

Prevention of Significant Deterioration
Sulfur Dioxide
Baseline Emission Rates

Draft
April 2002

ND Department of Health
Division of Air Quality
1200 Missouri Avenue, Room 304
Box 5520
Bismarck, ND 58506-5520

Table of Contents

	<u>Page</u>
I. Introduction	5
A. Purpose	5
B. Definitions	5
C. Baseline Areas	11
D. Normal Operations	12
II. Emission Calculation Methodologies	18
A. Emission Factors	19
B. Emissions Testing Data	25
C. Continuous Emission Monitor (CEM) Data	26
III. Major Source Baseline Emission Rate Calculations	26
A. Beulah Power Plant	26
B. R.M. Heskett Station	32
C. Leland Olds Station	36
D. Lignite Gas Processing Plant	42
E. Mandan Refinery	45
F. Wm. J. Neal Station	51
G. Royal Oak Charcoal Briquette Plant	55
H. Tioga Gas Plant	63
I. Williston Refinery	65
J. Stanton Station Unit 1	67
K. M.R. Young Station	71
IV. Oil and Gas Wells Baseline Emission Rate Calculations	79
Appendix A - Beulah Power Plant Data	
Appendix B - R.M. Heskett Station Data	
Appendix C - Leland Olds Station Data	
Appendix D - Lignite Gas Plant Data	
Appendix E - Mandan Refinery Data	
Appendix F - Wm. J. Neal Station Data	
Appendix G - Royal Oak Briquetting Plant Data	
Appendix H - Tioga Gas Plant Data	
Appendix I - Williston Refinery Data	
Appendix J - Stanton Station Unit 1 Data	
Appendix K - M.R. Young Station Data	

List of Figures

		<u>Page</u>
1	Heat Input per Operating Hour	14
2	Total Heat Input	15
3	Beulah Station Units 1-2 Sulfur Data	28
4	Beulah Station Units 3-5 Sulfur Data	29
5	Beulah Station Units 1-5 Heat Input	30
6	R.M. Heskett Station Sulfur Data	33
7	R.M. Heskett 1 Heat Input	34
8	R.M. Heskett 2 Heat Input	35
9	Leland Olds 1 Sulfur Data	37
10	Leland Olds 2 Sulfur Data	38
11	Leland Olds 1 Heat Input	39
12	Leland Olds 2 Heat Input	40
13	Wm. J. Neal Station Sulfur Data	53
14	Wm. J. Neal Station Heat Input	54
15	Royal Oak Sulfur Data	56
16	Royal Oak Boilers Coal Usage	58
17	Royal Oak Carbonizers Coal Usage	59
18	Royal Oak Briquetting Plant Coal Usage	60
19	Stanton 1 Sulfur Data	68
20	Stanton 1 Heat Input	69
21	M.R. Young 1 Sulfur Data	72
22	M.R. Young 1 Heat Input	73
23	M.R. Young 2 Sulfur Data	74
24	M.R. Young 2 Heat Input	76

List of Abbreviations

API	American Petroleum Institute
AP-42	Compilation of Air Pollutant Emissions Factors; Fifth Edition
Avg.	average
bb1	barrel
Btu	British thermal unit
Btu/hr	British thermal units per hour
Btu/lb	British thermal units per pound
CEM	continuous emission monitor
CO	carbon monoxide
F	emission factor
FCCU	fluidized catalytic cracking unit
ft ³	cubic feet
gal	gallon
H ₂ S	hydrogen sulfide
lb/day	pounds per day
lb/hr	pounds per hour
lb/10 ⁶ Btu	pound per million British thermal units
lb-mole	pound mole
lb/lb-mole	pounds per pound mole
lb/gal	pounds per gallon
lb/scf	pounds per standard cubic foot
lb/ton	pounds per ton
MWe	megawatts electricity
Na ₂ O	sodium oxide
NDAC	North Dakota Administrative Code
NO ₂	nitrogen dioxide
ppmv	parts per million volume
PM ₁₀	particulate matter less than 10 micrometers
PSD	Prevention of Significant Deterioration
S	sulfur
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
SO _x	sulfur oxides
scf	standard cubic feet
scfd	standard cubic feet per day
scf/day	standard cubic feet per day
SRU	sulfur recovery unit
tons/yr	tons per year
WBS	Williston Basin Regional Air Quality Study
µg/m ³	micrograms per cubic meters

Baseline Emission Rates

I. Introduction

A. Purpose:

The purpose of this document is to present the data and the methodology that were used in establishing the proposed emission rate for sources that contribute to the baseline concentration. This document presents data for each source on production rates (heat input, coal usage, processing rates, etc.), fuel and raw materials quality, hours of operation and other pertinent data. The calculation of the baseline emission rate is presented along with the methodology used in the calculation. The methodology for the various sources includes the use of factors from AP-42, Compilation of Air Pollutant Emission Factors, stack test data, or a mass balance approach. Any interpretation of the data or assumptions are also explained.

B. Definitions:

Within the Prevention of Significant (PSD) rules found in NDAC 33-15-15, there are several definitions of terms and the interpretation of those definitions that are critical to the establishment of the emission rate that is used to establish the baseline concentration. These terms, as defined in NDAC 33-15-15, include:

"Actual emissions" means the actual rate of emissions of a contaminant from an emissions unit, as determined in accordance with paragraphs a through d.

- a. In general, actual emissions as of a particular date must equal the average rate, in tons per year, at which the unit actually emitted the contaminant during a two year period which precedes the particular date and which is representative of

normal source operation. The department may allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions must be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

- b. The department may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.
- c. For any emissions unit (other than an electric utility steam generating unit specified in paragraph 4) which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.
- d. For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the source owner or operator maintains and submits to the reviewing authority, on an annual basis for a period of five years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed ten years, may be required by the department if it determines such a period to be more representative of normal source postchange operations.

"Allowable emissions" means the emission rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to

enforceable construction permit conditions which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

- a. Applicable standards of performance or emission limitations as set forth in this article.
- b. The emission rate specified as an enforceable permit condition.

"Baseline area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under section 107 (d)(1)(D) or (E) of the Federal Clean Air Act [Pub. L. 95-95] in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact equal to or greater than one $\mu\text{g}/\text{m}^3$ (annual average) of the contaminant for which the minor source baseline date is established. Any baseline area established originally for the total suspended particulate increments shall remain in effect and shall apply for purposes of determining the amount of available PM_{10} increments, except that such baseline area shall not remain in effect if the department rescinds the corresponding minor source baseline date. North Dakota is divided into two intrastate areas under section 107 (d)(1)(D) or (E) of the Federal Clean Air Act [Pub. L. 95-95]: the Cass County portion of Region No. 130, the Metropolitan Fargo-Moorhead Interstate Air Quality Control Region; and Region No. 172, the North Dakota Intrastate Air Quality Control Region (the remaining fifty-two counties).

"Baseline concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each contaminant for which a minor source baseline date is established and includes:

- a. The actual emissions representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph b.;
- b. The allowable emissions of major stationary sources which commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increases:

- a. Actual emissions from any major stationary source on which construction commenced after the major source baseline date; and
- b. Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

"Major source baseline date" means:

- a. In the case of particulate matter and sulfur dioxide, January 6, 1975; and
- b. In the case of nitrogen dioxide, February 8, 1988.

"Minor source baseline date" means the earliest date after the trigger date on which a major stationary source or a major modification subject to requirements of this chapter submits a complete application under the relevant regulations. The trigger date is:

- a. In the case of particulate matter and sulfur dioxide, August 7, 1977; and
- b. In the case of nitrogen dioxide, February 8, 1988.

The baseline date is established for each contaminant for which increments or other equivalent measures have been established if:

- a. The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107 (d)(1)(D) or (E) of the Federal Clean Air Act [Pub. L. 95-95] for the contaminant on the date of its complete application under this chapter; and
- b. In the case of a major stationary source, the contaminant would be emitted in significant amounts or, in the case of a major modification, there would be a significant net emissions increase of the contaminant.

Any minor source baseline date established originally for the total suspended particulate increments shall remain in effect and shall apply for purposes of determining the amount of available PM_{10} increments, except that the department may rescind any such minor source baseline date where it can be shown by the applicant, to the satisfaction of the department, that the emissions increase from the major stationary source, or the net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM_{10} emissions.

Although not defined in the PSD rules, several other terms are used in this document. For purposes of this document:

"average emission rate" means the average hourly emission rate within a year based on the annual emission rate and actual hours of operation for the given year.

"baseline emission rate" means the emission rate of a source that contributes to the baseline concentration.

"baseline period" means the two year timeframe for which the baseline emission rate is calculated.

"baseline source" means a facility of which any portion of its emissions contributes to the baseline concentration.

"two year average emission rate" means the average hourly emission rate within two consecutive years based on the total annual emissions and total hours of operation for the two year period. Mathematically, it equals the total emissions divided by the total hours of operation.

The Department has interpreted the definition of "actual emissions" to mean the two year average emission rate of the source which is representative of normal operations for a given period (see Summary of Legal Issues Relating to Administration of the Prevention of Significant Deterioration Provisions of North Dakota's State Implementation Plan - hereafter Legal Summary).

The baseline emission rate is the two year average emission rate calculated for the baseline period, and is used for determining the baseline concentration for all averaging periods. The Department has determined that a time period (two or more years) other than the two year period immediately preceding the minor source baseline date may be used for establishing the baseline emission rate provided it is more representative of normal operation (see Legal Summary). This may include a time period after the minor source baseline date. The Department has also determined that any reasonably anticipated increases or decreases in emissions due to production increases, as of the minor source baseline date, that genuinely reflect normal source operation can be taken into account when determining the baseline concentration and baseline emission rate (see Legal Summary).

C. **Baseline Areas:**

North Dakota is divided into two interstate areas under Section 107(d)(1)(D) or (E) of the Federal Clean Air Act (Public Law 9595): The Cass County portion of Region No. 130, the Metropolitan Fargo-Moorhead Interstate Air Quality Control Region; and Region No. 172, the North Dakota Intrastate Air Quality Control Region (the remaining 52 counties). Under the present PSD regulations, North Dakota is divided into two baseline areas (the same two areas).

The minor source baseline dates for the two baseline areas are as follows: 1) Region No. 130: Sulfur Dioxide - November 30, 1979, Particulates - November 30, 1979; 2) Region No. 172: Sulfur Dioxide - December 19, 1977, Particulates - January 13, 1978; 3) NO₂ - October 31, 1989.

The particulate matter and sulfur dioxide minor source baseline dates for Region 130 were established by the application of Cargill, Inc. for a sunflower seed processing plant.

In Region No. 172, the minor source baseline date for sulfur dioxide was established by the Warren Petroleum Company application for the Little Knife Natural Gas Processing Plant in Billings County. The minor source baseline date for particulate matter was established by Basin Electric Power Cooperative's application for the Antelope Valley Station Units No. 1 and 2 steam electric generating facility in Mercer County. The minor source baseline date for NO₂ was established by Dakota Gasification Company's application for an amended Permit to Construct. The minor source baseline dates are the dates of receipt by the Department of the last submittals of information from the applicants that made the applications complete.

The discussion in this section will be limited to Region No. 172 and sulfur dioxide. However, the methodology is applicable to Region No. 130 and for nitrogen oxides and PM₁₀.

The minor source baseline date for the eastern portion of Montana that may be affected by sulfur dioxide emissions from North Dakota sources is March 26, 1979. No attempt has been made to determine baseline emission rates for the Montana minor source baseline date. If no problems with Class I increment are encountered in North Dakota, none are expected in Montana. The correction of any increment problems in North Dakota should resolve any problems in Montana.

D. Normal Operations:

The Prevention of Significant Deterioration rules do not contain a definition of "normal operations". The Department searched other rules such as the New Source Performance Standards (40 CFR 60), National Emission Standards for Hazardous Air Pollutants (40 CFR 61), the National Emission Standards for Hazardous Air Pollutants for Source Categories (40 CFR 63) and the Acid Rain Program rules (40 CFR 72, 73 and 75) for a definition of normal operations. However, a definition and a methodology for determining normal operations were not found. Therefore, the Department had to establish its own methodology for determining normal operations for the baseline sources.

Most of the baseline sources that were evaluated are or were coal-fired electric utility steam generating facilities. Other sources include two natural gas processing plants, two oil refineries, and a charcoal briquette plant. In determining normal operations for the facilities, the Department decided that actual pollutant emission rates should not be a direct factor in the decision process. Production rates appear to be the factor which defines normal operations.

The Department evaluated the currently existing coal-fired utility plants based on the annual heat inputs for the various units. Both total heat input and heat input per operating hour for a given year were evaluated. The amount of electricity generated was also evaluated. However, data on electrical generation was only available to the Department from 1989 to the present. The amount of electricity generated correlated well with the heat input. Therefore, data on electricity generation is not presented.

Figures 1 and 2 depict the heat input per hour of operation and total heat input for the existing major baseline coal-fired utility steam generating facilities. The heat inputs were calculated from information supplied in the Annual Emission Inventory Reports for the various facilities. In reviewing the data, the heat input near the minor source baseline date was compared to operations before and after that date. Since emissions for the baseline period are to be calculated based on the actual hours of operation (lb/hr), the heat input per hour of operation was used to define normal operations for existing coal-fired steam electric utility boilers. For nearly all sources, there is a maximum two year period very near the minor source baseline date that is nearly equivalent to any other period after the baseline date. The one exception is the M.R. Young Station Unit 2. Beginning in 1990, the heat input to this unit increased dramatically. The reasons for this increase are unclear. However, based on the twelve years of previous operation, it appears that a two year period near the baseline date can adequately represent normal operations for this unit as of the minor source baseline date.

Based on the data, it is proposed that the time period 1975 through 1980 contains two consecutive years that were representative of normal operations for currently existing utility boilers. This time period represents nearly three years before the minor source baseline date (December 19, 1977) and approximately three years after

FIGURE 1
HEAT INPUT PER
OPERATING HOUR

14

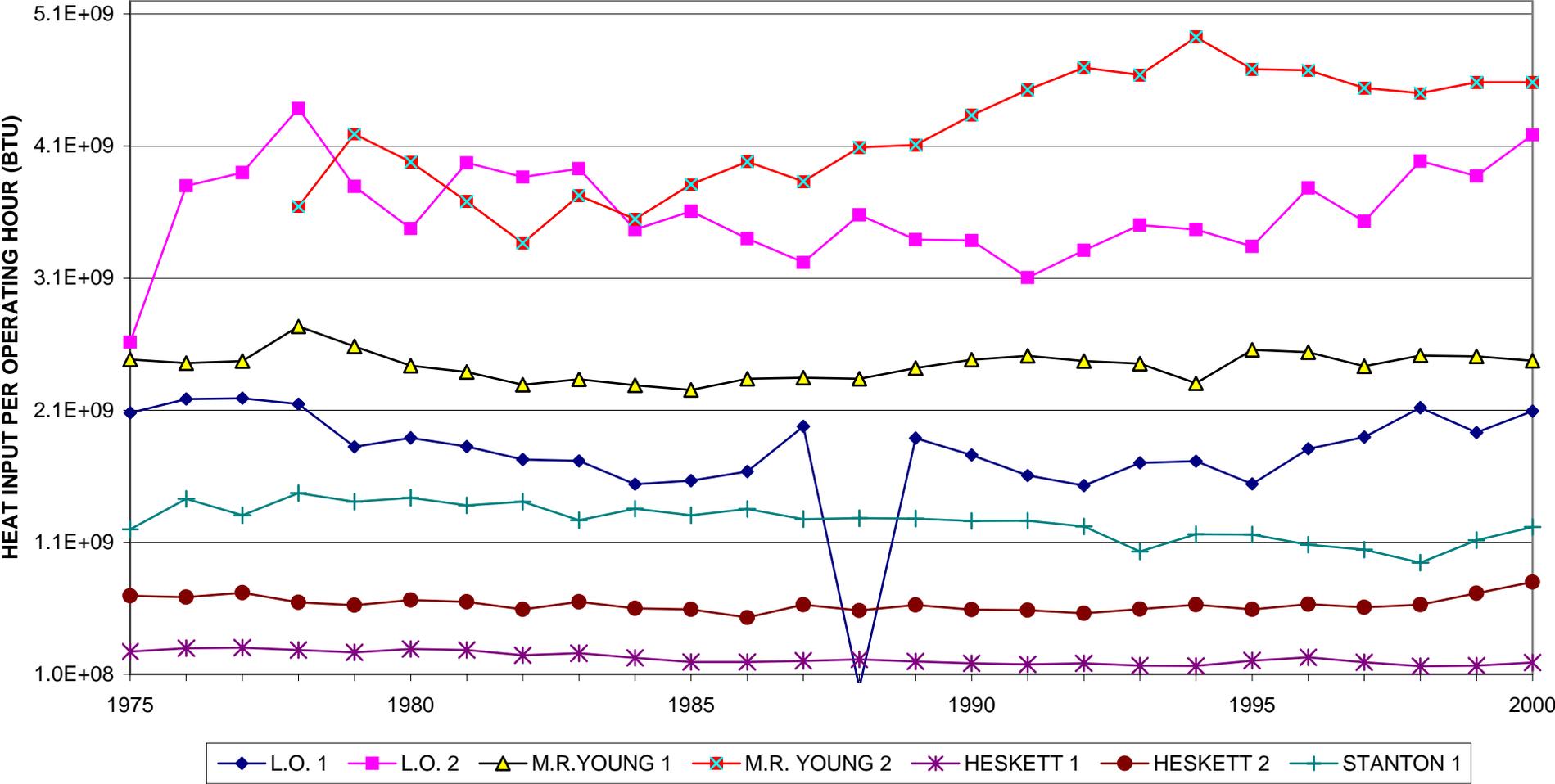
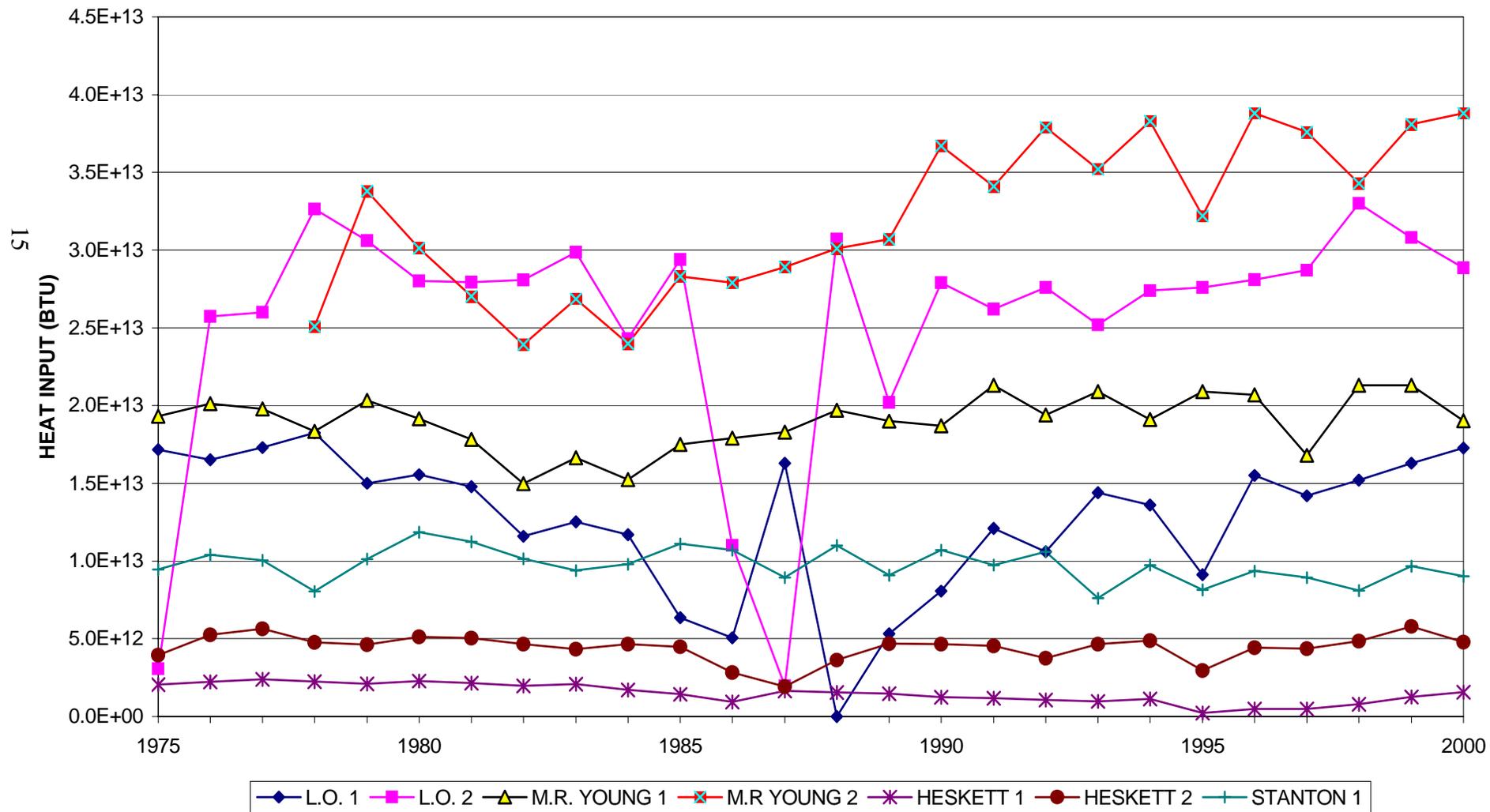


FIGURE 2
TOTAL HEAT INPUT



it. This close proximity to the minor source baseline date maintains some consistency with EPA's policy of determining actual emissions in the two years preceding the baseline date but also provides some flexibility for taking into account production increases that were anticipated on the baseline date (see F.R. Vol. 45, No. 154, p. 52714). The two years immediately prior to the baseline date (1976-77) were evaluated and either accepted or rejected as being representative of normal operations. Where a period other than 1976-77 was used for the baseline emission rate calculation, the reasons are given for the choosing a different period.

All other source categories were evaluated independently; however, weight was given to using the same time period for consistency. After review of the other sources, it is proposed that two years within this same time period (1975-80) adequately represented normal operations for these other sources. Again, the 1976-77 time period was used unless there was sufficient evidence to support use of a different period.

When determining normal operations for a facility, the fuels or raw materials (coal, natural gas, oil, etc.) used in the process must be considered. When changes in the fuels or raw materials could have been anticipated on the baseline date, the Department proposes that it is appropriate to take these changes into account when determining the baseline emission rate. For the baseline sources, the characteristic that is most important is the sulfur content of the fuel burned or raw materials processed.

For coal-fired steam generating units, the sulfur dioxide emission rate is directly proportional to the sulfur content of the coal provided all other conditions remain the same. Based on discussions with one mine operator, the sulfur content of the coal within mine areas is, to a certain extent, known by the mine operator as well as the source receiving the coal. Mining plans are prepared at the beginning of the mine operation and amended as

conditions warrant. When developing a mine, the quality of coal (including the sulfur content) determined from core sampling is considered. Although the core sampling data is not comprehensive, it is one of the factors evaluated. The Department's experience indicates that mining plans are developed thirty years or more in advance and are developed to provide the customer's (e.g. power plant) needs. Since changes in sulfur content could have been anticipated based on data used in developing the mining plan, the Department proposes that it is appropriate to consider the changes when calculating the baseline emission rate.

Some baseline sources have used coal from the same mine since the beginning of operation. However, other sources have changed coal suppliers and mines. A change in the source of the coal could change the sulfur content and other properties of the coal substantially. The source of coal for the Stanton Station switched from the Indianhead Mine in 1992 to the Freedom Mine. In 1993, the Leland Olds Station switched from the Glenharold Mine to the Freedom Mine. Because of the length of time after the minor source baseline date, the Department proposes that it is appropriate only to consider sulfur changes at the mine that was supplying the coal on the baseline date.

Figures in Section III, Baseline Emission Rate Calculations, present the annual average sulfur content for the baseline sources as reported in the Annual Emission Inventory Reports. Data was generally available from the early 1970's through 2000. The Department has no information on the sampling and analysis techniques that were used to obtain these results. As can be seen, results vary somewhat from year to year. This variation could be due to actual variations in coal quality, due to a variation in sampling or analysis techniques, or both. Therefore, the Department proposes that the average sulfur content over the life of the mine which was in use on the minor source baseline date is the appropriate value for determining the baseline emission rate. When

determining the mine average sulfur content, the average was weighted based on the amount of coal burned in a particular year. The average was also determined independent of its effect on the emission rate. In some cases, the mine average sulfur content is greater than the 1976-77 average (or other baseline period) and in some cases it is less. There was also no attempt made to average the sulfur content over units receiving coal from the same mine (e.g. Leland Olds 1 and 2). Other factors may have required some coal blending or selective mining for a particular unit. Leland Olds 1 is a wall-fired unit while Leland Olds 2 is a cyclone unit. M.R. Young 1 and 2 are both cyclone units; however, Unit 2 is equipped with a scrubber while Unit 1 is not. Unit 2 also has a lower emission limit (1.2 lb/10⁶ Btu vs. 3 lb/10⁶ Btu). Any of these factors could have influenced the quality of coal sent to the particular unit.

II. Emission Calculation Methodologies

There were a number of options available for calculating the baseline emission rates for the various sources. These include various emission factors, continuous emission monitor data where available, stack testing data from individual sources and a mass balance approach. Each of these methods has some advantages and disadvantages over another method. The one common factor that is important to each method is the quality of the fuel combusted or raw material processed. The qualities of the material in question includes the heat content, sulfur content, alkalinity of the coal ash, the sulfur content of the oil that is refined or natural gas processed, the density of fuel oil combusted, or the sulfur content of the coal carbonized. Where air pollution control equipment for sulfur dioxide was utilized, the efficiency of the unit may be required. In general, not all of this data is available for the baseline period. In order to calculate the baseline emission rates, certain assumptions have to be made and an appropriate method selected. The following discusses the merits of each method.

A. **Emission Factors:**

The primary source for emission factors for air pollution sources is AP-42, Compilation of Air Pollution Emission Factors. This document is published by the U.S. Environmental Protection Agency's Office of Air Quality Planning and Standards. The fifth addition of this document was published in 1995 with updates in 1996 through 2000. For lignite combustion sources, AP-42 was last updated in September of 1998. For other North Dakota baseline source categories, there have been no updates since 1995.

AP-42 emission factors represent average emission factors for a given source category. The average emission factor is based on the data EPA has evaluated and may not represent the actual emission rate for a specific source. However, it does represent EPA's best estimate of the emissions over the source category.

1. Lignite Combustion

For lignite combustion units, the sulfur oxides emission factor for all of the baseline sources is 30(S). The Heskett Station Unit 2 is currently a fluidized bed combustor for which the emission factor is 10(S). However, during the baseline period, the unit was a spreader stoker combustor which has an emission factor of 30(S). The emission factor indicates that average sulfur oxides emissions in pounds per ton of coal combusted (lb/ton) will equal 30 times the sulfur content. A footnote to this emission factor states "S = Weight % sulfur content of lignite, wet basis. For example, if the sulfur content equals 3.4%, then S = 3.4. For high sodium ash ($\text{Na}_2\text{O} > 8\%$), use 22S. For low sodium ash ($\text{Na}_2\text{O} < 2\%$), use 34S. If ash sodium content is unknown, use 30S". An explanation of the ash sodium content issue is found previously in AP-42 and states, "The SO_2 emissions from lignite combustion are a function of

the sulfur content of the lignite and the lignite composition (i.e., sulfur content, heating value, and alkali concentration). The conversion of lignite sulfur to SO_x is generally inversely proportional to the concentration of alkali constituents in the lignite. The alkali content is known to have a great effect on sulfur conversion and acts as a built-in sorbent for SO_x removal."

An emission factor of 30(S) indicates that 75% of the sulfur entering the combustion unit is emitted as sulfur oxides and 25% is captured in the ash (bottom ash or fly ash). An emission factor of 22(S) indicates 55% emitted as SO_x and 45% is captured in the ash. An emission factor of 34(S) indicates 85% emitted and 15% captured. The emission factor (and emissions) can vary greatly depending on the sodium oxide (Na_2O) content of the ash. Little information is available regarding lignite ash sodium content for the baseline units during the baseline period. Given this fact and that the ash sodium content can vary significantly from one mine to another, and even within a mine, the average emission factor of 30(S) appears to be the appropriate factor when using emission factors to calculate emission rates. If additional information on the sodium oxide content of the ash of the coal consumed during the baseline period would become available, the emission factor should be reevaluated.

In response to the Department's letter of July 3, 2001, regarding baseline issues, two companies that operate coal-fired electric utilities submitted a comparison of 1995-2000 continuous emission monitoring data to estimated emissions using the AP-42 emission factor 30(S). The analysis by both companies suggests that the AP-42 emission factor 30(S) underestimated the emission rate for their baseline source units. One company states their analysis showed that a factor of 33.14(S) should be

used for annual emissions estimates and 45(S) for short-term estimates. Any emission factor greater than 40(S) is theoretically impossible; however, the analysis may have yielded this result because of inaccuracies in stack gas flow measurement. The other company suggested emission factors of 36.0(S) for one unit and 40.5(S) for another unit.

As discussed earlier, the alkalinity of the lignite ash significantly affects the sulfur dioxide emission rate. No data on the sodium (Na_2O) content of the lignite ash was submitted with the analyses by the two companies. Both companies obtain their current coal supply from the same mine. This mine is different from the mines that supplied coal during the baseline period. There is insufficient data to compare the emission factor for the baseline period to emission factors derived from recent continuous emission monitoring data. Unless coal ash sodium data is available for comparison for both time periods, any analysis is suspect.

AP-42 uses a rating system from A to E for the emission factors listed. The emission factor for sulfur dioxide for lignite combustion units is given a rating of C. The ratings are described as follows:

- A - Excellent. Factor is developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.
- B - Above average. Factor is developed from A- or B-rated test data from a "reasonable number" of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with an A rating, the source

category population is sufficiently specific to minimize variability.

- C - Average. Factor is developed from A-, B-, and/or C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- D - Below average. Factor is developed from A-, B- and/or C- rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.
- E - Poor. Factor is developed from C- and D-rated test data, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.

It should also be noted that the AP-42 emission factor is based on a number of stack tests at North Dakota power plants from the 1970's into the 1990's. Since only the average emission rate is being calculated, any short term variations in emission rates within the two year baseline period due to coal ash sodium content may tend to average out. Unless specific coal ash sodium (Na_2O) data can be obtained for the coal consumed during the baseline period which would justify a different emission factor, the Department believes the average AP-42 emission factor, 30(S), represents the best emission factor available. For purposes of the baseline emission rate calculations, all

sulfur oxides emissions are considered to be sulfur dioxide.

On March 20, 2002 and March 26, 2002, additional information regarding the sodium content of coal consumed at two facilities was received. The Department has not had time to evaluate the data. However, an evaluation of the data will be made and any adjustments to the emission factor that are justified will be made in the final determination of the baseline emission rates.

2. Fuel Oil Combustion

For fuel oil combustion units, AP-42 lists sulfur oxides emission factors ranging from 157(S) to 142(S) (lb/1000 gal) depending on the grade of oil fired. The emission factors indicate that all of the sulfur present in the fuel oil is emitted as a sulfur compound. AP-42 states "The emission of SO_x from conventional combustion systems are predominantly in the form of SO_2 . Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2 , about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in the flue gases) to form a sulfuric acid mist."

The sulfur content of the fuel oil is generally expressed as a weight percent. The variation in the emission factors is due to the difference in density of the various grades of fuel oil. Distillate oil is the least dense fuel and has an emission factor of 142(S). Grade 6 fuel oil is the densest and has an emission factor of 157(S).

Since all of the sulfur in the fuel oil will be emitted, the Department proposes that AP-42 emission factors adequately represent emissions when firing fuel oil. However, where the actual density of any fuel oil combusted is known, a mass balance approach should be used to determine sulfur oxides emissions. For purposes of the baseline emissions calculations, all sulfur oxides emissions were assumed to be sulfur dioxide.

3. Gaseous Fuels or Waste Gas Combustion

AP-42 states "Emissions of SO₂ from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO₂ emissions. Boilers combusting unprocessed natural gas may have higher SO₂ emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO₂ emissions."

The Department proposes that emissions of sulfur dioxide from baseline sources combusting "pipeline quality natural gas" are insignificant when compared to emissions due to other fuels and waste products. Therefore, sulfur dioxide emissions from the combustion of pipeline quality natural gas are not calculated and not included in the baseline emission rates. This determination only affects the oil refinery and natural gas processing source categories.

For fuel gas combustion and waste gas (tail gas or acid gas) incineration/flaring, the Department proposes that a mass balance approach is appropriate and adequately represents the baseline emission rate. The Department assumed that all

sulfur in the sour gas was converted to sulfur dioxide and emitted to the atmosphere.

B. Emissions Testing Data:

Emissions testing data represents a good snapshot of emissions during the testing period provided the test methods, procedures, and analysis methods are sufficient for the task. However, emissions testing data may or may not be representative of emissions over a longer period of time such as the baseline period. As discussed earlier, emissions can vary significantly depending on the characteristics of the fuel. The sulfur content of lignite combusted at a power plant in North Dakota can vary by as much as a factor of 4 or more in a given year. Short-term sulfur dioxide emission rates can vary by the same factor. One or two emissions tests in a year are generally not sufficient to establish the emission rate for the whole year (or baseline period). However, if the emissions testing data can be correlated with sufficient fuel characteristics, it can provide a basis for establishing emission factors for the source. Also, using emissions testing data may provide a preferable approach to a mass balance approach especially when coal is burned as fuel or processed.

The Royal Oak charcoal briquetting plant was a unique facility because it utilized lignite to make charcoal briquettes. The Department is not aware of any other charcoal briquetting facility in the United States that used lignite. Sulfur dioxide emissions from the boilers can be adequately estimated using AP-42 emission factors. However, there are no AP-42 emissions factors for sulfur dioxide emissions from the carbonizer furnaces (Herreschoff and Lurgi furnaces) that utilized lignite.

As discussed later, stack test data was used to establish an emission factor for the carbonizer furnaces.

C. **Continuous Emission Monitor (CEM) Data:**

The only baseline sources operating CEM systems for sulfur dioxide during the baseline period were Minnkota Power Cooperative at M.R. Young Unit 2 and Basin Electric Power Cooperative at Leland Olds Unit 2. Neither of these systems provided an emission rate on a mass per unit of time (i.e. lb/hr) basis. There is also no data currently available to the Department that would provide a comparison of the CEM readings to the sulfur content of the coal during the baseline period. Based on the limited CEM data available from the baseline period, the Department proposes that it is not an adequate resource to determine baseline emission rates.

As discussed earlier, a comparison of current CEM data to current emission rates may be useful provided adequate information is available about the current properties of the coal and the properties of the coal burned during the baseline period. Lacking information on the properties of the coal burned during the baseline period, any comparison to current CEM and coal data is of little value.

III. Baseline Emission Rate Calculations

A. **Beulah Power Plant:**

The Beulah Power Plant, which was located in Beulah, North Dakota, was owned and operated by Montana Dakota Utilities at the time it ceased operation in 1986. The facility actually consisted of two plants next to each other known as the Knife River Station and the Dakota Station. For clarity, the two plants are referred to as the Beulah Plant. The plant consisted of five different boilers. Boilers 1 and 2 were installed in 1927, Boiler 3 in 1928 and Boilers 4 and 5 in 1948. Boilers 1-3 were chain grate stokers while Boilers 4-5 were spreader stokers. Boilers 1 and 2 had a nominal rating of 77×10^6 Btu/hr each, Boiler 3 was 88×10^6 Btu/hr and Boilers 4 and 5 were 91×10^6 Btu/hr each. Boilers 1 and 2

exhausted emissions through separate stacks while Boilers 3-5 vented through a common stack as of the minor source baseline date. Since Boilers 1 and 2 have been modeled in the past as a single source and boilers 3-5 as another single source, the units are treated the same way in this analysis.

The Beulah Plant obtained its coal from the Beulah Mine (North Beulah Mine and later South Beulah Mine). Figures 3 and 4 present the coal sulfur content data submitted in the Annual Emission Inventory Reports for the facility. Based on this data, an average sulfur content, weighted on coal usage, was determined to be 0.70% for Units 1 and 2 and 0.71% for Units 3-5.

Figure 5 presents the total heat input for all units. The facility was evaluated to determine normal operations based on the total heat input for the facility and not the heat input per operating hour. Because of the flexibility provided by five boilers at the facility, some boilers were not needed for power generation and maintained on warm standby. The Annual Emission Inventory Reports for the facility for some years during the period evaluated (1972-1986) list total coal usage for power generation and heating, while only listing the hours of operation for power generation. The total hours of operation for both heating and power generation is unknown. Therefore, an accurate estimate of the heat input per operating hour could not be calculated. Emissions were calculated separately for Boilers 1-2 and Boilers 3-5, because they are modeled separately. The Department proposes that the 1976-1977 period is representative of normal operations for the facility on the minor source baseline date. The Department has calculated the baseline emission rates based on the AP-42 emission factor 30(S) and data in the Annual Emission Inventory Reports.

**FIGURE 3
BEULAH STATION
UNITS 1 - 2**

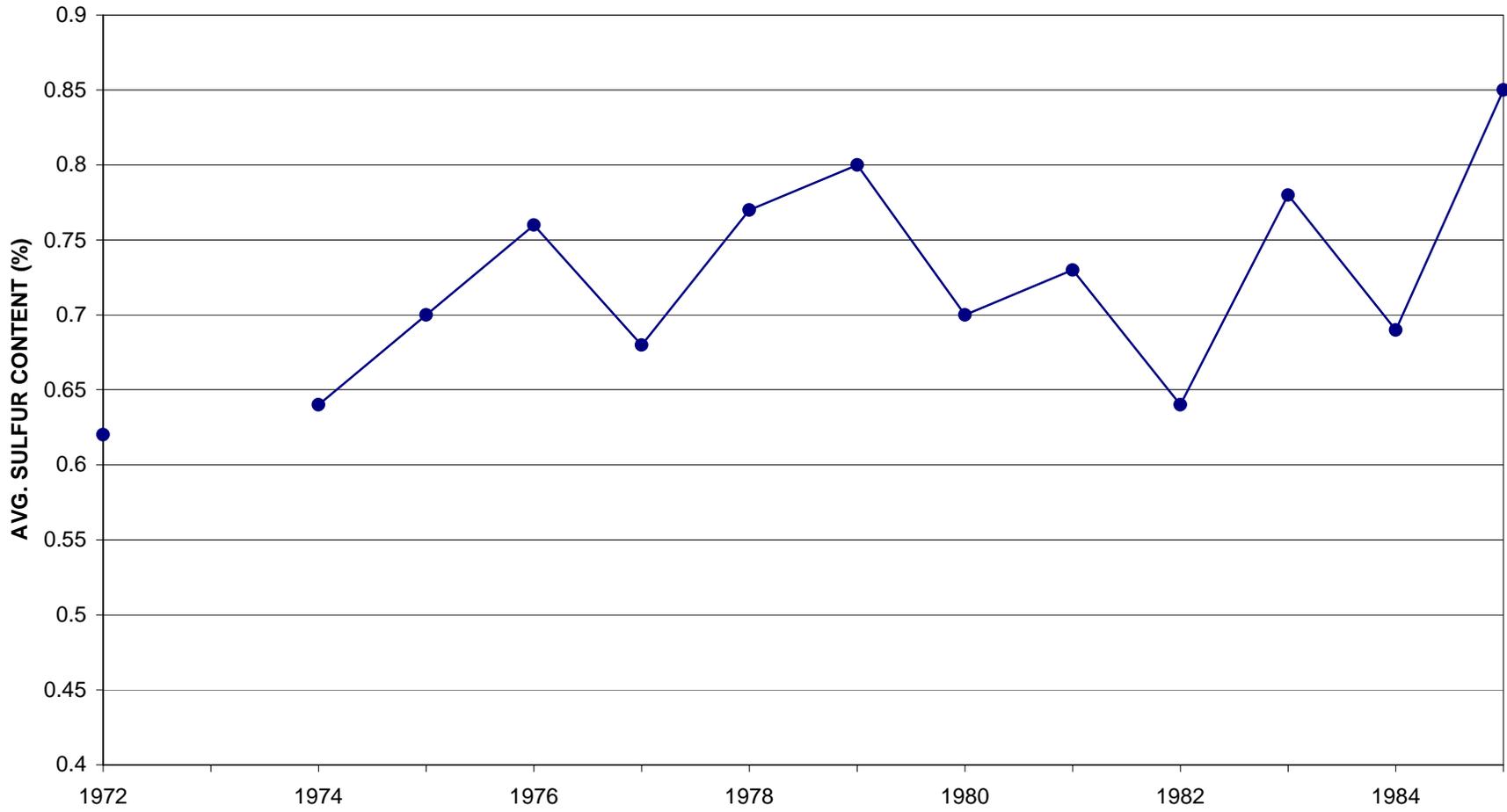
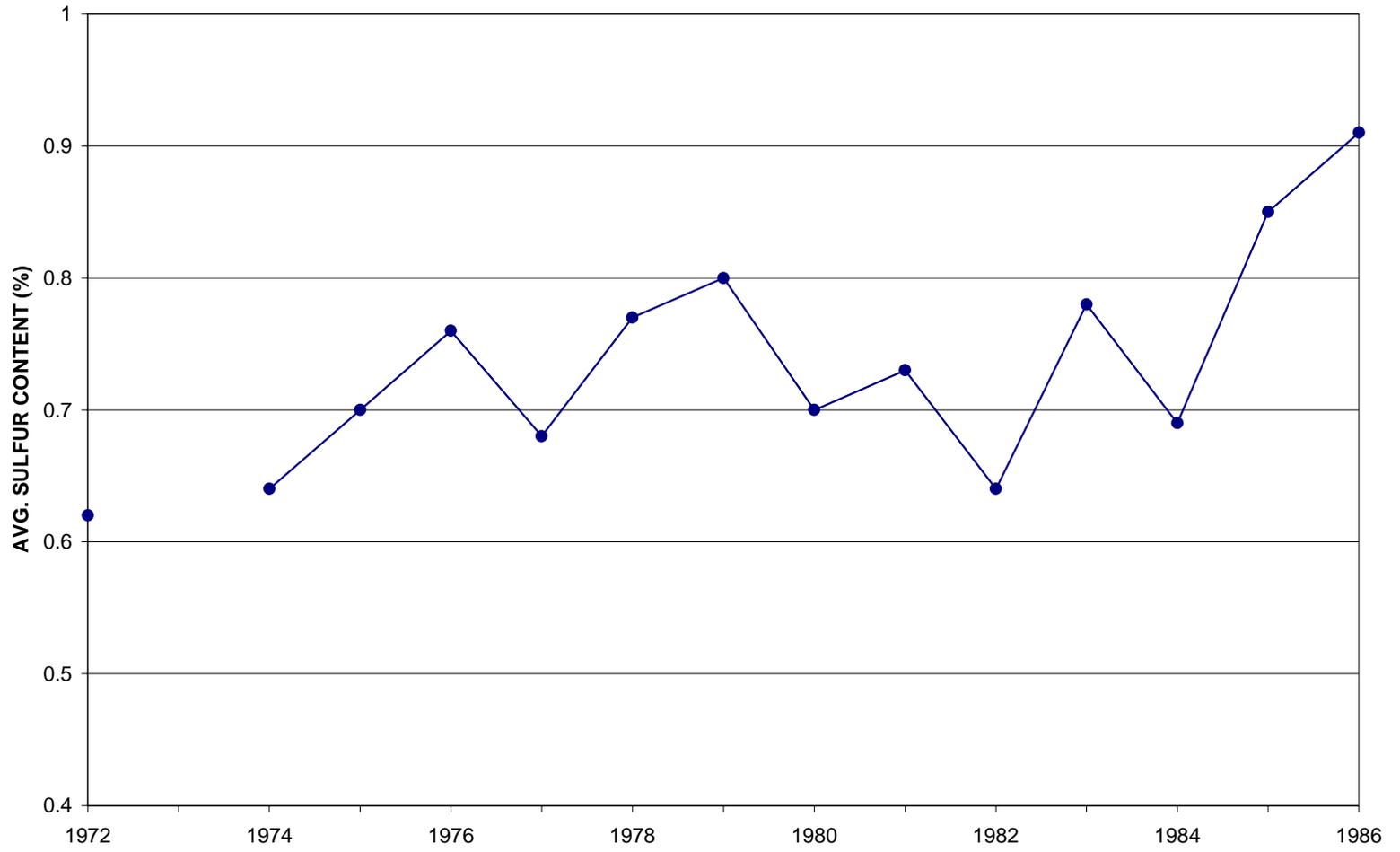
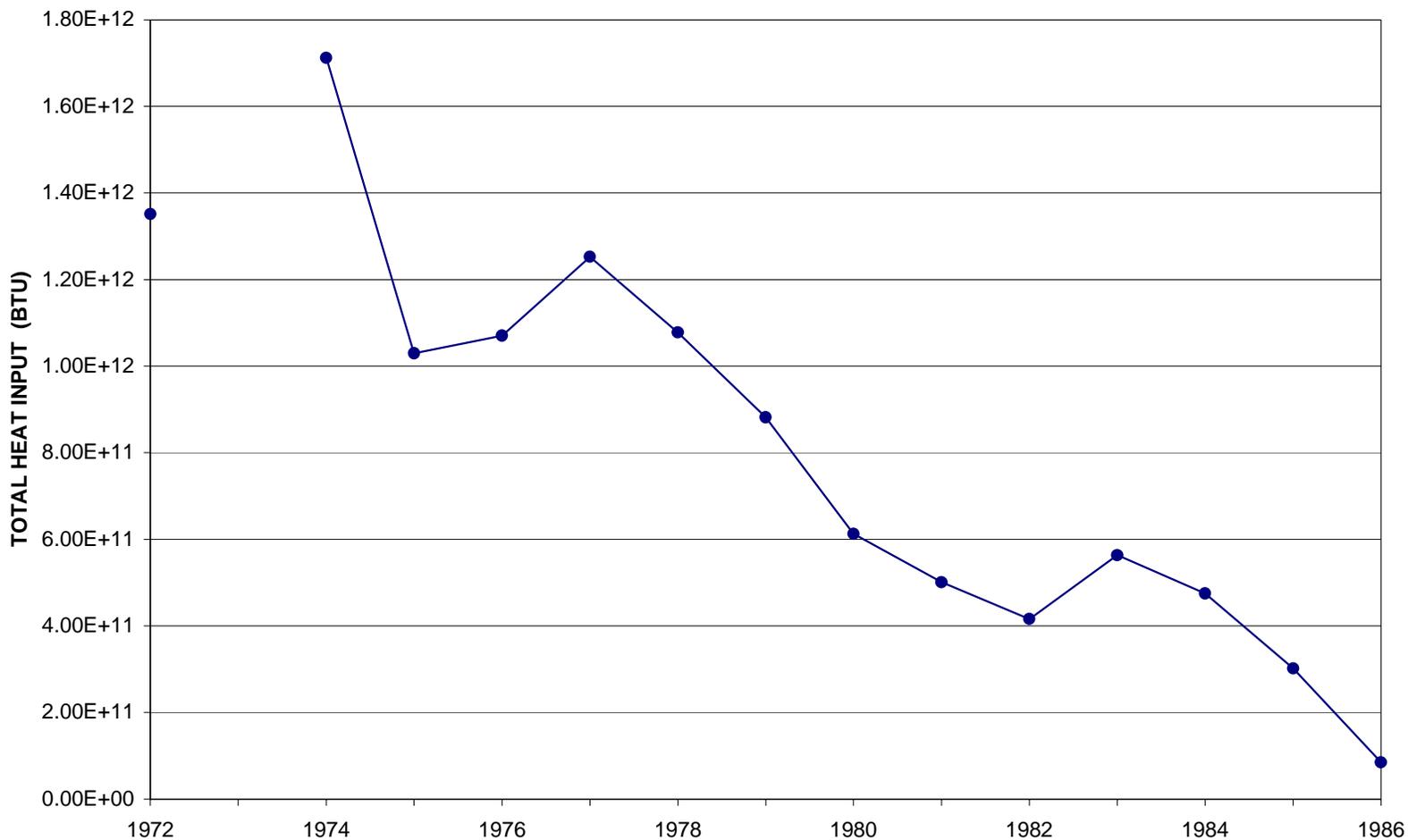


FIGURE 4
BEULAH STATION
UNITS 3 - 5



**FIGURE 5
BEULAH STATION
UNITS 1 - 5**



The data and results are as follows:

Units	Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation (Total for all Boilers)	Average Hours of Operation (per boiler)	2-Year Avg. Emission Rate (lb/hr)
1 & 2	1976	21811	0.70	229.0	7427.6	3713.8	137.1
1 & 2	1977	21322	0.70	223.9	5789.1	2894.6	
3 - 5	1976	54033	0.71	575.5	15879.9	5293.3	224.6
3 - 5	1977	68452	0.71	729.0	18975.4	6325.1	

Where:

$$\text{SO}_2 \text{ emissions (tons)} = (30)(\text{Mine Avg. Sulfur Content})(\text{Coal Usage}) \div (2,000 \text{ lb/ton})$$

$$\text{2-Year Avg. Emission Rate (lb/hr)} = \frac{[1976 \text{ SO}_2 \text{ Emissions (tons)} + 1977 \text{ SO}_2 \text{ Emission (tons)}] (2,000 \text{ lb/ton})}{[1976 \text{ Ag. Hours of Operation} + 1977 \text{ Ag. Hours of Operation}]}$$

B. R.M. Heskett Station:

The R.M. Heskett Station is located near Mandan, North Dakota and is operated by Montana Dakota Utilities. Unit 1 began operation in 1954 and Unit 2 in 1963. Unit 1 has a spreader stoker combustion unit and a nominal heat input rating of 387×10^6 Btu/hr. Unit 2 was originally constructed with a spreader stoker combustion unit but was converted to a fluidized bed unit in the 1980's. Unit 2 has a nominal heat input rating of 916×10^6 Btu/hr. Each of these units exhaust through a separate stack and are treated as separate units for purposes of this analysis.

The Heskett Station has obtained its coal from the Beulah Mine (North Beulah Mine and South Beulah Mine) in the past and continues to receive it from that mine. Figure 6 presents the coal sulfur content data submitted in the Annual Emission Inventory Reports for the facility. Based on the data, a weighted average sulfur content of 0.80% was calculated for each unit.

Figures 7 and 8 present the heat input for each unit. Based on this information, the Department proposes that the 1976-77 time period adequately represents normal operations for the facility as of the minor source baseline date. The Department has calculated the baseline sulfur dioxide emission rate for each source based on the AP-42 emission factor 30(S) and data from the Annual Emission Inventory Report. The data and results are as follows:

Unit	Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation	2-Year Avg. Emission Rate (lb/hr)
1	1976	159196	0.80	1910.4	7433	517.8
1	1977	171162	0.80	2053.9	7879	
2	1976	376017	0.80	4512.2	7668	1208.0
2	1977	406145	0.80	4873.7	7871	

Where:

$$\text{SO}_2 \text{ emissions (tons)} = \frac{(30)(\text{Mine Avg. Sulfur Content})(\text{Coal Usage})}{(2,000 \text{ lb/ton})}$$

$$\text{2-Year Avg. Emission Rate (lb/hr)} = \frac{[1976 \text{ SO}_2 \text{ Emissions (tons)} + 1977 \text{ SO}_2 \text{ Emission (tons)}] (2,000 \text{ lb/ton})}{[1976 \text{ Hours of Operation} + 1977 \text{ Hours of Operation}]}$$

FIGURE 6
HESKETT STATION

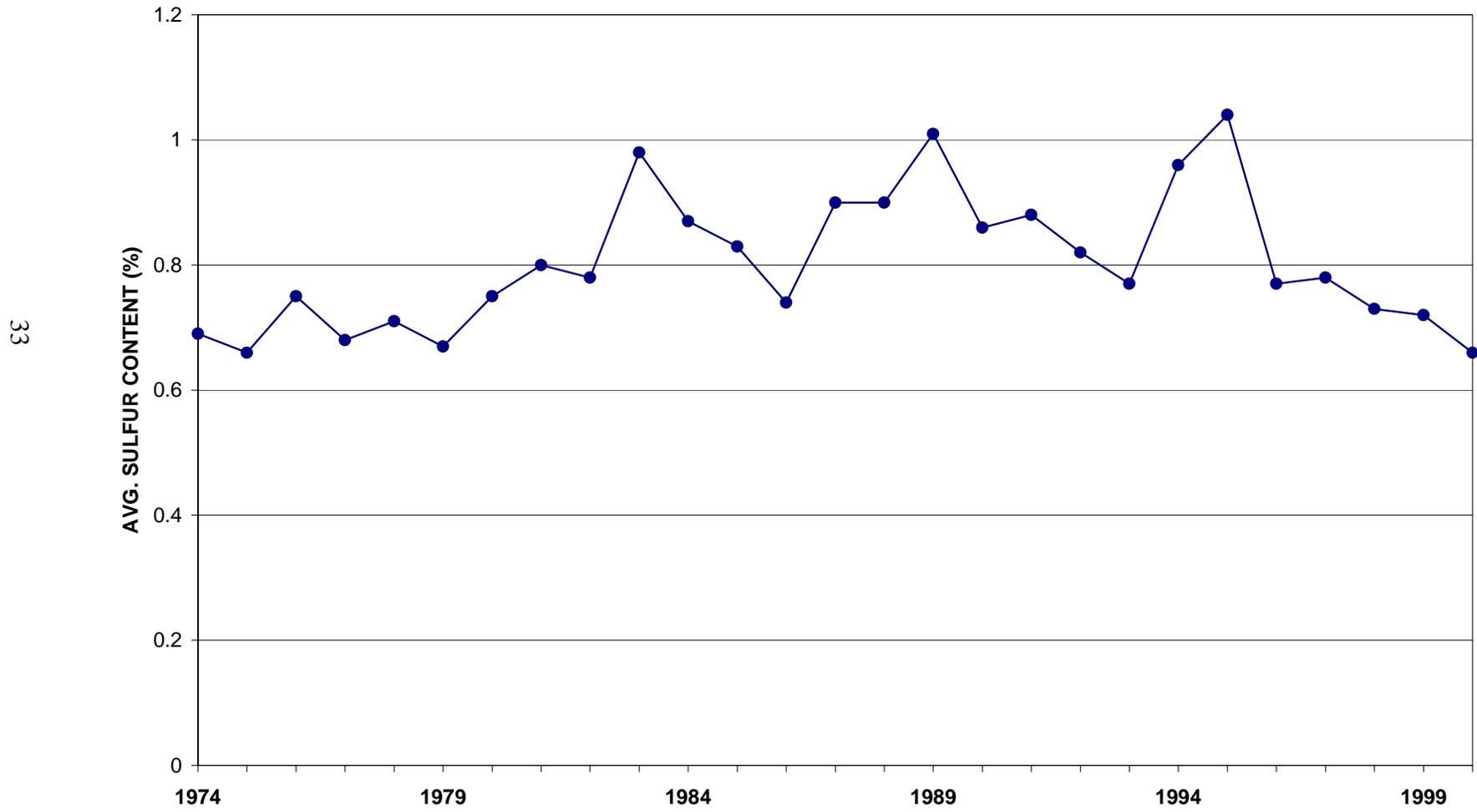


FIGURE 7
HESKETT 1

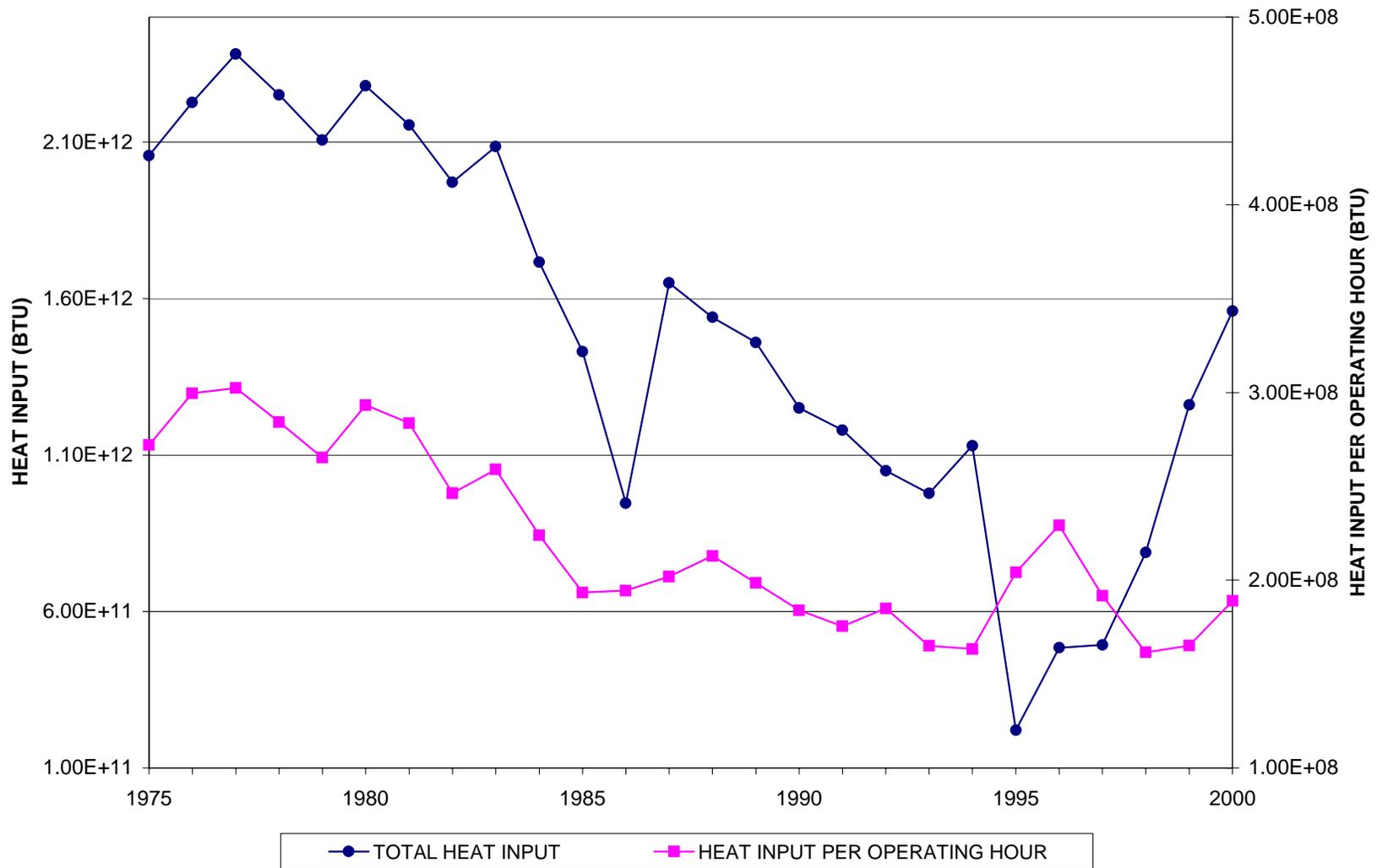
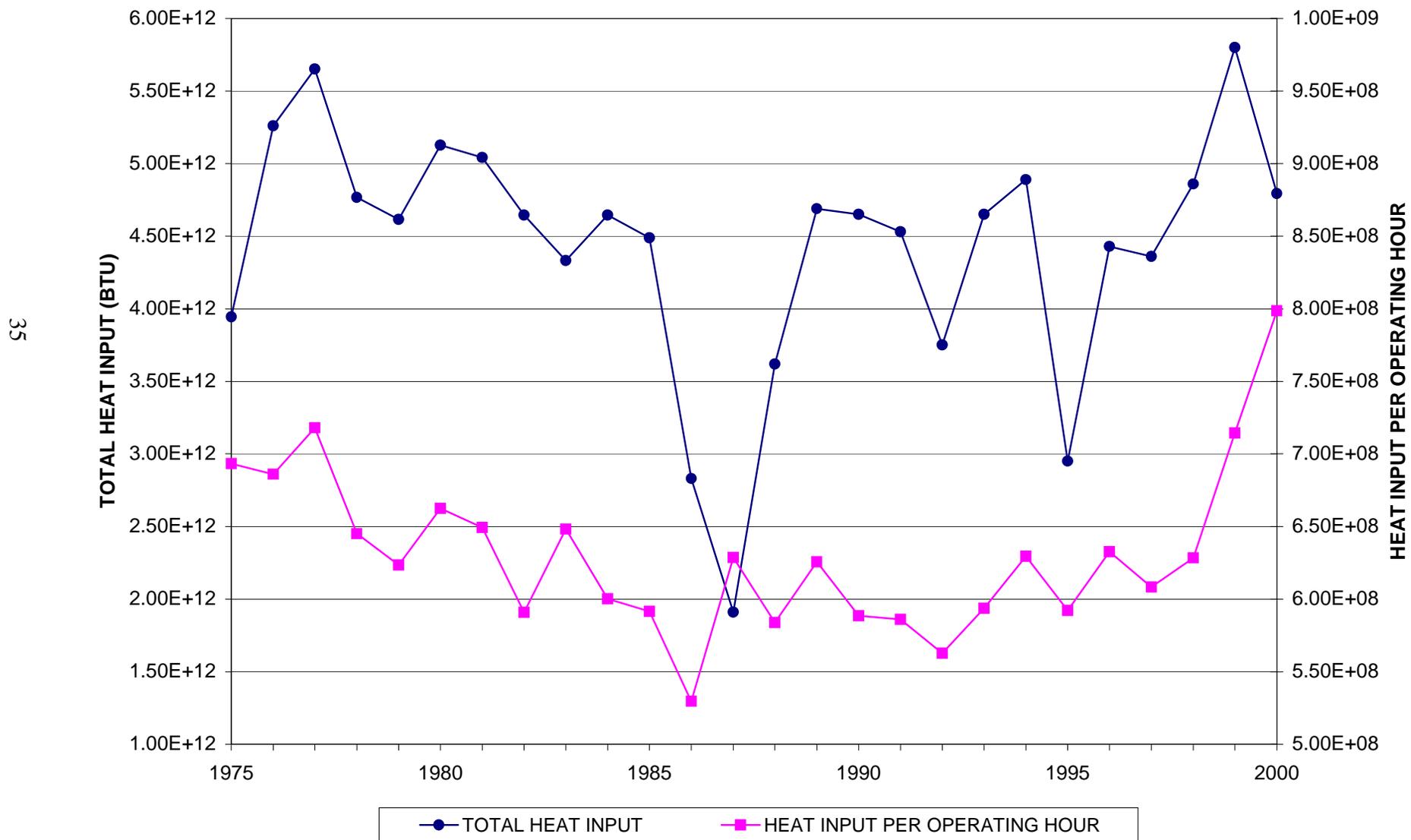


FIGURE 8
HESKETT 2



C. **Leland Olds Station**

The Leland Olds Station consists of two units and is located near Stanton in Mercer County. The facility is operated by Basin Electric Power Cooperative. Unit 1 is a pulverized wall fired unit which began operation in 1966. The unit has a nominal heat input rating of 2622×10^6 Btu/hr. Unit 2 is a cyclone unit with a nominal rating of 5130×10^6 Btu/hr and a generator nameplate rating of 440 MWe. This unit was put into operation in 1975. Each unit exhausts through a separate stack and is treated as separate unit for this analysis.

Coal for the Leland Olds Station was obtained from the Glenharold Mine until the mine closed in 1993. After this date, coal has been obtained from the Freedom Mine and other sources. Figures 9 and 10 shows the variation in the yearly average sulfur content of the coal consumed as reported in the Annual Emission Inventory Reports that were submitted for the facility. Based on the data, the Department has determined a weighted mine average sulfur content for the coal obtained from Glenharold Mine to be 0.65% for both units.

Figures 11 and 12 present the heat inputs for Units 1 and 2, respectively. The Department proposes that the 1976-77 time period is representative of normal operations for Unit 1. Unit 2 began operation in late 1975 with commercial operation on December 15, 1975. Commercial operation was only at 68% of the units rating because of equipment problems (see 12/2/75 letter in Appendix C). In a May 3, 1976 letter, Basin Electric explained that Unit 2 had operated at only about 300 megawatts for the first couple of months in 1976. In May of 1976 generator problems forced the shutdown of unit for an extended period (see 5/26/76 letter in Appendix C). The Department proposes that 1976 is not representative of normal operations for this unit. In part of 1976, the unit was still in a startup mode and there were problems that forced extended outages. The Department does not

FIGURE 9
LELAND OLDS 1

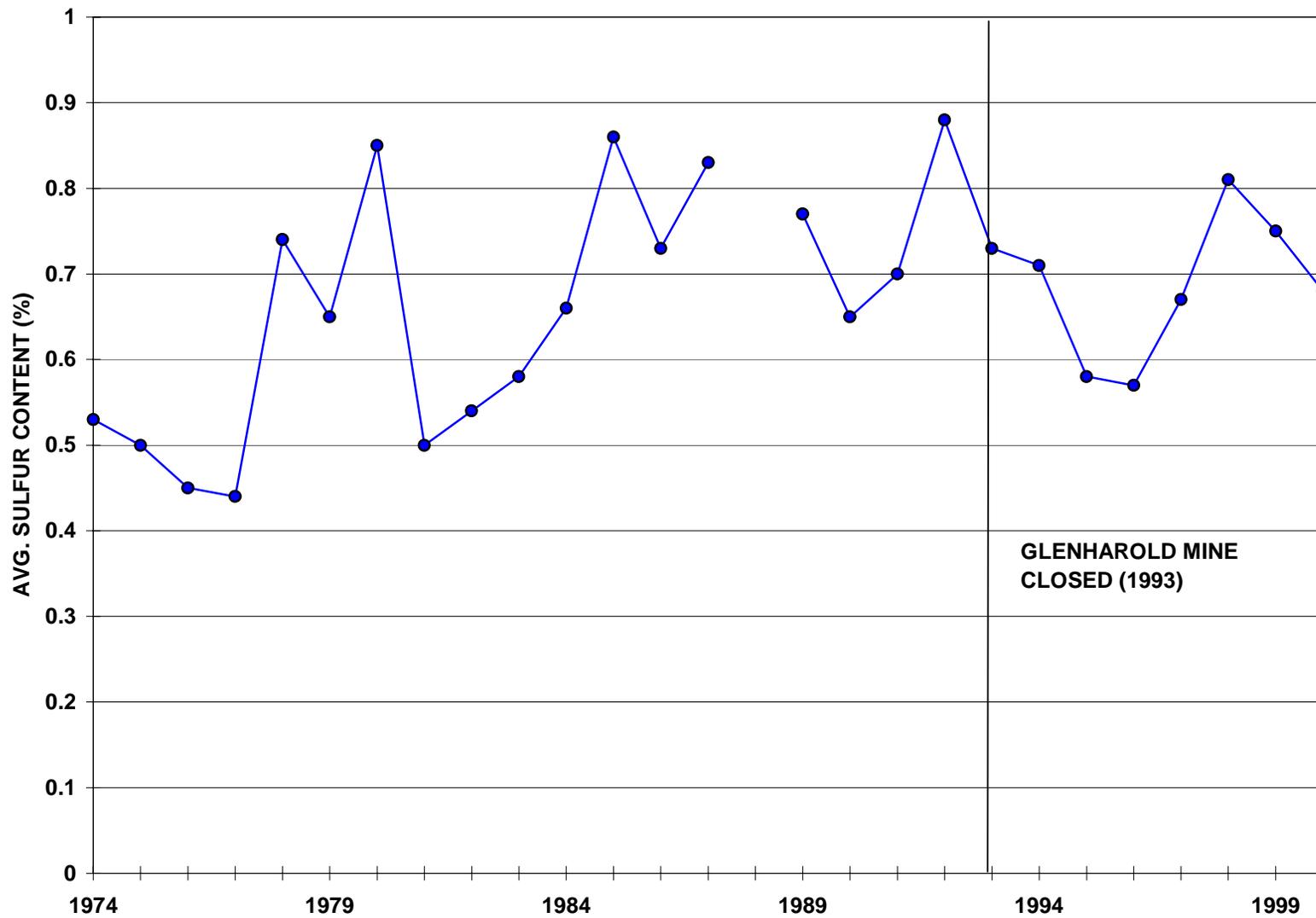


FIGURE 10
LELAND OLDS 2

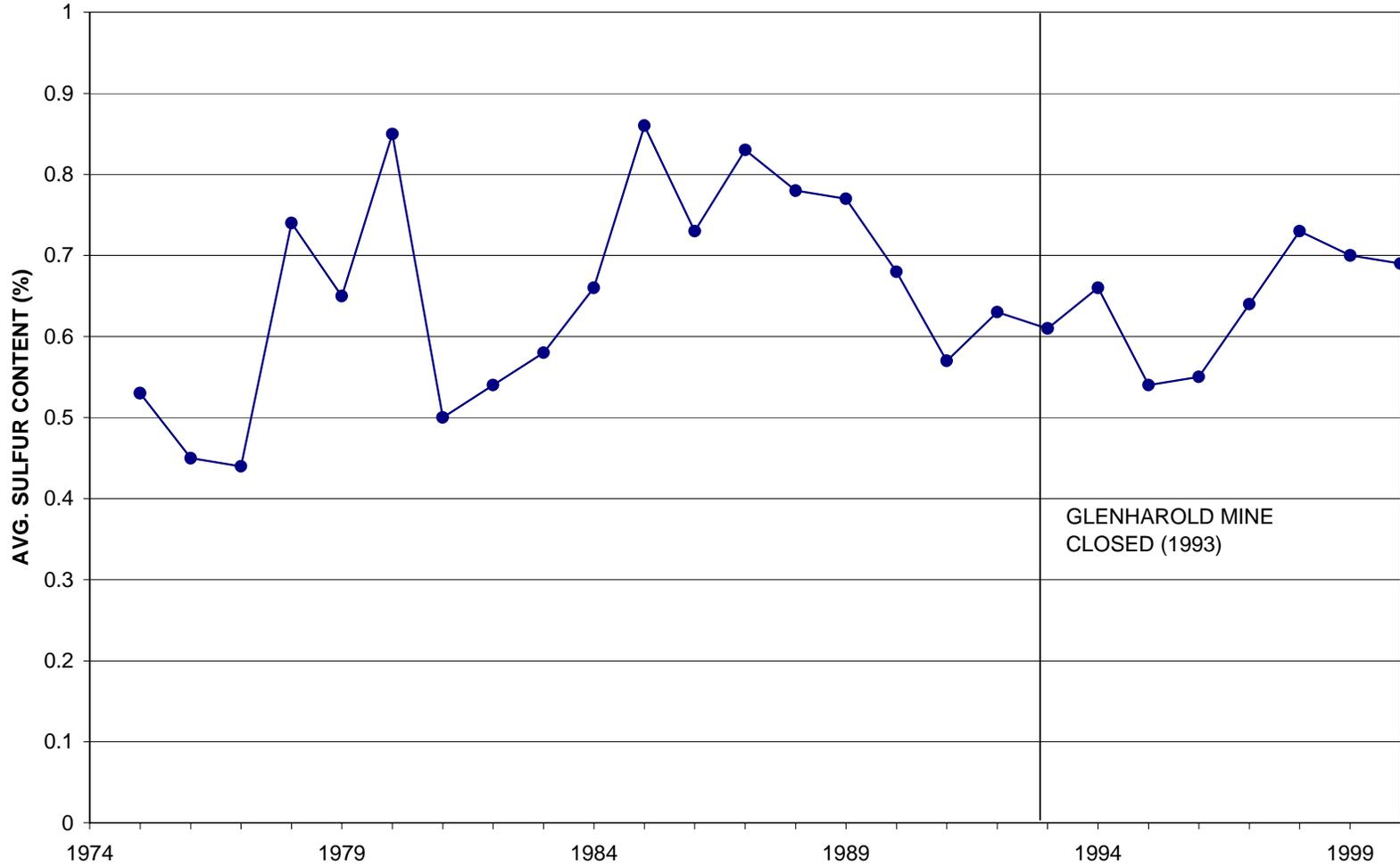


FIGURE 11
LELAND OLDS 1

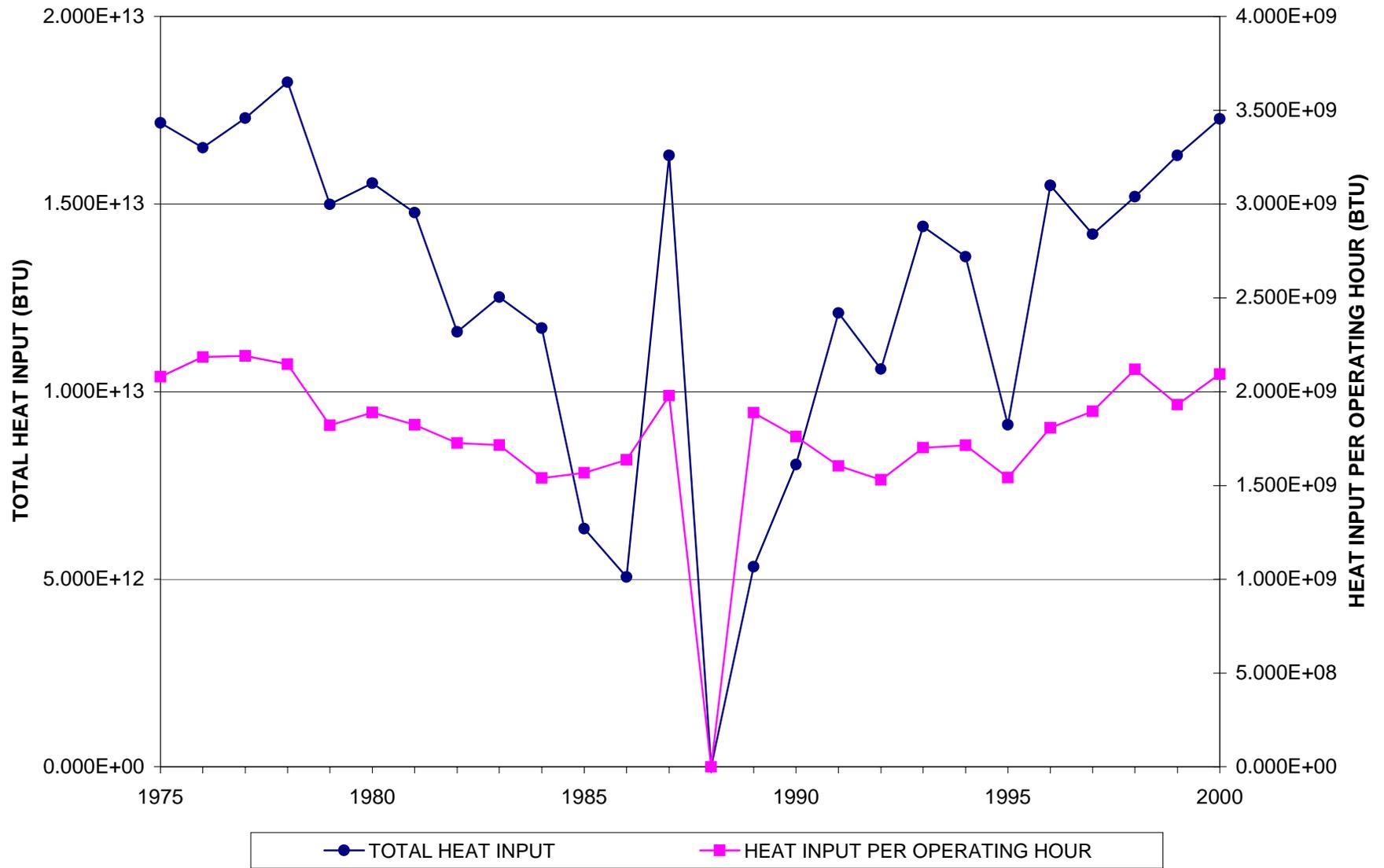
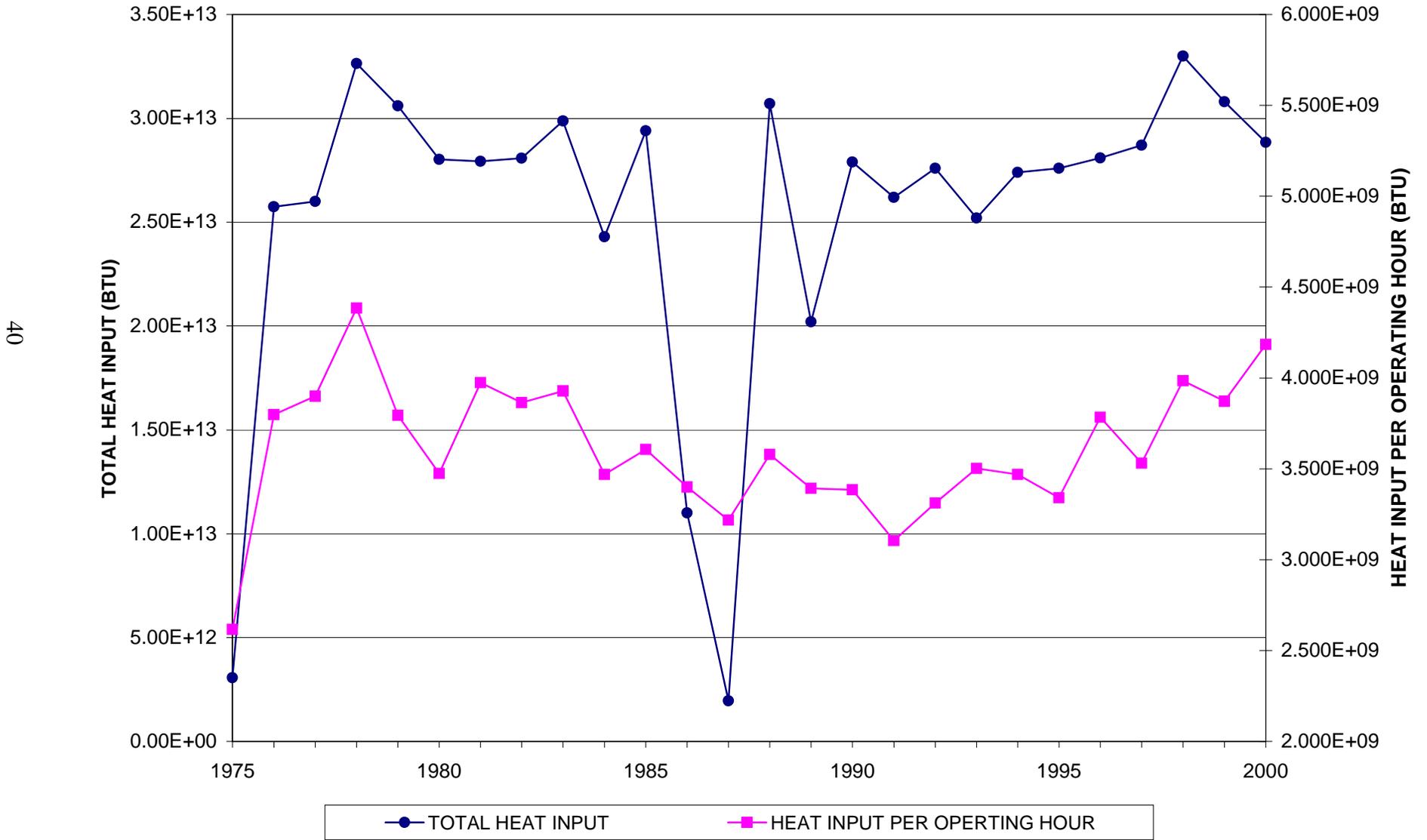


FIGURE 12
LELAND OLDS 2



consider initial startup mode to be normal operations for a power plant. Based on the heat input data, the Department proposes that the 1977-78 time period is representative of normal operations for the purpose of calculating the baseline emission rate.

The baseline emission rate for each unit was calculated based on the AP-42 emission factor 30(S) and data from the Annual Emission Inventory Reports for the facility. The data and results are as follows:

Unit	Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation	2-Year Avg. Emission Rate (lb/hr)
1	1976	1255995	0.65	12246.0	7553	3235.2
1	1977	1306785	0.65	12741.2	7894	
2	1977	1964660	0.65	19155.4	6667	6079.7
2	1978	2435160	0.65	23742.8	7445	

Where:

$$\text{SO}_2 \text{ emissions (tons)} = (30)(\text{Mine Avg. Sulfur Content})(\text{Coal Usage}) \div (2,000 \text{ lb/ton})$$

$$\text{2-Year Avg. Emission Rate (lb/hr)} = [(\text{2 year total SO}_2 \text{ Emission (tons)}) \div (2,000 \text{ lb/ton})] \div [\text{2 year total Hours of Operation}]$$

D. Lignite Gas Processing Plant

The Lignite Gas Processing Plant is located near Lignite, North Dakota in Burke County and is currently operated by Bear Paw Energy, Inc. The plant was built by Texaco, Inc. in 1962 and was designed to process 21 million standard cubic feet of gas per day. The plant was originally built with a 20 long ton per day two bed Claus sulfur recovery unit with a design efficiency of 94 percent. In 1971, the plant was processing about 8 to 9 million cubic feet per day of gas. The processing rate declined to 6 million cubic feet per day in 1973, 4 million cubic feet per day in 1976 and 2-3 million cubic feet per day in 1977. The decline in gas volume was primarily due to declining production at the wells, deterioration of the gas gathering lines and the removal of several compressors.

In December of 1975, the sulfur recovery unit mechanically failed. Texaco stated that it was not economically feasible to repair the sulfur recovery unit. The plant was then operated without the sulfur recovery unit. The plant was purchased by Darenco, Inc. in December of 1976. In September of 1977 the plant was sold to the Energy Operating Company (ENOPCO). The plant was again sold in January 1980 to Cities Service, Inc. Cities Service replaced the sulfur recovery unit in late 1983.

The original Permit to Operate for the facility was issued in 1980 with an emission limit of 708 lb/hr from the acid gas flare. Based on the PSD rules in effect in 1975, the shutdown of the sulfur recovery unit was not considered a major modification. In June 1983, a Permit to Construct was issued to Cities Service which allowed an increase in SO₂ emissions from the flare to 1416 lb/hr provided a new sulfur recovery unit was installed. On July 11, 1983, the Department issued a Permit to Construct for the sulfur recovery unit which limited emissions to 217 lb/hr.

In the analysis for the June 1, 1983 Permit to Construct, a determination was made that the baseline emission rate for the plant was 708 lb/hr. However, this determination was based on the potential to emit of the source (before air pollution controls) as of the major source baseline date (January 6, 1975). On August 7, 1980, substantial changes were made to the PSD rules. These changes render the earlier determination of the baseline emission rate invalid. It is proposed that the baseline emission rate be based on actual emissions on or near the minor source baseline date.

Up until December 1975, sulfur dioxide emissions from the plant were very small because of the sulfur recovery unit. An emissions inventory report for 1971 indicated approximately 40 tons of sulfur dioxide emissions. A review of the facility by Pacific Environmental Services in early 1975 estimated sulfur dioxide emissions at approximately 170 tons per year.

In a letter to the Department on February 26, 1976 (see Appendix D), Texaco estimated that the average emissions from the plant during 1976 would be 35.8 g/sec (284.1 lb/hr). This was based on an average processing rate of 3.60×10^6 SCFD and an H₂S content of the inlet gas of 1.12%. In early 1978, the Department conducted an inspection of the facility. The processing rate was listed as 2-3 million cubic feet per day and the H₂S content of the inlet gas was 1.64%.

Because of the frequent change in ownership near the minor source baseline, the future of the plant on that date was uncertain. If the plant were to continue to operate, the future production rate was also uncertain. Therefore, the Department proposes that the 1976-77 time period be used to calculate the baseline emission rate. Based on this information, the baseline emission rate was calculated as follows:

$$\begin{aligned}
 \text{SO}_2 \text{ Emissions (1976)} &= (3.6 \times 10^6 \text{ scfd})(0.0112 \text{ ft}^3 \text{ H}_2\text{S}/\text{ft}^3 \\
 &\text{ gas) (1 lb-mole}/379.4 \text{ ft}^3)(64 \text{ lb} \\
 &\text{ SO}_2/\text{lb-mole}) \\
 &= 6,801.5 \text{ lb/day} \\
 &= 283.4 \text{ lb/hr} \\
 &= 1,241.2 \text{ tons} \\
 \\
 \text{SO}_2 \text{ Emissions (1977)} &= (2.5 \times 10^6 \text{ scfd})(0.0164 \text{ ft}^3 \text{ H}_2\text{S}/\text{ft}^3 \\
 &\text{ gas) (1 mole}/379.4 \text{ ft}^3)(64 \text{ lb SO}_2/\text{lb-} \\
 &\text{ mole}) \\
 &= 6,916.2 \text{ lb/day} \\
 &= 288.2 \text{ lb/hr} \\
 &= 1,262.2 \text{ tons} \\
 \\
 \text{Avg. SO}_2 \text{ Emission Rate} &= (283.4 \text{ lb/hr} + 288.2 \text{ lb/hr}) \div 2 \\
 &= 285.8 \text{ lb/hr}
 \end{aligned}$$

E. **Mandan Refinery**

The Mandan Refinery was built in 1954 and is currently operated by Tesoro Refining and Marketing Company. The plant is located along the Missouri River near Mandan in Morton County. The refinery operates 24 hours per day, seven days a week and 52 weeks per year. The refinery has processed up to 65,000 barrels per day of crude oil with the maximum capacity unknown. On the minor source baseline date, the refinery consisted of the following source units that emitted significant amounts of sulfur dioxide:

<u>Source</u>	<u>Identification</u>
Boilers	1, 2, 3
Crude Furnace	Crude Furnace
Fluid Catalytic Cracking Unit	FCCU
Ultraformer Furnaces	F-100, F1, F2, F3, F4, Regeneration Furnace
Alkylation Unit Furnaces	B1, B2

The Department has no information about crude oil processing rates for the refinery. Records indicates that 1978 was a turnaround year for the facility and is not considered normal operations. In 1978, the crude furnace was replaced with a larger unit now commonly referred to as the CO furnace. In addition, carbon monoxide from the fluid catalytic cracking unit was now routed to this furnace. Since carbon monoxide has a heating value when combusted, the amount of fuel oil and fuel gas combusted in this unit dropped dramatically from 1978-1980. With the drop in fuel usage, sulfur dioxide emissions also dropped from this furnace. Because of the replacement of the crude furnace and the change in the method of operation of the refinery (i.e. routing off gas

from the FCCU to the CO furnace), the Department proposes that a time period before 1978 should be used to represent the baseline period. The only year prior to 1978 for which data is available is 1976. In a letter to the Department on September 13, 2001 BP (former owner of the refinery) indicated they could not locate emissions inventories for 1974, 1975 or 1977. They also indicated that 1976 data would be fairly representative of both 1976 and 1977. The one exception that BP noted was for the Ultraformer furnaces. BP indicated that the calculations for the 1976 data, which the Department has on file, did not account for sulfur in the fuel gas from the desulfizer hydrogen sulfide stripper on the Ultraformer. BP estimated the Ultraformer fuel gas contained 500 ppmv H₂S and emissions of sulfur dioxide were about 57 tons in 1976 for the heaters and furnaces at the Ultraformer.

The amount of fuel gas combusted in 1976 was reported in units of standard cubic feet. Tesoro has provided information that indicates that standard temperature for the report was 32°F. This is the standard temperature used in chemistry but not the temperature normally used for reporting gas volumes for air pollution calculations. Based on Tesoro's information, a value of 359 cubic feet/lb-mole was used in the calculations as the molecular volume of the fuel gas. The sulfur content of the fuel gas was also reported as percent by weight. This is also unusual since it is normally reported as a volume percentage (or mole percentage). The initial data that was supplied for the oil that was combusted provided the API Gravity (°API) from which the density of the oil can be calculated. Since the density of the oil is known, a mass balance approach to calculating emissions from the oil was used instead of AP-42 emission factors.

Based on the data available, the Department proposes to use the 1976 data for the determination of the baseline emission rates. The emissions for each unit was calculated as follows:

Boilers

- Boiler 1 & 2 (identical fuel usage)

Fuel Gas Combusted - 423.5×10^6 scf (each)
 Avg. Sulfur Content of Fuel Gas - 1.43% (weight %)
 Avg. Molecular Wt. of Fuel Gas - 19.30 lb/lb-mole
 Fuel Oil Combusted - 104,715 barrels (each)
 Sulfur Content of Fuel Oil - 1.66% (weight %)
 Avg. API Gravity - 11.26 °API (8.25 lb/gal)

$$\begin{aligned} \text{SO}_2 \text{ (Fuel Gas)} &= (423.5 \times 10^6 \text{ scf})(0.0143 \text{ lb S/lb gas})(19.30 \text{ lb gas/mole gas})(1 \text{ mole}/359 \text{ scf})(2 \text{ lb SO}_2 / 1 \text{ lb S}) \div (2,000 \text{ lb/ton}) \\ &= 325.6 \text{ tons (each)} \end{aligned}$$

$$\begin{aligned} \text{SO}_2 \text{ (Fuel Oil)} &= (104,715 \text{ bbl})(42 \text{ gal/bbl})(0.0166 \text{ lb S/lb oil})(8.25 \text{ lb/gal})(2 \text{ lb SO}_2/\text{lb S}) \div (2,000 \text{ lb/ton}) \\ &= 602.3 \text{ tons (each)} \end{aligned}$$

$$\begin{aligned} \text{Total SO}_2 &= (325.6 + 602.3)(2 \text{ boilers}) \\ &= 1,855.8 \text{ tons} \end{aligned}$$

- Boiler #3

Fuel Gas Combusted - 132.4×10^6 scf
 Avg. Sulfur Content of Fuel Gas - 1.43% (weight %)
 Avg. Molecular Wt. of Fuel Gas - 19.30 lb/lb-mole
 Fuel Oil Combusted - 49,791 barrels
 Sulfur Content of Fuel Oil - 1.66% (weight %)
 Avg. API Gravity - 11.26 °API (8.25 lb/gal)

$$\text{SO}_2 \text{ (Fuel Gas)} = (132.4 \times 10^6 \text{ scf})(0.0143 \text{ lb S/lb gas})(19.30 \text{ lb gas/mole gas})(1 \text{ mole}/359 \text{ scf})(2 \text{ lb SO}_2 / 1 \text{ lb S}) \div (2,000 \text{ lb/ton})$$

$$= 101.8 \text{ tons}$$

$$\text{SO}_2 \text{ (Fuel Oil)} = (49,791 \text{ bbl})(42 \text{ gal/bbl})(8.25 \text{ lb/gal})(0.0166 \text{ lb S/lb oil})(2 \text{ lb SO}_2/\text{lb S}) \div (2,000 \text{ lb/ton})$$

$$= 286.4 \text{ tons}$$

$$\text{SO}_2 \text{ (Total)} = 101.8 + 286.4 = 388.2 \text{ tons}$$

$$\text{SO}_2 \text{ (Total for all boilers)} = 1,855.8 + 388.2 = 2,244.0 \text{ tons}$$

Crude Furnace

Fuel Gas Combusted - 837×10^6 scf

Avg. Sulfur Content of Fuel Gas - 4.25% (weight %)

Avg. Molecular Wt. of Fuel Gas - 20.3 lb/lb-mole

Fuel Oil Combusted - 69,216 barrels

Sulfur Content of Fuel Oil - 1.66% (weight %)

Avg. API Gravity - 11.29 °API (8.25 lb/gal)

$$\text{SO}_2 \text{ (Fuel Gas)} = (837 \times 10^6 \text{ scf})(0.0425 \text{ lb S/lb gas})(20.3 \text{ lb gas/mole gas})(1 \text{ lb-mole}/359 \text{ scf})(2 \text{ lb SO}_2 / 1 \text{ lb S}) \div (2,000 \text{ lb/ton})$$

$$= 2,011.5 \text{ tons}$$

$$\text{SO}_2 \text{ (Fuel Oil)} = (69,216 \text{ bbl})(42 \text{ gal/bbl})(8.25 \text{ lb/gal})(0.0166 \text{ lb S/lb oil})(2 \text{ lb SO}_2/\text{lb S}) \div (2,000 \text{ lb/ton})$$

$$= 398.1 \text{ tons}$$

$$\begin{aligned} \text{Total SO}_2 &= 2,011.5 + 398.1 \\ &= 2,409.6 \text{ tons} \end{aligned}$$

FCCU

AP-42 lists a sulfur dioxide emission factor of 493 lb/1,000 barrels of fresh feed. However, this factor does not take into account any variation in the sulfur content of the oil fed to the FCCU and there is no explanation of the sulfur content on which the factor was derived. Therefore, the Department proposes that a mass balance approach is more appropriate. In the 1976 data, the amount of coke burned off the FCCU catalyst during regeneration and the sulfur content of the coke are reported.

Coke Burned during Regeneration - 75379 tons
Sulfur Content of Coke - 3.3% (wt. %)

$$\begin{aligned} \text{SO}_2 &= (75379 \text{ tons})(0.033 \text{ lb S/lb coke})(2 \text{ lb SO}_2/1 \text{ lb S}) \\ &= 4975.0 \text{ tons} \end{aligned}$$

Alkylation Unit Furnaces

Fuel Gas Combusted - 972×10^6 scf
Avg. Sulfur Content of Fuel Gas - 1.95% (weight %)
Avg. Molecular Wt. of Fuel Gas - 13.3 lb/lb-mole
Oil Combusted - 1,490 barrels
Avg. Sulfur Content of Oil - reported as 0%
Avg. API Gravity - 22.3 °API (7.66 lb/gal)

$$\begin{aligned} \text{SO}_2 \text{ (Fuel Gas)} &= (972 \times 10^6 \text{ scf})(0.0195 \text{ lb S/lb gas})(13.3 \\ &\quad \text{lb gas/mole gas})(1 \text{ lb-mole}/359 \text{ scf})(2 \text{ lb} \\ &\quad \text{SO}_2 /1 \text{ lb S}) \div (2,000 \text{ lb/ton}) \\ &= 702.2 \text{ tons (each)} \end{aligned}$$

Ultraformers Furnaces

Total Fuel Gas Combusted - 1345.87×10^6 scf
H₂S Content - 500 ppmv (per BP 9/13/01)

$$\text{SO}_2 = (1345.87 \times 10^6 \text{ scf gas})(500 \text{ scf H}_2\text{S}/10^6 \text{ scf gas})(1 \text{ lb-mole}/359 \text{ scf})(64 \text{ lb SO}_2/\text{lb-mole})(1 \text{ mole SO}_2/\text{mole H}_2\text{S}) \div (2,000 \text{ lb/ton})$$

$$= 60.0 \text{ tons}$$

Units	SO ₂ Emissions (tons)	Total Hours of Operation (all units)	Avg. Hours of Operation (per unit)	2-year Avg. Emission Rate (lb/hr)*
Boilers 1-3	2244.0	21624	7208	622.6
Crude Furnace	2409.6	8760	8760	550.1
FCCU	4975.0	8760	8760	1135.8
Alk. Unit Furnaces	702.2	17520	8760	160.3
Ultraformer Furnaces	60.0	46986	7831	15.3

*Emission rate is the total for all units.

F. **Wm. J. Neal Station:**

The Wm. J. Neal Station (Neal Station) was located near Velva in McHenry County. The facility, which was operated by Basin Electric Power Cooperative, began operation in 1952 and was shutdown in 1985. The facility consisted of two pulverized coal-fired boilers with a nominal rating of 305.5×10^6 Btu/hr each. Each of these units had a separate stack; however, all data to determine emission rates is reported as a total for the two units. For purposes of modeling, the plant has been treated as one unit. For this analysis, the two units are treated as a single entity.

The Neal Station obtained its coal from the Velva Mine which was located a few miles southwest of the plant. Figure 13 presents the coal sulfur content data submitted in the Annual Emission Inventory Reports for the facility. Based on the data, a weighted average sulfur content was calculated to be 0.32%.

Figure 14 presents the heat input for the facility. The Department proposes that the 1976-77 time period adequately represents normal operations for the baseline period.

The baseline emission rate was calculated using the AP-42 emission factor 30(S) and data included in the 1976 and 1977 Annual Emission Inventory Reports. The data and results are as follows:

Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation (total)	Avg. Hours of Operation (per boiler)	2-Year Avg. Emission Rate (lb/hr)
1976	249120	0.32	1195.8	14716	7358	354.6
1977	327882	0.32	1573.8	16523	8262	

Where:

$$\text{SO}_2 \text{ emissions (tons)} = (30)(\text{Mine Avg. Sulfur Content})(\text{Coal Usage}) \div (2,000 \text{ lb/ton})$$

$$\begin{aligned} \text{2-Year Avg. Emission Rate (lb/hr)} &= \frac{[1976 \text{ SO}_2 \text{ Emissions (tons)} + 1977 \text{ SO}_2 \text{ Emission (tons)}] (2,000 \text{ lb/ton})}{[1976 \text{ Ag. Hours of Operation} + 1977 \text{ Ag. Hours of Operation}]} \end{aligned}$$

Draft

FIGURE 13
Wm. J. NEAL STATION

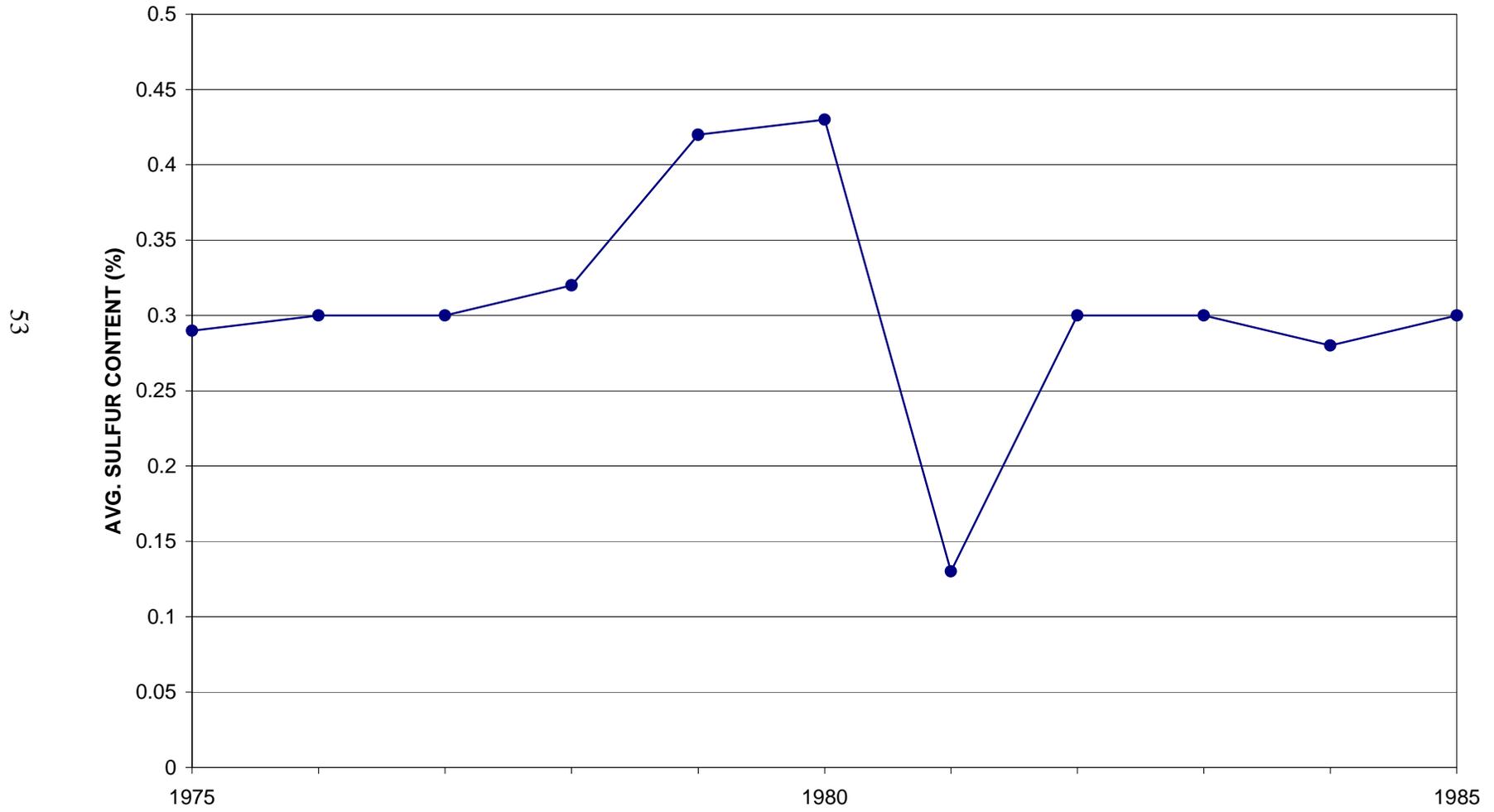


FIGURE 14
Wm. J. NEAL STATION

54



G. Royal Oak Charcoal Briquette Plant

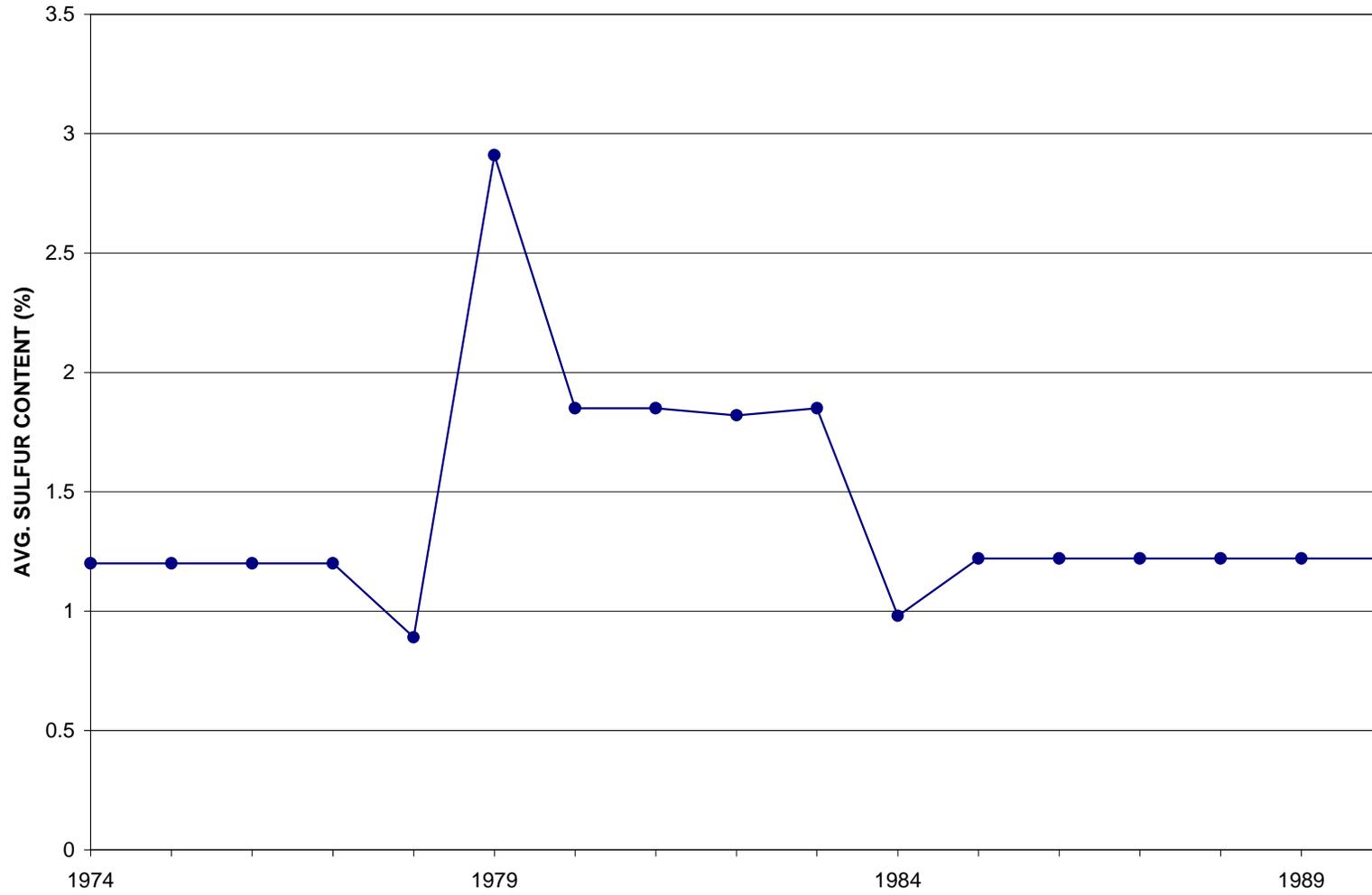
Royal Oak, Inc. operated a charcoal briquette plant southeast of Dickinson in Stark County until 1990. The plant was built in the 1920's and was operated by several different companies. The plant initially produced a domestic heating briquette from lignite char. In 1961, Husky Oil Co. bought the plant and converted to the production of barbeque briquettes. The main processes at the facility included lignite crushing, process steam and heat generation, carbonization, pyrite separation, grinding of the char, mixing with a binding agent, briquetting, drying the briquettes and bagging. The name of the subsidiary that operated the plant was later changed to Royal Oak. The facility ceased operation in 1990. Of the processes at the facility, only the steam/heat generation and carbonization generated significant amounts of sulfur dioxide.

Royal Oak obtained its coal from mines in the vicinity of the plant. The primary mine was located just south and east of the plant. The coal that was mined was characterized by a high sulfur content, high ash content and low heating value. Figure 15 presents the coal sulfur content data submitted for the facility in the Annual Emission Inventory Reports. Based on this data, a weighted average sulfur content of 1.53% was calculated for the boilers and 1.45% for the carbonizers.

The steam and heat for the plant was provided by three spreader stoker lignite-fired boilers. Boilers 1 and 2 had a nominal rating of 19.65×10^6 Btu/hr each and Boiler 3 had a rating of 57×10^6 Btu/hr. In 1984, the use of the lignite-fired boilers was significantly reduced by the installation of a waste heat boiler.

The carbonizer section of the plant consisted of two Lurgi carbonizers until 1976. The Lurgi carbonizers had a nominal rating of 150 tons of char per day. In July of 1975, the Department received a Permit to Construct

FIGURE 15
ROYAL OAK



application for the addition of a Herreschoff carbonizer furnace. A Permit to Construct was issued in September of 1975 and the unit started operation in July of 1976. Because of growing demand, Royal Oak applied for a Permit to Construct for a second Herreschoff carbonizer furnace in October of 1976. Due to a court decision, a Permit to Construct was never issued and the unit began operation in October of 1978. The output of the two Herreschoff carbonizers was limited to 288 tons per day by the Permit to Operate for the facility.

When determining normal operations for a facility, the Department has determined that production increases that are reasonably anticipated on the baseline date should be included when determining the baseline concentration. Because Royal Oak had anticipated production increases and had initiated or completed construction of two new carbonizer furnaces to accommodate this production increase prior to the minor source baseline date, the Department proposes that a two year period after the minor source baseline date is more representative of normal operations for the facility. Figures 16 and 17 present the coal usage for the boilers and carbonizer furnaces. Figure 18 presents the total coal usage for the facility. Because a waste heat boiler was installed in 1984 and heat input is not a value associated with carbonizer furnaces, the determination of the period that represents normal operations was based on total coal usage for the facility. The Department proposes that the 1978-79 period adequately represents normal operation of the facility.

When calculating emissions from the source units, the three boilers were considered one source and the four carbonizer furnaces were considered another source. Sulfur dioxide emissions for the boilers were calculated based on the AP-42 emission factor 30(S).

No emissions factors were available to determine sulfur dioxide emissions from the carbonizer furnaces. Stack testing has been done to determine emissions from the

FIGURE 16
ROYAL OAK BOILERS

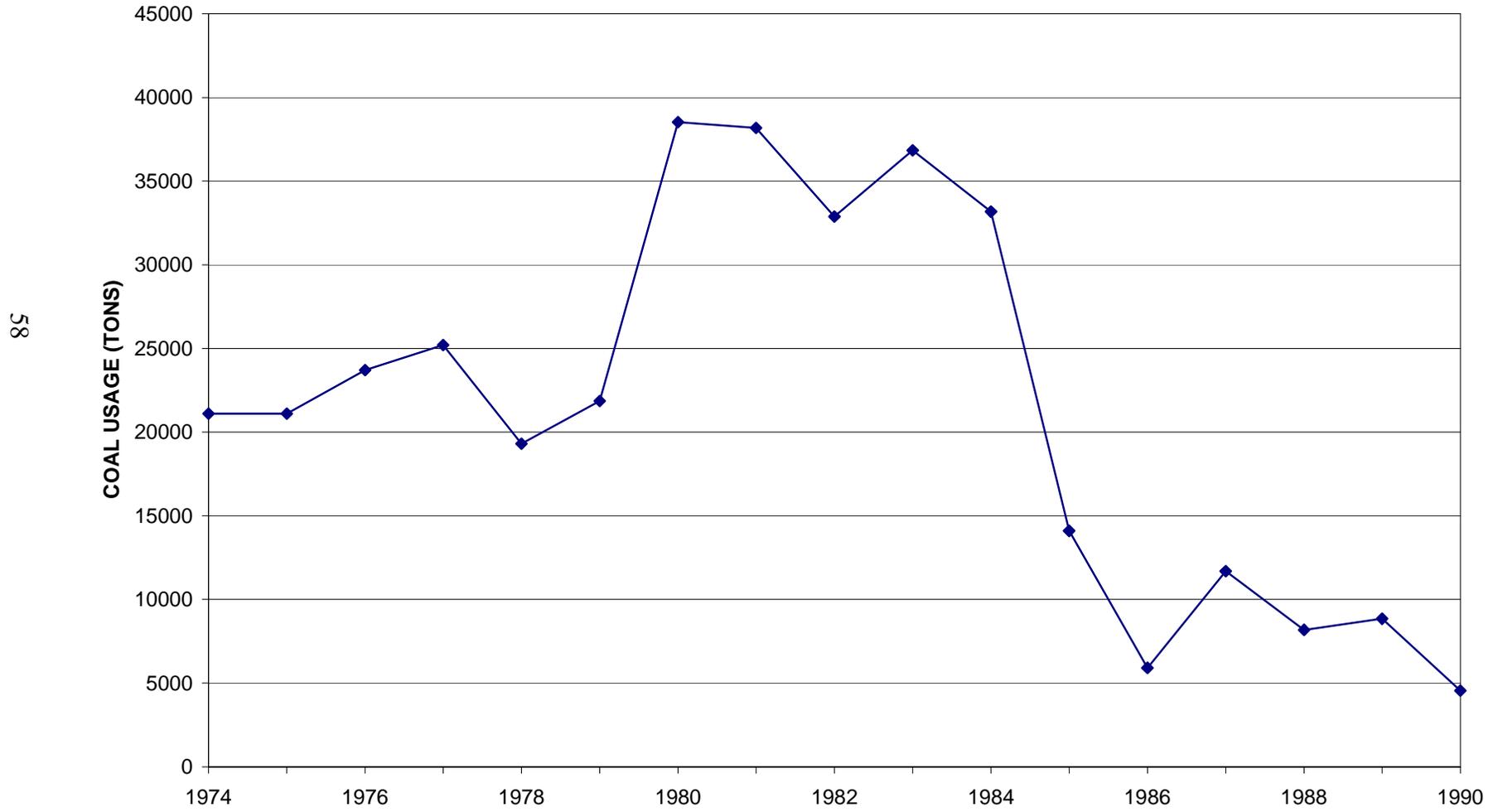


FIGURE 17
ROYAL OAK CARBONIZERS

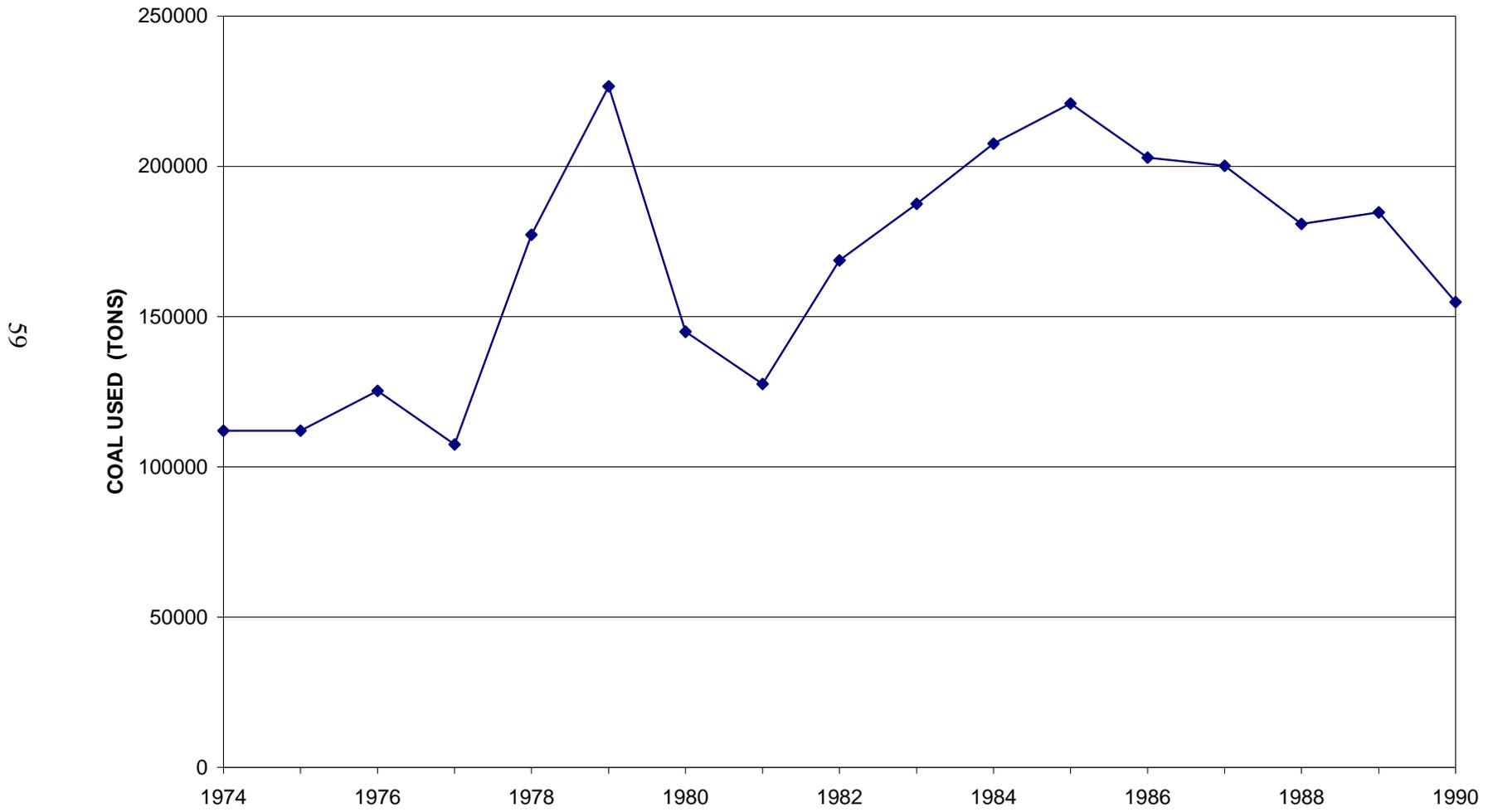
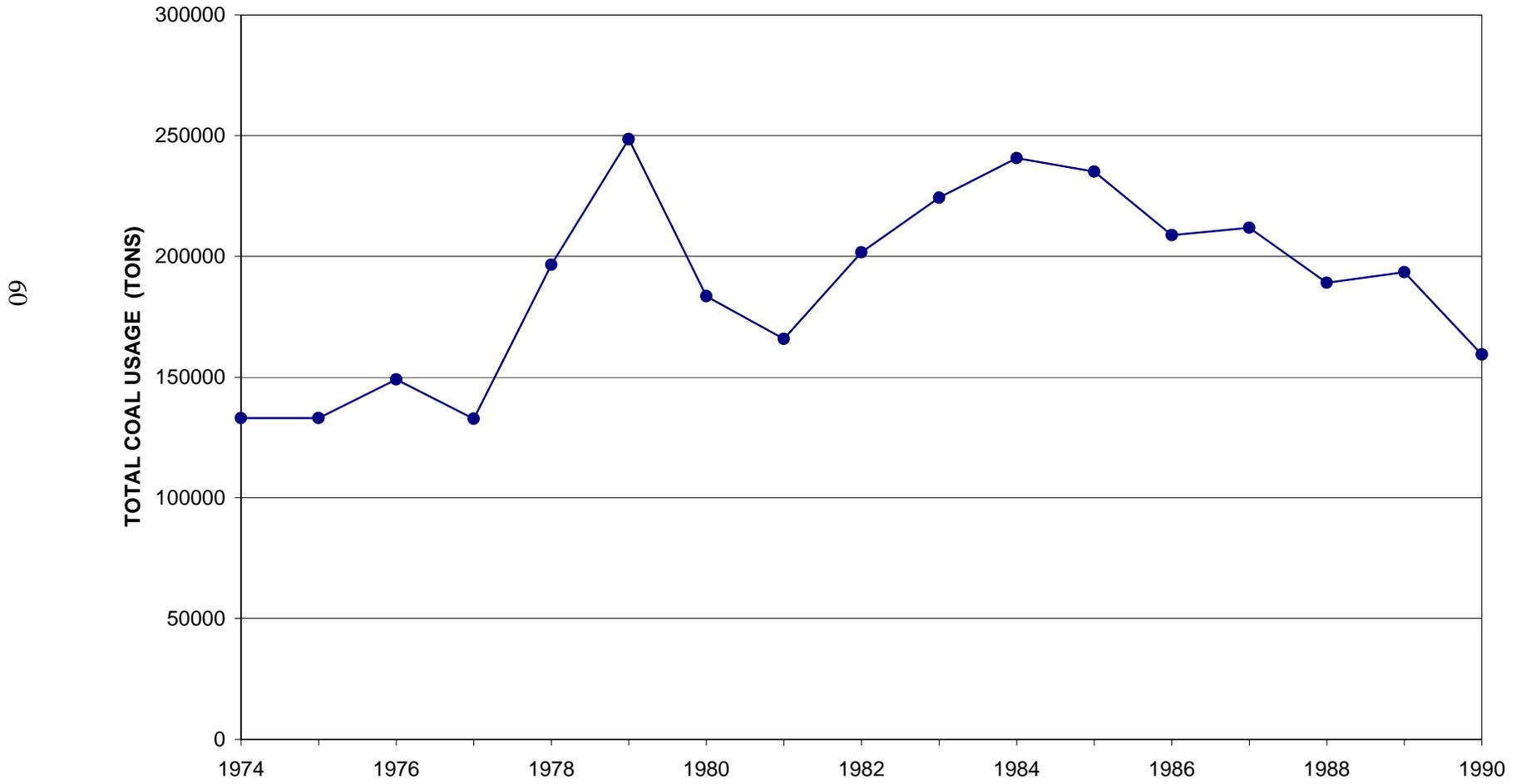


FIGURE 18
ROYAL OAK
BRIQUETTING PLANT



Herreschoff carbonizers. This data was used to develop an emission factor for use in the baseline emission rate calculations.

The Department files contain two emissions tests for sulfur dioxide from the carbonizer furnaces. The first test, in 1983, was conducted in the stack of the after combustion chamber for the Herreschoff carbonizer furnaces. The flue gas in the stack was characterized by severe cyclonic flow and negative velocity pressure at some sampling points. The testing that was conducted used a "blind man's" approach. That is, no adjustment of the sampling nozzle was made for the angle of the flow within the stack. Because the cyclonic flow problems and the measurement method, the data is considered unreliable by the Department.

In 1984, Royal Oak added a waste heat boiler to their carbonizer system. The flue gas from the after combustion chamber was routed to this boiler to recover heat and then transmitted to the atmosphere by way of a separate stack. In late 1984, stack testing was conducted to determine the sulfur dioxide emissions from the system. Based on the Department's review of the test, the data is considered valid and appropriate for determining emission rates. Based on the test results, an emission factor of 29.6(S) lb/ton was derived for the Herreschoff carbonizer furnaces. This factor is for only one test (3 runs) and does not account for the lignite ash sodium content. However, no better data exists for determining sulfur dioxide emissions. This emission factor was also used for the Lurgi carbonizer furnaces since no data on emissions was available for those units.

The data and calculations are summarized as follows:

Unit	Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation (total for all units)	Avg. Hours of Operation (per unit)	2-Year Avg. Emission Rate (lb/hr)
Boilers 1-3	1978	19300	1.53	442.9	16800	5600	172.1
Boilers 1-3	1979	21856	1.53	501.6	16128	5376	
Carbonizers 1-4	1978	177192	1.45	3802.5	21672	5418	1562.9
Carbonizers 1-4	1979	226637	1.45	4863.6	23289	5822	

Where:

$$\text{SO}_2 \text{ (tons)} = F (S)(\text{coal usage}) \div (2000 \text{ lb/ton})$$

$$F = 30 \text{ for the boilers}$$

$$F = 29.6 \text{ for the carbonizers}$$

$$\text{2-Year Avg. Emission Rate} = \frac{[(1978 \text{ SO}_2 \text{ Emissions} + 1979 \text{ SO}_2 \text{ Emissions})(2000 \text{ lb/ton})]}{[1978 \text{ Avg. Hours of Operation} + 1979 \text{ Avg. Hours of Operation}]}$$

H. **Tioga Gas Plant:**

The Tioga Gas Plant, which is located in Williams County near the city of Tioga, is currently operated by Amerada Hess, Inc. The plant was originally constructed in 1954 and had a nominal rating of approximately 110×10^6 scf/day. In 1967, a sulfur recovery unit was added which had a nominal rating of 150 long tons per day of sulfur. In 1975, the basic plant operations included compression, dehydration, fractionation, gas sweetening and sulfur recovery. The only significant source of sulfur dioxide was from the incineration of the tail gas from the sulfur recovery unit.

The initial Permit to Operate application was submitted in April of 1978 and the permit was issued in June of 1982. This permit limited sulfur dioxide emissions from the tail gas incinerator to 1,074 lb/hr.

In 1991, a new sulfur recovery unit was installed. The unit started up in October, 1991. In September of 1992, the Permit to Operate was modified such that it reduced the allowable SO₂ emission rate from the tail gas incinerator to 575 lb/hr (24-hr avg.) and 671 lb/hr (1-hr avg.). This is the same limit currently in the Title 5 Permit to Operate for the facility.

Emission estimates are available for the facility for 1971, 1975, 1977, and 1979. All of these estimates list 8760 hours of operation per year. The Department is not aware of any changes to the plant that were being planned on the minor source baseline date that would have significantly affected plant operations or sulfur dioxide emissions. The Department proposes that a period preceding the minor source baseline date is representative of normal operations.

The annual emission inventory report for 1971 estimated emissions at 4,560 tons. This estimate is based on an

efficiency of the sulfur recovery unit of 95% and was calculated as follows:

Sulfur in inlet gas - 45,600 tons

$$\begin{aligned} \text{SO}_2 \text{ Emission(tons)} &= (45,600 \text{ tons})(1 - .95)(2 \text{ tons} \\ &\quad \text{SO}_2/(\text{ton S})) \\ &= 4,560 \text{ tons SO}_2 \end{aligned}$$

In 1975, Pacific Environmental Services in a survey report for the facility listed the emission rate as 4,850 tons. In the 1978 Permit to Operate application, sulfur dioxide emissions were estimated at 4849 tons based on 1977 data. Both documents did not list sufficient information to verify the calculation and referenced a modeling analysis as the source of this estimate. The 1979 annual Emission Inventory Report listed the following:

Tail gas Incinerated - $2,528 \times 10^6$ scf
Sulfur content of Tail Gas - 0.00194 lb/scf

$$\begin{aligned} \text{SO}_2 \text{ Emissions} &= (2,528 \times 10^6 \text{ scf})(0.00194 \text{ lb/scf}) \\ &\quad (2 \text{ lb SO}_2/\text{lbs}) \div (2,000 \text{ lb/ton}) \\ &= 4,904.3 \text{ tons} \end{aligned}$$

The estimated emissions for the various years appear very similar. Since the 1975 and 1977 emissions estimates may be from the same source, it is proposed that the 1971 and 1977 data should be used to calculate the baseline emission rate as follows:

$$\begin{aligned} \text{Avg. SO}_2 \text{ Emission Rate (tons)} &= (4,560 + 4849) \div 2 \\ &= 4,704.5 \end{aligned}$$

$$\text{SO}_2 \text{ Emission (lb/hr)} = [(4,560 + 4,849)(2,000 \text{ lb/ton})] \div (8,760 + 8,760)$$

$$\text{SO}_2 \text{ Emission (lb/hr)} = 1,074$$

I. Williston Refinery:

The Williston Refinery was located in Williams County just east of the City of Williston. The refinery, which began operation in 1954, was last operated by Flying J, Inc. The facility ceased processing operations in 1984 and none of the source units exist anymore. At its closing, the facility was capable of processing 5200 barrels per day of crude oil.

The plant consisted of several boilers and heaters for processing the crude oil. The facility did not have a catalytic cracking unit or other process units that are normally associated with larger refineries. Prior to 1976, the heaters were primarily fired on pipeline quality natural gas. In 1975, Pacific Environmental Services estimated sulfur dioxide emissions from the facility to be less than 1 ton per year. In 1976, there was a switch to the use of fuel gas and fuel oil to fire the boilers and heaters.

On April 1, 1977, Thunderbird Resources, Inc. (the operator at that time) submitted a Permit to Construct application to the Department for improvements to the refinery. On December 29, 1977, the Department issued a Permit to Construct for those changes. Because of economic conditions, some of the changes listed in the Permit to Construct were never completed. Therefore, it is proposed that these changes not be considered in the determination of the baseline emission rate.

In the 1977 Permit to Construct application, Thunderbird Resources, Inc. provided an estimate of emissions from the existing sources based on 1976 data. There is no other data available to estimate emissions from the facility until 1982. The Department proposes that the 1976 data is representative of normal operations. The 1976 fuel usage data was presented as a total for all existing units; however, a breakdown of emissions by unit is made. No sulfur content information is available for the fuel gas; however, the sulfur content of the oil was

listed as 0.81%. The sulfur dioxide emissions estimates, as provided in the application are as follows:

1977 Source Units	Identification	SO ₂ Emissions (lb/hr)	SO ₂ Emissions (tons)
Preflash Heater	S-1	7.13	28.7
Crude Heater	S-2	7.67	30.8
Thermal Cracking Heater	S-3	0.29	1.2
Charge Heater	S-7	0.12	0.5
Reformer Heater	S-9	0.46	1.9
Boiler 1	S-11	10.51	42.3
Boiler 2	S-12	10.51	42.3
Boiler 3	S-13	15.02	60.4

These emission rates are proposed to be the baseline emission rates for the Williston Refinery.

J. Stanton Station Unit 1:

The Stanton Station power plant is located along the Missouri River in Mercer County near Stanton, North Dakota. The facility consists of two units referred to as Units 1 and 10. Unit 1 began operation in 1967 and is considered a baseline source. Construction of Unit 10 began in 1980 with startup in 1982. The emissions from Unit 10, without consideration of Unit 1, consume sulfur dioxide increment. Therefore, only Unit 1 is addressed in this analysis.

Unit 1 is a pulverized front wall fired unit with a nominal rating of 1800×10^6 Btu/hr. The unit has no sulfur dioxide control equipment and vents to a common stack with Unit 10. Unit 1, along with Unit 10, is operated by Great River Energy.

Coal for the Stanton Station Unit 1 was obtained from the Indianhead Mine until 1992 when the mine closed. Coal is currently obtained from the Freedom Mine. Figure 19 presents the coal sulfur content data submitted in the Annual Emission Inventory Reports for the facility. Based on the data, the Department has calculated a weighted average sulfur content for coal obtained from the Indianhead Mine as 0.69%.

Figure 20 presents the heat input for Unit 1 based on data from the Annual Emission Inventory Reports. The graph shows that the heat input to Unit 1 was much greater in 1970, 1972 and 1974 than subsequent years. On February 18, 1977, the Department received a letter (see Appendix J) from United Power Association (operator at the time) indicating that over the past few years they had experienced difficulty in supplying sufficient steam to operate the turbine at the Stanton Station at the capacity level for which it was designed. The problem was directly related to the sodium content of the fuel. The high sodium coal caused fouling of the boiler to the point it could not provide enough steam for an extended

**FIGURE 19
STANTON 1**

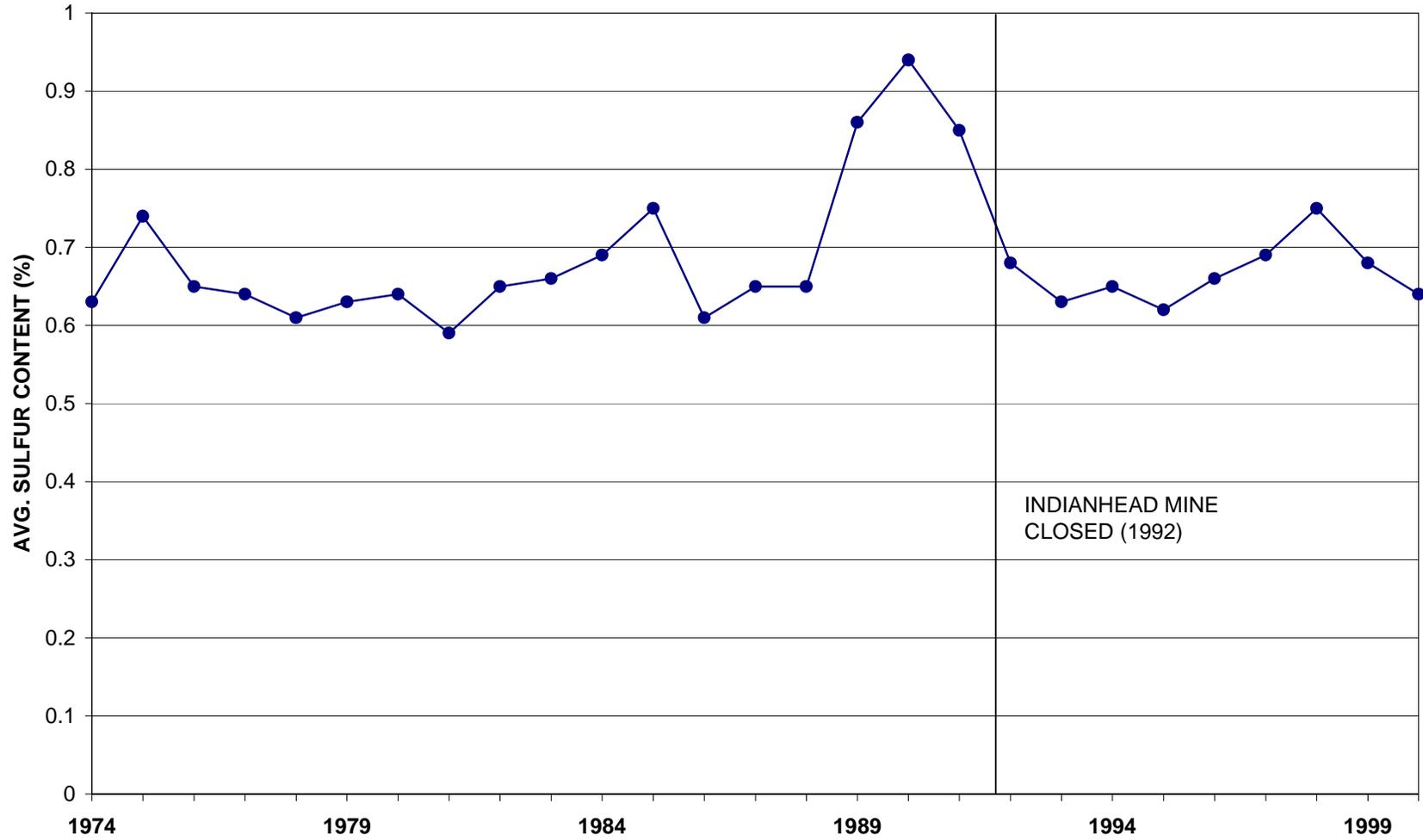
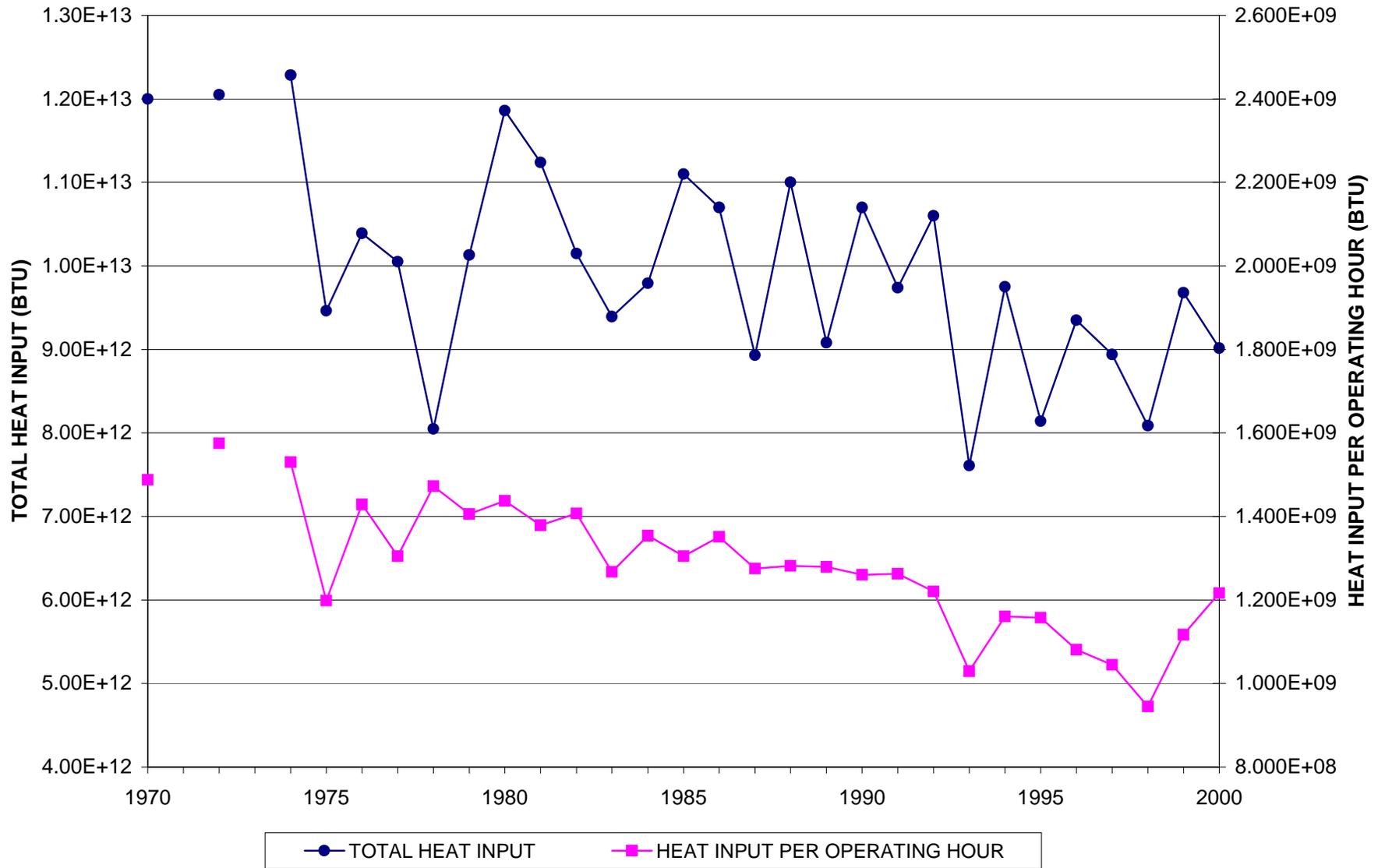


FIGURE 20
STANTON 1

69



period of time. United Power's solution to the problem was the construction of Unit 10. Unit 10 provides the additional steam necessary to run the generator at full capacity. Based on United Power's February 18, 1977 letter and the data available to the Department, it appears that the period 1975-1977 is not representative of normal operations. There are no two consecutive years prior to this period for which data is available. Therefore, it is proposed that the baseline period be represented by the 1978-79 period.

The proposed sulfur dioxide baseline emission rate was calculated using the AP-42 emission factor 30(s). The data and the results of the calculations are as follows:

Year	Coal Usage (tons)	Mine Avg. Sulfur Content(%)	SO ₂ Emissions (tons)	Hours of Operation	2-year Avg. Emission Rate (lb/hr)
1978	577004	0.69	5972.0	5466	2132.1
1979	728136	0.69	7536.2	7205	

Where:

$$SO_2 \text{ (tons)} = (30)(\text{Mine Avg. Sulfur Content})(\text{coal usage}) \div (2000 \text{ lb/ton})$$

$$\begin{aligned} \text{2-Year Avg. Emission} \\ \text{Rate (lb/hr)} = & [(\text{1978 } SO_2 + \text{1979 } SO_2)(2000 \text{ lb/ton})] \div \\ & [\text{1978 Hours of Operation} + \text{1979 Hours of} \\ & \text{Operation}] \end{aligned}$$

K. **M.R. Young Station:**

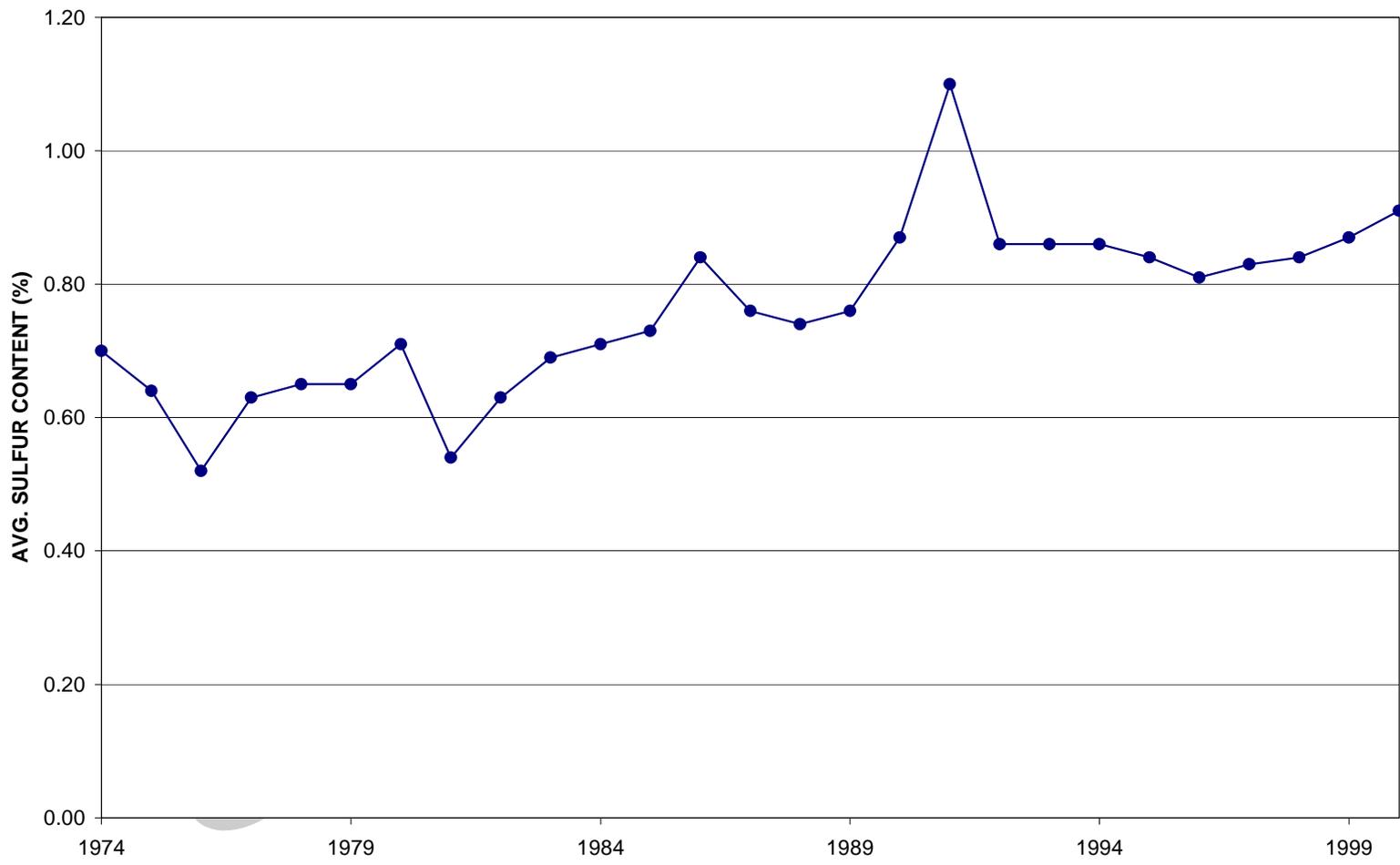
The M.R. Young Station is located in Oliver County approximately 5 miles southeast of Center, North Dakota. The facility consists of two units and is operated by Minnkota Power Cooperative. Unit 1 is a cyclone boiler with a nominal heat input rating of 2500×10^6 Btu/hr. Unit 2 is also a cyclone boiler with a nominal heat input rating of 4696×10^6 Btu/hr.

Unit 1 began operation in 1970 and Unit 2 in March of 1977. Therefore, both sources are considered baseline sources. Each boiler exhausts through a separate stack of different heights and are treated as separate units. Unit 2 is equipped with a wet scrubber for sulfur dioxide control.

Coal for the M.R. Young Station has been obtained from the Center Mine since the startup of the facility. The mine is located adjacent to the plant. Figures 21 and 23 present the coal sulfur content data submitted in the Annual Emission Inventory Reports for the facility. Based on this data, a weighted average sulfur content was calculated to be 0.77% for Unit 1 and 0.80% for Unit 2.

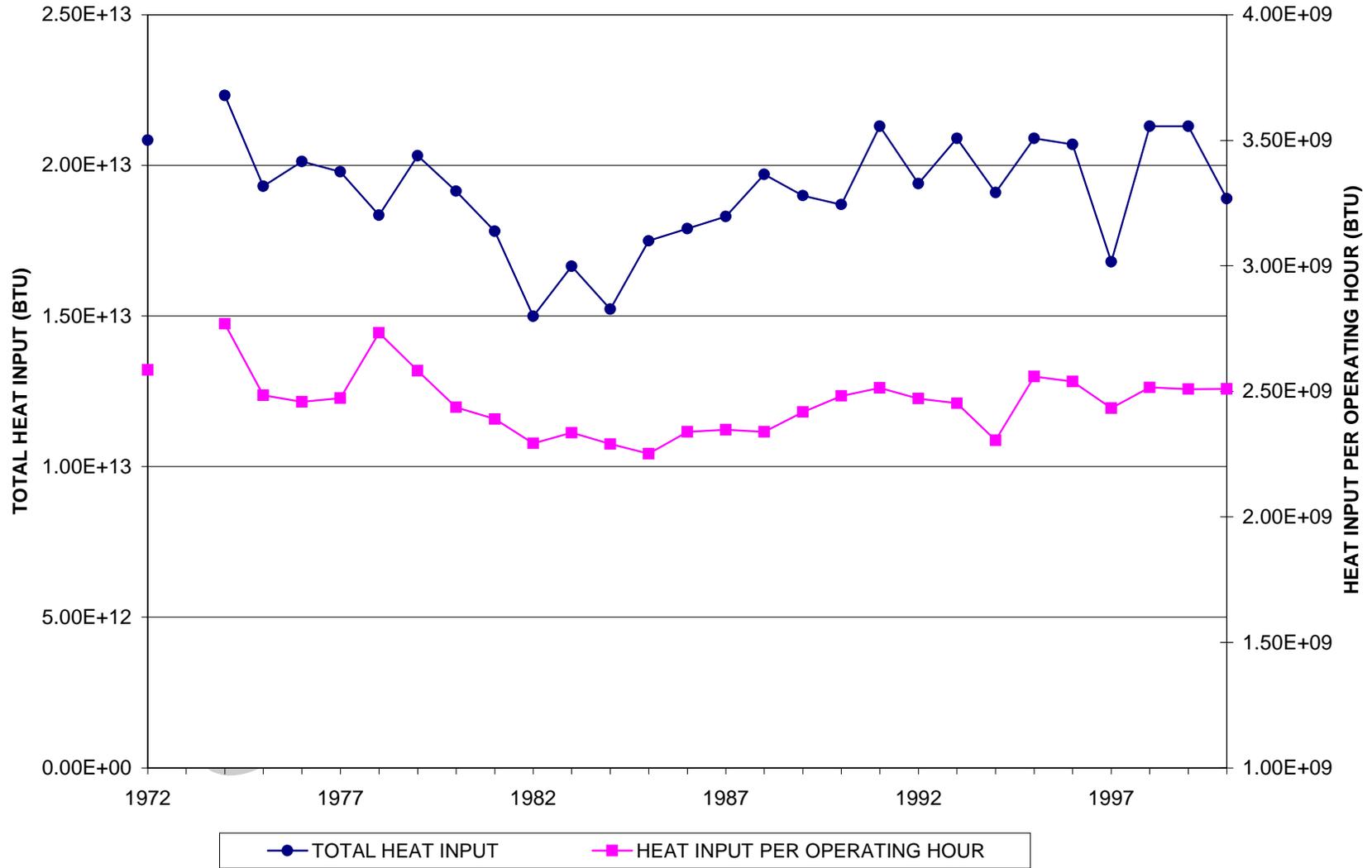
Figure 22 presents the heat input for Unit 1 based on data in the Annual Emission Inventory Reports. The graph shows higher heat input per operating hour in the early 1970's, lower levels in the mid 1970's and higher levels again in the late 1970's. The dip in heat input after 1978 may be due to Unit 2 coming on line. With Unit 2 providing capacity to the load area the demand on Unit 1 was lessened. There is no data available to the Department for 1973; however, a two year period near the baseline date could be selected which is indicative of normal operations. Because of the variation in heat input per operating hour during the 1970's, it is proposed that the 1978-1979 period represents normal operations for Unit 1.

FIGURE 21
M.R. YOUNG 1



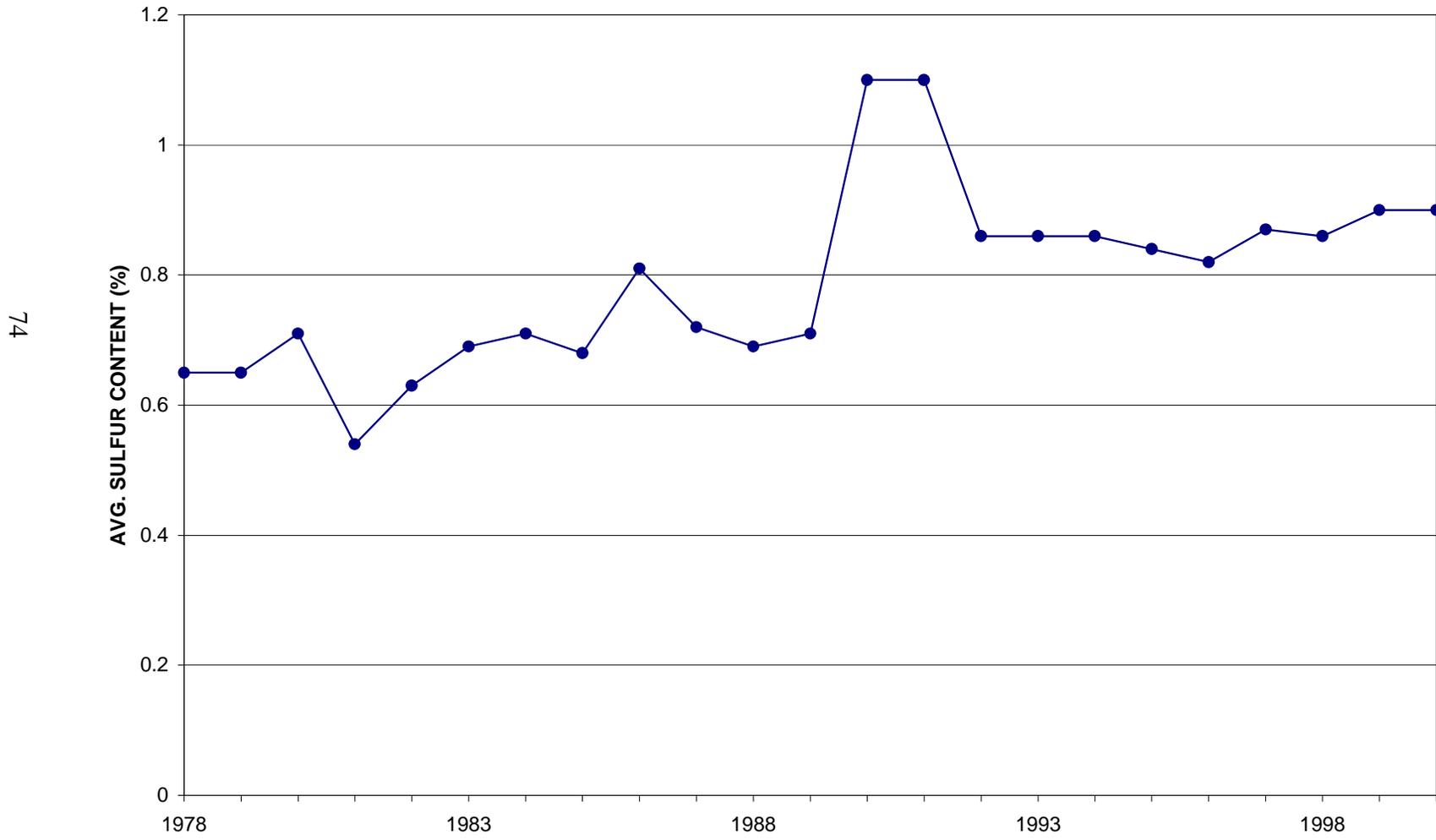
72

FIGURE 22
M.R. YOUNG 1



73

FIGURE 23
M.R. YOUNG 2



For Unit 1, the baseline sulfur dioxide emission rate was calculated based on the AP-42 emission factor 30(S) and the data from the Annual Emission Inventory Reports. The data and the results of the calculations are as follows:

Unit	Year	Coal Usage (tons)	Mine Avg. Sulfur Content (%)	SO ₂ Emissions (tons)	Hours of Operation	2-Year Avg. Emission Rate (lb/hr)
1	1978	1427485	0.77	16587.5	6714	4649.9
1	1979	1508182	0.77	17419.5	7870	

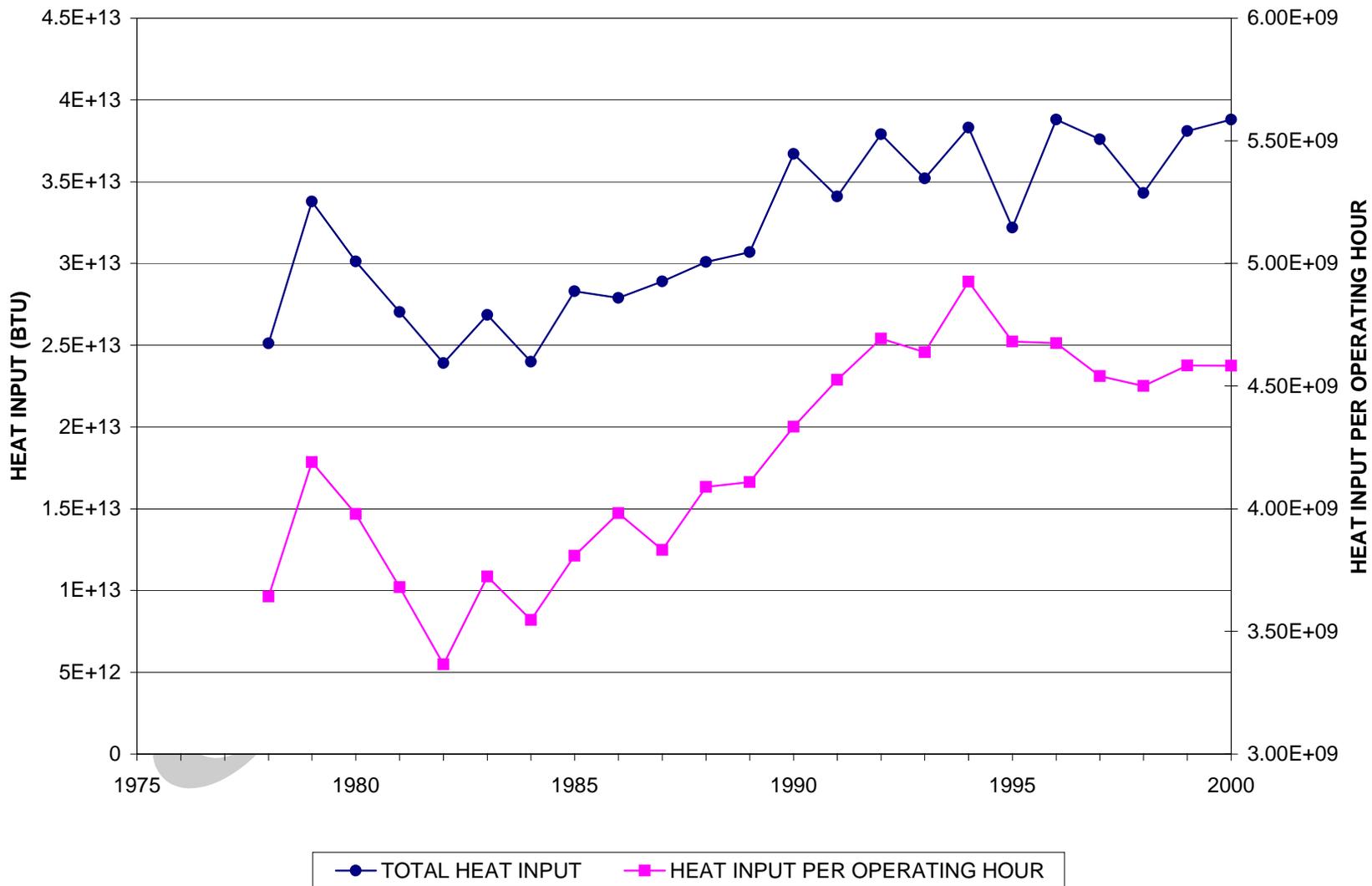
Where:

$$\text{SO}_2 \text{ (tons)} = (30)(\text{Mine Avg. Sulfur Content})(\text{Coal Usage}) \div (2,000 \text{ lb/ton})$$

$$\begin{aligned} \text{2-Year Avg. Emission Rate (lb/hr)} &= [(\text{1978 SO}_2 \text{ Emissions (tons)} + \text{1979 SO}_2 \text{ Emissions (tons)})(2,000 \text{ lb/ton})] \\ &\div [\text{1978 hours of operations} + \text{1979 hours of operation}] \end{aligned}$$

Unit 2 represents a baseline source unlike any other source in this analysis. Figure 24 presents the heat input for the unit. The unit is equipped with a wet scrubber for SO₂ control and was in operation only nine months prior to the minor source baseline date. In addition, there were significant problems with the sulfur dioxide removal system. The facility was the subject of enforcement action by both the U.S. Environmental Protection Agency and the Department due to various problems, including availability of the scrubber system. A May 9, 1978 letter to the Department documents the problems associated with the scrubber to that date (See Appendix K). The Department files contain other documentation of scrubber problems after this time. Since the unit was in a startup mode and only operated for approximately nine months in 1977, the Department does not consider 1977 to be indicative of normal operations. The scrubber problems and other problems with the boiler and generator limited operation of the

FIGURE 24
M.R. YOUNG 2



unit to only 6,890 hours in 1978 or 79% of the available hours. The heat input to the unit was only 61% of the nominal rating of the unit. This is contrasted with 1978 when the unit operated 8064 hours or 92% of the available hours. The heat input in 1978 was 82% of the nominal rating of the boiler. It appears that 1978 is not indicative of normal operations because of the somewhat limited operation. Therefore, the Department proposes that the 1979-80 time period be used to calculate the baseline emission rate.

The Annual Emission Inventory Reports for Unit 2 for 1979 and 1980 list emission rates that indicate noncompliance with the allowable emission rate of 1.2 lb/10⁶ Btu of heat input. Therefore, the Department proposes to calculate the baseline emission rate for this unit based on the allowable emission rate (1.2 lb/10⁶ Btu) and the actual heat input for the baseline period selected (1979-80). The data and results are as follows:

Year	Coal Usage (tons)	Hours of Operation	Avg. Heat Content of Coal (Btu/lb)	Total Heat Input (Btu's)	Allowable Emission Rate (lb/10 ⁶ Btu)	SO ₂ Emissions (tons)	2-Year Avg. Emission Rate (lb/hr)
1979	2508465	8064	6736	3.379 x 10 ¹³	1.2	20276.4	4905.6
1980	2410163	7571	6249	3.012 x 10 ¹³	1.2	18073.3	

Where:

$$\text{SO}_2 \text{ Emissions (tons)} = \frac{(\text{Total Heat Input})(\text{Allowable Emission Rate})}{(2000 \text{ lb/ton})}$$

$$\text{2-Year Avg. Emission Rate} = \frac{[(1979 \text{ SO}_2 \text{ Emissions (tons)} + 1980 \text{ SO}_2 \text{ Emissions (tons)})(2000 \text{ lb/ton})]}{[1979 \text{ Hours of Operation} + 1980 \text{ Hours of Operation}]}$$

Baseline Emission Rates
Summary

Source	Unit	Emission Rate (lb/hr)	Baseline Period
Beulah Power Plant	1 & 2	137.1	76-77
	3-5	224.6	76-77
R.M. Heskett Station	1	517.8	76-77
	2	1208.0	76-77
Leland Olds Station	1	3235.2	76-77
	2	6079.7	77-78
Lignite Gas Plant	SRU Incinerator	285.8	76-77
Mandan Refinery	Boilers 1, 2 & 3	622.6	76-77
	Crude Furnace	550.1	
	FCCU	1135.8	
	Alkylation Unit Furnaces	160.3	
	Ultraformer Furnaces	15.3	
Neal Station	1 & 2	354.6	76-77
Royal Oak Briquetting Plant	Boilers 1, 2 & 3	172.1	78-79
	Carbonizer Furnaces	1562.9	78-79
Tioga Gas Plant	SRU Incinerator	1074.0	71 & 77
Williston Refinery	Preflash Heater	7.1	76
	Crude Heater	7.7	
	Thermal Cracking Heater	0.3	
	Charge Heater	0.1	
	Reformer Heater	0.5	
	Boiler 1	10.5	
	Boiler 2	10.5	
	Boiler 3	15.0	
Stanton Station	1	2132.1	78-79
M.R. Young Station	1	4649.9	78-79
	2	4905.6	79-80

IV. Oil and Gas Wells Baseline Emission Rate Calculations

Estimating baseline SO₂ emissions from oil and gas wells involves similar difficulties as with estimating baseline emissions from other major SO₂ sources. Oil and gas well emissions must be calculated from other data, and the needed oil and gas data from the period 1976-77 are not very complete or reliable. First, emissions from oil and gas wells must be calculated from monthly values of wellhead gas produced and relatively sparse data on the H₂S content of the wellhead gas.

All oil and gas production data are collected and maintained by the Oil and Gas Division of the North Dakota Industrial Commission. The Oil and Gas Division has given the Department access to the well production data in order to track air contaminant emissions from oil and gas wells. The Department collects from well operators data on the H₂S content of the wellhead gas and adds it to the Oil and Gas Division's database. In general, a well's SO₂ emission rate is calculated by multiplying a monthly total of wellhead gas produced by the percent of H₂S in the gas and dividing by the number of days of production in the month (as well as some other conversion factors). Data from additional months may be added together to obtain an average emission rate over several months or a year.

Emissions of SO₂ from oil and gas wells typically come from two sources, either treaters or flares. Treaters separate the fluids in the crude oil for later transport or disposal. Flares burn the waste gas, which contains hazardous H₂S gas, converting the H₂S into less harmful SO₂. Since about the mid-1980s, the Oil and Gas Division has been collecting well production data on the amount of wellhead gas flared monthly and the amount of wellhead gas used in firing the treater or other on-site equipment (lease use). These two monthly gas totals, amount of lease use and the amount flared, are used directly by the Department to calculate the SO₂ emissions from a well's treater and flare, respectively.

The Department has been requiring well operators to measure and report the H₂S content (percent) of the wellhead gas since

the 1980s. However, such H₂S measurements generally are required only when the well is first completed for production or when it is recompleted into another geologic formation. Thus, there are generally only one or two values of H₂S, at most, for each well. The H₂S data are generally not concurrent with the gas production data. In addition, many older wells have either unreliable H₂S data or no H₂S data at all. In these cases, it was necessary to substitute for the missing H₂S data from a nearby similar well.

The Oil and Gas Division considers its gas production data back to about 1987 to be very reliable, but considers gas production data before 1987 to be at least somewhat unreliable. The earlier gas production data are considered somewhat unreliable because, until about the early to middle 1980s, the main product from the wells was oil, and the gas was considered a waste product. It was important to accurately keep track of the valuable oil production for the benefit of the owners, operators, and the State. However, because the gas was considered a waste product to be disposed of, data on gas production were not consistently and reliably reported or recorded until the importance of the gas changed in the mid-1980s.

Some data on total wellhead gas production are available back to 1976-77, the two years before the baseline date, but in most cases the data represent the amount of gas sold to a gas processing plant. The amount of wellhead gas used in the treaters or flared which is necessary for emissions calculations was not consistently reported before the mid-1980s and was available for only a very few wells in 1976-77.

Because of the unreliability and the lack of gas production data before the mid-1980s, the Department did not consider the data to be good enough for calculating oil and gas well baseline emissions. The recent needs for more completely and accurately determining the state's compliance status with respect to Class I PSD increments has necessitated the Department reevaluate calculating the baseline emissions of oil and gas wells. The problem was obtaining reasonably complete, reliable gas production data appropriate for 1976-

77. The Department's strategy has been to use the oldest available gas production data that is considered complete and reliable and apply it to the wells producing during the period 1976-77. Based on the Oil and Gas Division's judgment that gas production data before 1987 were not completely reliable, the Department is proposing to use 1987-1988 gas production data to calculate the baseline emission rate for wells that existed during the 1976-77 time period.

The Department has calculated SO₂ emissions for oil and gas wells for 1987-88 that were used in a regional air quality study conducted in 1989-90. The Department conducted a study named the "Williston Basin Regional Air Quality Study" (WBS, 1990) based on using air quality dispersion models to predict what SO₂ concentrations were occurring in and around numerous oil and gas well fields in North Dakota.

The Williston Basin Study processed oil and gas H₂S and production data for all North Dakota wells producing during the period November 1987-March 1988. Modeled SO₂ concentrations were compared to the State and Federal Ambient Air Quality Standards (AAQS) and Class II and Class I PSD increments. The Department examined impacts in or near 12 worst-case oil and gas fields and in four Class I areas in North Dakota. Software programs were written and executed by Department personnel to calculate SO₂ emission rates for all oil and gas wells producing gas during November 1987-March 1988 and output the oil and gas well source data in a format ready for input to an air quality dispersion model. The programs use a mass balance approach to calculating sulfur dioxide emissions and are based on the assumption that all of the H₂S is converted to SO₂.

With SO₂ emissions data calculated for 1987-88, the challenge was in applying this data to wells producing during 1976-77. Increases or decreases in gas production back to 1977 could not be reliably and consistently determined, but the data from 1987-88 could be applied to the wells producing during 1976-77. Basic identifying information, such as the wells' names, file numbers, field names, and locations of all wells producing during 1976-77 were extracted from the Oil and Gas

Division database. Only wells that actually existed and were producing during 1976-77 were accepted in a new 1976-77 emissions inventory by using this information as a starting point. For wells that existed in both time periods, the 1987-88 emissions data were copied over from the WBS inventory to the new inventory. For wells that produced in 1977 but not in 1987, there were no emissions data directly available. The average emission rate over all wells in the same field from the WBS was calculated and substituted into the new inventory for each well of this type, where data were available. In cases where data were needed for a 1977 well in a field that did not produce at all during 1987-88, then a field-average emission rate from a similar, nearby field was added to the new inventory for all such wells.

A problem with using the WBS data "as is" is that much of the gas produced during 1987-88 was sold to gas processing plants and not flared. Many of these gas plants didn't exist in 1976-77, so that all of that sold gas would have been flared otherwise if not sold. In cases where a 1977 well was not selling gas to a gas plant, all of the gas produced at a well in 1987, except for lease-use gas, would have been flared in 1977. Applying the WBS data to these wells involved adding the 1987-88 sold gas to the flared gas amount before calculating the flare emission rate. These recalculated flare SO₂ emission rates for the 1976-77 wells were often much higher than the original WBS flare emission rates because of the sold gas being included. Any wells that did not sell gas in 1976-77 but did sell gas in 1987-88 would be assigned a higher flare emission rate including the sold gas. Wells that either sold gas in both periods or did not sell gas in both periods were assigned a flare emission rate unchanged by sold gas amount because the sold gas was already accounted for consistently.

The remaining task was to determine which wells were selling gas in 1976-77. Gas processing plants receive their gas from oil and gas wells through a pipeline, or gas-gathering system, that connects the wells to the gas plant. The gas-gathering system may be relatively small and serve only one oil and gas field, or it may be large and extensive, connecting to many

fields over large distances. In 1977, there were two large gas plants and two smaller gas plants operating in North Dakota. The Tioga Gas Plant, near Tioga, was connected to the largest gas-gathering system in the state at the time, reaching from about 20 miles north of Tioga southward to southeastern McKenzie County southeast of Watford City. The Tioga pipeline connected to at least 20 separate oil and gas fields. The Lignite Gas Plant, near Lignite, was connected to a somewhat smaller gas-gathering system serving about nine fields in Burke County. Two small gas plants, the Red Wing Creek Gas Plant and the Boxcar Butte Gas Plant in western McKenzie County, also were operating in 1977 and received gas from only two isolated fields.

All other fields in the rest of the state were not served by any gas-gathering systems in 1977 and could not have sold gas. In particular, later development in west-central North Dakota between Williston and Belfield triggered the construction of at least three additional gas plants and an extensive gas-gathering system in this area by 1987. Many wells in this part of western North Dakota were selling gas by 1987 where no gas plants existed in 1977.

When applying the above procedure for flare emission rates, it was assumed that any field connected to a gas-gathering system in 1977 was selling gas in 1977. Therefore, all wells in fields connected to the Tioga and Lignite gas-gathering systems and the Red Wing Creek and Boxcar Butte gas plants were assumed to be selling gas both in 1976-77 and 1987-88 and so were assigned flare emission rates from the WBS inventory unchanged by sold gas. However, many other wells in western North Dakota were not connected to gas-gathering systems in 1977 and thus got credit for higher flare emissions in 1977 because of sold gas in 1987-88. The result of this procedure was an SO₂ emissions inventory for all oil and gas wells producing in 1976-77 that reflected gas production levels back to 1987, using the earliest reliable gas production data, and appropriately accounted for gas sold to gas processing plants.

Appendix A

**Beulah Power Plant
Data**

Appendix B

R.M. Heskett Station Data

Appendix C

Leland Olds Station Data

Appendix D

Lignite Gas Plant Data

Appendix E

Mandan Refinery Data

Appendix F

Wm. J. Neal Station Data

Appendix G

**Royal Oak
Briquetting Plant Data**

Appendix H

Tioga Gas Plant Data

Appendix I

Williston Refinery Data

Appendix J

Stanton Station Unit 1 Data

Appendix K

M.R. Young Station Data