ILLINOIS POLLUTION CONTROL BOARD
April 21, 1988

IN THE MATTER OF:	)	
	)	
AMENDMENTS TO 35 ILL.	)	
ADM. CODE 214,	)	R86-30
SULFUR LIMITATIONS	)	
	)	

PROPOSED RULE. FIRST NOTICE.

PROPOSED OPINION AND ORDER OF THE BOARD (by J. Theodore Meyer):

This matter is before the Board on a joint proposal for regulatory amendment filed by the Illinois Environmental Protection Agency (Agency) and Shell Oil Company (Shell) on July 7, 1986. The joint proposal seeks to amend 35 Ill. Adm. Code 214, which regulates sulfur emissions from stationary sources. The proposal is designed to tighten emissions from Shell's Wood River Manufacturing Complex (WRMC) so as to ensure the attainment and maintenance of National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2) for the Wood River area.

A merit hearing on the proposal was held on October 30, 1986 in Wood River, Illinois. On February 26, 1987 the Department of Energy and Natural Resources (DENR) filed a negative declaration, setting forth its determination that the preparation of a formal economic impact study is not necessary in this proceeding. The negative declaration was based upon DENR's findings that the economic impact of the regulation is favorable and that the costs of compliance are small or are borne entirely by the proponent of the regulation. On March 4, 1987, the Board received notification that the Economic and Technical Advisory Committee (ETAC) concurred in DENR's negative declaration. The Hearing Officer subsequently directed that the record be closed on April 30, 1987. However, on that date the Agency filled a motion for extension of time to present additional evidence. The basis of the Agency's request was its notification by the United States Environmental Protection Agency (USEPA) that additional technical work needed to be done for the rule to be federally approvable as a part of the State Implementation Plan (SIP) for SO_2. The Hearing Officer granted the Agency's motion, and ordered that the record be kept open indefinitely.

The necessary technical work was completed in late 1987, and the final hearing was held on January 22, 1988 in Chicago. At that hearing, the Agency and Shell submitted a revised proposal (Ex. 9) and presented testimony in support of the revisions. DENR has indicated that it feels that its February 1987 negative declaration is still appropriate.

BACKGROUND

The purpose behind the joint proposal is to remedy the inadequacy in the Illinois SIP for SO_2. On September 28, 1984, USEPA notified Governor Thompson that it found the SIP substantially inadequate to achieve the NAAQS for SO_2 in the Alton and Wood River areas of Madison County, Illinois. The SIP deficiency notice was made pursuant to Section 110(a)(2)(H) of the Clean Air Act, 42 U.S.C. 7410(a)(2)(H). USEPA called for Illinois to submit a curative SIP revision or be subject to sanctions under the Clean Air Act. Because Shell's allowable emissions contribute significantly to the modeled nonattainment in the Alton-Wood River area, Shell and the Agency worked together to develop a proposal to assure attainment of the NAAQS for SO_2. The instant proposal is the result of that cooperation.

Shell's WRMC is the largest refinery in Illinois, and processes approximately 12 million gallons of crude oil per day. At the refinery, the crude oil is separated, and the parts, or fractions, are converted and upgraded. About 6.5 million gallons become motor gasoline and aviation fuel. The remainder becomes home heating oil, liquefied petroleum gas, diesel fuel, aviation turbine fuel, industrial fuel oil, asphalt, solvents, chemicals such as benzene and acetone, and more than 500 varieties of lubricating oil. (See generally Ex. 7.) The refinery processes used to create these products include distillation, vacuum flashing, fluid catalytic cracking, gas plant fractionation, hydrocracking, reforming, hydrotreating, and alkylation. (Transcript of October 30, 1986 (Tr.I), p. 58.) The WRMC employs over 1700 people, who earned over $80,000,000 in wages and benefits in 1985. (Tr.I, p. 40.)

Sulfur Emission Sources

There are forty-eight SO_2 emission sources at Shell's WRMC. Forty-three of these sources are fuel combustion emission sources, both process heaters and boilers. The process heaters supply heat to the various refinery processes for the conversion and/or separation of crude oil and intermediate products into gasoline and other saleable products. Nine boilers produce steam, which is used primarily for fractionation, turbine drivers, equipment maintenance, and heat tracing. The fuel demands of the process heaters and the boilers are primarily met with by-product fuels produced within the refinery, including refinery flasher pitch and refinery fuel gas. Some sources also use small amounts of residual oil called utility fuel oil. In addition, a relatively small amount of natural gas is purchased and used to balance WRMC's fuel gas system. (Tr.I, pp. 61-62; Transcript of January 22, 1988 (Tr. II), pp. 40-41.)

Shell's refinery flasher pitch (RFP) system is a fuel supply system which is unique to WRMC. This system supplies preheated pitch fuel at a constant temperature and pressure to the larger fuel combustion sources at WRMC. RFP, which is a by-product of the vacuum flashing units, has a very high viscosity and acts like a solid at room temperatures. The sulfur content of RFP is related to the sulfur content of the crude oil. The pitch is circulated via supply and return headers. In addition to the main headers, each individual unit has an internal circulating loop, allowing pitch which is not consumed at that individual source to go back into the return header. A small heater is used to maintain the temperature of the RFP at about 500 degrees Fahrenheit so that the pitch may be pumped. (Tr.I, pp. 62-3; Ex. 6, Figure I.)

The refinery fuel gas (RFG) system is the other main fuel supply system at WRMC. RFG is primarily composed of the light hydrocarbons methane and ethane with some propane and butane plus hydrogen. RFG has a variable heating value and can have up to 7,000 grains of hydrogen sulfide (H_2S) per 100 standard cubic feet (scf) prior to treatment. By-product vent gases from the various processing units at WRMC are collected and routed to fuel gas absorbers. The H_2S is removed from the sour fuel gases, and the treated RFG is then ready to burn at the various fuel combustion sources. The recovered H_2S is routed to the sulfur recovery plant where it is converted and recovered as elemental sulfur (Tr.I, pp. 63-64; Ex. 6, Figure II.)

The five remaining SO_2 emission sources are process emission sources. WRMC's process emission sources include Fluid Catalytic Cracking Unit No. 1 (CCU-1), Fluid Catalytic Cracking Unit No. 2 (CCU-2), Asphalt Converter No. 5, Sulfuric Acid Unit (SAU), and the Sulfur Recovery Unit (SRU). These processes produce sulfur emissions to varying degrees. (Tr.I, pp. 65-67.)

SO_2 Air Pollution Control Equipment

Shell currently has several types of air pollution control equipment which control SO_2 emissions. This existing equipment includes the sulfur recovery plant, the fuel gas treatment facilities, facilities segregating low and high sulfur content refinery flasher pitches, the sulfuric acid unit dual absorption facilities, and the fluid catalytic cracking unit feed hydrotreater. The estimated replacement cost of this control equipment is approximately 100 million dollars, and annual operating and maintenance costs are on the order of 20 million dollars. (Tr.I, pp. 68-69.)

THE JOINT PROPOSAL

Shell's WRMC presently has a maximum permitted emission rate of 19,160 pounds of SO_2 per hour. The actual maximum emission rate during the period 1982 through 1985 was 11,063 lbs/hr, excluding any period of malfunction. This maximum emission rate for 1982-1985, however, is not indicative of full capacity operations at WRMC. This is related to the general economic climate for the refining industry during this period, and because of reduced operations on some units since late 1984 due to a major modernization project. Shell estimates that full operating conditions during this time would have resulted in maximum emission rates of approximately 13,000 lbs/hr. (Tr.I, pp. 48-49.)

The permitted 19,160 lbs/hr maximum emission rate is based upon the supposition that each individual emission source will operate simultaneously at maximum permitted rates. However, Joseph Brewster, Technical Manager of Process Engineering - Environmental Conservation/Utilities at WRMC, testified that the refinery never operates in that fashion. Instead, the refinery operation uses a large variety of operating combinations with the maximum permitted emission rates occurring with only a few of the operating combinations. (Tr.I, p. 49.) Therefore, Shell and the Agency worked to prepare a regulation which will give Shell its necessary operating flexibility while ensuring that ambient air quality standards will not be exceeded under any permitted condition. The resulting proposal, as revised, would reduce Shell's allowable SO_2 emission from the current 19,160 lbs/hr to 10,384 lbs/hr. This is a reduction of 8,776 lbs/hr, or 46 percent. (Tr.II, p. 47; Ex. 15, Table 2.)

The joint proposal accomplishes this reduction by bringing maximum permitted SO_2 emissions more in line with the actual emissions. This is possible because there is considerable redundancy in the various refinery processes. For example, there are nine boilers at WRMC. At any one time only six boilers may be operating, with the other three shut down for maintenance. (Tr.I, p. 69.)

Mass Emission Limits

The heart of the joint proposal consists of two basic concepts set forth in new Section 214.382(c)(3): Source Operations Groupings (SOGs) and the rollback. A SOG is a group of similar SO_2 sources which have been capped with a mass SO_2 limit. The emissions cap for a SOG is less than the total of the current maximum permitted emissions from each individual source within that SOG. As a result, the SOG more closely reflects actual maximum conditions. The proposal contains nine SOGs. Eight of the SOGs are made up of fuel combustion sources, while the ninth consists of process emission sources. The individual SOGs were chosen on the basis of location, control, type of source, and fuel monitoring. Sources within a particular SOG are located no more than 500 feet apart and are controlled from a common manned control room. In two cases (distilling unit No. 2

and the hydrocracker complex), the SOG consists of sources vented to a common stack. (Tr.I. pp. 69-71.) Exhibit 6, Figure IV shows the location of the SOGs.

The rollback caps SO_2 emissions from four SOGs. The affected SOGs are distilling unit No. 1, the gas plant process heaters, the boilers which generate steam for general plant use, the aromatics east process, and asphalt converter No. 5. This cap, which is set forth in Section 214.382(c)(3)(J), is in addition to the individual SOG mass SO_2 emission limit and the maximum permitted emission limit for asphalt converter No. 5. The justification for the rollback is contained in Exhibits 2 and 12, which are Agency reports on air quality analysis and compliance with the SO_2 NAAQS for the Alton-Wood River area.

Fuel Sulfur Limits

The joint proposal also imposes limits on the amount of sulfur in the fuels used at WRMC. New Section 214.382(c)(1) limits the refinery flasher pitch used at the facility to that containing no more than 3% sulfur by weight. New Section 214.382(c)(2) limits refinery fuel gas (RFG) to 39 grains of hydrogen sulfide per 100 dry standard cubic feet. These sulfur limits are consistent with the values presently applicable to WRMC under Section 214.162. (Tr.I, pp. 71-72; Tr.II, pp. 10-11, 39-44.)

Sulfur Recovery Unit Emission Limit

Proposed Section 214.382(b) changes the emission limit applicable to the sulfur recovery unit (SRU) from 14 pounds per metric ton of sulfur recovered to 1000 parts per million(ppm) sulfur dioxide in the final flue gas. This concentration in the flue gas is approximately equal to the present 14 lbs/T sulfur recovered at maximum permitted rates. Shell contends that a concentration limit is consistent with federal New Source Performance Standards (NSPS) for sulfur recovery units and with existing Board regulations for other sulfur recovery units in Illinois. (Tr. I, pp. 73-74.)

Shell has already made actual emission reductions pursuant to this proposed section. The SRU, which converts hydrogen sulfide derived from crude oil processing to elemental sulfur, is the primary SO_2 emission control equipment at WRMC. The SRU has four units, or trains, which were built at different times. The oldest unit, called the D-train, previously exhausted to the atmosphere without tailgas treatment. This was the standard technology at the time of the construction of the D-train in the early 1960s, and was allowed for by Section 214.382(a) of the Board's regulations. In 1985, Shell tied the D-train into the existing tailgas cleanup unit, called the SCOT unit. The SCOT unit had sufficient capacity to accommodate the additional gas load. This tie-in decreases SO_2 emissions in the tailgas from approximately 10,000 ppm to within the proposed standard of 1000 ppm. This step reduces maximum permitted and maximum actual emissions by 2,406 pounds per hour. (Tr.I, pp. 50-52.)

Compliance

One of the issues raised by USEPA in its April 9, 1987 letter (Ex. 11) detailing its concerns about the federal approvability of the joint proposal was the lack of compliance test methods. The revised proposal addresses this concern. Proposed amendments to Section 214.104 will incorporate by reference two standard test methods. An addition to subsection (b) will incorporate "Standard Test Method for Sulfur in Petroleum Products (X-Ray Spectographic Method)", ASTM D-2622 (1982). (Ex. 17.) This method will be used to measure the amount of sulfur in the refinery flasher pitch in order to determine compliance with new Section 214.382(c)(1). The joint proposal would also add a new subsection (c) incorporating by reference the Tutwiler procedure. (Ex. 18.) This standard procedure, found at 40 CFR 60.648 (1986), is to be used to measure the amount of hydrogen sulfide in refinery fuel gas, so as to show compliance with proposed Section 214.382(c)(2). Additionally, new Section 214.382(d) specifies that compliance with the emission limits of Section 214.382(b) and (c) shall be demonstrated on a three-hour block average basis. The Board has added a sentence to subsection (d) which requires that collection of data necessary to adequately determine the SO_2 emission rate from each SOG be made a permit condition. Agency comment is requested on the adequacy of the listed data and any need to expand the list. New Section 214.382(c)(1) states that compliance with that subsection shall be demonstrated by daily sampling of the refinery flasher pitch, while new Section 214.382(c)(2) provides that compliance with the refinery fuel gas standard shall be demonstrated by sampling the gas once every shift (i.e. every eight hours). Comment is requested on the eight hour sampling requirement. Shell introduced a report entitled "Sulfur Dioxide Emissions Determination Procedure" (Ex. 16), which describes how Shell will implement the rule to show compliance on an ongoing basis. A Shell engineer testified that Shell expects this report to be referenced as a standard condition in future operating permits. (Tr. II, pp. 8-10, 42-46.) Finally, USEPA expressed concern over which emission limits apply to the various sources at WRMC. A summary of the limits applicable to each source is contained in Exhibit 15, Table 1.

Alternative Emission Standard

Shell and the Agency also propose a new Section 214.382(g), which would provide for establishment of an alternative emission rate to the limits found in Section 214.382(c). Proposed subsection (g) states that any owner or operator of an emission source to which subsection (c) applies may petition the Board for approval of an alternative rate. Such person would be required to demonstrate in an adjudicative hearing that the proposed rate would not under foreseeable conditions cause or contribute to a violation of any applicable SO_2 air quality standard or any applicable prevention of significant deterioration (PSD) increment. Shell testified that this provision is intended to provide flexibility for future development. Mr. Brewster stated that there could come a time when Shell wanted to retire an older process and substitute a new process. This alternative emission standard procedure is intended to allow such changes without the necessity of a lengthy rulemaking proceeding. (Tr.I. pp. 83-85.)

Modifications

New Section 214.382(g) would change the definition of modification for purposes of this set of rules only. New subsection (g) provides that notwithstanding the definitions contained in Section 201.102, any physical change in any emission source which alters the height of release, diameter of the exit stack, temperature, or volumetric flow rate of the effluent gases shall be deemed a modification for purposes of Section 201.142 "Construction Permit Required." The Agency stated at hearing that this subsection will provide for Agency review of a physical change which may alter the impact of the emissions from the source, regardless of whether the change would increase the amount of emissions. This is necessary because the predicted air quality is already at the maximum level. (Tr.I, pp. 85-88.)

Environmental Impact

The Agency presented two witnesses who testified to the modeling done to assure that the joint proposal will result in SO_2 emissions which are within the NAAQS. (Tr.I, pp. 7-36; Tr.II, pp. 1-34; Ex. 2, 12.) Two different studies were performed: one prior to the development of this proposal (Ex. 2), and one after USEPA, in its April 1987 letter, raised several questions about the modeling. (Ex. 12.) The studies used a comprehensive inventory of all SO_2 emission sources in the area, modeled at their maximum permitted levels, and five years of representative meteorological data. Appropriate dispersion modeling techniques were then used to characterize potential ambient SO_2 concentration levels in the Wood River area. (The modeling studies and their results are discussed more fully in Exhibits 2 and 12.) These studies concluded that the 24-hour average ambient air quality standard is violated when the maximum SO_2 emission rates currently allowed by Board regulations were used in the dispersion calculations. No violations of the annual or 3-hour average air quality standards were found. After Shell and the Agency developed a compliance strategy, additional modeling runs were performed. This analysis showed that the second-high impacts for any year of meteorological data modeled at any receptor near WRMC are less than or equal to the 24-hour air quality standard for SO_2. Thus, the Agency feels that this joint proposal will adequately protect the NAAQS for sulfur dioxide. At the January 22, 1988 hearing, an Agency witness testified that the Agency believes that USEPA's questions have been satisfactorily answered. (Tr. II, pp. 32-34.)

Summary of Reductions

In addition to the emission reductions made by tieing the D-train of the SRU into the existing tailgas cleanup unit, Shell has made other reductions by doing such things as relinquishing operating permits for asphalt converters 1, 2, and 4. The following table (Ex. 12, Table 13) summarizes the reductions made by the proposed rule and through Shell's operating changes:

	SO_2 Emission (Tons/Year)
Current Maximum Permitted Emissions	83,921
Proposed Emission Reductions:	
SOGs/Rollback (Maximum 3% Sulfur Pitch Content)	-20,711
Tie-in D-Train to SCOT	-10,665
Reduce Catalytic Cracker Units maximum permitted emissions by 27.5%	-5,694
Relinquish operating permits for Asphalt Converters Nos. 1, 2, and 4	-850
Relinquish permit to burn utility fuel oil and substitute refinery fuel gas at Precursor, Alky HM-1, and LFE-Ext Furnaces	-657
Revise SRU/SCOT emission limit to a ppmv limit from a lbs/ton limit	+128
Total Reductions	-38,449
Proposed Maximum Permitted Emissions	-45,472

The Board specifically notes that although the proposal greatly reduces Shell's permitted emission limits, the actual reductions will be smaller. This is because although Shell is currently permitted to emit 19,160 pounds of SO_2 per hour, full capacity operations at WRMC produce actual emission rates of approximately 13,000 pounds per hour. (Tr. I, pp. 48-49.) Since this proposal is based upon bringing maximum permitted SO_2 emissions into line with actual emissions, the actual emission reduction is less than the 38,449 tons per year indicated in the table. Shell's actual emissions will be reduced approximately 20% by the proposal, while its permitted emission will be reduced 46%.

FINDINGS

The Board first notes that there is no evidence in this record which in any way rebuts or challenges the testimony presented by the Agency and Shell in support of the joint proposal. Therefore, there are no controversies or conflicting testimony for the Board to resolve. The Board will propose the bulk of the requested relief for First Notice publication. The Board wishes to point out that the record does not contain any information as to the manner in which the proponents arrived at the actual mass emission limits for each SOG. There is no justification for the manner in which specific emission limits for each particular SOG were allocated, and thus no way for the Board to determine whether these limits are reasonable. Nevertheless, because Shell and the Agency have agreed on those particular limits and because the modeling shows that the total emissions under this proposal will protect the NAAQS for SO_2, the Board will propose the suggested limits.

The fact that this is a joint proposal with a somewhat scanty record has posed other problems in reviewing the requested rule. First, the Board notes that 35 Ill. Adm. Code 214.301, which sets a SO_2 emission limit of 2000 ppm for process emission sources, continues to apply to Shell's process emission sources other than the sulfur recovery unit (SRU). This fact has been articulated in new Section 214.382(f). Sulfur emissions from the SRU are limited to 1000 ppm under new 35 Ill. Adm. Code 214.382(b). Shell's other individual process emission sources are not given a new rate-based limit by the proposal: the only new emission limits are under the SOG and rollback provisions. (Tr. II, pp. 40-41.) The Board points out that each individual process or fuel combustion emission source either remains regulated under the existing standard or is subject to a new standard for that individual source which is equivalent or more stringent than existing regulatory standards.

Second, and more troubling, the record does not clearly show why the proposal includes an exemption from Section 214.162 "Combination of Fuels." It is not clear why Shell cannot use the equation set out in that section. The original proposal specified that refinery flasher pitch (RFP) would be limited to 3.33 pounds of SO_2 per million btu (lbs/mmbtu) of actual heat input, while refinery fuel gas (RFG) would be limited to 39 grains of H_2 per 100 dry standard cubic feet (gr/scf). At the first hearing it was stated that these limits were equivalent to

3% sulfur in the RFP and 0.1 lbs/mmbtu for the RFG. (Tr. I, pp. 71-72). The revised proposal substituted the 3% sulfur by weight standard for RFP. When testifying to the need to exempt Shell from the combination of fuels rule, an Agency witness stated that because the original RFG standard and the revised RFP standard are not expressed in lbs/mmbtu, those standards would not yield a lbs/hr emission rate when used in the Section 214.162 combination of fuels rule. (Tr. II, p. 10.) Since the testimony at the first hearing provided the emission limits in lbs/mmbtu, it is unexplained why the RFG and RFP emission limits cannot be expressed in values applicable to Section 214.162. In sum, the Board questions: (1) why, under this proposal, Section 214.162 cannot apply to Shell's WRMC; and (2) whether the emission limits given in Section 214.382 are higher than those provided for in Section 214.162. Comments on these issues are invited during the First Notice period. For purposes of First Notice, the Board will propose an exemption from Section 214.162 for sources in the Village of Roxana which burn RFG and RFP.

The Board also notes that the record is somewhat unclear on equivalence considerations. For example, the proposed revision to Section 214.382(b) changes the emission limit for the SRU from 14 lbs/T sulfur recovered to 1000 ppm in the final flue gas. Although it is stated that the 1000 ppm standard is approximately equal to the 14 lbs/T of sulfur recovered rule (Tr. I, p. 74), the equivalence calculation has not been provided. The record is also somewhat foggy on how compliance will be shown when a particular source is subject to more than one of the proposed limits. For example, distilling unit No. 1 is subject to the RFP standard of Section 214.382(c)(1), the RFG standard of Section 214.382(c)(2), the SOG ceiling of Section 214.382(c)(3)(A), and the rollback of Section 214.382(c)(3)(J). (See Ex. 15, Table 1.) The Board assumes that compliance with the limitations of each applicable section will be shown. This also again raises the issue of why Section 214.162 "Combination of Fuels" cannot be used in those instances where a source uses more than one type of fuel. Comments are invited on these issues.

It is also not clear why the proposed regulation has been placed in Section 214.382, which regulates the petroleum and petrochemical processes industry, rather than in a separate section. The Board notes that there are other refineries in the Wood River - Alton area, and is unclear as to what rules applies to these other refineries. Since the effect of the proposal will be the same regardless of where the regulation is placed, however, the Board will propose the rule as requested, pending any comments on this issue.

The only portion of the joint proposal which the Board will not propose for First Notice is the request for a subsection which would establish a procedure for obtaining an alternative emission rate to the limits set forth in this rule. The record contains no justification for such a procedure beyond Shell's assertion that it is needed to provide flexibility for future development. (Tr. I, pp. 84-85.) The Board believes that it is not good policy to provide a procedure for obtaining an alternative emission rate within a site specific rule. By definition, a site specific rule is itself tailored to the needs of a particular facility. To place an alternative emission rate procedure within a site specific regulation could lead to a situation where a facility attempts to "escape" from emission limits which it originally proposed, without proceeding through the notice and comment provisions of a rulemaking.

Finally, it should be pointed out that the Board has slightly revised the regulation proposed by Shell and the Agency. These revisions are not substantive; for example, the exemption from Section 214.162 has been moved from that section to Section 214.382(e). The language of some of the proposed sections has also been modified to clarify the purpose of those sections. The substance of the regulation remains the same.

ORDER

The Board hereby directs the Clerk of the Board to cause publication in the Illinois Register of the First Notice of the following amendments:

TITLE 35: ENVIRONMENTAL PROTECTION
SUBTITLE B: AIR POLLUTION
CHAPTER I: POLLUTION CONTROL BOARD
SUBCHAPTER c: EMISSION STANDARDS AND
LIMITATIONS FOR STATIONARY SOURCES

PART 214
SULFUR LIMITATIONS

SUBPART A: GENERAL PROVISIONS

Section 214.101 Measurement Methods

a) Sulfur Dioxide Measurement. Measurement of sulfur dioxide emissions from stationary sources shall be made according to the procedure published in 40 CFR 60, Appendix A, Method 6 (1982), or by measurement procedures specified by the Illinois Environmental Protection Agency (Agency) according to the provisions of 35 Ill. Adm. Code 201.

b) Sulfuric Acid Mist and Sulfur Trioxide Measurement. Measurement of sulfuric acid mist and sulfur trioxide shall be according to the barium-thorin titration method as published in 40 CFR 60, Appendix A, Method 8 (1982).

c) Solid Fuel Averaging Measurement. If low sulfur solid fuel is used to comply with Sections 214.121, 214.122, 212.141, 214.142, 214.162 and 212.421, the applicable solid fuel sulfur dioxide standard shall be met by a two month average of daily samples with 95 percent of the samples being no greater than 20 percent above the average. A~~.~~S~~.~~T~~.~~M~~.~~ procedures D-2234 (1976) and D-2013 (1976) shall be used for solid fuel sampling, D-3177 (1976) and D-2622 (1982) for sulfur determinations and D-2015 (1976) and D-3286 (1976) for heating value determinations.

d) (Reserved)

e) (Reserved)

f) (Reserved)

g) (Reserved)

h) Hydrogen Sulfide Measurement. The concentration of hydrogen sulfide in petroleum refinery fuel gas shall be measured using the Tutwiler Procedure specified in 40 CFR 60.648 (1986).

(Source: Amended at 12 Ill. Reg. _____, effective ______________)

Section 214.102 Abbreviations and Units

a) The following abbreviations are used in this Part:

btu	British thermal units (60 F)
ft	foot
gr	grains
J	Joule
kg	kilogram
kg/MW-hr	kilogram per megawatt-hour
km	kilometer
lbs	pounds
lbs/mmbtu	pounds per million btu
m	meter
mg	milligram
Mg	megagram, metric ton or tonne
mi	mile
mmbtu	million British thermal units
mmbtu/hr	million British thermal units per hour
MW	megawatt; one million watts
MW-hr	megawatt-hour
ng	nanogram, one billionth of a gram by volume
ng/J	nanograms per Joule
ppm	parts per million

scf	standard cubic foot
scm	standard cubic meter
T	English ton

b) The following conversion factors have been used in this Part:

English	Metric
2.205 lb	1 kg
1 T	0.907 Mg
1 lb/T	0.500 kg/Mg
mmbtu/hr	0.293 MW
1 lb/mmbtu	1.548 kg/MW-hr or 430 ng/J
1 mi	1.61 km
1 gr/scf	2289 mg/scm

(Source amended at 12 Ill. Reg. _______, effective _____________)

Section 214.104 Incorporations by Reference

The following materials are incorporated by reference:

a) 40 CFR 60, Appendix A (1982):

1) Method 6: method for measurement of sulfur dioxide emissions;

2) Method 8: barium-thorin titration method

b) American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103:

1) For solid fuel sampling:

ASTM D-2234 (1976)
ASTM D-2013 (1976)

2) For sulfur determinations:

ASTM D-3177 (1976)

ASTM D-2622 (1982)

3) For heating value determinations:

ASTM D-2015 (1976)

ASTM D-3286 (1976)

c) Tutwiler Procedure for hydrogen sulfide, 40 CFR 60.648 (1986).

(Source: Amended at 12 Ill. Reg. ______, effective ___________)

Section 214.382 Petroleum and Petrochemical Processes

a) Section 214.301 shall not apply to existing processes designed to remove sulfur compounds from the flue gases of petroleum and petrochemical processes.

b) No person shall cause or allow the emission of more than 1,000 ppm of sulfur dioxide into the atmosphere from any ~~new~~ process emission source in the St. Louis (Illinois) major metropolitan area designed to remove sulfur compounds from the flue gas of petroleum and petrochemical processes. ~~to exceed 14 lbs/T of sulfur dioxide per metric ton of sulfur recovered (7 kg).~~

c) The following limitations apply to any petroleum refinery in the Village of Roxana:

1) No person shall cause or allow the combustion of refinery flasher pitch containing more than 3.0% (three percent) sulfur by weight. This shall be demonstrated by daily sampling of refinery flasher pitch.

2) No person shall burn petroleum refinery fuel gas in any fuel gas combustion device if that refinery fuel gas contains more than 39 grains hydrogen sulfide per 100 dry standard cubic feet (893 mg/scm). This shall be demonstrated by sampling the refinery fuel gas once every eight hours.

3) No person shall cause or allow the total emission of sulfur dioxide into the atmosphere from the following source groupings to exceed the following amounts:

A) All process heaters at distilling unit No. 1 - 459 lbs/hr (208 kg/hr).

B) All process heaters at distilling unit No. 2 - 1260 lbs/hr (571 kg/hr).

C) All gas plant process heaters - 159 lbs/hr (72.1 kg/hr).

D) All vacuum flasher unit heaters - 378 lbs/hr (171 kg/hr).

E) All process heaters at the alkylation, benzene extraction unit and catalytic feed hydrotreating units - 346 lbs/hr (157 kg/hr).

F) All boilers generating steam for general plant use- 2,400 lbs/hr (1,090 kg/hr).

G) All heaters serving the hydrocracker unit catalytic reformer No. 1, and the saturates gas plant - 1,660 lbs/hr (753 kg/hr).

H) All process heaters at the aromatics east process - 768 lbs/hr (348 kg/hr).

I) All catalytic cracking units - 3,430 lbs/hr (1,560 kg/hr).

J All asphalt converters, distilling unit No. 1, the aromatics east process, all boilers generating steam for general plant use, and all gas plant process heaters - 2,710 lbs/hr (1,230 kg/hr.)

d) Compliance with the emission limitations of subsections (b) and (c)(3) of this Section 214.382 shall be demonstrated on a three-hour block average basis. Such demonstrations shall require, as a permit condition, that data, including but not limited to, fuel feed rates, specific gravity of refinery flasher pitch, sour water sulfide content, fresh and hydrotreated feed rates to the catalytic cracking units and the percent oxygen, carbon monoxide and carbon dioxide in the flue gas leaving the catalytic cracker unit regenerators be maintained in order to adequately determine the sulfur dioxide emission rate from each source operations group.

e) Sources in the Village of Roxana are not subject to the emission limitations of Section 214.162 when burning refinery flasher pitch or refinery fuel gas.

f) Individual process emission sources in the Village of Roxana are still subject to the emission limitation of Section 214.301 notwithstanding their inclusion in a source operations group.

g) Notwithstanding the provisions of Section 201.102 of this Chapter, any physical change in any emission source subject to subsection (b), (c), (d), or (e) of this Section which alters the height of release, temperature or volumetric flow rate of the effluent gases of such source, or alters the diameter of the exit stack, shall be deemed a modification for the purposes of Section 201.142 of this Chapter.

(Source: Amended at 12 Ill. Reg. ______, effective ____________)

IT IS SO ORDERED.

I, Dorothy M. Gunn, Clerk of the Illinois Pollution Control Board, hereby certify that the above Proposed Opinion and Order was adopted on the 21st day of April, 1988, by a vote of 7-0.

Dorothy M. Gunn

Dorothy M. Gunn, Clerk
Illinois Pollution Control Board