/MMBtu, in addition to the 30-day rolling average BACT limit of 0.12 lb/MMBtu.

1.15 BACT Selection Review For SO₂

Information concerning recently proposed or permitted coal-fired power projects was obtained from EPA's Clean Air Technology Center (CATC) website, where a list of nationwide coal-fired power projects has been compiled and is available for downloading at <http://www.epa.gov/ttn/catc/dir1/natlcoal.xls>. Additional information was obtained through EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. The list of comparable, permitted or proposed, coal-fired facilities is presented in tabular form in Appendix D of the permit application. This information provides a comparison of actual or proposed BACT limits at other facilities with the proposed BACT limits for Unit 2. The proposed 0.12 lb/MMBtu SO₂ limit for Unit 2 is comparable with other recently permitted and newly operating facilities such as Holcomb Unit #2 (Kansas) and Hawthorn (Missouri) facilities, both of which have a limit of 0.12 lb/MMBtu on a 30-day average.

1.20 NO_x BACT Analysis

The objective of this analysis is to determine BACT for NO_x emissions from the proposed Unit 2 Boiler. Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

NO_x Formation. There are two primary mechanisms of NO_x formation in utility boilers that combust coal; thermal production of NO_x from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N₂) and oxygen (O₂) molecules in the combustion air to react and form NO_x. Because the thermal NO_x production is primarily a function of combustion temperature, NO_x emission rates vary greatly with burner design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time. The formation of fuel NO_x from reactions of fuel bound nitrogen and air, can account for up to 80 percent of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

1.21 Identification of NO_x Control Technologies

The following paragraphs identify potentially available control technologies for coal-fired boiler processes and address the feasibility of the technologies as applied to the operation of the proposed Unit 2 Boiler.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH₃) or urea to reduce the NO_x in the flue gas to N₂ and H₂O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH₃ emissions (NH₃ slip). As the catalyst degrades, NH₃ slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel source, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO₂), zirconium oxide (ZrO₂), vanadium pentoxide (V₂O₅), silicon oxide (SiO₂), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH₃, anhydrous NH₃, or a urea solution to produce NH₃ on demand. Aqueous NH₃ is generally transported and stored in concentrations ranging from 19 to 30% and therefore requires more storage capacity than anhydrous NH₃. Anhydrous NH₃ is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH₃ must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH₃ on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH₃ and isocyanic acid (HNCO). Application of urea-based SCR systems to utility boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

SCR is a proven technology that has been in commercial use on utility boilers since the late 1970s. Therefore, SCR is considered a feasible NO_x control technology and will be considered further in this BACT analysis.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia

(NH₃) or urea to reduce the NO_x in the flue gas to N₂ and H₂O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on industrial and utility boilers, and can achieve NO_x reduction efficiencies of up to 75%, however in typical applications SNCR provides 30% to 50% NO_x reduction. SNCR is a proven technology that has been in commercial use on utility boilers, and therefore, is considered a feasible NO_x control technology and will be considered further in this BACT analysis.

Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls (such as SCNR) to increase the NO_x removal efficiency. New developments in LNB technologies have demonstrated substantial reductions in NO_x formation, however only limited data are available that demonstrate control potential approaching that of SCR systems. Combustion controls have been in commercial use on industrial and utility boilers and are considered a feasible NO_x control technology.

1.22 Top-Down Ranking

The NO_x control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 6 summarizes the control technology and ranking.

Table 6 – NO_x Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control NO_x emissions	Available and demonstrated effective^a	In service on similar systems	Technically feasible for Unit 2	% NO_x Reduction
SCR	Yes	Yes	Yes	Yes	up to 90%
SNCR	Yes	Yes	Yes	Yes	30-75%
Combustion Controls	Yes	Yes	Yes	Yes	30-75% ^b

^a Based on design and configuration of the Unit 2 Boiler.

^b Estimated control efficiency depends greatly on uncontrolled NO_x level and boiler design..

1.23 Proposed NO_x BACT Selection

The proposed NO_x BACT for Unit 2 is the use of SCR as a post-combustion technology to control NO_x emissions. Based on the above top-down ranking of control technologies, SCR provides the highest level of NO_x control and is therefore considered the “top” control technology. Because HU proposes to use the most effective NO_x control technology for the Unit 2 boiler, a cost analysis and further technology review has not been included in the BACT analysis. Table 3 lists the NO_x emission limitations proposed as BACT under typical operating ranges for the Unit 2 boiler. The emission limit of 0.08 lb/MMBtu is an aggressive limit based on the expected performance of an SCR system on a similar type and size of utility boiler burning PRB coal. Therefore, during the first 18 months following initial startup of Unit 2, the emission limit shall be 0.12 lb/MMBtu utilizing SCR. If, with good faith efforts in the operation of the

installed NO_x control equipment, and sufficient demonstration that other steam generating units of similar size and control equipment burning PRB subbituminous coal are unable to achieve the 0.08 lb/MMBtu emission rate, then the proposed BACT limit shall be subject to revision in coordination with the Department and EPA.

1.24 BACT Selection Review for NO_x

As described in Section 1.15, information concerning recently proposed or permitted coal-fired power projects was compared to show that the proposed NO_x BACT limit of 0.08 lb/MMBtu is consistent with the lowest NO_x level proposed and permitted at other facilities. Recent EPA Region VII permits of utility boilers burning PRB coal have contained conditions to allow the sources to operate up to 36 months (Hawthorne unit in Missouri) or 18 months (Holcomb 2 in Kansas) at a higher NO_x limit (0.12 lb/MMBtu) to evaluate and optimize the SCR control system.

1.30 CO BACT Analysis

The objective of this analysis is to determine BACT for CO emissions from the proposed Unit 2 Boiler. The rate of CO emissions from combustion sources is dependant upon the combustion efficiency of the source. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion can minimize CO emissions. Control of CO emissions can be achieved by application of combustion controls or by treatment of the flue gas after combustion. Often, measures used to minimize or control emissions of NO_x can result in incomplete combustion and increased CO emissions. Therefore, an acceptable compromise is necessary to achieve the lowest NO_x emission rate possible while still keeping CO emissions as low as possible.

CO Formation. CO formation occurs primarily through incomplete combustion. The oxidation of CO to carbon dioxide (CO₂) is dependent on temperature, residence time during the combustion process, and the amount of excess O₂ present. Since temperature and residence time are critical factors in formation of CO, smaller boilers often emit more CO than larger combustion units, because these units have less high-temperature residence time to achieve complete combustion.

1.31 Identification of CO Control Technologies

As stated previously, CO emissions can be controlled at the combustion source or post-combustion in the flue gas exhaust. The following technologies have been identified for control of CO emissions: catalytic oxidation, thermal oxidation, SCONO_x, and combustion controls. Catalytic oxidation, thermal oxidation, and SCONO_x are all post-combustion controls designed for the exhaust gas stream.

Catalytic Oxidation

There are a variety of manufacturers who offer oxidation catalysts to control CO emissions. The catalysts are a flue gas treatment technology with a typically honeycomb type of arrangement to allow the maximum surface area exposure to a given gas flow. CO catalysts are generally precious metal based. Catalytic oxidation has never been applied to a coal-fired unit. The use of an oxidation catalyst with sulfur-containing fuels can promote oxidation of SO₂ to SO₃, which can readily form H₂SO₄ in the presence of moisture. Oxidation catalysts also require a minimum temperature (>500 °F) for proper operation, which would necessitate that the catalyst be installed upstream of the FGD system and fabric filter. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of any oxidation catalyst. In addition, trace elements that are present in coal and resulting combustion gases, in particular chlorine, may foul an oxidation catalyst and dramatically reduce its

effectiveness. There are currently no known pulverized coal boilers that are equipped with oxidation catalysts, and for the reasons listed above, use of a catalytic oxidation system for the proposed pulverized coal-fired boilers is not considered technically feasible.

Thermal Oxidation

High temperature oxidation is another method for controlling emissions of CO in the flue gas. This type of system would be added at the exit of a baghouse, and has been reported to achieve up to 95% reduction of CO in the exhaust gas on other types of industrial facilities with much higher CO emissions and lower flow rates than the proposed Unit 2 boiler. Because a coal boiler is essentially a thermal oxidation device, adding this type of control would seem to be redundant. The application of thermal oxidation would require additional fuel usage, and would result in secondary emissions from that combustion. A review of the EPA's RACT/BACT/LAER Clearinghouse for pulverized coal boilers did not reveal any documentation of any facilities that have specified thermal oxidation as BACT. Therefore, thermal oxidation is not considered further as an option for the proposed PC boiler at WEC.

SCONO_x

SCONO_x technology utilizes the same principles as catalytic oxidation for CO control. The SCONO_x bed uses a coating of the same catalyst material as that in an oxidation catalyst, which is used primarily to oxidize NO to NO₂, but also oxidizes CO to CO₂. To date, there is very limited commercial application of SCONO_x and thus very little emissions data available for review. Due to the fact that SCONO_x technology is very similar to catalytic oxidation, all the technical limitations for that technology also apply to SCONO_x. The SCONO_x technology for CO control has not been installed on coal-fired boilers, and therefore this control is not considered technically feasible for the proposed application.

Combustion Controls

CO emissions primarily result from incomplete combustion. The oxidation of CO to CO₂ is dependent upon temperature and residence time of the combustion process. The use of good combustion practice (GCP) such as high combustion temperatures, adequate combustion air, and proper air/fuel mixing can minimize CO emissions. Proper design and operation of a pulverized coal-fired boiler effectively acts like a thermal oxidizer for control of CO emissions. Additionally, there are no incremental costs associated with GCP for CO controls. Therefore, GCP is considered a feasible control technology for CO emissions.

1.32 Proposed CO BACT Selection

Based on the CO control technologies presented above, good combustion practices (GCP) is the only remaining technology for this application and is the proposed CO BACT for the Unit 2 boiler. None of the other control technologies have been proposed or demonstrated for use on a pulverized coal-fired boiler. Table 3 lists the CO emission limitation proposed as BACT under typical operating ranges for the Unit 2 boiler.

1.33 BACT Selection Review for CO

Information was obtained concerning recently proposed for permitted coal-fired power projects within the past three years. In all cases, GCP has been determined as BACT for control of CO emissions from these sources. Additionally, the proposed CO permit limit (0.15 lb/MMBtu) is comparable with other recently

issued permitted and newly operating facilities such as Holcomb Unit #2 (0.15) and Hawthorn (0.16) facilities.

1.40 PM/PM₁₀ BACT Analysis

The objective of this analysis is to determine BACT for PM and PM₁₀ emissions (and any necessary visible emission standards) from the proposed Unit 2 boiler.

PM/PM₁₀ Formation. PM emissions from utility boilers are a function of the boiler burner configuration, operation practices, coal properties and pollution control equipment. Uncontrolled PM emissions include ash from the non-combustibles in coal as well as unburned carbon resulting from incomplete combustion. When combusting pulverized coal, such as proposed for Unit 2, PM emissions are primarily composed of inorganic ash residue because combustion is nearly complete, resulting in minimal unburned carbon from incomplete combustion. PM₁₀ emissions are classified as filterable and condensable. Filterable PM₁₀ is the portion of total PM₁₀ present in the exhaust stream as a solid or liquid, and which is typically measured on an EPA Method 5 filter (40 CFR 60, Appendix A). Condensable PM₁₀ is the portion of PM₁₀ that is initially present as a gas in the exhaust stream, but condenses to a liquid or solid state at cooler ambient temperatures.

1.41 Identification of PM Control Technologies

Control of PM/PM₁₀ emissions is achieved through the addition of equipment downstream of the combustion device. Three control technologies have been identified as alternatives for Unit 2: fabric filter baghouses, electrostatic precipitators (ESPs), and wet electrostatic precipitators (WESP). These technologies are considered to have the highest control efficiency of all particulate control options.

Fabric Filter Baghouse

Fabric filtration in a baghouse consists of a number of filtering bags that are suspended in a housing. The particulate-laden gas passes through the housing and collects on the fabric of the filter bag. Accumulated particulate matters on the bag surfaces enhance the bag's filtering efficiency. Periodically, the accumulated material or "cake" is removed from the bags through the use of a physical mechanism such as shaking or blasting the bags with compressed air. The dust is collected in a hopper and eventually removed. Fabric filtration has been widely used in coal combustion sources since the early 1970's and is considered a technically feasible control option for Unit 2.

Electrostatic Precipitator

Electrostatic precipitators (ESPs) remove PM from the flue gas stream using the principle of electrostatic attraction. PM in the exhaust stream is charged with a very high direct current (DC) voltage, and the charge particles are attracted to oppositely charged collection plates in the ESP. PM collected by the ESP continues to accumulate on the plates until removed by rapping the electrodes. The dust is then collected into a hopper for disposal. As opposed to baghouses, ESPs can handle large gas streams, high particulate loading and can operate at higher temperature and pressure conditions with wet or dry gas streams. However, the ESP is less effective at capturing fine particles than the baghouse. Very fine particles cannot carry a strong enough electrical charge to result in complete collection in an ESP. When using a dry flue gas desulfurization (FGD) system for SO₂ control, a much higher loading of fine particles is produced, making it more difficult to achieve acceptable control of particulate matter with an ESP as compared to a baghouse.

Wet Electrostatic Precipitator

Wet electrostatic precipitators (WESP) operate using the same principles as a standard ESP, but the final cleaning step is different. The collection surfaces are cleaned with water that can be delivered from spray nozzles or by condensing moisture from the flue gas. WESPs are effective in reduction of particle re-entrainment since the surfaces of the collection plates are constantly cleaned with liquid. WESPs also operate under higher electrical power than standard ESPs and enable higher reduction of very small particles. Operation of a WESP requires the collection and treatment and/or disposal of wastewater containing fly ash from the boiler.

1.42 Top-Down Ranking

The PM control technologies that are considered technically feasible for implementation on Unit 2 have been ranked from most to least effective in terms of emission reduction potential. Table 7 summarizes the control technology and ranking.

Table 7 – PM Control Technology Summary & Top-Down Ranking

Identified Control Technology	Potential to control PM emissions	Available and demonstrated effective	In service on similar systems	Technically feasible for Unit 2	% PM Reduction
Fabric Filter	Yes	Yes	Yes	Yes	99.9%
ESP	Yes	Yes	Yes	Yes	>99% ^a
Wet ESP	Yes	Yes	Yes	Yes	>99% ^a

^a Control efficiency varies for large and small particles and type of coal combusted.

1.43 Proposed PM/PM₁₀ BACT Selection

The proposed PM/PM₁₀ BACT for Unit 2 is use of a fabric filter baghouse. Based on the above top-down ranking of control technologies, fabric filters provide an equal or higher level of PM control in comparison to other technologies. Therefore, fabric filters are considered the “top” level of control. Additionally, the use of a baghouse does not have any significant adverse energy, environmental, or economic impacts. Because HU proposes to use the highest available level of PM control for Unit 2, a cost analysis and further technology review has not been included in this BACT analysis. Table 3 lists the PM emission limitation proposed as BACT under typical operating ranges for the Unit 2 Boiler.

Additionally, since the fabric filter baghouse will be controlling particulate emissions (the primary cause of opacity) down to permitted BACT levels, a separate visible emission standard is not necessary. In other words, BACT for visible emissions is the use of a fabric filter baghouse.

It is noted in the application that HU is planning to install an ESP upstream of the SDA system and baghouse, solely for recovering dry ash for sale. This ESP will not be considered part of the PM emission control system and will not increase or decrease the design efficiency of the proposed fabric filter for PM control.

BACT must also be considered for other PM/PM₁₀ emitters at WEC even though they represent only about 12.5% of the total PM₁₀ emissions combined. These include the cooling tower (210) and coal storage and handling emission points (201, 203-209). The required use of a high efficiency drift eliminator is considered BACT for the cooling tower. BACT for coal storage bins and coal handling is considered the use of fabric filter baghouses. Fugitives emissions from the haul roads and coal storage

pile have not been modified and experience no change in the method of operation, therefore BACT application is not required for these emission points. To minimize particulate emissions from these fugitive emission points, HU will utilize paved haul roads and maintain the existing use of dust suppressants and shrouded conveyor drop points at the coal storage pile.

1.44 BACT Selection Review for PM/PM₁₀

Fabric filter baghouses are the most common control of PM₁₀ from PC boilers and are listed as BACT for PM/PM₁₀ in a large number of the PC boiler applications. The proposed 0.018 lb/MMBtu limit for Unit 2 is comparable with other recently permitted and newly operating facilities such as Holcomb Unit #2 (Kansas) and Hawthorn (Missouri) facilities, both of which have a limit of 0.018 lb/MMBtu. Emission rate averaging time shall be based on the performance testing protocol submitted by HU and is averaged over the period of 3 test runs of at least 60 minutes in duration each.

1.50 Fluorides BACT Analysis

Fluoride Formation. Similar to SO₂, fluoride emissions are formed from coal combustion due to trace concentrations of fluoride-containing compounds in the fuel. Fluoride emissions are primarily in the form of hydrogen fluoride (HF, or hydrofluoric acid). HF is water soluble and is readily controlled by acid gas scrubbing systems.

1.51 Identification of Fluoride Control Technologies

Three control technologies have been identified for control of fluoride emissions from pulverized coal-fired boilers. They are SDA's in combination with an ESP, SDA's in combination with a baghouse, and caustic wet scrubbers. As stated previously, HF is very readily removed in the SDA reaction with the flue gas stream. In addition, fabric filters are considered to have higher residual acid gas removal efficiencies than ESPs. Thus, the SDA in combination with the baghouse is considered the top control option for control of fluorides from the Unit 2 boiler.

1.52 Proposed Fluoride BACT Selection

SDA in combination with a baghouse has been selected as the control option for SO₂ and is also considered the top control option for control of fluorides. The SDA system is expected to achieve HF control of at least 95%, yielding a maximum fluoride emission rate 0.0004 lb/MMBtu, based on the coal types to be burned. Averaging time will be based on the test method and protocol submitted by WEC and approved by the Department.

1.53 BACT Selection Review for Fluorides

A review of the RBLC database did not provide any information regarding controls and limits for fluorides for pulverized coal-fired boilers. The updated national coal power projects list from the EPA CATC website and the additional information obtained from the individual permitting authorities have shown that an SDA in combination with a fabric filter baghouse is the control option for most proposed and/or permitted pulverized coal units.

2.0 Air Quality Impact Analysis:

This air quality impact analysis for the proposed WEC Unit 2 modification consists of two components. The first component of the air quality analysis consists of a preliminary modeling analysis of all new

emission sources at the facility (WEC Unit 2 equipment, coal handling sources, wind erosion sources, and fugitive truck emissions), to determine if the emissions from the new sources would cause ambient pollutant concentrations in excess of 1) concentration thresholds above which preconstruction ambient air quality monitoring may be required, or 2) significant impact levels (SILs), which determine if further modeling is required on a pollutant-by-pollutant basis.

The second component of the analysis consists of a refined modeling analysis to demonstrate that the proposed facility will not cause or contribute to violations of applicable Ambient Air Quality Standards (AAQS) or PSD Increments for those pollutants with concentrations above the respective SILs. This analysis includes sources which contribute to baseline concentrations of each pollutant and sources which have been determined to consume available increment for each pollutant. This analysis was completed for CO, NO₂, PM₁₀, and SO₂.

Source Input Data

The stack parameters and emission rates for the emission points modeled can be found in the PSD application. In order to account for potential inconsistencies in the heating rate of coal combusted in the proposed Unit 2 boiler, as well as potential plant efficiency degradation over time, all dispersion modeling runs were performed at 5% over the 2,210.5 MMBtu/hr Unit 2 boiler rating (105%). This 5% increase affected emission rates of all modeled pollutants and exhaust gas flow from the Unit 2 boiler stack.

PSD increment-consuming sources, major or minor, within 50 km of the proposed facility were included in the PM₁₀ and SO₂ refined analyses.

2.10 Preliminary Analysis for Significant Impacts

The purpose of the preliminary dispersion modeling analysis was to determine if emissions from operation of Unit 2 and associated new emission sources would cause ambient pollutant concentrations in excess of concentration thresholds above which pre-application ambient air quality monitoring may be required. In addition, the results were reviewed to determine if a SIL would be exceeded for any pollutant. The latest version of the EPA Industrial Source Complex Short-Term dispersion model (ISCST3, Version 02035) was used for this analysis.

The meteorological data used for this analysis consisted of five years (1985-1986, 1989-1991) of National Weather Service surface data from Grand Island, Nebraska (station number 14935) and mixing height data for North Platte, Nebraska (station number 24023).

Table 8 shows the results of the SIL and pre-application ambient monitoring threshold analysis. The results indicate that the operation of the facility will not cause a significant impact in the area surrounding the proposed WEC for the 1-hour or 8-hour averaging periods for CO, nor for the annual averaging period for SO₂ or NO₂. PM₁₀ and short-term SO₂ concentrations (3-hr and 24-hr) exceed the SIL, therefore these two pollutants were further evaluated in this refined modeling analysis.

Table 8 - Maximum Modeled WEC Unit 2 Concentrations, Significant Impact Levels, and Pre-application Monitoring Thresholds

Pollutant	Averaging Period	Modeled Concentration (ug/m³)	SIL (ug/m³)	Pre-application Monitoring Threshold Concentration (ug/m³)
CO	1-hr	147.4	2,000	NA

	8-hr	23.4	500	575
SO ₂	Annual	0.2	1.0	NA
	24-hr	17.8	5.0	13
	3-hr	208.0	25.0	NA
PM ₁₀	Annual	2.5	1.0	NA
	24-hr	13.5	5.0	10
NO ₂	Annual	0.9	1.0	14

The 24-hr SO₂ and PM₁₀ impacts also exceed the *Pre-application Ambient Monitoring Thresholds*. This means that the source could have been required to conduct ambient air monitoring prior to submitting their PSD application in accordance with 40 CFR 52.21(m). However, The Department has approved a waiver of the pre-construction ambient air monitoring requirements for PM₁₀ and SO₂, based on availability of representative monitoring data for SO₂ (2001 Omaha data) and availability of representative monitoring data for PM₁₀ (1996 Hastings data). It should be noted that, due to the age of the representative data for PM₁₀, one year of monitoring is required by the Department prior to the start of major construction activities to verify the 1996 ambient concentrations are still representative of the Hastings area.

2.20 Refined Modeling Analysis for NAAQS and PSD Increment Compliance

The purpose of the final refined modeling analysis was to demonstrate that the proposed facility will not cause or contribute to violations of applicable NAAQS or PSD Increments for PM₁₀ and SO₂ (3 & 24-hour only). The AAQS and PSD increments are shown in Table 9. The Nebraska and National AAQS and PSD increments are identical.

**Table 9 - Nebraska and National Ambient Air Quality Standards and PSD Increments
For PM₁₀ and SO₂ ^a**

Pollutant	Averaging Period	Ambient Air Quality Standards		PSD Class II Increments	
		National	Nebraska	National	Nebraska
PM ₁₀	24-hour ^b	150	150	30	30
	Annual	50	50	17	17
SO ₂	3-hour ^b	1,300	1,300	512	512
	24-hour ^b	365	365	91	91

^a All standards and increments are in units of $\mu\text{g}/\text{m}^3$.

^b Concentration or increment is allowed to be exceeded once per year at a single receptor. A second exceedence of the standard or increment constitutes a violation of the standard.

This ambient air quality impact analysis takes into account the combined impacts of emissions from the existing and proposed WEC sources, contributions from nearby major and minor sources, and background concentrations due to distant major and minor sources and natural sources. Based on the potential emissions from WEC and other sources' estimated and allowable emissions, this analysis demonstrates facility compliance with AAQS and PSD Increments for PM₁₀ and SO₂.

2.21 PM₁₀ Results

The PM₁₀ results for PSD Class II Increment consumption and NAAQS compliance demonstration are described below.

PSD Increment

The ISCST3 model output files for the PM₁₀ increment consumption analysis indicate that the total PM₁₀ concentrations for both the 24-hour and annual periods would exceed the PSD allowable concentration increments near the Chief Ethanol facility located northwest of WEC. Chief Ethanol is the nearest PSD increment consuming source modeled.

Annual PM₁₀ Increment Analysis

To make a demonstration of compliance for the annual PM₁₀ increment analysis, the ISCST3 model was executed with source groups for all increment-consuming sources (PSD source group) and for all WEC Unit 2 project sources. These plots were submitted by the source and show that the annual PM₁₀ significant impact area (1 ug/m³ SIL) for the project is limited to areas very near the WEC fence line, and does not overlap areas (near Chief Ethanol) where the PSD annual PM₁₀ increment is modeled as being exceeded. Because operation of WEC Unit 2 will not significantly contribute to any exceedence of the PM₁₀ annual PSD increment, the project complies with this standard.

24-Hour PM₁₀ Increment Analysis

The 24-hour SIL contour for WEC Unit 2 project sources was compared against the total 24-hour PM₁₀ increment consumption for each year of meteorology. These plots show that for some years of meteorology, there is overlap between the SIL contour (5 ug/m³) and the 30 ug/m³ contour representing the allowable increment. For other years of meteorology, the contours come very close to overlapping.

To complete the compliance determination for the 24-hour PM₁₀ increment, it was necessary to determine whether, for any time and location where total concentrations exceeded 30 ug/m³, the WEC Unit 2 project sources would also exceed the SIL of 5 ug/m³. Analysis results indicated that there were no times or locations where the proposed WEC Unit 2 project sources contributed significantly to an exceedence of the PSD 24-hour allowable PSD increment of 30 ug/m³.

Ambient Air Quality

The ISCST3 model output files for the PM₁₀ analysis also indicate that the total PM₁₀ concentrations for both the 24-hour and annual periods, including contributions from background concentrations, would exceed the national and state AAQS near the Chief Ethanol facility.

Annual PM₁₀ Ambient Air Quality Analysis

The background concentration (25 ug/m³) was subtracted from the annual NAAQS (50 ug/m³) to determine the modeled concentration level of 25 ug/m³ that would cause a predicted exceedence of the standard. The annual PM₁₀ significant impact area (1 ug/m³) for the project is limited to areas very near the WEC fence line, and does not overlap areas where the model predicts an exceedence of the annual ambient air quality standard. The modeling demonstrates that WEC Unit 2 will not significantly contribute to any violation of the annual ambient air quality standard in any area where the standard is predicted to be exceeded. Therefore, the proposed WEC Unit 2 project will comply with the standard.

24-Hour PM₁₀ Ambient Air Quality Analysis

For the 24-hour PM₁₀ ambient air quality analysis, a similar approach was used as with the annual ambient air quality analysis. The background concentration (60 ug/m³) was subtracted from the 24-hour AAQS to determine the concentration (90 ug/m³) level that would just equal standard. The 24-hour PM₁₀ significant impact area (5 ug/m³) for the project is limited to areas very near the WEC fence line, and does not overlap areas where the 24-hour ambient air quality standard is predicted to be exceeded. The modeling demonstrates that WEC Unit 2 will not significantly contribute to any violation of the 24-hour ambient air quality standard in any area where the standard is exceeded. Therefore, the proposed WEC Unit 2 project will comply with the 24-hour AAQS.

2.22 SO₂ Results

The SO₂ results for PSD Class II Increment consumption and NAAQS compliance demonstration are described below. For the SO₂ analysis, a "maintenance" scenario was evaluated for the 3-hour and 24-hour averaging periods. This analysis used an emission rate equivalent to 1.1 lb/MMBtu to account for brief periods (usually 3 hours or less) when the FGD system atomizer needs to be replaced. The normal schedule for changeout (with a spare) and replacement of the atomizer is once every 3-4 months. When the atomizer is out of operation, the SO₂ emissions from Unit 2 would be uncontrolled. A separate long-term scenario was performed for annual average concentrations of SO₂ evaluated in the SIL analysis. This analysis used an emission rate equivalent to the proposed BACT limit of 0.12 lb/MMBtu.

PSD Increment

The results of the SO₂ increment consumption analysis indicate that the operation of WEC Unit 2 will not cause an exceedence of the 3-hour allowable PSD increment but did show an exceedence of the 24-hour increment northwest of WEC. To complete the compliance determination for the 24-hour SO₂ increment, it was necessary to determine whether, for any time and location where total concentrations exceeded 91 ug/m³, the WEC Unit 2 project sources would also exceed the SIL of 5 ug/m³. Analysis results indicated that there were no times or locations where the proposed WEC Unit 2 project sources contributed significantly to an exceedence of the PSD 24-hour allowable increment of 91 ug/m³. Results of the PSD SO₂ increment consumption analysis are summarized in Table 10.

Table 10 - Maximum Predicted SO₂ Increment Consumption From All Sources

Averaging Period	Year	UTM Coordinates (m)		H2H Increment Consumption ^a (ug/m ³)	Allowable PSD Increment (ug/m ³)
		X	Y		
3-hour	1985	555,685	4,493,452	381.8	512
	1986	555,685	4,493,452	392.3	
	1989	555,685	4,493,452	467.7	
	1990	556,046	4,493,279	502.4	
	1991	556,045	4,493,401	461.6	
24-hour	1985	555,685	4,493,452	135.4	91
	1986	555,685	4,493,452	157.6	
	1989	555,685	4,493,452	146.6	
	1990	556,046	4,493,279	141.7	
	1991	556,045	4,493,401	158.1	

^a Value shown is highest-second-high (H2H) concentration, since one exceedence of the short-term standard is allowed per year.

Ambient Air Quality

The SO₂ results for AAQS compliance are shown in Table 11 for 24-hour and 3-hour concentrations, including contributions from existing sources of SO₂ emissions in the project area. As shown in the Table, the 24-hour and 3-hour concentrations are predicted to be below the ambient standards.

Table 11 – Maximum Predicted Ambient SO₂ Concentrations

Averaging Period	Year	UTM Coordinates (m)		Background (µg/m ³)	Modeled (µg/m ³)	Total (µg/m ³)	AAQS (µg/m ³)
		X	Y				
3-hour	1985	556,045	4,493,622	120	448.7	568.7	1,300
	1986	556,045	4,493,622		402.5	522.5	
	1989	556,045	4,493,352		467.7	587.7	
	1990	556,045	4,493,426		502.4	622.4	
	1991	556,045	4,493,598		465.5	585.5	
24-hour	1985	555,685	4,493,452	48	124.5	183.4	365
	1986	555,685	4,493,452		121.9	205.6	
	1989	555,685	4,493,452		110.3	194.6	
	1990	556,046	4,493,279		132.1	189.7	
	1991	556,045	4,493,401		110.9	212.1	

NOTE: The values shown for the 3-hour and 24-hour averaging periods are the highest second high results, since one exceedence of the short term standard is allowed per year at each location.

2.30 Air Quality Impact Summary

The analyses described above demonstrate that the addition of WEC Unit 2 will not significantly contribute to any exceedence of the 24-hour or annual allowable PM₁₀ PSD increments or AAQS for any episode. The analysis also demonstrates that the addition of WEC Unit 2 will comply with all applicable SO₂ AAQS and PSD increments and will not have a significant impact on NO₂ annual, CO 1-hour or 8-hour, or SO₂ annual concentrations.

3.00 Additional Impacts Analysis

An Additional Impacts Analysis, as required by 40 CFR 52.21(o), describes air quality and related impacts due to associated growth and construction, as well as potential impacts of atmospheric emissions on soils, vegetation, and visibility impairment. This analysis was provided in the PSD application and indicates no adverse impacts.

Visibility Impacts

A plume visibility screen modeling analysis was performed for this project. Because the nearest Federal Class I areas are several hundred kilometers away from the proposed facility site, the potential impacts at one area, Mormon Island State Recreation Area located approximately 28 km (17 mi) NNW of WEC was evaluated.

The particulate matter emission rate input to the VISCREEN model was a conservative maximum (based on the design 100% heat input rate plus a 5% margin) PM₁₀ emission rate (filterable plus condensable PM) from

WEC Unit 2. PM₁₀ emissions were used rather than TSP based on the assumption that the larger particles found in TSP would fall out well before the plume reached either area of question. The finer particles, which make up PM₁₀, are responsible for visual impairment beyond the immediate vicinity of an emission source. As with PM₁₀, the NO_x emission rate input to VISCREEN was a conservative maximum (based on the design 100% heat input rate plus a 5% margin, 0.12 lb/MMBtu) NO_x emission rate. The results show the model screening thresholds are exceeded in terms of the "Delta E" coefficient for sky inside the State Recreation Area, and for sky and terrain outside the State Recreation Area. Delta E is a measure of perceived magnitude of color or brightness changes. However, because the VISCREEN results are known to be very conservative, it is concluded that plumes of air pollutants from WEC Unit 2 will not be visible from the Mormon Island State Recreation Area. The PSD Application submitted by the source includes more details to support this conclusion.

Because WEC Unit 2 will emit a plumes containing moisture, both from combustion products and from water added in the FGD system, it is expected that the new stack will occasionally have a visible moisture plume, especially on cold days. Given the very flat terrain in the area, the moisture plume may, in fact, be visible in the distance to an observer at the Mormon Island State Recreation Area. However, such moisture plumes would occupy only a tiny fraction of the observer's horizon, and thus are not considered an adverse visible impact.

As documented in the PSD Application, impacts of the proposed project on soils, vegetation, and visibility from atmospheric emissions are expected to be negligible.

4.00 Air Quality Monitoring

The Department received a request from HU to waive all pre-application monitoring requirements. Pre-application monitoring is required under the PSD regulations in 40 CFR 52.21(m)(1) for those modifications at a source that are anticipated to produce ambient concentrations equal to or greater than thresholds indicated in 40 CFR 52.21(i)(8)(i). WEC's preliminary dispersion modeling analysis demonstrates that the potential ambient impacts exceed the monitoring thresholds for SO₂ and PM₁₀.

The Department issued a letter on December 27, 2002, waiving pre-application monitoring for SO₂ and PM₁₀, but concluded that some form of monitoring for PM₁₀ shall be included in the PSD permit to verify the default PM₁₀ background concentrations used in the modeling analysis.

Based upon the analysis of HU's waiver request, pre-application monitoring could have been required for PM₁₀. However, the Department feels that the 1996 Hastings data still represents a conservative background value in the Hastings area and monitoring prior to permit application is not necessary and may impact the applicant's schedule. Instead, the source will be required to conduct and submit a full years worth of ambient air monitoring data prior to beginning major construction of the Unit 2 boiler. This monitoring requirement will still give the Department necessary information to calculate background PM₁₀ concentrations. If necessary, the Department may require the source to re-model the facility and revise or add any permit requirements in order to comply with the NAAQS in areas where the revised modeling results show significant impacts or violations. In addition, it will be the intent of the Department to also review other nearby sources that have Operating Permits (i.e. Chief Ethanol, AGP) to seek overall compliance with any modeled NAAQS violations.

Ambient air monitoring is deemed to be beneficial for both the Department and for HU. Monitoring will enable HU to construct the electrical generating unit without obtaining and submitting a full year's worth of ambient data to the Department prior to submitting their PSD application. This monitoring is also deemed to be more beneficial for analyzing the ambient air concentrations in the environment and will

allow more data to be collected to better understand the ambient concentration profile near Hastings, Nebraska.

Meteorological monitoring shall also be required as part of the ambient air monitoring requirements and will be conducted simultaneously with PM₁₀ monitoring. Meteorological measurements shall be consistent with the PSD monitoring guidance and with other applicable EPA monitoring guidance documents. The meteorological station may be used as a representative station of the Hastings area for future air quality modeling analyses. The combination of hourly meteorological data and hourly PM₁₀ concentrations will enable the Department to improve the estimate of PM₁₀ background levels.

The construction permit shall include the monitoring requirements and will detail when monitoring plans are to be submitted for review, when monitoring plans are to be finalized, and when monitoring activities are to commence.

B. New Source Performance Standards (NSPS):

Federal NSPS found in 40 CFR 60 have been adopted by reference within Title 129, Chapter 18. In addition to Subpart A, General Provision, the Unit 2 boiler is subject to opacity and emission limitations for NO_x, SO₂ and PM found in Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The auxiliary boiler is subject to emission limitations for SO₂ and PM found in Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The new coal conveying system is subject to the opacity limitation found in Subpart Y, Standards of Performance for Coal Preparation Plants.

Unit 2 Boiler

As stated in Subpart Da, 40 CFR 60.44a(d)(1), no new source owner or operator shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997 any gases which contain nitrogen oxides (expressed as NO₂) in excess of 200 nanograms per joule (ng/J) (1.6 lbs/MW-hr) gross energy output, based on a 30-day rolling average. The maximum rated gross energy output of Unit 2 is proposed to be 251 MW, based on the average annual wet bulb temperature. Therefore the applicable NSPS NO_x emission limitation based on annual average ambient temperature conditions will be:

$$(1.6 \text{ lbs/MW-hr}) \times (251 \text{ MW}) = 401.6 \text{ lb/hr (0.18 lb/MMBtu)}.$$

Additionally, per 40 CFR 60.42a(a)(1) and (2), no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain PM in excess of 13 ng/J (0.03 lb/MMBtu) and 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel. The proposed baghouse will easily remove over 99% of the PM generated by the combustion process, and the proposed PM limit of 0.018 lb/MMBtu is less than the NSPS limit of 0.03 lb/MMBtu. The opacity is limited to 20% and the source must install a Continuous Opacity Monitoring System (COMS) or other approved method per 40 CFR 60.47a(a). Upstream monitoring of PM emissions is not required (in order to calculate control efficiency) per 40 CFR 60.46a(a).

Finally, as stated in 40 CFR 60.43a(a)(2), no owner or operator shall cause to be discharged into the atmosphere from any affected facility, which combusts solid fuel, gases which contain SO₂ in excess of 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input. These limits apply on a 30-day rolling average. The proposed

spray dryer absorber (SDA) system will remove at least 90% of the SO₂ from the design maximum sulfur coal (maximum sulfur of 1.2 lb/MMBtu), and will have outlet emissions of no more than 0.12 lb/MMBtu on a 30-day rolling average basis. Monitoring is required at both the inlet and outlet of the SDA system per 40 CFR 60.47a(b)(1) or as allowed under 40 CFR 60.47a(b)(3).

The following table summarizes the NSPS Subpart Da limitations applicable to the proposed Unit 2.

Table 12 - NSPS Subpart Da Emission Limitations Applicable to Unit 2^a

Pollutant	% Reduction Requirement	NSPS Limit lb/MMBtu	Limit lb/hr	Permitted lb/MMBtu
NO _x	Not applicable	0.18	401.6	0.08
PM	99%	0.03	66.3	0.018
SO ₂	70%	0.36	802.4	0.12

^a The above listed NSPS emission limitations are provided for reference only and will be superseded by more stringent BACT limitations for each of the listed pollutants. (See Section 4.0 of this application)

A Continuous Emissions Monitoring System (CEMS) must be installed to measure NO₂, SO₂, and CO₂ (or O₂) per 40 CFR 60.47a. The Acid Rain rules also require the installation and operation of a CEMS.

Auxiliary Boiler

In addition to the standard NSPS initial notification and general reporting requirements found in Subpart A, the auxiliary Boiler has the following requirements from Subpart Dc pertaining to PM and SO₂ emissions:

Particulate Matter: The NSPS limits opacity to no more than 20 percent, except for one 6-minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.43c(c). An initial performance test is required in order to determine compliance with the opacity limit.

Fuel Sulfur: The fuel combusted in the auxiliary boiler shall not contain greater than 0.5 percent sulfur by weight pursuant to 40 CFR 60.42c(d). WEC proposes to limit their fuel oil to 0.05% sulfur. Fuel supplier certifications will be used to comply with this requirement per 40 CFR 60.42c(h).

Coal Handling

The new coal conveying system is subject to Subpart Y since it is considered an affected facility that commenced construction or modification after October 24, 1974. The only applicable requirement is that exhaust gases are limited to less than 20% opacity. The use of baghouses 201 and 203 on the coal system will ensure compliance with this requirement.

C. National Emissions Standards for Hazardous Air Pollutants (NESHAPs):

NESHAPs are the regulations that contain the Maximum Achievable Control Technology (MACT) standards, and their associated compliance and reporting requirements. They are listed under 40 CFR 63.

On December 14, 2000, the EPA announced that coal and oil-fired electric utility steam generating units would be added to the list of source categories under which a MACT standard will be developed.

Prior to the announcement that coal and oil fired electric utility steam generating units would be added to the list of source categories under Section 112(c), electric utility steam generating units were specifically

exempted from case-by-case analysis of new, modified or reconstructed major sources of HAPs under Section 112(g) of the CAA (otherwise known as a case-by-case MACT analysis). However, because the source category has been added to the list, new major coal or oil fired electric utility steam generating units are subject to the requirements under 112(g). The Utility Boiler MACT (Subpart UUUUU) proposal was signed by EPA on December 15, 2003 and was published in the Federal Register on January 30, 2004. The proposed standard, if promulgated, would limit mercury emissions from the Unit 2 boiler to 20×10^{-6} lb/MWh (mega-watt hours), or approximately 1.9 lb per trillion Btu (lb/TBtu). In comparison, the potential mercury emission rate for the Unit 2 boiler is approximately 8.6 lb/TBtu. An alternate scenario to limit mercury emissions from utility boilers was simultaneously proposed by EPA under NSPS program (40 CFR 60, Subpart Da). The mercury emission limit for new units is the same as proposed under the MACT proposal, but includes a "cap-and-trade" provision so a source may purchase "allowances" if necessary if they cannot (or choose not to) meet the emission limit. The NSPS cap-and-trade option is proposed as 40 CFR 60, Subpart HHHH.

Under 40 CFR Part 63.40, the applicability of 112(g) is identified. The requirements of 112(g) apply to any owner or operator who constructs a major source of HAPs (greater than 10/25 tpy) after June 29, 1998, the effective date of 112(g). Unit 2 will be a new utility boiler proposed at an existing facility. Thus, from 40 CFR Part 63.41, the definition of *construct a major source* means "to fabricate, erect, or install at any developed site a new process or production unit which in and of itself has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP...". The potential, controlled emissions of HAPs for the proposed WEC Unit 2 are below the major source thresholds. Therefore, the addition of WEC Unit 2 is not subject to a case-by-case MACT analysis under 112(g). Initial performance testing is required for HCl (the largest single HAP) and HF to verify the control device can achieve the minimum control efficiency indicated. If minimum control is not obtained, additional limits may need to be added to the permit and/or the source will be required to do a case-by-case MACT analysis.

Assuming that the total WEC facility (including Units 1 and 2) is a major source of HAPs when the coal and oil fired electric utility steam generating unit MACT is promulgated (expected to be in December 2004) Units 1 and 2 will be subject to the emission standards under the NESHAP. In addition, the MACT for industrial, institutional, and commercial boilers (Subpart DDDDD) proposed January 13, 2003, may require additional emission limits or controls on the existing and new auxiliary boiler.

Since no chromium-based water treatment chemicals shall be used in the circulating water system of the cooling towers, 40 CFR 63, Subpart Q will not apply.

D. Acid Rain Program:

The proposed Unit 2 will be considered an affected unit for purposes of the acid rain rule because it is a utility unit that will generate more than 25 MW of electricity. The acid rain rule requires a facility to monitor opacity, and all sulfur dioxide, nitrogen oxides, and carbon dioxide emissions for each affected unit. Therefore, WEC will implement the applicable monitoring requirements of 40 CFR 75, Continuous Emission Monitoring. The proposed Unit 2 will also be subject to a requirement to submit an Acid Rain permit application per 40 CFR 72, to meet the SO₂ allowance requirements of 40 CFR 73, and to meet the NO_x emission limitations of 40 CFR 76. Note that the 40 CFR 76 NO_x limits are far less stringent than the applicable NSPS NO_x limit and the proposed BACT NO_x limit.

E. Chemical Accident Prevention (40 CFR 68):

The proposed WEC Unit 2 is expected to require anhydrous ammonia storage (for the SCR system) of approximately 60,000 pounds. This will require the facility to prepare and file a Risk Management Plan (RMP) under Chemical Accident Prevention rules (40 CFR 68), prior to bringing a threshold quantity of ammonia (10,000 pounds) on site.

The proposed water disinfection is expected to be done using sodium hypochlorite which would not require an RMP. However, if chlorine is used and a storage volume of over 2,500 pounds is required, the RMP will also include chlorine.

F. Additional Title 129 Regulations:

Chapter 20 – Particulate Matter Emissions: The source will comply with the emission limits for material handling in Section 001 since all emission points are required to operate with a baghouse. Limits for fuel combustion in Section 002 will be met with the required use of a baghouse on Unit 2 boiler and the use of distillate fuel oil for the auxiliary boiler, emergency generator, and fire pump.

Chapter 24 – Sulfur Compound Emissions: The source will comply with the emission limit for equipment that burns fossil fuels since it combusts only low-sulfur PRB coal and utilizes a SDA system for SO_x removal. The required use of distillate fuel oil with a maximum sulfur content of 0.05% in the auxiliary boiler, emergency generator, and fire pump will ensure compliance for these emission units.

Chapter 27 – Hazardous Air Pollutants: Since the net increase in potential to emit of any single HAP (HCl and HF) and total HAP is greater than the 2.5/10 tpy thresholds listed in Section 002, toxic BACT must be applied to the Unit 2 boiler. The proposed SDA system and baghouse on the Unit 2 boiler will control HAPs by up to 95%, and is considered BACT in accordance with Chapter 27.

Specific terms and conditions of this permit (Condition XIII.) are discussed as follows:

- (A) This condition specifies the emissions-related equipment that is allowed to be installed under this construction permit. Per Title 129, Chapters 17 and 19, HU is required to obtain a construction permit from the Department.
- (B) Operational and Fuel Limitations:
 - (1) Places fuel and operation limitations on existing WEC Unit 1 equipment and WEC Unit 2. Dispersion modeling and BACT decisions were based on these requirements. Although not necessary for modeling purposes or NSPS, HU requested to be limited to low sulfur (0.05%) distillate oil in ancillary equipment.
 - (2) High efficiency mist (drift) eliminators are required as BACT on the new cooling tower, and must be installed on the existing cooling tower serving Unit 1 based on dispersion modeling. This will help limit PM₁₀ emissions from the cooling towers and ensure compliance with Title 129, Chapter 20.
 - (3) This is the standard permit language for the proper operation of baghouses.

- (4) This condition requires the source to have a broken bag detector on the Unit 2 baghouse. Broken bag detectors provide additional monitoring to verify proper operation of the baghouse in accordance with BACT.
 - (5) Modeling was conducted for the haul roads assuming they were paved. In order to validate the modeling input data, the source is required to pave the haul roads associated with lime and ash transportation. The PM₁₀ modeling is not accurate if these roads are not paved. Ash and lime trucks enter the property at the south side of the property.
- (C) Stack Dimensions: This condition specifies the stack height and stack cross-section dimensions, upon which the dispersion modeling analysis is based. If any stack exit point dimensions differ from the information used in modeling for the basis of this permit (Table 3), the permittee shall provide a discussion of the discrepancy with respect to modeling issues and submit justification as to why the modeling analysis remains valid with supporting conclusions, or submit revised modeling based on the as-build stack parameters. The Department may require that the project be remodeled to demonstrate compliance with 40 CFR 52.21(k).
- (D) Emission limitations
- (1) This condition specifies the numerical emission limitations for equipment approved under this permit. The regulatory basis for emission limits on Emission Point (EP) 101 and the 3-hr SO₂ limit on EP 202 is Chapter 4. Chapter 19 provides the basis for the emission limits on EP 202 show in Table 3 and for EP 201, 203-209. Chapter 27 provides the basis for the emission limits on H₂SO₄ and HCl for EP 202.
 - (2) Provides an 18-month period of time to demonstrate compliance with the NO_x limit in Table 4. The ability of an SCR system to remove NO_x down to 0.08 lb/MMBtu from a utility boiler burning PRB coal has not been consistently achieved in practice. For this reason, the source is given a “demonstration period” to allow for “tuning” of the SCR system after Unit 2 boiler startup. This condition requires up-front system planning, operation, and recordkeeping and allows for revision of the emission limit if necessary based on operational data from this and other similar boilers/SCR systems. The source may petition the Department for a longer period of time if the source is unable to operate the boiler or SCR system for extended periods of time due to startup-related malfunctions or breakdowns.
 - (3) Outlines the statewide opacity emissions limit (less than 20% opacity) provided under Title 129, Chapter 20, Section 004. Note that this limit is more stringent than the opacity limits specific to the WEC Unit 2 main and auxiliary boilers from 40 CFR 60, Subpart Da and Dc. Chapter 20, Section 006 exempts units from Section 004 if they are subject to other opacity standards such as an NSPS. Emission points 201 & 202 are subject to Subpart Y (NSPS), but they are not specifically excluded from the Chapter 20 opacity requirement because the NSPS opacity limit is the same as the Chapter 20 limit.
 - (4) Startup and shutdown requirements in accordance with Chapter 35.
- (E) Notifications: reflects the NSPS requirements per 40 CFR 60, Subpart A (General Provisions) and as referenced by Title 129, Chapter 18, Section 001.01
- (F) Testing Requirements
- (1) Table 5 lists the initial performance testing that is required to demonstrate compliance with various state and federal regulations. If approved by EPA the CEMS may be used after certification to demonstrate compliance with the NO_x and SO₂ BACT limits. Performance testing shall be done at 100% load unless otherwise approved by the Department.

- (2)-(6) This requirement lists the testing schedules and procedures necessary to satisfy the testing requirements of Condition XIII.(F). Applicable testing requirements include 40 CFR 60.48a, 60.45c, and 40 CFR 60.8.
- (G) Monitoring Requirements
- (1) Lists the CEMS requirements for the Unit 2 boiler. The monitoring system shall be used for measuring and demonstrating compliance with the SO₂, NO_x and CO emission limitations and opacity listed in Condition XIII.(D)(1), and to meet Acid Rain monitoring requirements. The source has agreed to use the CO CEMS for continuous compliance demonstration of the CO emission limit instead of periodic CO testing.
- (2) Ambient air monitoring of PM₁₀ is deemed necessary by the Department to validate the PM₁₀ background concentrations used in the dispersion modeling analysis. Paragraph (2)(e) allows the Department to require continued ambient air monitoring if, for example, significantly higher or lower than expected readings are obtained.
- (H) Reporting
- (1) This condition lists the required reporting with respect the planning and progress of the SCR system for NO_x emissions control.
- (2)-(4) Lists reporting requirements applicable to the facility under 40 CFR 60.7, 60.49a, 60.48c and 40 CFR 75. The reporting requirements include reports of excess emissions, malfunctions, and miscellaneous permit-related correspondence.
- (I) Recordkeeping: Conditions (1) through (4) list recordkeeping requirements. These records shall be readily accessible to state and/or EPA inspectors to review compliance status of the facility. These records must be kept on file at the site for a minimum of five years from the date of the record.
- (J) Acid Rain Requirements: states that the facility shall comply with applicable portions of the Acid Rain Program

STATUTORY OR REGULATORY PROVISIONS ON WHICH PERMIT REQUIREMENTS ARE BASED:

Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended February 7, 2004.

PROCEDURES FOR FINAL DETERMINATION WITH RESPECT TO THE PROPOSED CONSTRUCTION PERMIT:

The public notice, as required under NAQR Chapter 14, shall be published on August 12, 2003. Persons or groups shall have 30 days from that issuance of public notice (September 11, 2003) to provide the NDEQ with any written comments concerning the proposed permit action and/or to request a public hearing, in accordance with NAQR Chapter 14. If a public hearing is granted by the Director, there will be a notice of that meeting published at least 30 days prior to the hearing. Persons having comments or requesting a public hearing may contact:

W. Clark Smith-Permitting Section Supervisor
Air Quality Division
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

If no public hearing is requested, the permit may be granted at the close of the 30-day comment period. If a public hearing is requested, the Director of the NDEQ may choose to extend the date on which the permit is to be granted until after that public hearing has been held. During the 30-day comment period, persons requiring further information should contact:

Bradley W. Reid, P.E.
Air Quality Division-Permitting Section
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

Telephone inquiries may be made at:

(402) 471-2189

TDD users please call 711 and ask the relay operator to call us at (402) 471-2186.