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ENERGY EFFICIENCY AUDIT REPORT
PETROCHEMICAL FERTILIZER PLANT
KUTINA, CROATIA, YUGOSLAVIA

MARCH 1992

PREPARED BY: RCG/HAGLER, BAILLY, INC.
Arlington, VA

and

TEKON Tehno-Konsalting
Belgrade, Yugoslavia

U.S. EMERGENCY ENERGY PROGRAM FOR EASTERN AND CENTRAL EUROPE

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
BUREAU FOR EUROPE
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OFFICE OF DEVELOPMENT RESOURCES
ENERGY & INFRASTRUCTURE DIVISION
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QUALITY ASSURANCE

The contents of this report include recommendations based on data provided by the client plant, measurements made on site, calculations, and engineering judgment. The conclusions reached were based on a limited engagement of only about one week's duration in the plant, and not an exhaustive engineering analysis. RCG/Hagler, Bailly, Inc. certifies that this report conforms to the level of best commercial practice for industrial energy audits of similar level of effort, as conducted in the United States. This report has been prepared under the guidance of a registered Professional Engineer, licensed to practice in the United States.

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Mr. Vlado Maric, Technical Manager
Mr. Stjepan Leakovic, Fertilizer Production Manager
Mr. Miroslav Brnada, Senior Ammonia Process Engineer
Mr. Slobodan Jeftimija, Head Energy Engineer
Ms. Nevenka Jerbic, Electrical Engineer for Power Generation and Distribution

INA PETROKEMIJA KUTINA
PRELIMINARY ENERGY AUDIT

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EXECUTIVE SUMMARY

This report presents the results from a preliminary energy audit carried out by a team of engineers from RCG/Hagler, Bailly, Inc. and TEKON Tehno-Konsalting at INA Petrokemija, Kutina in Croatia, Yugoslavia from April 22 through April 26, 1991. The objectives of the audit were to work with the plant staff to: evaluate energy consumption at the plant; determine the level of energy management practiced; to identify energy conservation actions or opportunities; and identify instrumentation and low-cost equipment needed by the plant to implement the more attractive energy conservation actions.

Primary products of the plant are ammonia, nitric acid, ammonium nitrates, urea, NPK fertilizers, as well as sulfuric and phosphoric acid. A summary of the primary energy consumption at the plant based on 1990 data estimates annual energy costs is given below.

		Energy Distribution		Cost Distribution	
	actual units	TJ	%	US $	%
Electricity	155,600 MWh	1,866	8	8,558,000	14
Natural gas	574 million Sm3	19,704	87	49,260,000	80
Heavy fuel oil	26,620 tonnes	1,080	5	3,460,600	6
TOTALS		22,650	100%	61,278,000	100

Notes:

- a terajoule, TJ, is 10^{12} Joules
- electricity shown is purchased electricity only; an additional 116,000 MWh are co-generated in the plant, using natural gas or heavy fuel oil
- natural gas consumption includes feedstock gas consumption, which makes up approximately 1/3 of the total quantity
- boiler fuel consumption makes up approximately 4,000 TJ/y, approximately 20% of the thermal energy consumption
- Cost distribution is illustrative; because of variation in the value of the Yugoslav dinar, costs are estimated in US dollars, based on typical May 1991 prices in Croatia ($0.055/kWh; $3.16/GJ fuel oil; $1.62/GJ natural gas).

INA Petrokemija has some energy efficiency efforts already in progress. In addition, detailed energy consumption and production records are maintained for each department.

During the brief preliminary energy audit work on site, INA staff worked with the audit team to identify additional energy efficiency measures. Based on the discussions with management, production and technical staff, inspection of equipment and operating procedures, analysis of plant energy and production data, and measurements of certain process parameters, RCG/Hagler, Bailly estimates the potential for energy efficiency improvement at the INA Fertilizer Complex as 15-20% without process changes. During the survey, the RCG/Hagler, Bailly team identified short-term, low-cost energy efficiency and productivity improvement projects (a financial payback of less than one year each), which, if implemented, will enable INA to achieve a financial benefit of $7.2 million per year, or 33% higher value added at expected 1991 energy costs and ammonia prices. The total cost to achieve these benefits is less than $3 million. These measures are summarized on the following page.

RCG/Hagler, Bailly recommends the following procurement budget for INA Petrokemija, subject to final approval by USAID:

portable electronic combustion analyzer: $ 4,000
portable ultrasonic tester: $1,400
infrared pyrometer: $2,000

INA Ammonia agreed to pay for duties and other costs necessary to implement the projects and make full use of the equipment supplied by USAID.

All the recommendations are presented on the following page. Below is a summary of the information regarding the Ammonia II plant only.

	Ammonia ton/yr	Fuel Gas GJ/ton	Energy TJ/yr	Value added[1] MUS$/yr
BASE CASE - AMMONIA II	426,000	14.0	5,964	$21.533
Improvement:	47,500	1.5	917	$7.228
Ammonia II only	11%	15%	15%	33%
(denoted by * on next page)				

[1] Based on world price of $110/ton for ammonia less total gas cost at $1.62 per GJ. Total gas is fuel gas plus process gas (process gas at 22.7 GJ per ton).

INA PETROKEMIJA KUTINA (INA)

Summary of energy efficiency and productivity projects

RECOMMENDATIONS AND ESTIMATED BENEFITS

	Ammonia ton/yr	Energy Savings TJ/yr	Energy Savings M$US/yr	Financial[2] MUS$/yr
A. General & Energy Management				
A.1 Prioritize NH3	3,500			$0.283 *
A.2 Superheat temp		106	0.173	0.173 *
A.3 Comb. analyzer		12	0.038	0.038
A.4 Efficiency teams		78	0.182	0.182
A.5 Increase NH3 rate	22,000	224	0.363	3.091 *
A.6 Comb. efficiency		8	0.019	0.019
A.7 Delay turnaround	9,000	25	0.041	1.157 *
A.8 Energy management		226	0.500	0.500
B. Short-term, Low-cost Efficiency Improvements				
B.1 Fast start-up	4,000	45	0.074	0.570 *
B.2 Combustion - NH3		50	0.082	0.082 *
B.3 Reduce heat loss		60	0.066	0.066
B.4 Cooling Water System		58	0.264	0.264
C. Recommended Major Maintenance				
C.1 103-D catalyst	9,000	467	0.756	1.872 *
TOTAL BENEFITS	**47,500**	**1,438**	**2.558**	**$8.297**

[2] Financial benefit of productivity improvement is based on avoided cost of ammonia imported to the plant at $170 per ton in 1991.

I. INTRODUCTION

2.1 General Plant Description

The INA plant is a full fertilizer production complex, consisting of process plants for ammonia, nitric acid, ammonium nitrates, urea, NPK fertilizers, as well as sulfuric and phosphoric acid. A power station provides steam and electricity for the entire complex. Annual production is about 1.5 million tonnes of fertilizer. In addition to supplying markets in Yugoslavia, INA exports products with a value of over $100 million per year.

2.2 Energy Supplied

The complex is supplied with natural gas by a sister company of INA. The complex needs about 80,000 m3/hr. In January and February of 1991, the gas flow rate was limited by the supplier to 75,000 m3/hr. This is often the case during winter months; during this time, mazout is used in addition to gas in the boilerhouse.

Effective March 1, 1991, the price of gas was Dn 1.2 per m3. As of May 1, 1991, the price of gas increased to Dn 1.89 per m3, and the price of the alternative fuel (mazout, heavy fuel oil) was set at Dn 4.1 per kg. In US dollars (at Dn22 = $1.00), the equivalent energy prices used in this report are as follows:

natural gas: $0.055 per m3, $1.62 per GJ
mazout: $130 per ton[3], $3.16 per GJ

Of the electricity required at the INA complex, approximately 43% is self-generated in the power station, which has a turbine capacity of 35 MW but is effectively limited to 13 MW by the demand for steam. During the peak demand periods of the day, the turbine load is increased in order to The rest of the electric energy, a demand of about 22 MW, is purchased from Hrvatska Electroprivreda according to the following time-of-day tariff, effective April 1, 1991 (converted to US$ at Dn22 = $1.00)

[3] The calculated price at Dn 4.1 per kg is $186 per ton. However, this price far exceeds Gulf postings, which were about $130 per ton for residual fuel oil at the time of the audit visit in April 1991. The Government-controlled price still reflects some of the high prices associated with the Gulf Conflict.

Demand charges:

Low season (April 1 - Sept 30): $ 7.73 per kW per month
High season: $ 11.59 per kW per month

Energy charge ($ per kWh):

	High season	Low season
0800 - 1400 hours	$0.077	$0.052
1400 - 1800 hours	$0.031	$0.021
1800 - 2200 hours	$0.077	$0.052
2200 - 0800 hours	$0.021	$0.015

The total cost of the purchased electricity is about $8.45 million per annum, of which 30% is for demand and 70% is for energy charges.

The Ammonia II plant at INA is a M.W. Kellogg design, rated at 1350 metric tonnes per day (mtpd) capacity came on-stream in February 1984. Production for November 1990 - March 1991 averaged about 35,000 tonnes per month (1170 tons per day). Effective 15 February 1991, the INA Ammonia I plant, an old 600 mtpd Foster-Wheeler plant, was retired. Following this, there is a shortage of ammonia available at INA to feed the urea plants (Urea I is 300 mtpd and Urea II is 1500 mtpd) and the other ammonia users in the complex (total complex demand is 1800 mtpd at full capacity). Therefore INA was importing about 10,000 tonnes of ammonia per month from off-site during early 1991.

2.3 Energy Audit Activities

A team of senior engineers from RCG/Hagler, Bailly, Inc. and TEKON, carried out site activities at INA Petrokemija from April 22-26, 1991 to work together with INA staff to identify improvements to energy efficiency. The project manager for the effort was Mr. Slobodan JEFTIMIJA, Manager of Power and Energy at INA, reporting to Mr. LEAKOVIC Stjepan, Manager of Fertilizer Production, and Mr. Vlado MARIC, Technical Director. The project manager for the effort at the Ammonia plant was Mr. MIROSLAV Brnada, Senior Ammonia Process Engineer. The RCG/Hagler, Bailly team consisted of:

David KEITH, RCG/Hagler, Bailly, Project Director
Mark OVEN, RCG/Hagler, Bailly, Project Manager for Yugoslavia
Theodore NAYDAN, K&M Engineering & Consulting Co.
(subcontractor to RCG/Hagler, Bailly)
Ljubomir RADENKOVIC, TEKON, Director

Based on agreement with the management of INA Petrokemija, the audit team focused their efforts in the short time available on the power station and the ammonia II plant. Some of the other parts of the plant were briefly inspected by the team.

During the first day of the audit, the team traveled to Kutina, held discussions with plant management to plan the audit, and began evaluation of data prepared by the plant.

Based on agreement with INA the first day, one objective of the audit was to measure the combustion efficiency of the boilers in the power station and the primary reformer and auxiliary boiler in the ammonia II plant. For this purpose, RCG/Hagler, Bailly's digital combustion analyzer (which measures O_2, CO, CO_2, unburned hydrocarbon combustibles (HC)) was used, together with a laptop personal computer, using software developed by RCG/Hagler, Bailly which calculates combustion efficiency from these measurements, on the basis of the chemical equations of combustion (molal basis).

Two full days were spent reviewing operations in the ammonia II. The purpose of this review was to identify short-term, low-cost improvements which could save energy and increase productivity and to develop estimates of the benefits which could be obtained from such projects.

By the end of the week, INA Ammonia II had already begun implementing new management directives for setting superheated steam temperature, achieving a significant improvement in energy efficiency.

The RCG/Hagler, Bailly team presented its recommendations to Mr. Maric, Mr. Leakovic, and Mr. Jeftimija at the final review meeting April 26, 1991, before leaving INA. RCG/Hagler, Bailly recommended, and INA agreed that portable meters should be procured under the USAID emergency energy program.

The RCG/Hagler, Bailly team observed that the standard of management and engineering expertise already in place at INA is excellent. Technical staff is very knowledgeable about energy conservation in general, especially in relation to their process. The RCG/Hagler, Bailly team expects that this staff, with a few modifications to procedures and some additional instruments, tools, and equipment, will be fully capable of making significant improvements to energy efficiency.

II. ENERGY CONSUMPTION AND PRODUCTION ANALYSIS

A graphical presentation prepared by RCG/Hagler, Bailly of basic data received from INA is presented in Appendices 1 to 3. The graphs in Appendix 1 provide an overall view of energy consumption and production, showing significant monthly variations at INA over the last two years. Appendix 2 presents data from Ammonia II on energy consumption, production, specific energy consumption, and other key parameters on a monthly basis for the last 15 months. Appendix 3 presents detailed analysis of daily data for January through April 1991.

These graphs are provided for use by INA in identifying variations in energy efficiency. The analysis is a tool to point the way for more detailed investigations. These detailed investigations are beyond the scope of the current study, but several points are evident from the analysis. The main points arising from the analysis which were used to develop specific recommendations regarding the operation of Ammonia II are as follows:

- Energy efficiency of Ammonia II is increased substantially at higher production rates. Above about the 1150 tpd rate, fuel gas consumption increases very little for additional production.

- Production at Ammonia II was turned down from Feb 5 - March 12 by about 100 tpd. The reason for this turndown was apparently insufficient natural gas supply.

- Ammonia II consistently operates well below its rated capacity of 1350 tpd. In 1991, Ammonia II ran for the 35 days at about 93%, the next 35 days at about 88%, and the next 45 days at about 97%.

- Process gas is well-correlated with production, at about 22.7 GJ per tonne NH_3. However, there is variability for each of the production run periods which appears to be metering error.

- Fuel gas is not well-correlated with production. At a given production level, there is substantial variability in the amount of fuel gas that could be required, as measured by daily data. For example:

  - at 1200 tpd, fuel gas 14.5 - 16.0 GJ/ton
  - at 1280 tpd, fuel gas 13.6 - 15.2 GJ/ton
  - at 1320 tpd, fuel gas 13.2 - 15.0 GJ/ton

- Steam-to-carbon ratio is very high at 3.85 - 4.1, indicating high steam consumption.

IXI. RECOMMENDATIONS FOR ENERGY EFFICIENCY IMPROVEMENT

RCG/Hagler, Bailly's recommendations for energy management and efficiency improvement have been grouped in three categories:

A. General and Energy Management - These projects are opportunities which are recommended for immediate action, and require little or no expenditure. These projects affect management systems and techniques, rather than process equipment. These projects are the primary focus of the USAID Emergency Energy Program for Yugoslavia.

B. Low-cost, Short-term Improvements - These projects are low-cost improvements to process plant and equipment which are recommended for implementation in the short-term (in 1991). Because of the low cost and quick payback (less than one year), these projects could be implemented from the company's annual maintenance budget. Some of these projects may be of interest to the USAID Emergency Energy Program for Yugoslavia.

C. Major Maintenance - These projects are short-term improvements which require significant funding, but are necessary to return the plant equipment to design conditions. These projects should also provide a payback in one year or less.

D. Capital Improvements - These projects are longer term projects, requiring significant capital investment. Such projects would require careful study, beyond the scope of this preliminary energy audit. These projects are also beyond the scope of funding under the USAID Emergency Energy Program for Yugoslavia.

A. GENERAL AND ENERGY MANAGEMENT

AMMONIA PLANT II & POWER PLANT
INA Action A.1 -
Prioritize Ammonia II to receive available gas

Existing conditions:

The power plant can burn either natural gas or mazout to generate steam. Because the cost of natural gas is only about half the cost of mazout, the power plant burns gas whenever it can get it.

During February and March of 1991, there was a shortage of gas to INA. This shortage resulted in a turndown at the ammonia plant. During the same time that the ammonia plant was turned down, the power plant was burning some gas.

Recommended action:

Because of the high value added in ammonia production, the ammonia plant must be given top priority for gas. At no time should the ammonia plant be turned down for lack of gas while there still is gas being burned in a boiler which could be burning mazout instead.

The following calculation provides the basis for this recommendation:

> Near to full rate, the marginal energy cost of producing an additional ton of ammonia is about 28 GJ of gas. because of the shortage of supply, ammonia is being imported to INA at a cost of $170 per ton. Thus 28 GJ of gas provided to the ammonia plant would give a value added (or profit) of:
> $170 - (28 GJ x $1.62/GJ) = $124
>
> Assuming the boiler efficiency using either gas or mazout is about the same, the value added (or profit) by burning the same 28 GJ of gas in the boiler instead of burning mazout is:
> 28 GJ x ($3.16/GJ - $1.62/GJ) = $43

As can be seen, the power plant is doing the logical thing to save the company a lot of money ($43 for each 28 GJ). However, the opportunity for profit is nearly three times greater if the same gas is provided to the ammonia plant.

Greater awareness and communication between the production units of INA is recommended to prevent other similar such situations in the future.

Expected results:

This was explained to the management of INA in the closing meeting of the audit, and this situation is not expected to happen again.

The estimated loss to the company in 1991 was a turndown of about 100 tpd for about 35 days, calculated as follows:

35 days x 100 tons/day = 3,500 tons

Lost value added = 3,500 tons x ($124 - $43)/ton = $283,000

A. GENERAL AND ENERGY MANAGEMENT

AMMONIA PLANT II
INA Action A.2 -
Increase temperature of superheated steam to HP syngas turbine

Existing conditions:

Major problems occurred with the syngas machine which caused it to be taken out of service and returned to Germany for maintenance in 1990. This unfortunate circumstance put Ammonia II out of operation for more than four months.

Upon its return and reinstallation, a problem developed with overheating of the bearings on the high-pressure turbine. In order to correct this problem, the superheated steam temperature was reduced. Following this, INA staff developed a modification to address the problem - a compressed air line was connected to the bearing housing to provide additional cooling.

During the audit visit, the cooling system was installed and seemed to be operating well, but the steam temperature exit the superheater burners was still 500 C, down from a design value of 538 C.

Recommended action:

The steam superheat temperature should be carefully brought up to design conditions, with constant checking of temperature at the syngas turbine bearings.

Expected results:

The RCG/Hagler, Bailly team carried out thermodynamic analysis of the conditions at the syngas HP turbine. This turbine and the high pressure unit on the air compressor exhaust to the MP system. The analysis is carried out to condensing in order to represent the fact that about most of the MP steam is used for turbine drive in the various compressors (the remainder is 40 bar process steam injected into the primary reformer).

The calculation, as shown on the following page, indicates that 5% less work is available from each unit of steam. In certain applications, such as the steam used in the process, this is not critical, but for the turbine drive, this loss results in an increased flowrate of steam.

	Existing	Design
Steam temperature, inlet	496 C	5[illegible] C
Exhaust vacuum	0.85 bar	0.85 bar
Enthalpy, inlet	689 kJ/kg	711 kJ/kg
Enthalpy, outlet, isentropic	432 kJ/kg	440 kJ/kg
Enthalpy available	257 kJ/kg	271 kJ/kg
Turbine efficiency	75%	75%
Work extracted from steam	193 kJ/kg	203 kJ/kg
Reduction in work	5%	
Increase in steam flow	5% over design	

Heat output = 1.05 kg x 689 kJ/kg = 723.5 kJ (1.8% over design)

The increased flowrate of steam results in an increased fuel gas energy requirement of 1.8%. Based on a base fuel gas consumption of 14.0 GJ/ton ammonia, this recommendation will reduce fuel gas by 0.25 GJ/ton. Based on a base annual production rate of 426,000 tons, this recommendation will reduce gas consumption by 106.5 TJ, and save $173,000 per year.

A. GENERAL AND ENERGY MANAGEMENT

ENERGY & UTILITIES
INA Action A.3 -
Use portable combustion efficiency analyzer to check efficiencies throughout the plant

Existing conditions:

INA Petrokemija has combustion devices located throughout the complex, including the main steam high pressure steam boilers, the smaller firetube boilers, the ammonia reformers, spray dryers in the fertilizer manufacturing department, and other equipment. While the high pressure boilers are equipped with oxygen sensors, as is the primary reformer, many of the smaller combustors do not have O_2 measurement installed. Tuning of the burners for optimum combustion efficiency is done by eye and by the experience of the boiler operators. This is unsatisfactory in many cases: a more precise measurement of combustion conditions can improve the combustion efficiency by as much as 2 to 5%.

Recommended action:

Purchase an electronic gas analyzer. Assign a team of persons to be qualified to use the gas analyzer, and to be responsible for regular measurements of the boilers and other combustors identified by the central plant energy manager.

Use a gas analyzer to measure exhaust gas composition of the boilers on a regular basis. A weekly measurement will suffice for most of the boilers. For boilers with O_2 measurement already installed, the portable analyzer measurements will provide a check on the good operation of these O_2 meters. For other boilers, the measurements of the portable analyzer should provide the basis for adjustment of air/fuel ratios at different operating loads. Using the results of these measurements, adjust the mechanical linkages connecting the fuel valve and the air damper on the boilers to reduce or increase the excess air in the system.

Expected results:

Energy savings resulting from the improvement of combustion efficiency can reach as high as 2 to 5%, as discussed above. For INA, where maintenance of equipment is fairly good, a lower value of 2% savings is assumed. This 2% savings will not be available on the high pressure boilers, since those are already running at close to optimum efficiency based on the installed O_2 meters. Assuming that the savings will apply to only 10% of the fuel equivalent used in the plant, the savings can be estimated as follows:

$$12{,}000 \text{ TJ/y} \times 0.05 \times 0.02 \times \$3{,}160/\text{TJ} = \$\ 38{,}000$$

In addition, the portable combustion analyzer should be able to measure both SO_2 and NOx, thus making it indispensable in environmental monitoring of combustion processes throughout the INA facility.

Financial analysis:

Implementation costs are estimated at a total of $ 6,500, including $4,000 for the analyzer, $2,000 for duties and taxes, and $500 for training of staff and use of the analyzer.

The simple payback period is approximately 0.2 years, or 2 months.

Schedule:

Task 1 - RCG/Hagler, Bailly prepares specification for combustion analyzer, informs INA, and submits for approval by USAID.
Milestone: June 21, 1991

Task 2 - USAID provides final approval for procurement.
Milestone: June 31, 1991

Task 3 - RCG/Hagler, Bailly issues purchase order for equipment.
Milestone: July 2, 1991

Task 4 - Equipment delivered to INA.
Milestone: September 13, 1991

Task 5 - Equipment installed in plant, and INA completes development of operating procedure for use of equipment.
Milestone: September 27, 1991

Task 6 - Equipment fully operational and in use, monitoring begins by INA.
Milestone: October 11, 1991

Specification of Equipment:

Electronic Combustion Gas Analyzer

Type:	Electronic microprocessor-based
Physical:	Portable, self-contained with carrying case Probe length min 12", sample line length minimum 6 ft Silica gel sample dryer and condensate trap Built-in thermal printer, with line feed button
Output:	LCD display, backlit, adjustable - ambient temperature: 0-60 C - stack temperature: 0-600 C - O_2: 0-21%, electrochemical cell - CO: 0-1000 ppm, electrochemical cell - NOx or NO: 0-2000 ppm - SO_2: 0-2000 ppm - Combustibles: 0-2.5%, semiconductor sensor - Stack draft: mmHg, peizoresistive sensor - Computed values of CO_2, excess air, combustion efficiency
Power:	6-12V battery, rechargeable; input 220V 50Hz
Accessories: or Options:	memory for various fuels, with possibility to custom set diagnostic messages autozero on startup
Spares:	O_2 cell (1) CO cell (1) 6 rolls printer paper 4 bottles silica gel

A. GENERAL AND ENERGY MANAGEMENT

ENERGY & UTILITIES
INA Action A.4 -
Put energy efficiency teams in action to reduce energy losses

Existing conditions:

During the audit, the RCG/Hagler, Bailly team observed steam leaks with substantial energy cost in the urea plant, the high pressure lines coming from the third boiler, and various other points throughout the plant. There also appears to be an opportunity to return additional steam condensate from the plant to the boilerhouse.

Recommended action:

RCG/Hagler, Bailly recommends that INA form "Energy Efficiency Teams" for steam, electric motors, and compressed air. Personnel for this team should be drawn from INA staff, and this exercise should become a continuous part of plant operations and maintenance. The organization of such a team for steam and condensate distribution systems was already under way at INA at the time of the audit.

The Steam Efficiency Team would be responsible for the identification and repair of leaks in steam systems, inspection and replacement or repair of steam traps, and identification and repair of inadequate thermal insulation.

The Steam Efficiency Team should have the following tasks:

- Develop an inventory of the uses of steam in the plant.
- Carry out a survey of the condition of steam pipe insulation in the plant, using thermocouples and other temperature indicators.
- Develop an inventory and check the operation of all steam traps in the plant on a monthly basis, using the temperature or ultrasonic testing techniques, or visual observation where possible. Repair or replace leaking traps as found.

- Carry out a survey of steam leaks on a monthly basis. For each leak found, calculate the cost of the leak (using Georgia Tech's Steam Leak chart on the following page) and estimate the cost to repair the leak. If the payback period is less than 1 year, recommend the repair of the leak. Develop a log to keep track of the growth of leaks from month-to-month. Develop a monthly plan for repairs.

The Electric Motor Efficiency Team would be responsible to survey electric motor load and efficiency, check and clean motors, replace underloaded motors, rewind or replace motors with excessive reactance, and develop a plan for introduction of high efficiency motors. The Compressed Air Efficiency Team would be responsible to evaluate efficiency of compressed air systems, and to seek out and repair leaks in compressed air lines.

The Electric Motor Efficiency Team should have the following specific tasks:

- Based on nameplate and available meters, make a complete inventory of all motors over 10 kW, which identifies the motor number, rating (kW), location, age, voltage, rpm, running amperes, expected annual energy consumption, description of use.

- Obtain curves of efficiency vs. percentage load and power factor vs. percentage load from INA's major suppliers of motors families of motors now installed in the plant.

- Develop specifications for the procurement of new motors for the plant, for new applications. Obtain manufacturer's data on price, efficiency and power factor (cos phi) for alternative lines. In the U.S., manufacturers offer two types of electric motors - standard motors and high efficiency motors which reduce energy consumption by 3-10% for the same application. The increase in efficiency is greatest for smaller sizes (under 50 kW), since large motors are relatively efficient. The high efficiency motor costs about 50% more than the standard motor, but in applications with high duty factor (over 4,000 hours per year, like INA), this incremental cost can be recovered in one year or less. RCG/Hagler, Bailly expects that the results of this analysis will result in the development of a new specification, for high efficiency motors.

- After carrying out the analysis and developing the new high efficiency specification for new motors, consider the possible replacement of existing motors with high efficiency motors on a phased basis. One way to implement this policy would be to buy a quantity of high efficiency motors which would be used to replace burned-out motors, instead of rewinding them. Often, rewound motors have lower efficiency than new motors, as the magnets can suffer reduced flux if they are overheated in the process. Efficiency loss can also result because rewinding is usually done to lower quality standards than new manufacturing, so increased friction can result from slight misalignment. Finally, if wire of smaller diameter or higher resistivity is used in the rewind job, resistive losses will increase. It is the RCG/Hagler, Bailly team's experience that a rewound motor has an efficiency 1-5% less than a new motor, and rewinding costs 50% or more of the cost of a new motor.

- Using portable volt-ammeter, power factor meter, carry out an electric motor load survey. The load (kW, kVAr, cos phi), voltage on each phase, and efficiency of all motors over about 10 kW should be checked using a systematic procedure.

- Using a strip-chart demand recorder, carry out power demand survey (kW, kVAr, metered demand kW, and kWh/shift) for load centers over 100 kW. Based on this data, develop a power demand balance for the plant, under various operating conditions.

- Based on the results of the power demand survey, work together with process personnel to investigate ways to reschedule operations to reduce peak demand and to shift consumption from peak to off-peak hours.

- If motors with excessive reactance are identified, they should be taken out of service for rewinding or replacement.

- Institute a monthly policy of motor maintenance. Check that bearings are getting proper lubrication. Electrical connections should be checked and tightened if necessary. The housing and ventilation air intake on all motors should be cleaned to improve cooling and efficiency. Compressed air should be used to blow out dust and dirt from internal parts of the motor (air should be dry and less than 4 bar pressure to avoid damaging insulation).

The motor and its drive system drive should be checked for proper alignment, proper belt tension, and proper lubrication. Insulation should be tested with a megohmeter, and a log should be kept of these readings so that comparisons can be made from month-to-month. Check for excessive vibration.

- As underloaded motors are identified by the survey, they should be changed for motors appropriately sized for the job. The inventory (developed above) should serve as the basis for moving motors from one location to another within the plant to match sizes to loads. If properly sized motors are available from spares or stocks, replacements of a given kW rating should prioritized on the basis of the possible efficiency improvement (degree of underloading and operating hours per year).

- If phase-to-phase voltage imbalance is found (over 2%), then adjustments should be made to correct the problem. For every 2% variation in phase-to-phase voltage, a motor loses about 1% in efficiency. For the 0.4 kV system, the phase voltages should be equal within ±5 volts, otherwise efficiency is reduced. Voltage imbalance can be caused by loose or corroded connections at bus bars, starter terminals, fuses, or the motor itself. If the problem is caused by single-phase loads which are attached one of the phases, these loads should be more equally distributed among the phases, or else the transformer should be retapped.

The Compressed Air Efficiency Team should have the following tasks:

- Based on design data, make an inventory of all uses of compressed air

- On a monthly basis, carry out an analysis of air compressor efficiency and record in logbook. If less than design, investigate the causes.

- Carry out a survey of the plant every month to identify compressed air leaks, and record them in a log book. Measure the flow of leaks using a velometer and prepare a report, with the monthly cost of each leak clearly indicated. Develop a plan for leak repair, based on priority.

Expected results:

The RCG/Hagler, Bailly team estimates that the potential savings of an improved maintenance program based on these procedures is 0.5% of peak electrical demand, 1.0% of the plant's electric energy consumption and 1.5% of steam energy consumption. The savings are estimated at approximately $287,000 annually, as follows:

Electrical:
0.005 x 22 MW x $10,000/MW/mo x 12 mo/y = $13,000/y
0.01 x 155 million kWh/yr x $0.055/kWh = $85,000/yr

Thermal (mazout and natural gas for steam):
0.015 x 4,000 TJ/yr x $1620/TJ = $ 97,000/y

Total energy savings in TJ:

0.015 x 4,000 TJ/y + 0.01 x 1,866 TJ/y = 78.7 TJ/y

The maintenance program will increase motor life, thereby reducing replacement and rewinding costs over the long run. The maintenance and monitoring program will also reduce the frequency of shutdowns in production operations because of motor failures, thereby having a productivity benefit. These benefits are not estimated in this report.

Equipment required:

(1) Digital strobe tachometer
(1) Digital multimeter/megohmeter with current clamp and Power factor meter
(1) Velometer
(1) Ultrasonic tester (for steam traps, leaks, motor bearings)
(1) Digital thermocouple indicator and probes
(1) Infrared thermal imager (USAID)

Total estimated cost $25,000

RCG/Hagler, Bailly estimates that INA should budget approximately $100,000 per year for additional incidental equipment and repairs (additional maintenance), such as steam traps, insulation, motors, and the like.

Financial analysis:

Based on a cost of $25,000 and a net savings of $82,000 per year, the project payback period is approximately 0.3 years, or 4 months.

Schedule:

Task 1 - RCG/Hagler, Bailly prepares specification for IR thermal imager and ultrasonic tester, and submits for approval by USAID.
Milestone: June 21, 1991

Task 2 - USAID provides final approval for procurement.
Milestone: June 31, 1991

Task 3 - RCG/Hagler, Bailly issues purchase order for equipment.
Milestone: July 2, 1991

Task 4 - Equipment delivered to INA.
Milestone: September 13, 1991

Task 5 - Equipment installed in plant, and INA completes development of operating procedure for use of equipment.
Milestone: September 27, 1991

Task 6 - Equipment fully operational and in use, monitoring begins by INA.
Milestone: October 11, 1991

IEES Energy Tips

Energy management suggestions from the Industrial Energy Extension Service
a joint service of the Georgia Office of Energy Resources and Georgia Tech's Engineering Experiment Station

ENERGY TIP NO. 2

ELIMINATE STEAM LEAKS

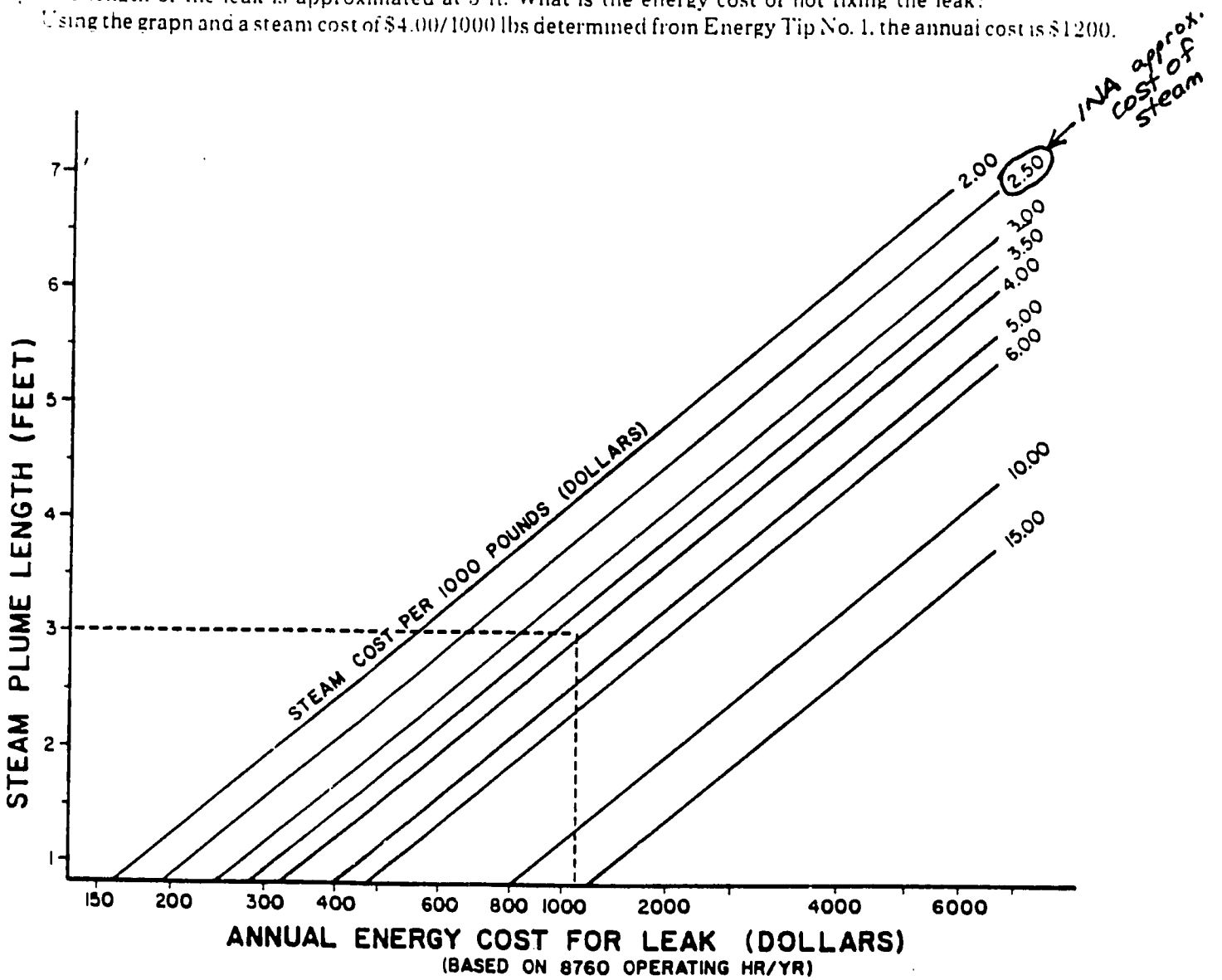
A conspicuous waste of energy are the numerous steam leaks at pipe joints, valves, unions, etc. Until the cost of energy skyrocketed, it was generally thought that small leaks should be tolerated and that fixing them was not worth the time or cost.

The graph below is a rough approximation of what a steam leak costs in terms of annual fuel expense. To use the graph, determine the leak's "Blow Length" by measuring the length of the steam plume or the approximate distance at which water condenses out of the stream onto your hand (usually beyond the visible plume). Enter the graph with the blow length and move across to the corresponding cost of steam line determined by using the "Steam Cost" chart, Energy Tip No. 1. Read the annual energy cost at the bottom of the graph.

EXAMPLE

A survey of a plant's steam distribution system reveals a steam leak at an equipment connection flange. The plume length of the leak is approximated at 3 ft. What is the energy cost of not fixing the leak?

Using the graph and a steam cost of $4.00/1000 lbs determined from Energy Tip No. 1, the annual cost is $1200.



SOURCE: GA TECH EES

A. GENERAL AND ENERGY MANAGEMENT

AMMONIA PLANT II
INA Action A.5 -
Increase production rate to maximum comfortable level

Existing conditions:

INA Ammonia II operated in the first four months of 1991 at a rate less than 100%, achieving its best day March 15 at 99%.

Kellogg ammonia plants all over the world are consistently able to operate at 100%, and many operate at 105-108%. The limits to operation are the RPM of the main compressors (syngas, air). For these machines, INA is not close to the limits.

Recommended actions:

RCG/Hagler, Bailly recommends that INA carry out a controlled experiment to increase the production rate over time according to comfort level. It is vital that plant personnel feel comfortable and it should not be a risky proposition. Step by step over time, the production rate should be carefully increased in an organized way, with the whole plant staff working together to learn the characteristics of operation at the higher rates.

In order to increase INA's comfort level, RCG/Hagler, Bailly recommends that INA contract with one or two experienced engineers who have operated similar plants to assist during the exercise.

Expected results:

RCG/Hagler, Bailly estimates that an average annual production rate of 100% is achievable at INA, for 448,000 tons/year. The marginal energy cost of ammonia is much less than the average cost, so increasing the production rate will not only increase output but also save energy. This can be seen from the scatter diagram of fuel gas GJ/ton vs. production rate. Based on the regression line, an increase from 95% rate (1292 tpd, 14.3 GJ/ton) to 100% rate (1360 tpd, 13.8 GJ/ton) will save 0.5 GJ/ton.

At $124/ton value added, the 22,000 tons increased production is worth $2.728 million. Based on the revised annual production rate of 448,000 tons, this recommendation will reduce gas consumption by 224 TJ, and save $363,000 per year in gas costs. The total value added by the project is $3.091 million.

B. GENERAL ENERGY MANAGEMENT

PRIMARY BOILER STATION
INA Action A.6 -

Optimize combustion efficiency on main boilers: adjust CO analyzers for output range of 0-1000 ppm CO, and use these values to manually trim boiler excess air.

Existing Conditions:

The control of the air-to-fuel ratio in the main two boilers (50-101 and 50-102) is performed automatically on a setpoint entered by the operator. This setpoint is normally approximately 1.6 to 1.3% oxygen in the boiler stack gas. CO is presently not measured. CO analyzers are installed in both boilers; however, the output range of the analyzers is 0-4% CO. This is much too high a range to be of value in optimizing air-to-fuel ratio.

In general, the air-fuel ratio of these two boilers is very good. As shown in the measurements taken by the audit team on April 23, the oxygen levels are very close to the levels recommended by the boiler manufacturer. Parameters measured by the audit team were fuel input, CO, O_2, HC (combustibles), stack temperature, combustion air pressure (draft) and other pressures and damper settings. Computer analysis, performed later, was used to calculate combustion efficiency based on lower heating value (LHV).

INA PETROKEMIJA - BOILER COMBUSTION EFFICIENCY (80% LOAD)

	Measurements O_2 %	CO ppm	HC %	Diff Temp C	Calculation Combstn effy on LHV,%	
50-101 (fuel oil)						
RCG measurement	2.0	0	0.00	170	92.48	
INA analyzer	1.6	0		170	92.61	
design	1.05				92.79	@ 170 C
50-102 (natural gas)						
RCG measurement	1.6	0	0.00	170	92.55	
INA analyzer	1.4	0	0.00	170	92.61	
design	1.1				92.70	@ 170 C

Recommended Actions:

RCG/Hagler, Bailly recommends that the CO analyzers be repaired, calibrated and adjusted so their output is proportional to 0-1000 ppm. These values should be used to ensure that the O_2 level, and therefore the excess air, is at the optimum (minimum) value. With natural gas fuel, O_2 should be reduced until CO levels reach 25-50 ppm; with liquid fuel oil, the values can be twice as high. CO should be regularly and automatically logged on the TDC 3000 system.

Expected Results

As the table above shows, only a few tenths of a percent of improvement can be achieved in the already high combustion efficiency maintained by INA. Nevertheless, with the large fuel consumption of these boilers, this can represent a significant savings for a relatively small investment.

Based on the estimated annual consumption of 4,000 TJ by the boilers, and assuming a 0.2% average annual reduction in fuel consumption by efficiency optimization, this recommendation will reduce gas consumption by 8 TJ, and save $19,000 per year in combined gas and fuel oil costs.

The cost of implementing this recommendation would be several hours of work by the instrumentation staff, and possibly some additional parts for the existing analyzers. Total cost is estimated at less than $2,000.

Financial analysis:

The payback for this recommendation is calculated at 0.1 year, or one month.

A. GENERAL AND ENERGY MANAGEMENT

AMMONIA PLANT II
INA Action A.7 -
Delay turnaround scheduled for June 1991 until optimum time as indicated by catalyst conditions

Existing conditions:

INA Ammonia II suffered a long shutdown in 1990 and was brought back on-stream in October 1990. The annual maintenance turnaround (extended 30-day planned shutdown) is coming up in June.

Kellogg plants all over the world have been able to extend the time between turnarounds to 15-18 months, thanks to improved catalysts with longer life. INA is now using some of these same catalysts.

Recommended action:

Delay the turnaround until at least October 1991 (however, see also Action C.1). Monitor catalyst conditions and attempt to move to an 15-month cycle over the next two years, and attempt to reach 18-months between turnarounds within five years.

Expected results:

Extending the time between turnarounds not only increased production because of the increased on-stream factor, but also saves energy because of the reduced number of start-ups and shut-downs. An annual turnaround start-up/shut-down sequence requires about 2% of the plant's annual fuel gas consumption, without any production.

Assuming 15-months between turnarounds, the benefits are:
- 9,000 tons increased production per year
- 0.4% reduced annual fuel gas consumption (0.056 GJ/ton)

At $124/ton value added, the 9,000 tons increased production is worth $1.116 million. Based on the revised annual production rate of 454,000 tons, this recommendation will reduce gas consumption by 25 TJ, and save $41,000 per year in gas costs. The total value added by the project is $1.157 million.

B. LOW-COST, SHORT-TERM IMPROVEMENTS

INA Action A.8 - Improve energy monitoring and targeting

Existing conditions:

INA presently collects voluminous amounts of data, thanks to the TDC 3000 computer system, and metering systems installed throughout the plant. Detailed information on production, energy consumption, specific energy consumption are available on a daily basis. They are provided monthly to all departments, and are compiled annually in an operating report and plan for the following year. Each production manager is responsible for his or her own department.

While there are certainly enough data taken and recorded, the analysis of this data, and the attention paid to it can be improved. Currently, Mr. Jeftimija evaluates much of this data in a general way. However, the plant is very large, and his primary responsibility is to maintain the central energy plant.

Recommended action:

RCG/Hagler, Bailly offers several points that should serve to increase the value of the large amount of data taken each day.

- Issue a management directive that requires a more careful approach to energy efficiency, more detailed scrutiny of operating parameters relating to efficiency, and a stronger maintenance program to carry out many of the practical activities.

- Automate the printout of data by the central cost control department when requested by production departments. While large amounts of data were provided to the audit team, much of this data was hand written. This example shows that the cost control department is not always able to provide exactly what might be needed by the production departments to maintain a better control of efficiency.

- Add more energy efficiency parameters to the regular data printouts. Perform analyses such as shown in the appendices of this report, providing production managers with visual presentations of performance trends and developments.

- Initiate a centralized evaluation of energy efficiency. Use existing underloaded staff to perform the analyses for the managers to review at monthly meetings dealing specifically with energy issues.

- Set targets, and continue to improve them. Use improved specific energy consumption or efficiency ratios previously achieved as targets in the planning for future years. At present, in most instances, the original design values are still used for planning purposes, even though in many cases operation has been better than design.

- Develop incentive schemes to reward managers with good energy efficiency performance in their department; eventually involve technical and operating staff in such schemes.

Expected results:

INA should set a target to reduce energy consumption by 3% throughout the plant over the next year. Approximately 2% could be expected to come from the measures described previously. Even for those measures to succeed there must be some management commitment; thus it could be said that the whole energy efficiency and production improvement program rests on this recommendation.

If a 1% improvement in energy efficiency were credited to this recommendation, annual savings would result in approximately $500,000.

The major investments are management time, some additional computer equipment, and eventually some improved metering equipment in some particular areas. If $250,000 were budgeted for this effort, the payback would be approximately 6 months.

B. LOW-COST, SHORT-TERM IMPROVEMENTS

INA Action B.1 - Reduce start-up time

Existing conditions:

INA Ammonia II is started in the conventional way. From the time of first lighting the burners until ammonia production is 3-4 days.

Most Kellogg plants in North America have instituted new procedures for fast start-up. These procedures have been developed over time in conjunction with catalyst manufacturers, reformer tube manufacturers, and suppliers of other critical components. These plants are now able to achieve production in about 24 hours. The procedure is actually said to be safer that conventional start-up, because there is less operator fatigue, and less time is spent in the critical modes, when an operator error would be disastrous.

Recommended action:

RCG/Hagler, Bailly recommends that INA use the fast start-up method after its next turnaround, and adopt the procedure if satisfactory.

Expected results:

INA should expect to pay about $300,000 for the design and assistance required for the fast start-up technique.

Reducing start-up time by 2 days would increase ammonia production by about 4,000 tons per year and would reduce fuel gas consumption by 0.8% (0.1 GJ/ton).

At $124/ton value added, the 4,000 tons increased production is worth $496,000. Based on the revised annual production rate of 458,000 tons, this recommendation will reduce gas consumption by 45 TJ, and save $74,000 per year in gas costs. The total value added by the project is $570,000.

The payback period on the project cost is about six months.

B. LOW-COST, SHORT-TERM IMPROVEMENTS

AMMONIA PLANT II
INA Action B.2 -

Improve combustion efficiency - install fixed instrumentation to measure CO and O_2 content of the stack gases from primary reformer and auxiliary boiler. Revise operating procedures.

Existing Conditions:

The control of the air to fuel ratio in the primary reformer and auxiliary boiler is presently done based on manual settings of dampers. The operator sets the damper position based on readings taken with an oxygen analyzer.

On 25 April, 1991 the RCG/Hagler, Bailly team made a series of measurements of the exhaust gases from the primary reformer and auxiliary boiler using our portable combustion analyzer. Parameters measured were fuel input, CO, O_2, HC (combustibles), stack temperature, combustion air pressure (draft) and other pressures and damper settings. Computer analysis, performed later, was used to calculate combustion efficiency based on lower heating value (LHV).

In the readings taken, excess air levels slightly about the design value of 15% were found, as follows:

primary reformer: 42%
auxiliary boiler: 26%
exit ID fan (mixed, total system exhaust): 32%

Based on these readings, computer calculations were made of combustion efficiency (see following pages).

Recommended Actions:

RCG/Hagler, Bailly recommends that equipment to continuously monitor O_2 and CO content of the stack gases be procured by INA. After installation, the sensors should be connected to the TDC3000 system. INA should provide training of Ammonia II operators in its use, and revise boiler operating procedures to control combustion air to the burners based on the O_2 and CO content of the stack gases. Primary and secondary air should be regulated to give the minimum amount of excess air to the burner which is required for complete combustion of the fuel.

Expected Results

The measurements made at INA and the combustion calculations demonstrated that significant energy savings are possible in the operation of the air to fuel ratio. the savings are estimated as 0.8% of fuel gas energy, as summarized below:

INA AMMONIA II PLANT - REFORMER/BOILER COMBUSTION EFFICIENCY

	Measurements				Calculation
	O_2 %	CO ppm	HC %	Temp C	Combstn effy on LHV,%
Primary Reformer					
before	6.5	0	0.00	220	88.3
after	3.0	0	0.00	230	89.7
savings					1.4
Auxiliary Boiler					
before	4.2	0	0.00	220	89.5
after	2.0	0	0.00	230	90.2
savings					0.7
Total system (Reformer + Boiler)					
before	5.4	0	0.00	220	89.0
after	2.7	0	0.00	230	89.8
savings					0.8 (0.11 GJ/ton)

Based on the revised annual production rate of 458,000 tons, this recommendation will reduce gas consumption by 50 TJ, and save $82,000 per year in gas costs.

The cost of implementing this recommendation would be approximately $31,000, calculated as follows:

Instrumentation	
Oxygen and CO Analyzers (3)	$24,000
(Ametek Thermox WDG-HPIIC, or equivalent)	
Calibration gas and spare cells	$3,000
Instrument Cable	$2,000
300 meters 6pr Shielded twisted pair @ $7/m	
Installation and Calibration	$500
20 man-hours @ $25/hr	
Experimentation for Operating Curves	$1,000
40 man-hours @ $25/hr	
Total	$30,500

Financial analysis:

Based on a total installed cost of $31,000 and a savings of $82,000 per year, the payback period is less than five months.

B. LOW-COST, SHORT-TERM IMPROVEMENTS

PLANT MANAGEMENT
INA Action B.3 -
Reduce heat loss - use portable infrared thermal imaging device to monitor heat loss.

Existing Conditions:

Substantial heat is radiated from a wide range of heating and combustion equipment throughout the INA Petrokemija facility. This equipment ranges from the refractory lined ammonia reformer, to a variety of steam heat exchangers in the plant. While maintenance on insulation and refractories is routinely performed during shutdown periods, INA does not currently have a good way of monitoring all this equipment for heat leaks and hot spots due to wear or deterioration of the insulation or refractory.

Recommended action:

RCG/Hagler, Bailly team recommends that INA adopt a new procedure for monitoring the condition of insulation and refractories, based on temperature readings from an infrared thermal imaging device (to be procured under Action A.3). This device can locate hot spots and damaged sections of refractory so that repairs can be made during scheduled maintenance shutdowns.

The device should be used in conjunction with a logbook drawn up for this purpose. The log should contain a complete inventory of thermal equipment, to require the operators of the thermal imager to enter readings for each equipment. These checks should be performed approximately 3 times per year for each major piece of equipment. A repair order should be prepared for each problem identified.

The thermal imager should be specified to give a monochromatic image of the surface of the kiln or other equipment. The temperature readout should be capable of 0-1000C.

Expected results:

Typically, the careful use of a thermal imaging device can provide savings of 0.5 to 3% of thermal energy used. RCG/Hagler, Bailly estimates that the use of the thermal imager, together with revised maintenance procedures to optimize refractory and insulation replacement, can reduce annual fuel consumption throughout the INA facility by approximately 0.5%. At the current consumption rate of oil, the energy savings are estimated as follows:

0.005 x 12,000 TJ/yr x US$ 1,600/TJ = $ 96,000 per year

The cost of the IR thermal imager, with temperature readout, is estimated as $19,000.

RCG/Hagler, Bailly estimates an additional maintenance budget of $30,000 per year, to allow for shutdowns and refractory, will be required.

Financial analysis:

Based on a cost of $17,000 and a net savings of $66,000 per year, the payback period is less than 4 months.

B. LOW-COST, SHORT-TERM IMPROVEMENTS

WATER TREATMENT AND COOLING SYSTEM
INA Action B.4 -

Reduce pumping power in the cooling water distribution systems for both Ammonia II and Ammonia I. Identify needs for additional flow or pressure, and install local booster pumps where necessary. Eliminate one or more of the large electric pumps.

Existing Conditions:

An expansive cooling water system exists to meet the needs of the INA facility. For the newer Ammonia II complex, usually 6 pumps of 800 kW each circulate water through the facility. For the Ammonia I plant, two pumps of 900 kW are operated. This operation appears to be fairly consistent throughout the whole year.

These pumps and motors consume nearly 15-20% of the total electricity at INA. This is an extremely large quantity, and merits detailed investigation. Furthermore, there appear to be cooling problems which might be able to be solved by means other than running most of the pumps. For example, one heat exchanger in Ammonia II requires a cooling water velocity of 1.5 m/s in the shell side to minimize scaling. It should be investigated whether this velocity might not be better met by a localized booster pump for that heat exchanger. Similarly, the Ammonia I pumps are both operated to maintain a required pressure head; together they provide a total of 50,000 m3/h of water at the required head, while less than 1/3 of that flow is actually needed.

Other problems mentioned during the audit team visit were the poor efficiency of the cooling tower, and the poor distribution of flow among the pumps at Ammonia II.

Recommended action:

Lack of time during the preliminary audit precluded more detailed investigation of the pumping problems. The RCG/Hagler, Bailly team recommends that INA internally lead a study to identify the problems of the cooling water system, focusing initially on the energy consumption aspects. While the heat exchanger problem identified can be solved, it is important to know whether there are other similar constraints. The study should concentrate on ways to eliminate one or more of the existing pumps from operation.

Expected results:

If one 800 kW pump is eliminated during a period of 6,000 hours per year, the energy savings could amount to 4,800,000 kWh. This amount is worth $264,000.

The potential savings above makes the study of the pumping and distribution system requirements extremely attractive. Such a study could be performed for approximately $5,000, and even much less if done by in-house staff. The cost of installing a booster pump system, including controls could range from $20,000 to $30,000, depending on the exact application. In such a case, the payback would be several months; in a more optimistic case, the payback would be almost immediate.

C. MAJOR MAINTENANCE

AMMONIA PLANT II
INA Action C.1 -
Improve catalyst activity in 103-D (secondary reformer)

Existing conditions:

The catalyst in the secondary reformer, 103-D, at INA Ammonia II now has a low activity and is unable to perform up to specification. It may have been poisoned by oil, perhaps from the syngas turbine before it was taken out of service in 1990.

As a result, much more fuel energy is being used in the primary reformer. This causes INA to try to force more of the reaction to occur in the primary reformer, by increasing firing in the primary reformer and by increasing steam flow. The result is that the stack temperature is increased and the plant runs at a high steam-to-carbon ratio, about 3.9 or about 10% more steam than optimum. Inerts in the syn loop are also quite high at 13%, leading to a greater purge rate and resultant loss of hydrogen.

Furthermore, the feed gas delivered to INA is of varying composition. The state of the catalyst makes it difficult to handle these variations.

Recommended action:

INA plans to invest in feed gas pretreatment equipment and to change part of the catalyst for new catalyst of greater surface area during the next turnaround. RCG/Hagler, Bailly supports the use of the new catalyst, which is of the "wagon-wheel" shape.

Expected results:

Improving the catalyst conditions and solving the feed gas problem should enable comfortable plant capacity to be increased slightly, about 2%, or 9,000 tons per year.

A reduction in steam to the primary reformer of 10% is estimated, and a reduction in the stack temperature of 20C should result from the reduction in firing at the primary reformer, for an energy savings of 1.0 GJ/ton.

The expected cost of implementing the project is $2 million or less. This should be made available to increase the funding of the next turnaround budget, from about $6 million.

At $124/ton value added, the 9,000 tons increased production is worth $1,116,000. Based on the revised annual production rate of 467,000 tons, this recommendation will reduce gas consumption by 467 TJ, and save $756,000 per year in gas costs. The total value added by the project is thus $1.872 million.

The payback period on the initial investment is less than one year.

D. CAPITAL INVESTMENT

AMMONIA PLANT II
INA Action D.1 -
Revamp plant to improve design

Existing conditions:

INA Ammonia II is a standard Kellogg design plant. Many improvements to the basic design have been developed in the years since the plant was installed in 1984. Many Kellogg plants all over the world have now successfully carried out projects to improve the design of their plants.

Recommended action:

RCG/Hagler, Bailly recommends that INA develop a plan for the revamp of Ammonia II. There are several vendors which can support a revamp with equipment designs. While all Kellogg ammonia plants are similar, each one has differences which are important and which can jeopardize the success of a revamp. Not all plants have achieved the same success by installing success by installing a given piece of equipment.

To be effective, the Ammonia II revamp program should be carried out in a number of steps, as follows:

Step 1 - Determine objectives

- Maintain production to serve fertilizer operations. A prolonged shutdown to revamp the plant would not be appropriate.
- Increase capacity. Given the shortage of ammonia at INA, this should be the primary objective. An increase of 20% (to 1650 tpd) should be achievable.
- Save energy. The project should be able to reduce specific energy consumption by at least 10%.
- Improve reliability. If necessary, selective equipment improvements may be carried out in problem areas.

Step 2 - Characterize plant

-- Determine bottlenecks. Controlled engineering tests and experiments must be carried out to increase plant output, measure the results, and analyze the data to identify areas in which limitations occur. It appears that some of the classical bottlenecks (such as the synloop pressure, the syngas turbocompressor and the air turbocompressor) have plenty of available capacity.

-- Measure efficiency. The performance of key process converters, rotating equipment, and heat exchangers should be measured and carefully studied.

Step 3 - Decide on methodology

-- Annual step-wise investment. Carry out improvements over a period of several years. In this way, improvements will be gradual, but production disturbance will be minimized.

-- Single project. Carry out one large project to improve the plant in a single year. In this way, improvements will be achieved as early as possible. Large financing will be needed which may be difficult but may also be easier because the project will be of sufficient size to attract World Bank and other similar agencies. This method would entail greater risk of production loss and a long period of acclimation after the installation is complete.

Step 4 - Identify financing

Depending on the methodology, various sources are possible, including INA internal sources, the World Bank and other international development banks, or other sources.

Step 5 - Develop technical project

Because of the fast pace of technological developments in ammonia plant revamps, only after addressing the first four steps should serious consideration be made of the technology. In this way, INA will be able to obtain the most from the experience of the other ammonia plant operators who are installing similar equipment. Candidate technologies which are available for consideration are listed in Exhibit C.2.1. This list is not exhaustive.

Expected results:

RCG/Hagler, Bailly estimates that for a project budget of $20-30 million, INA Ammonia II can achieve the following benefits:

- Increase plant capacity from 1360 tpd (1400 tpd achievable) to 1650 tpd (regularly achievable)
- Increase annual production from 475,000 tons to 559,000 tons
- Reduce fuel gas energy from 12 GJ/ton to 9 GJ/ton
- Reduce process gas energy from 22.5 GJ/ton to 21.5 GJ/ton

INA AMMONIA PLANT II
REVAMP SUMMARY OF COSTS AND BENEFITS

	Cost	Benefit
BASE CASE - OPTIMIZED		
Production, tons		475,000
Production value, $/ton		110[4]
Production value, M$/yr		$52.25
Gas consumption, GJ/ton	34.5	
Gas usage, TJ/yr	16,400	
Gas price, $/TJ	$1,620[5]	
Gas cost, M$/yr	$26.57	
Value added, M$/yr		$25.68
INVESTMENT IN PLANT REVAMP		
Cost of revamp, M$	$30	
BASE CASE - OPTIMIZED		
Production, tons		559,000
Production value, $/ton		110
Production value, M$/yr		$61.49
Gas consumption, GJ/ton	30.5	
Gas usage, TJ	17,000	
Gas price, $/TJ	$1,620	
Gas cost, M$/yr	$27.54	
Value added, M$/yr		$33.95
RETURN ON INVESTMENT		
Increase in value added, M$/yr		$8.27

PAYBACK PERIOD =
$25 million/$8.27 million = 3 years

[4] Ammonia price FOB Gulf coast US, March 1991. This is used as an indicator for world prices, Yugoslavian prices may be higher

[5] Based on $1.62/GJ price now paid by INA.

INA AMMONIA PLANT II
REVAMP CANDIDATE TECHNOLOGIES

Feed gas pretreatment - to remove higher hydrocarbons, CO_2 or other contaminants.

Synthesis gas coolers or chiller - to reduce load on syngas compressor and also to replace or reduce duty on existing coolers, which are a reliability problem

Ammonia converter in-situ retrofit - to convert converter from axial flow to radial flow design and thereby reduce pressure drop and increase conversion rate

Purge gas hydrogen recovery - to extract hydrogen from the purge gas extracted from the synloop, and return it to the synloop instead of burning it as is done now.

Feed gas saturator - to recover waste heat from the stack and to use this heat to preheat a mixture of feed gas and water, thereby saturating the gas with water vapor and reducing the demand for process steam in the reformer.

Air compressor upgrade or parallel unit - assuming the air compressor is found to be a bottleneck, modify the compressor internals or install a second parallel unit

Synthesis gas compressor upgrade or parallel unit - assuming the air compressor is found to be a bottleneck, modify the compressor internals or install a second parallel unit

ID fan modifications - modify the fan to operate by steam only, rather than steam and electricity as present

CO_2 compressor condenser - poor vacuum is achieved at this condenser, so modify the condenser internals or install a second parallel unit

Condensate stripping tower heat recovery - the steam escaping from this tower is a small but obvious waste of energy, which could be avoided by installing a flash vessel or heat exchanger

LTS guard vessel - install second LTS vessel with sacrificial catalyst to reduce costs and increase reliability

Carbonate flash vessel - to recover heat in the CO_2 removal system

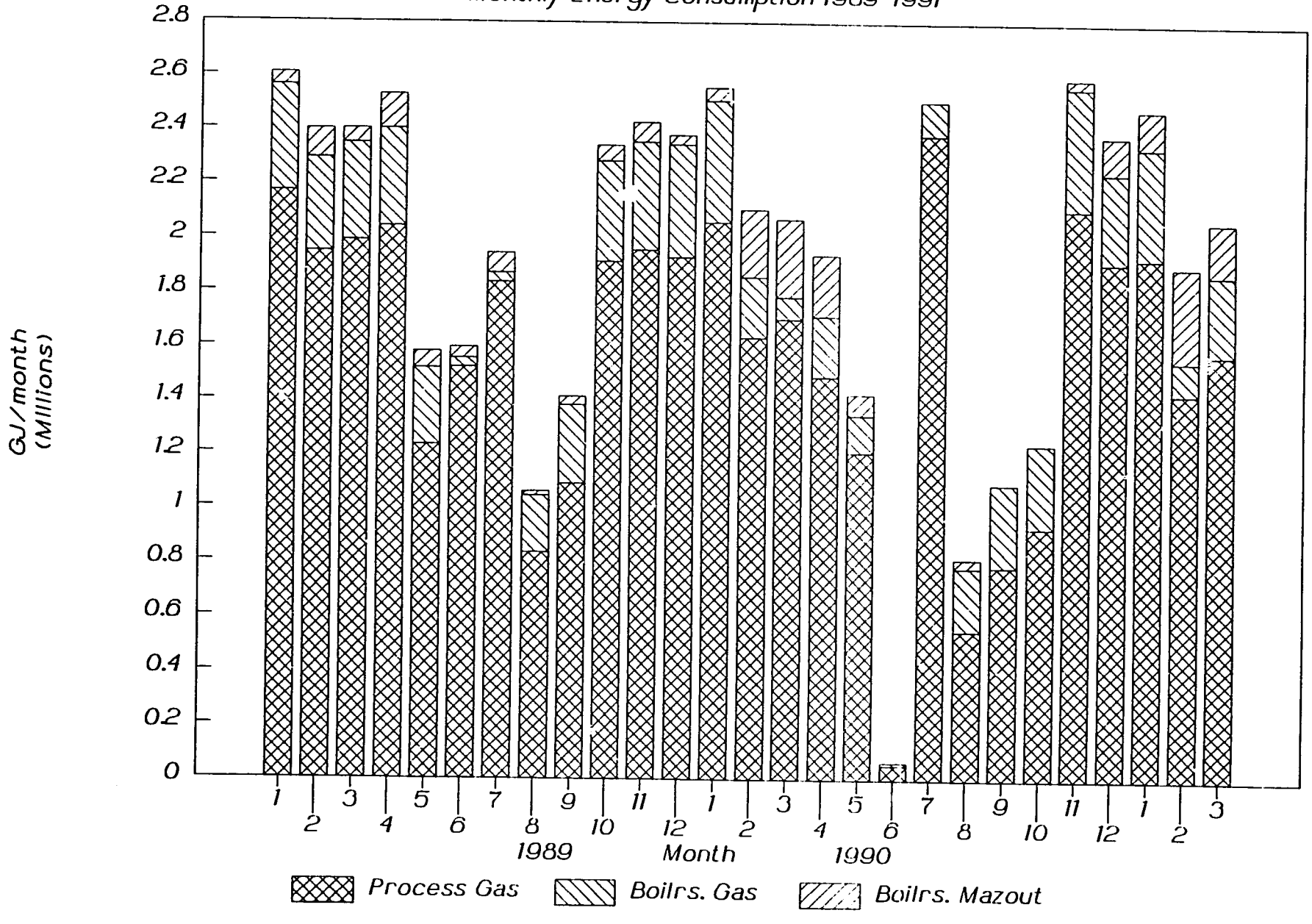
INA PETROKEMIJA, KUTINA

APPENDIX 1 -- ENERGY AND PRODUCTION GRAPHS

(TOTAL COMPLEX; MONTHLY DATA 1/89-3/91)

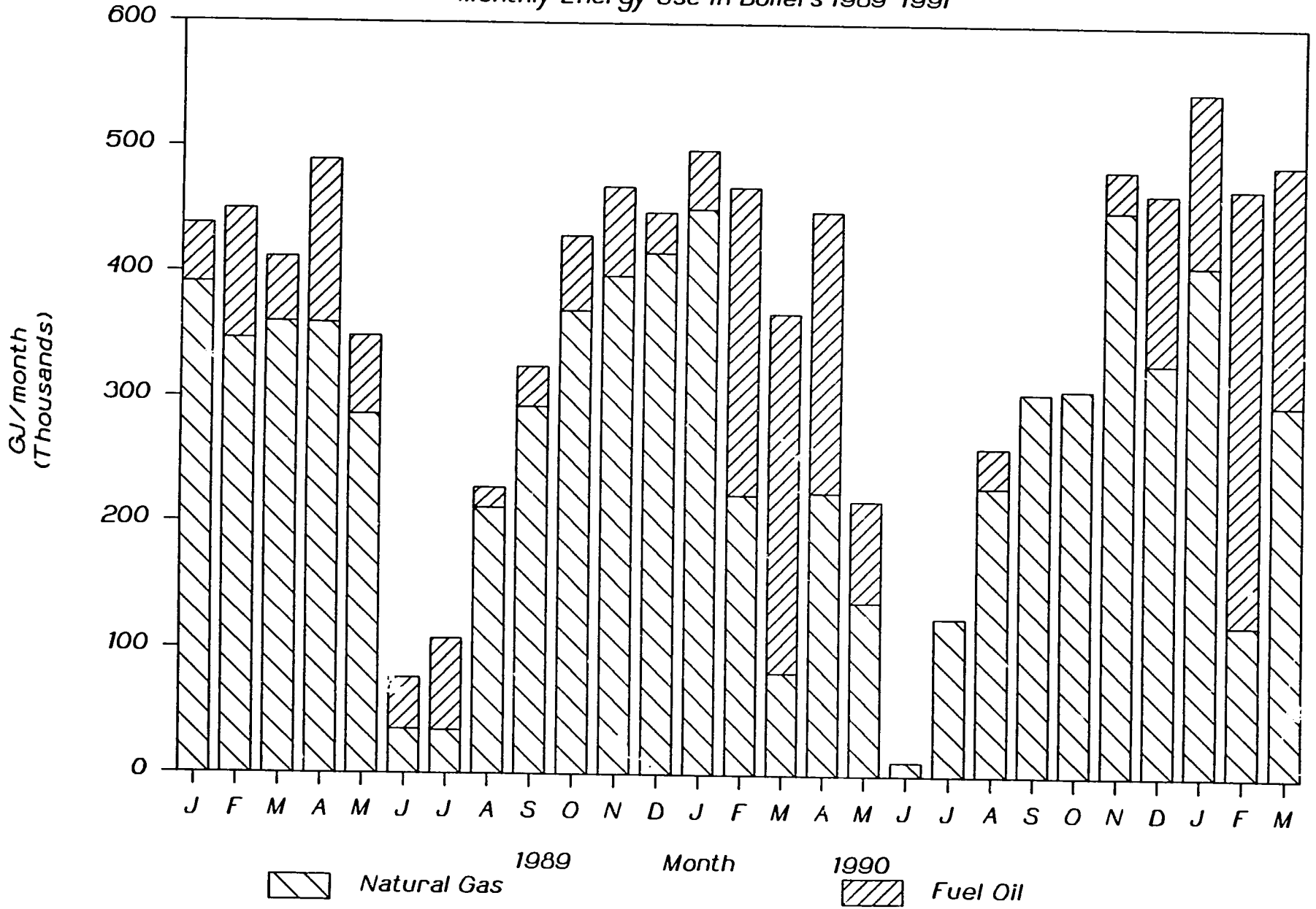
INA Petrokemija -- Total Plant

Monthly Energy Consumption 1989-1991



INA Petrokemija -- Total Plant

Monthly Energy Use in Boilers 1989-1991



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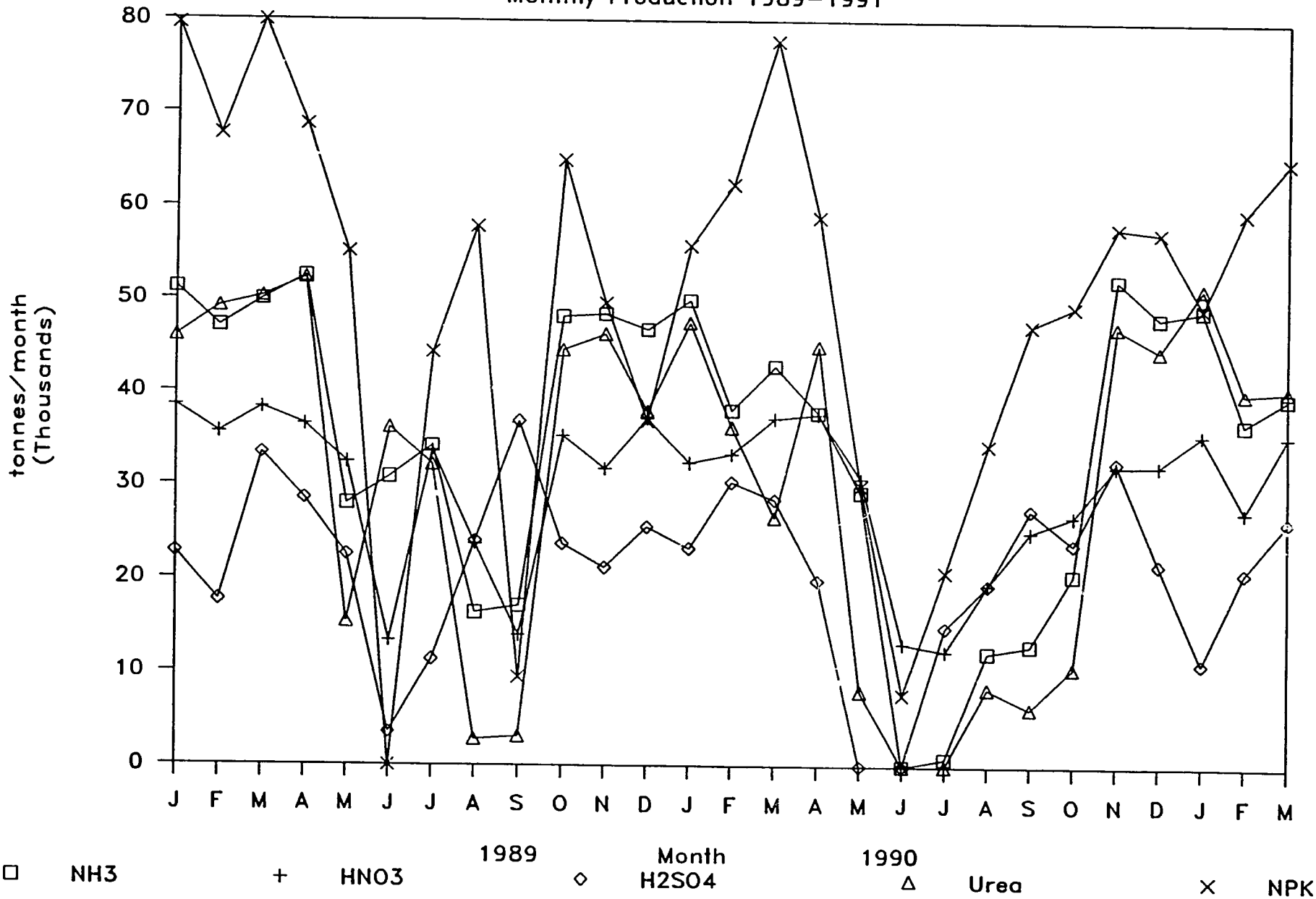
INA Petrokemija -- Total Plant

Monthly Production 1989–1991

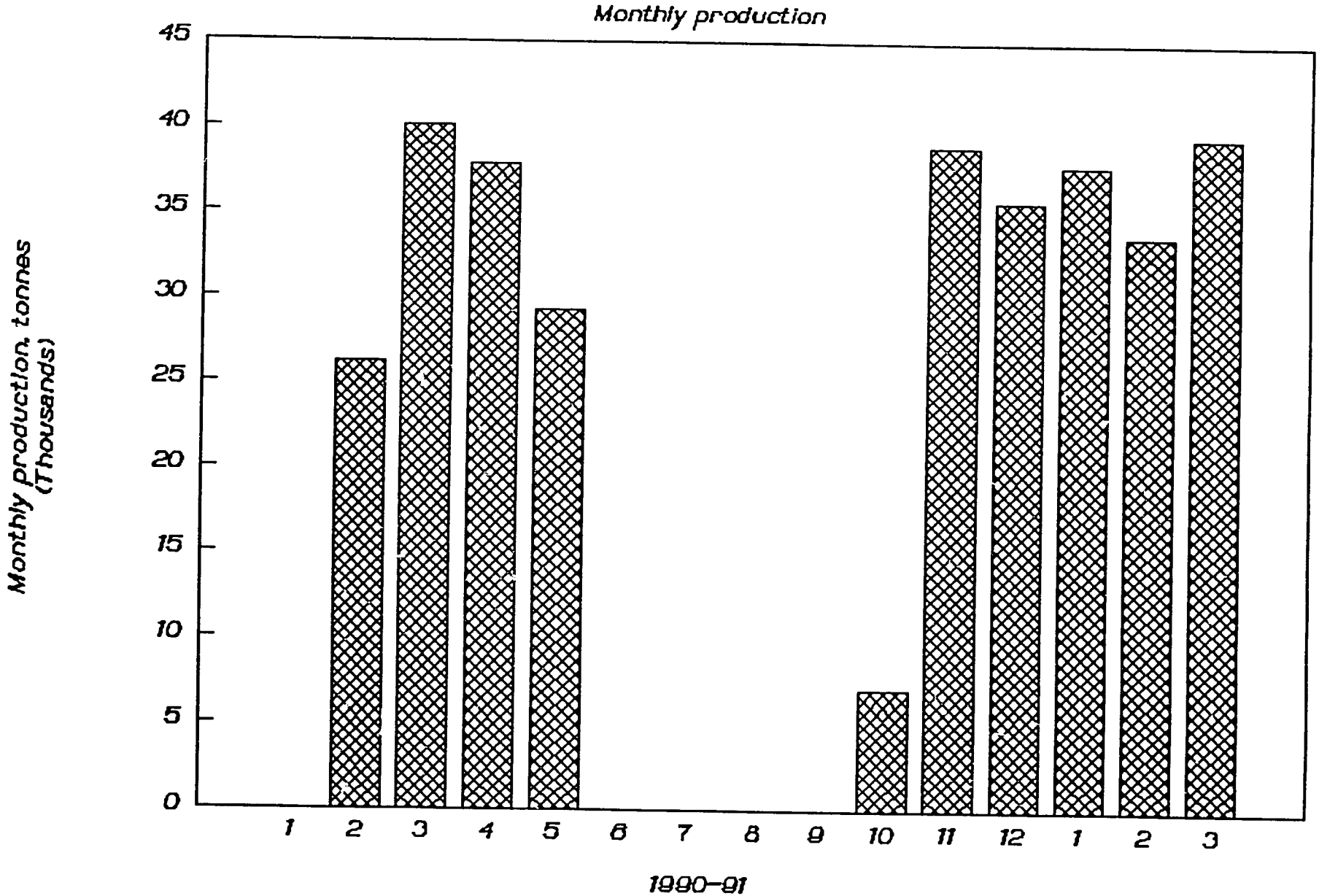


INA PETROKEMIJA, KUTINA

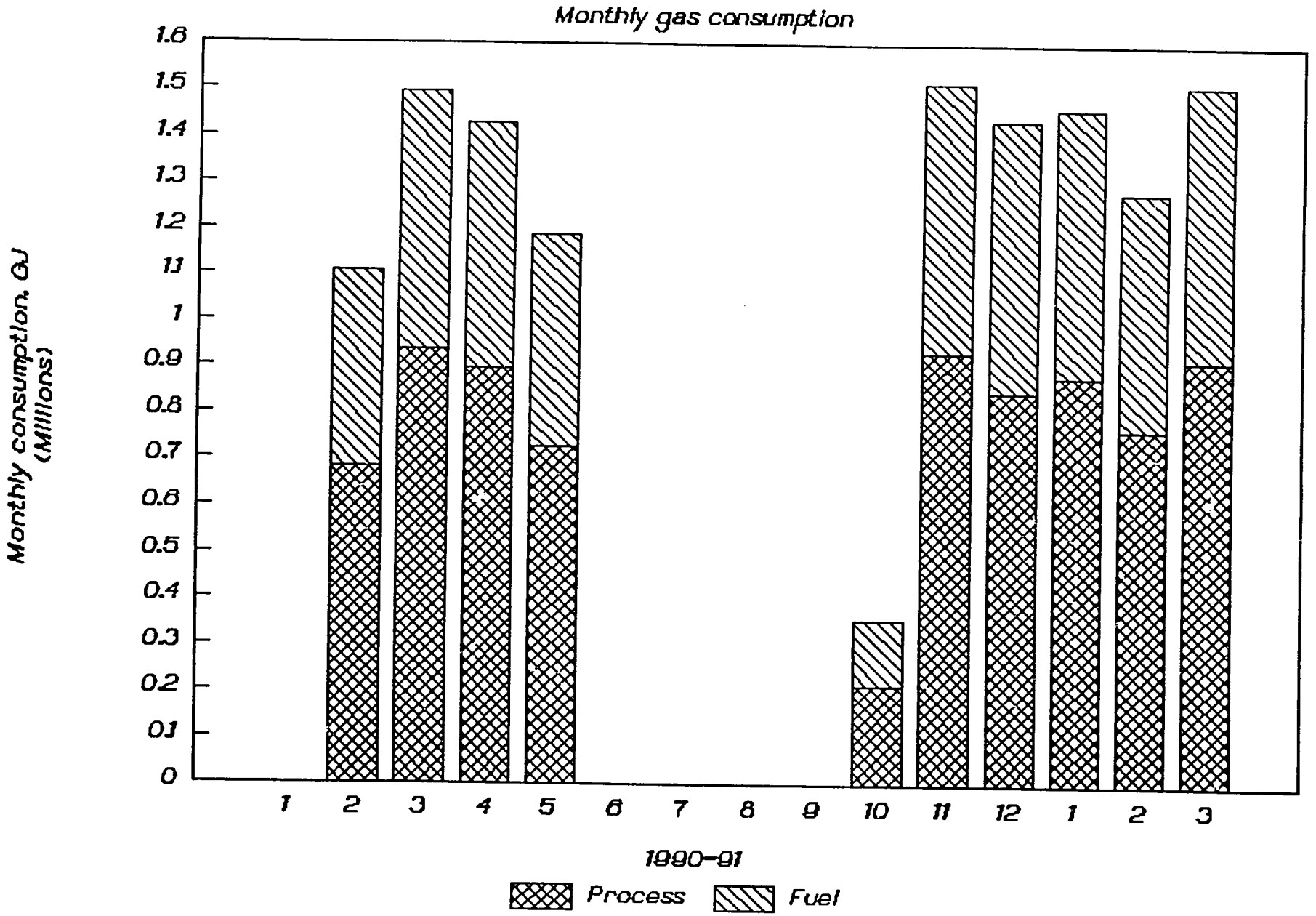
APPENDIX 2 -- AMMONIA II: ENERGY AND PRODUCTION GRAPHS

(MONTHLY DATA 1/90 - 3/91)

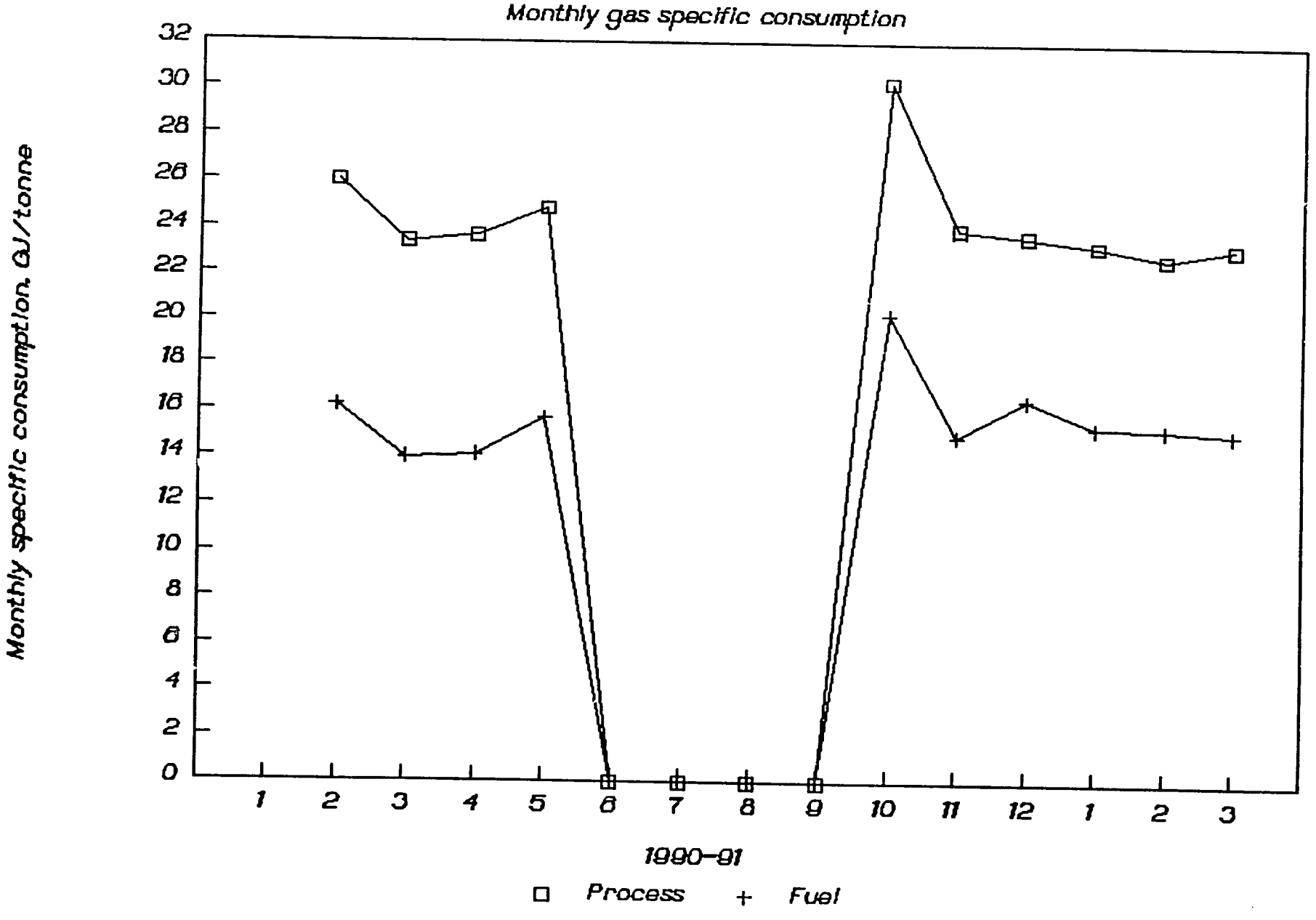
INA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



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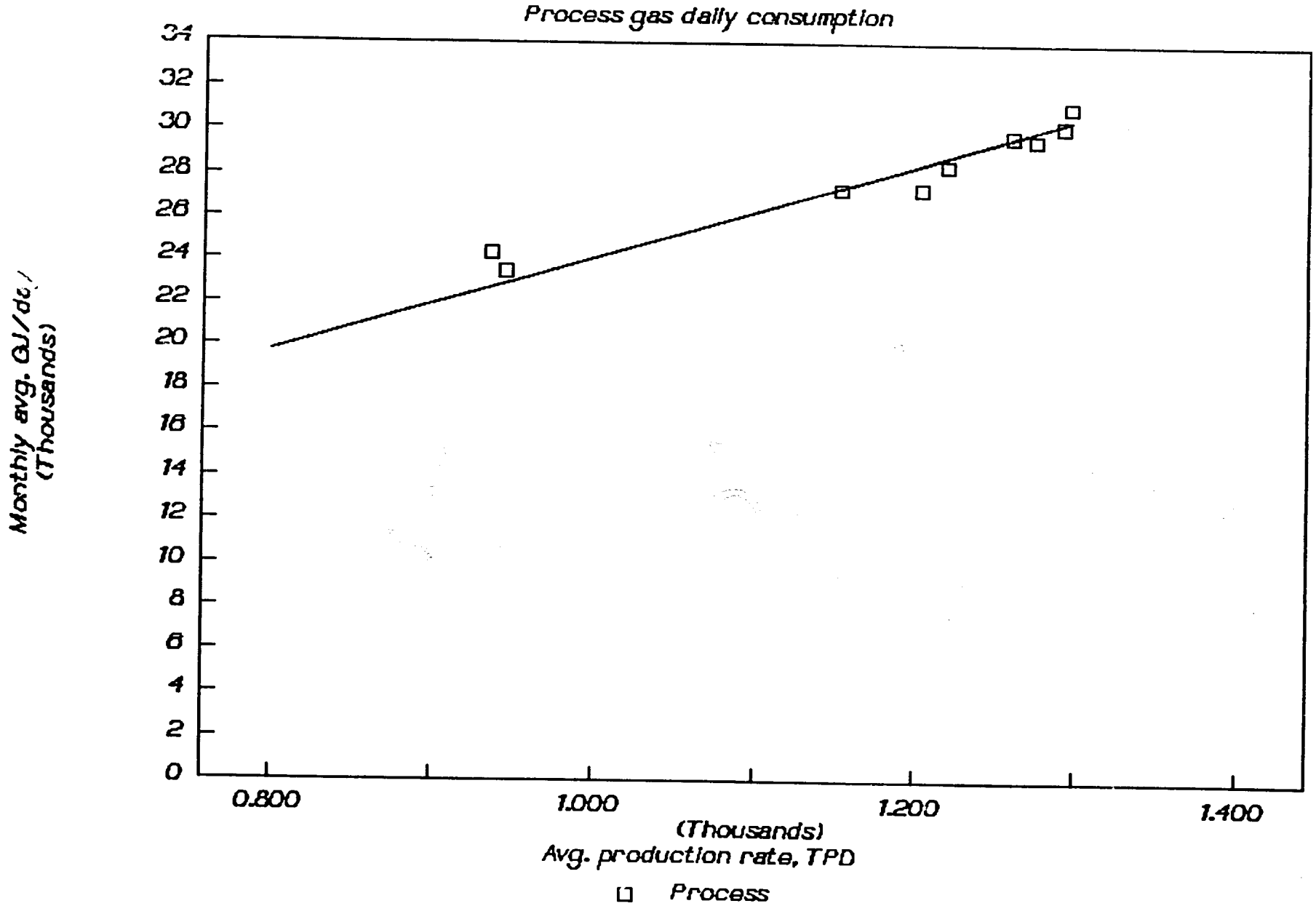
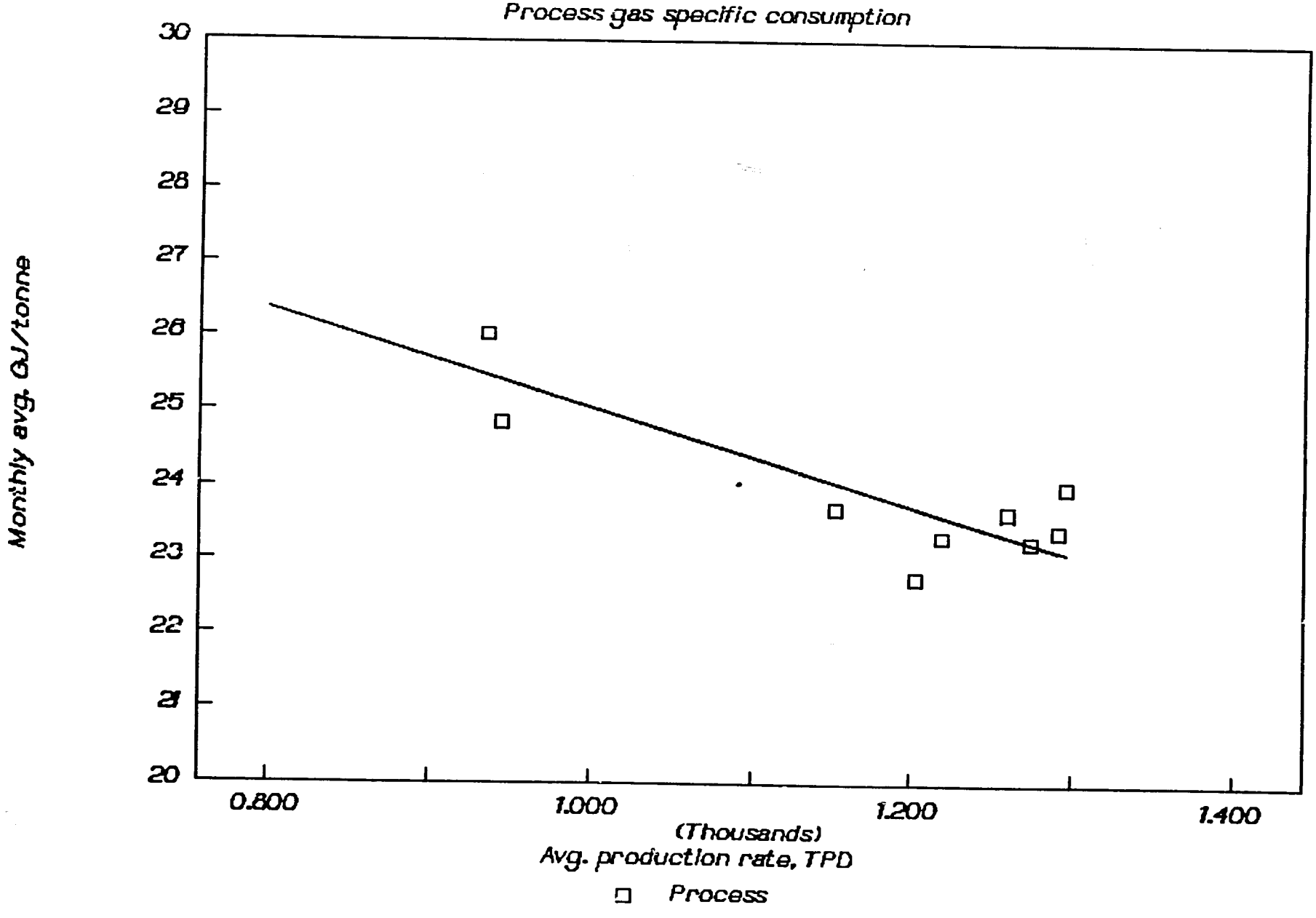


INA Petrokimija Kutina - Ammonia



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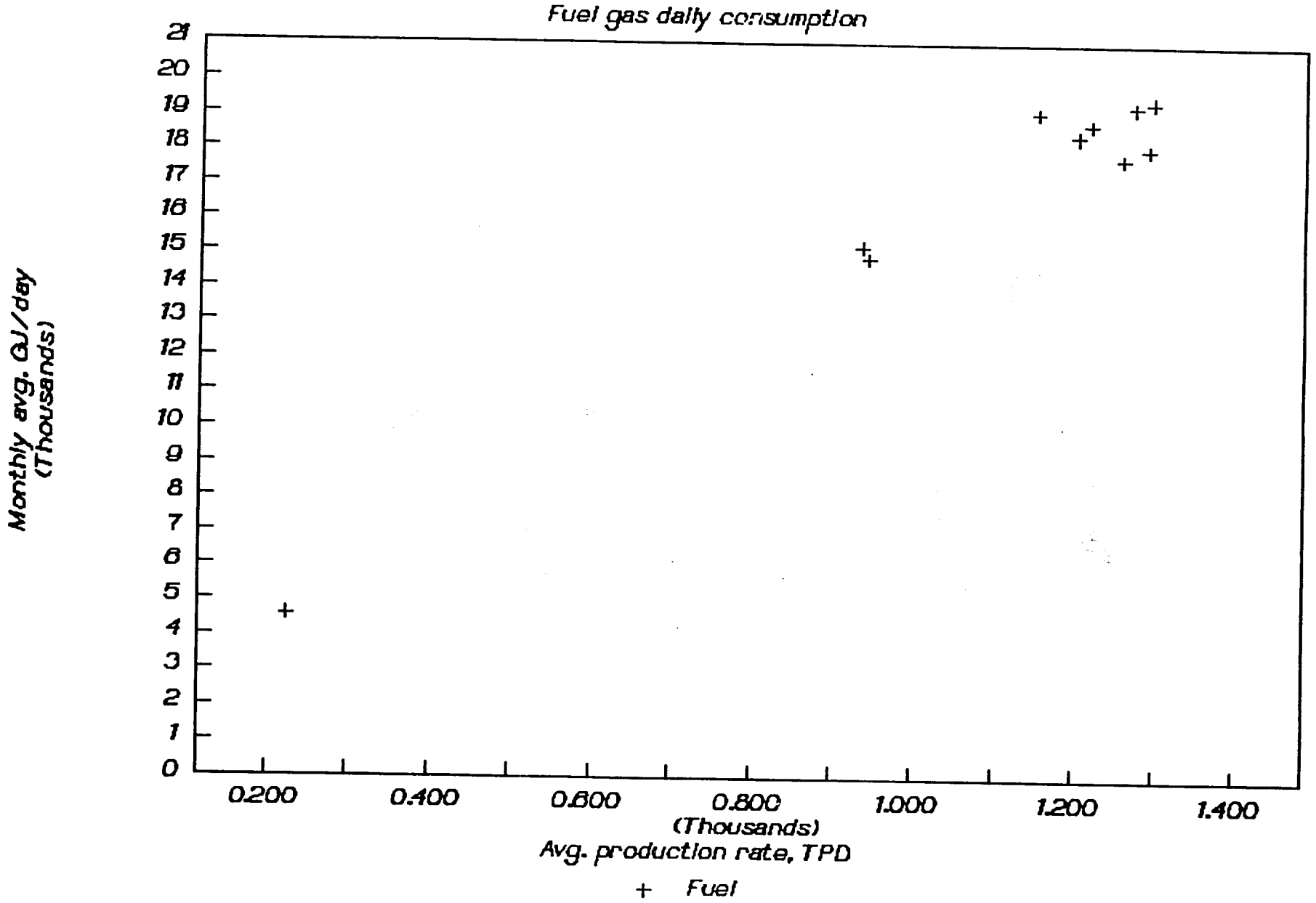
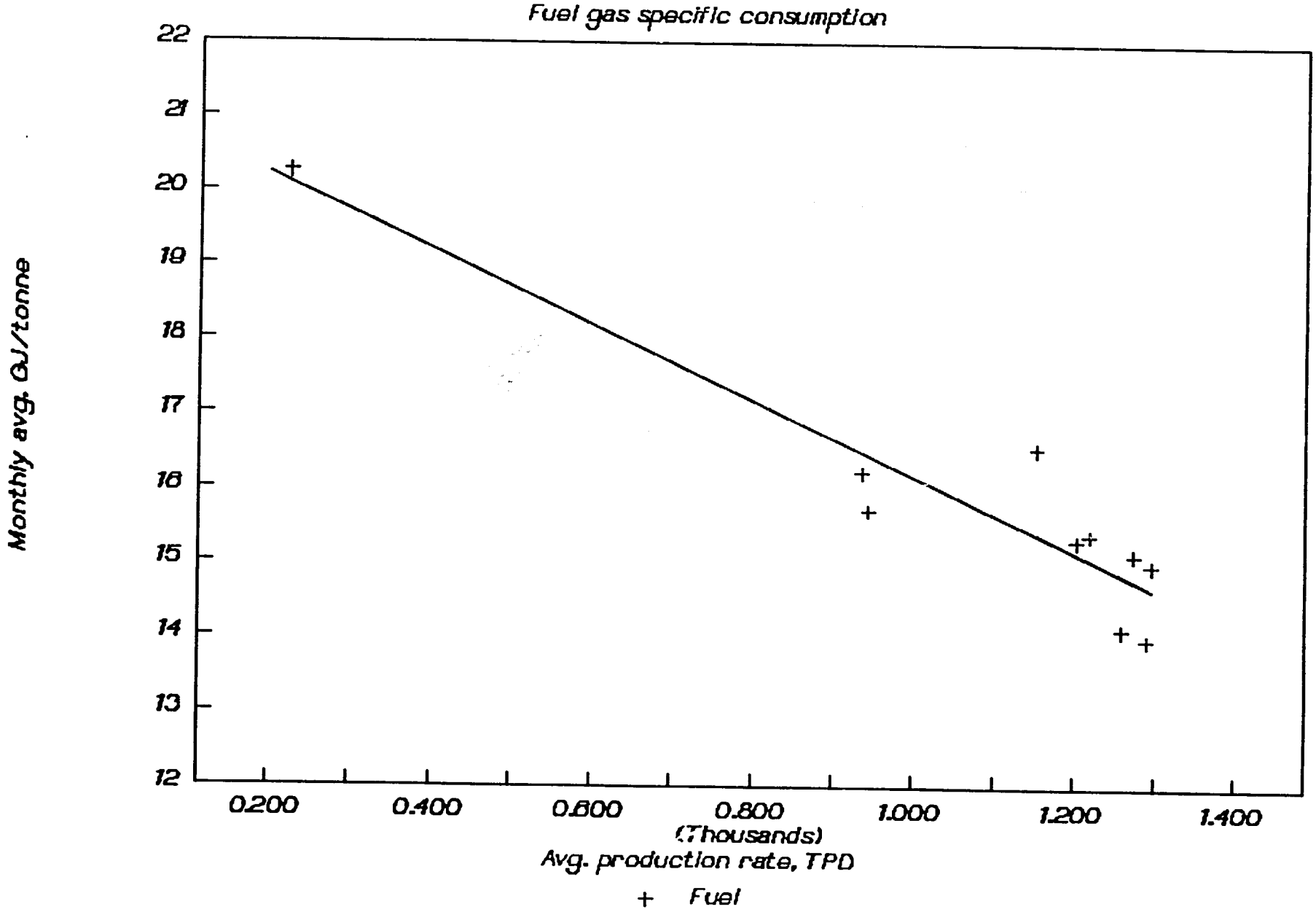


INA Petrokimija Kutina - Ammonia

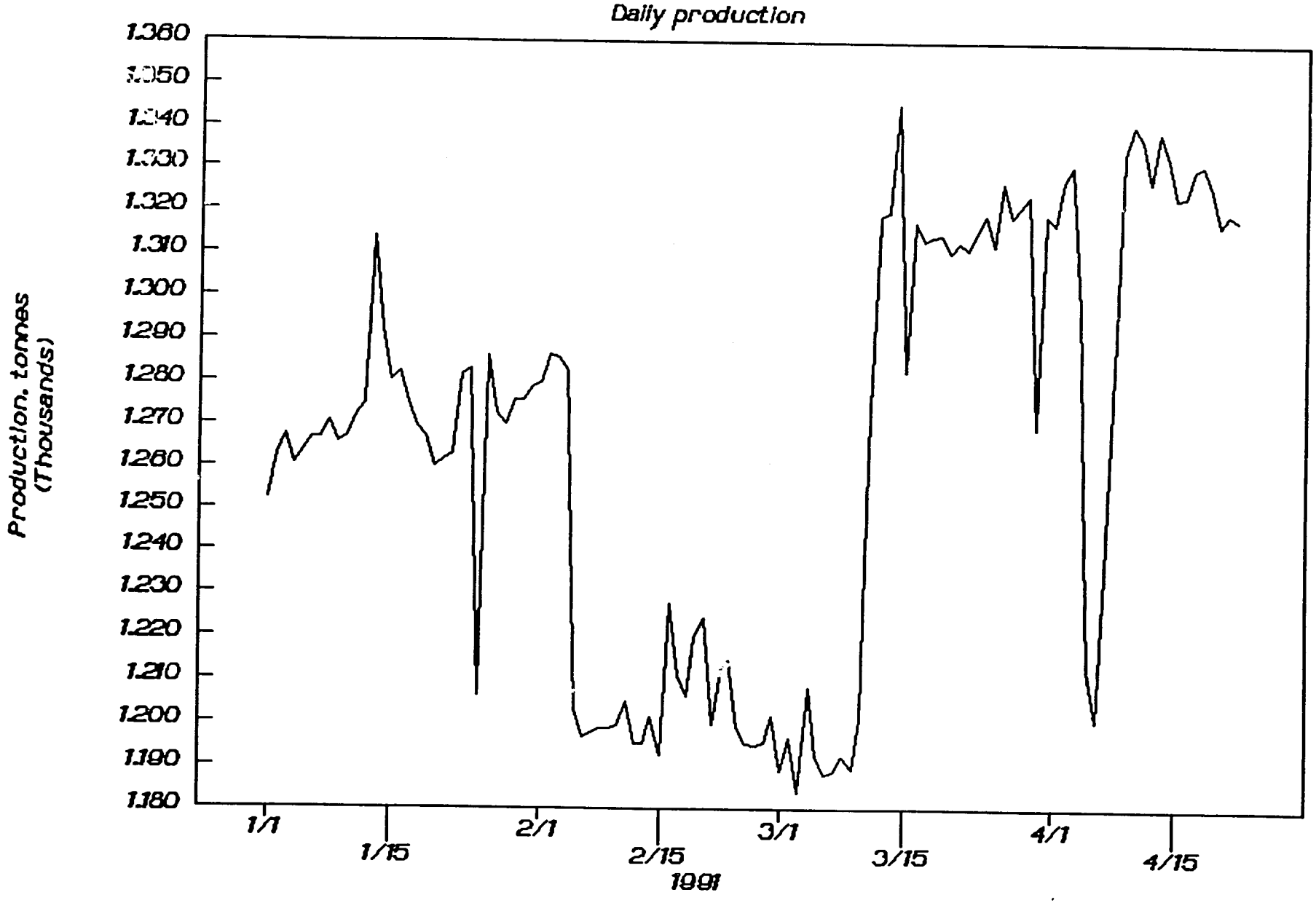


INA PETROKEMIJA, KUTINA

APPENDIX 3 -- AMMONIA II: ENERGY AND PRODUCTION GRAPHS

(DAILY DATA: 1/1/91 - 4/25/91)

INA Petrokimija Kutina - Ammonia



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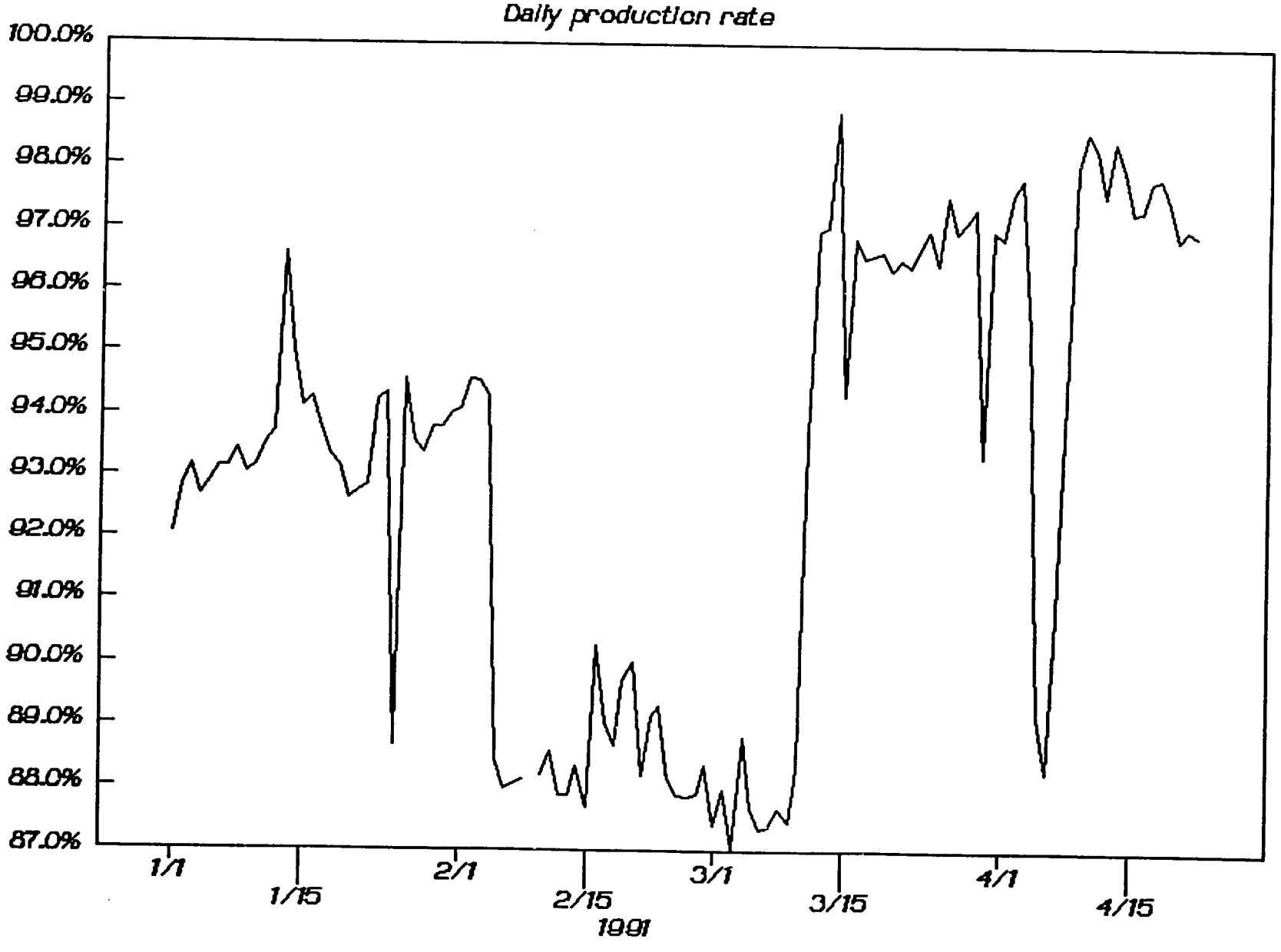
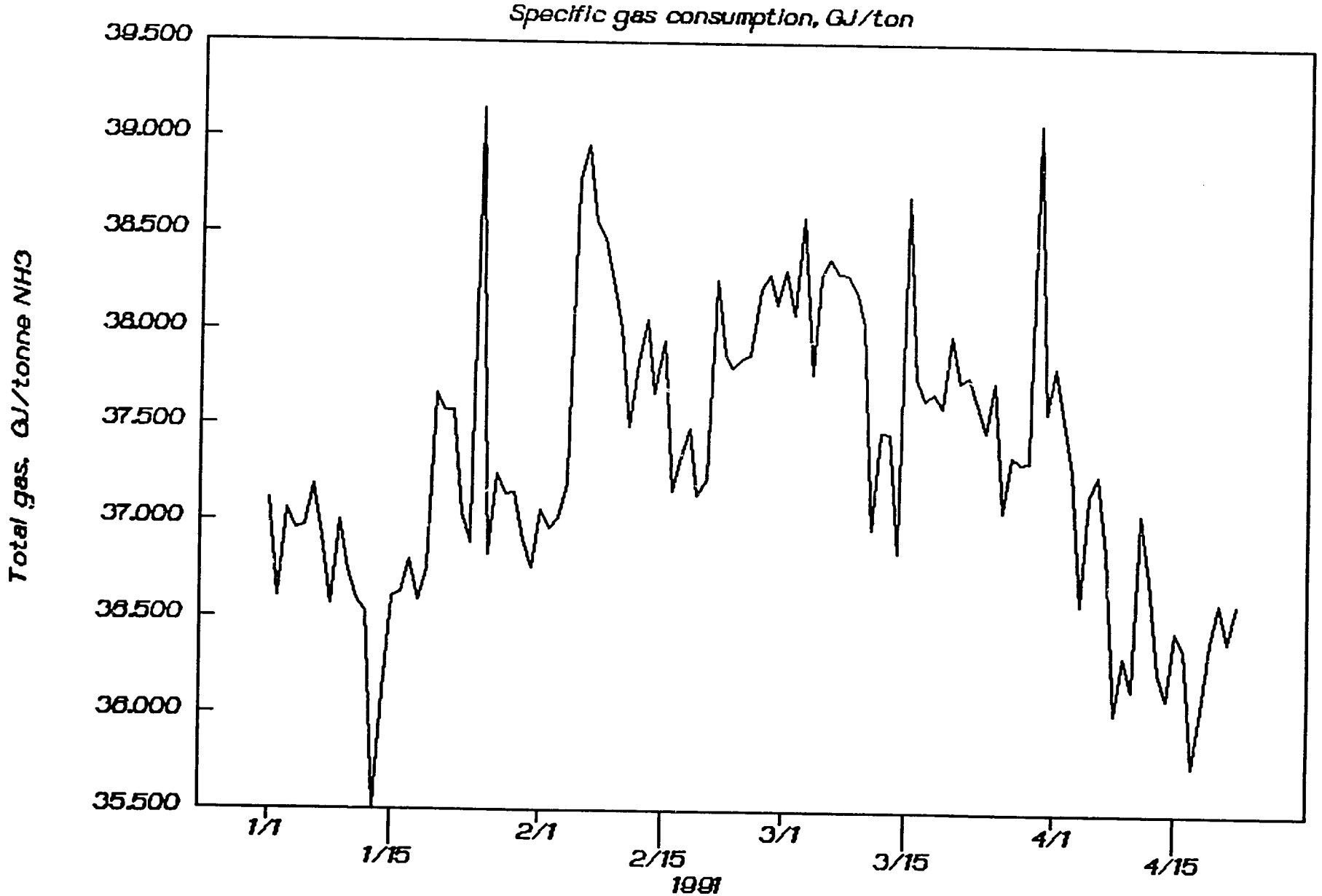


INA Petrokimija Kutina - Ammonia



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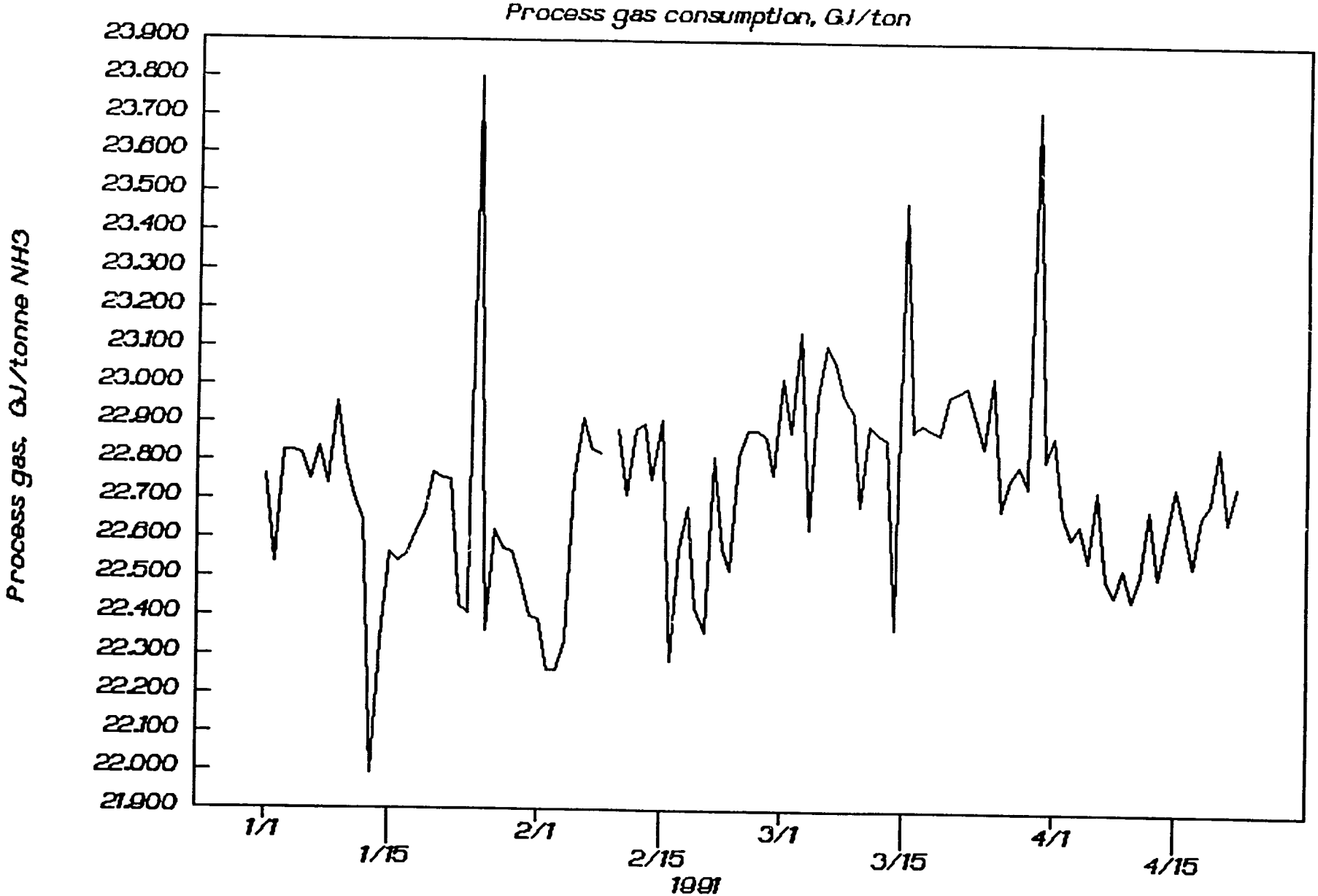
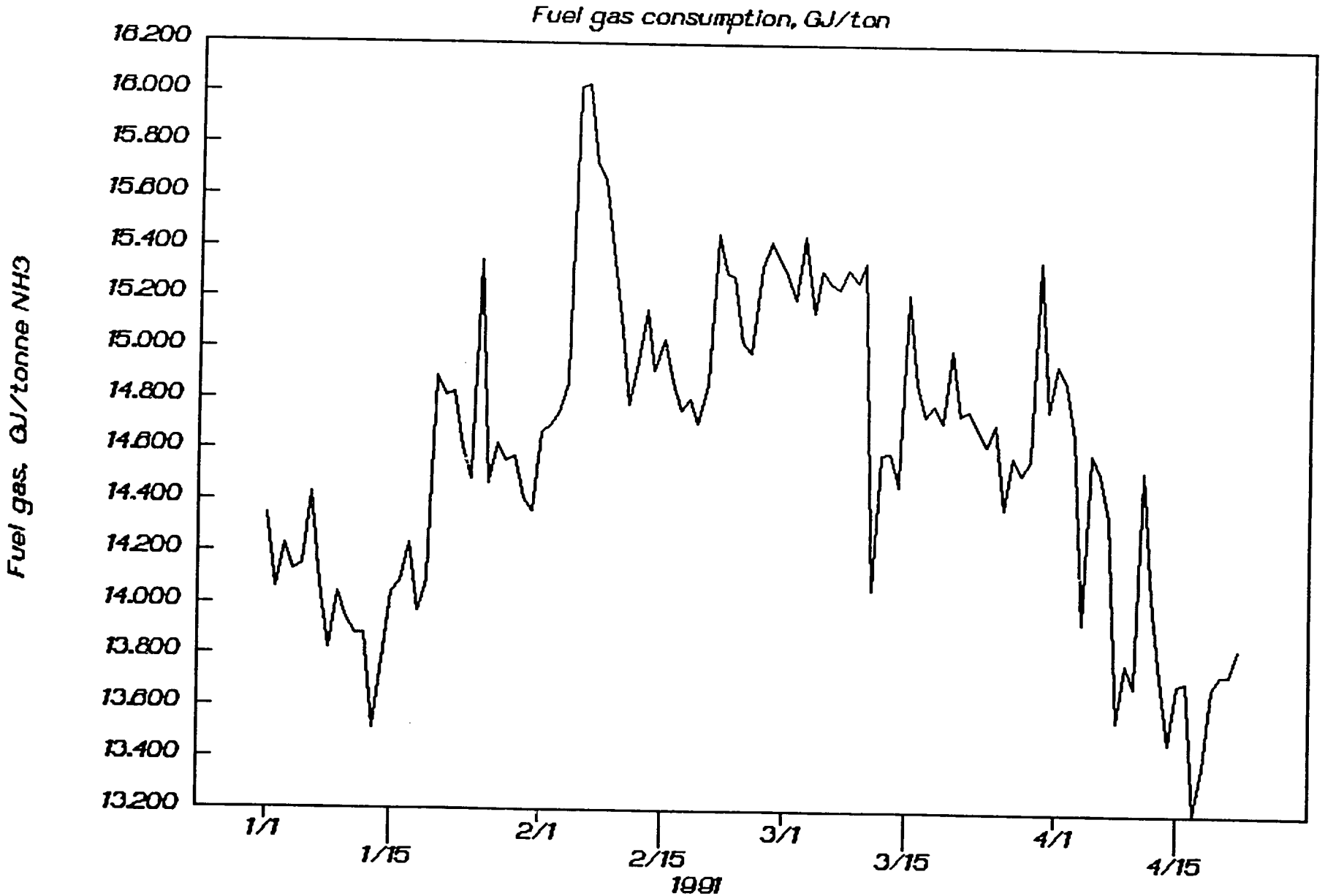
INA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



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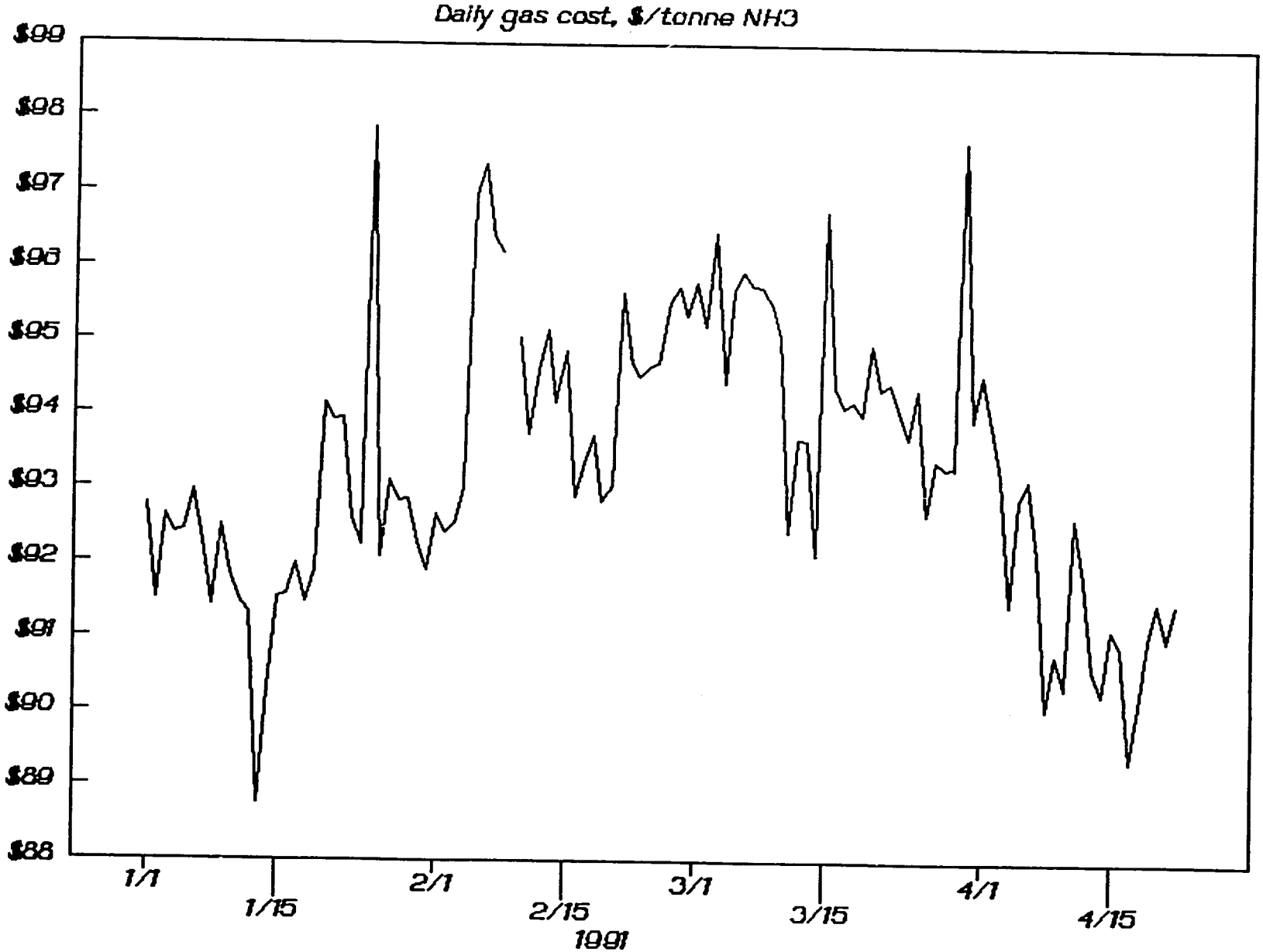

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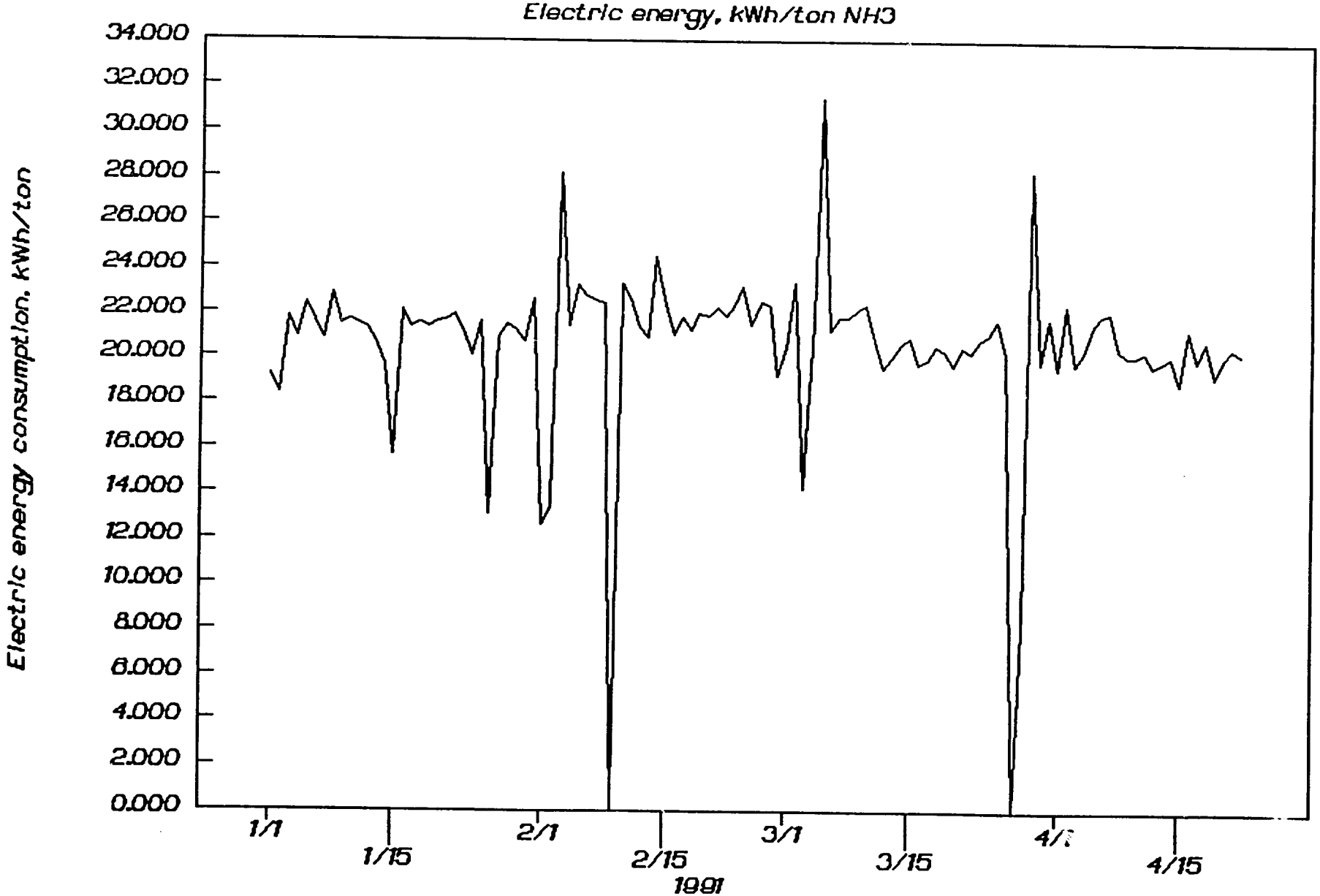
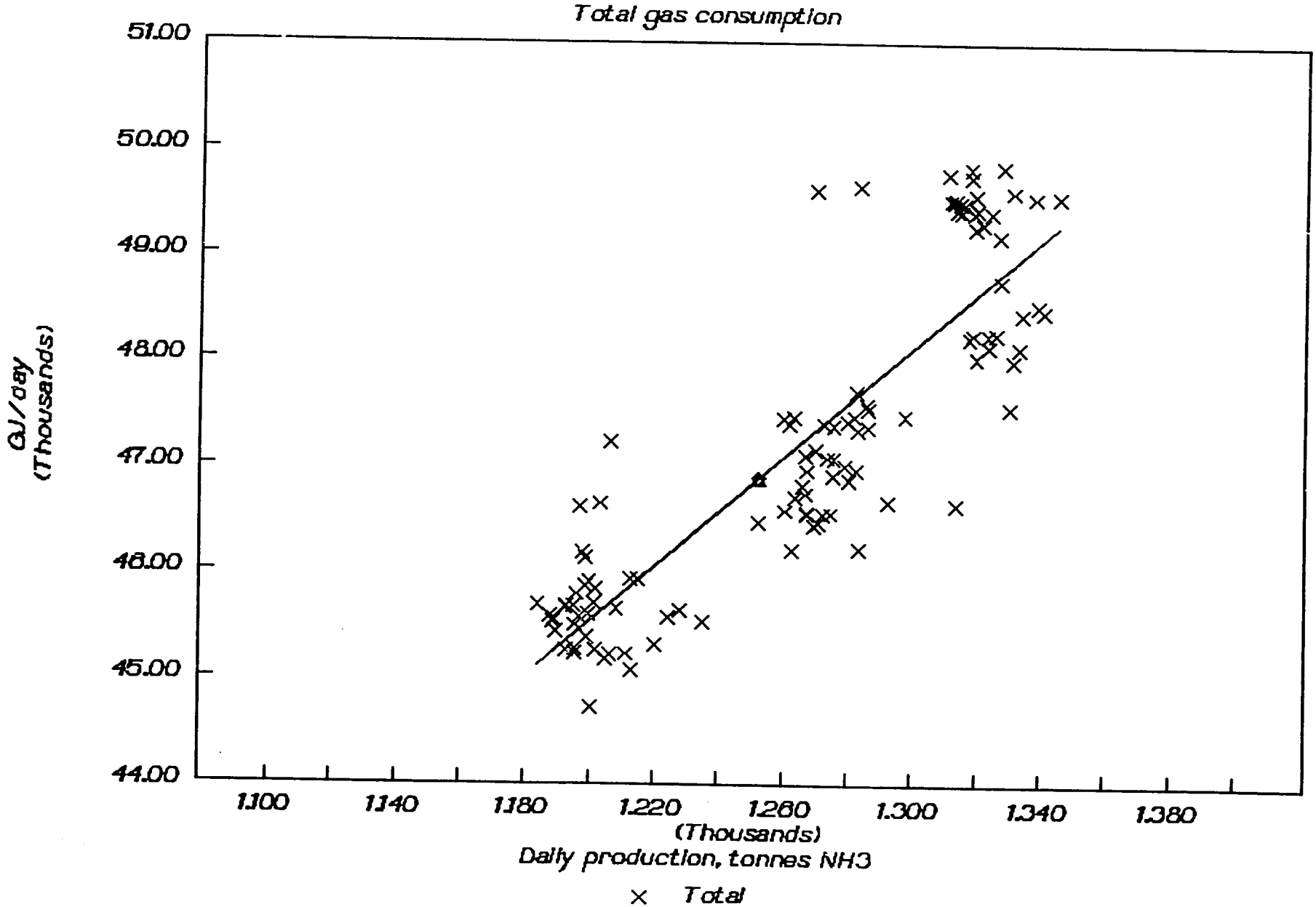
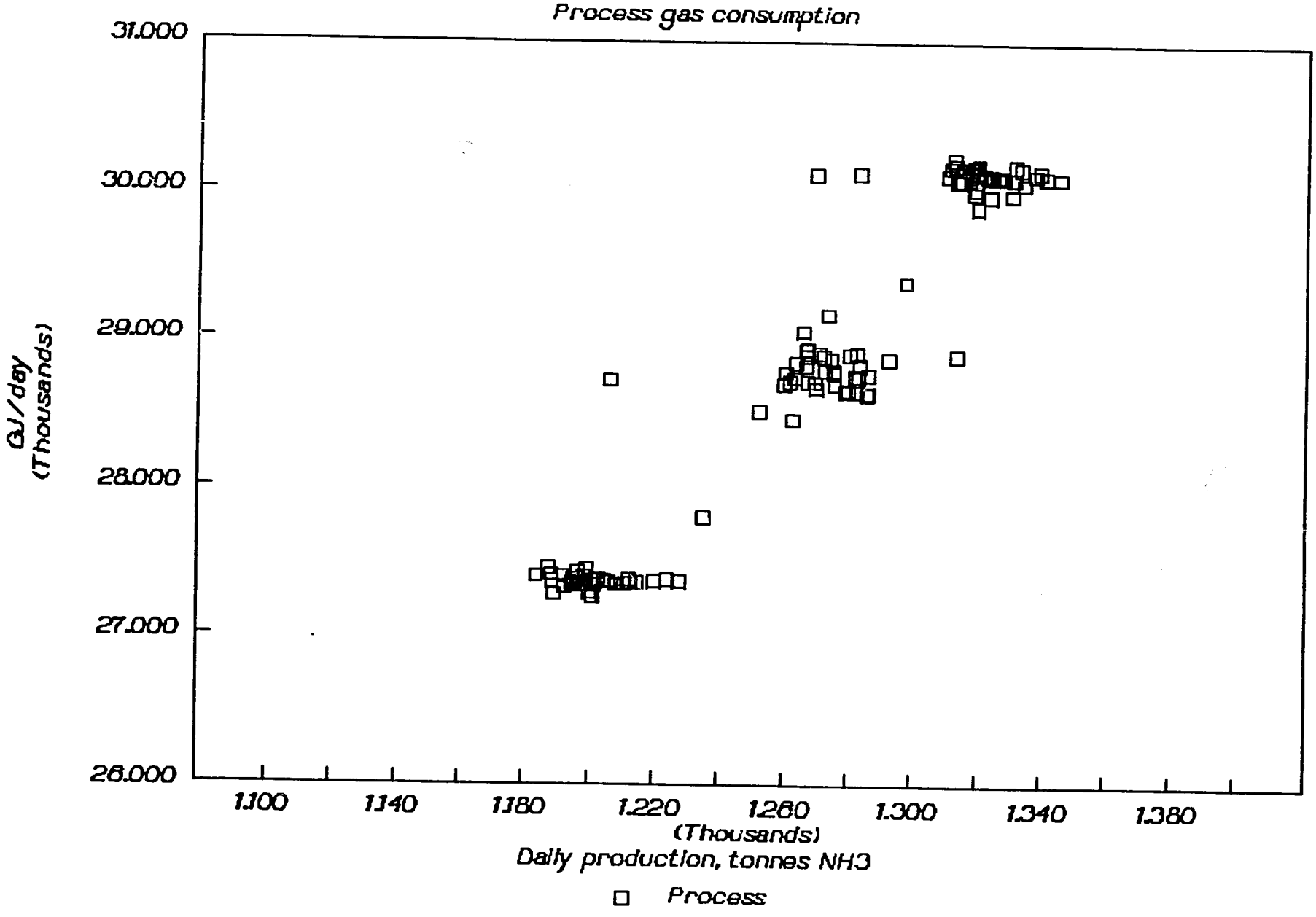


JNA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



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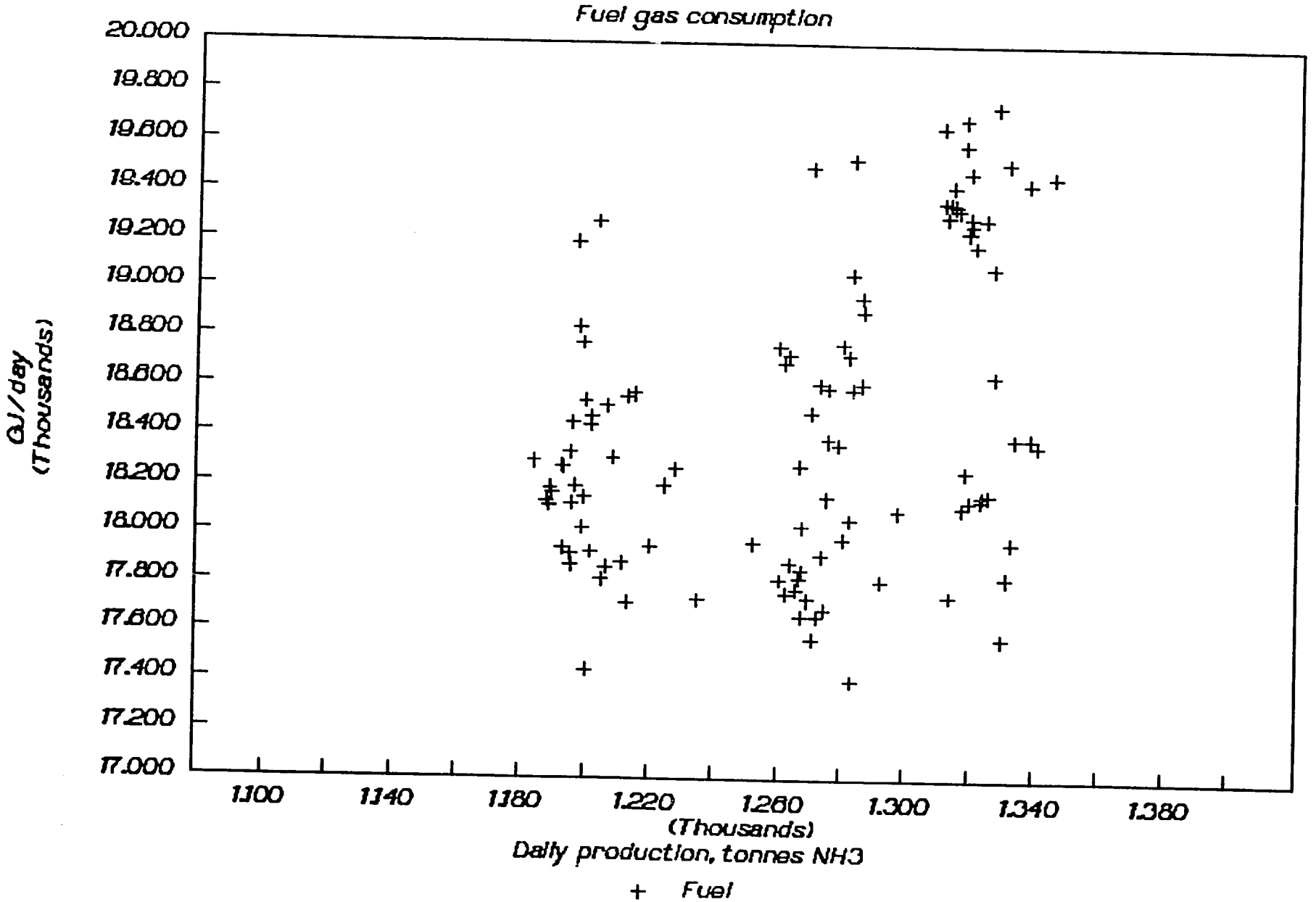
INA Petrokimija Kutina - Ammonia



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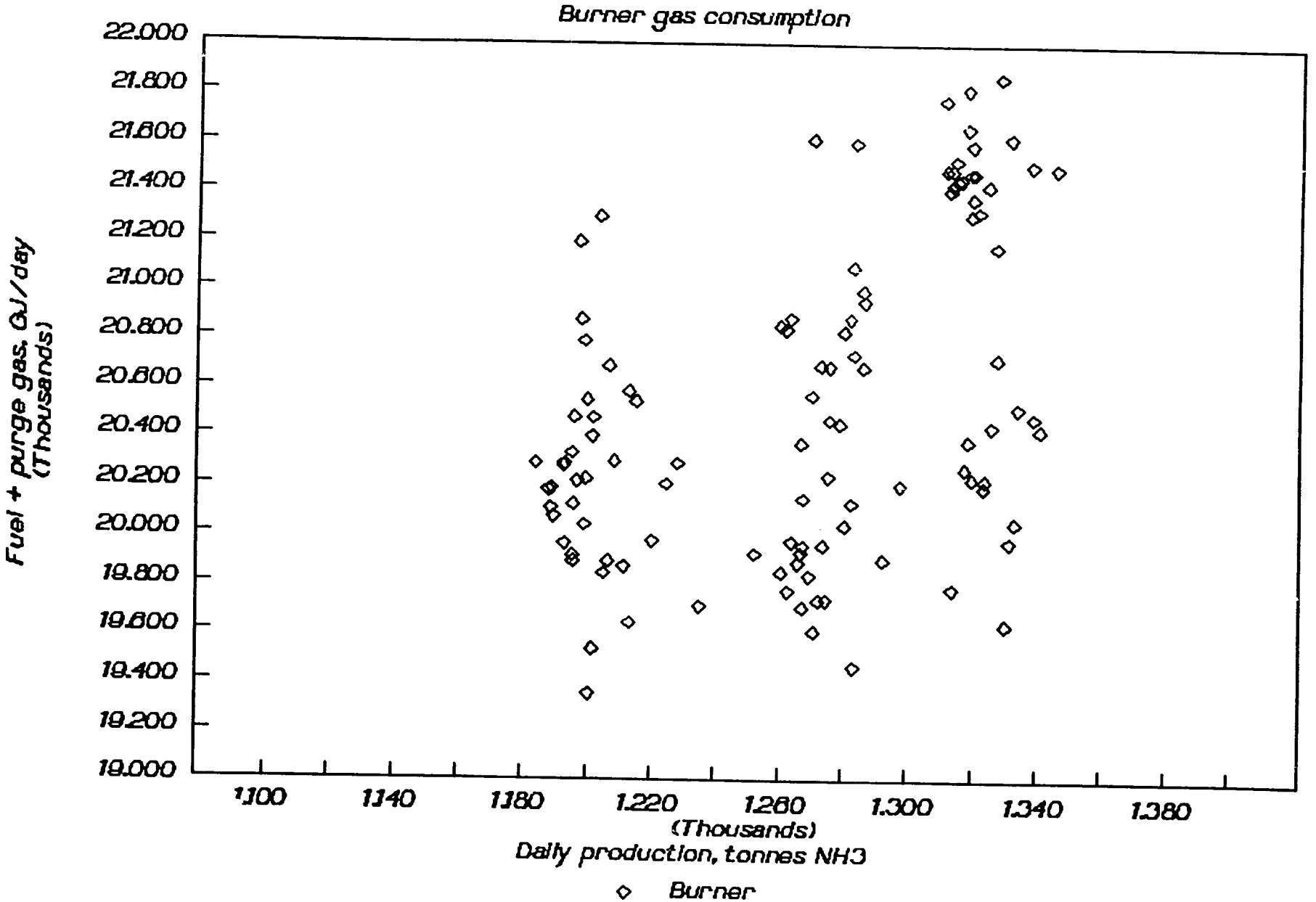

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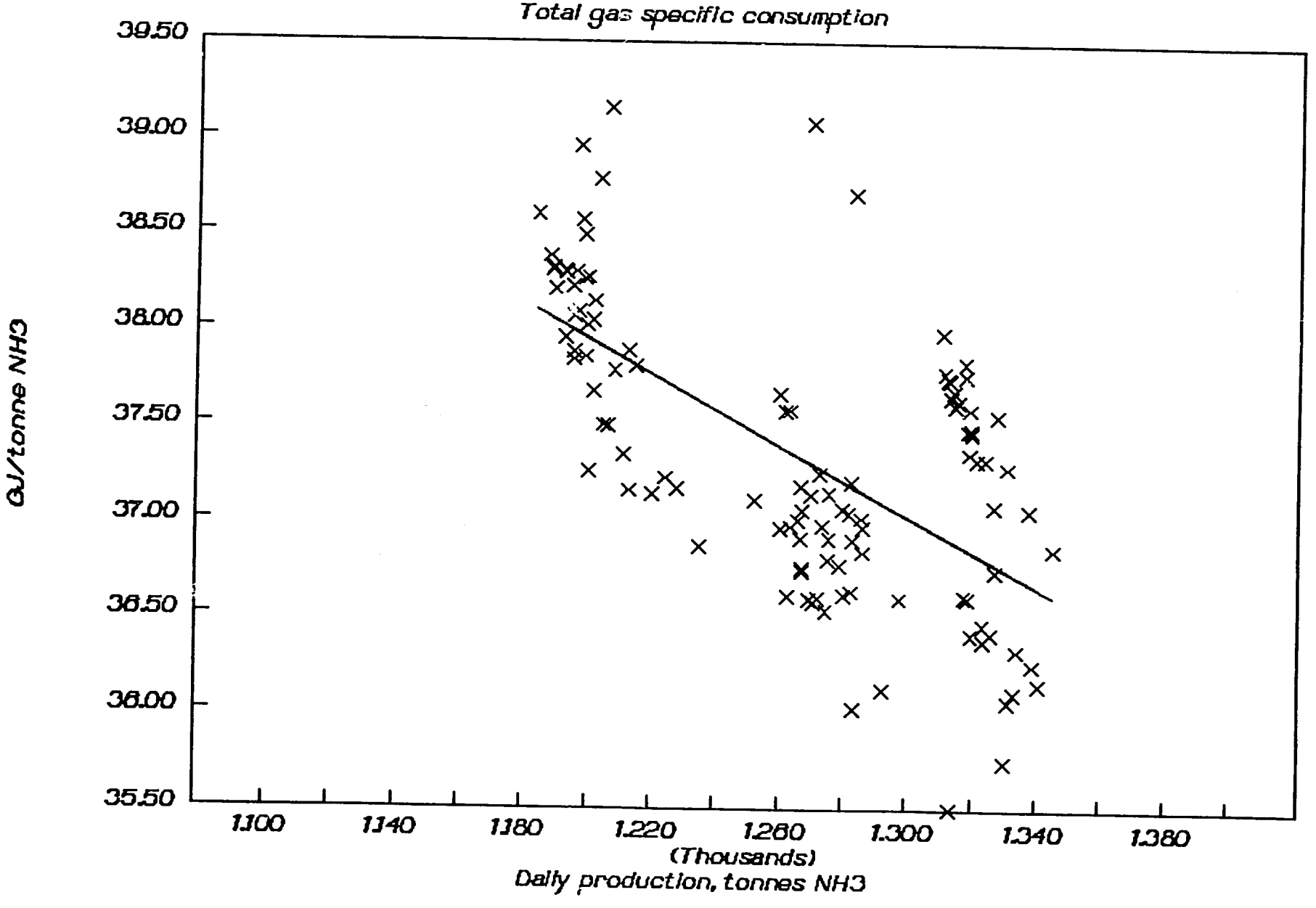
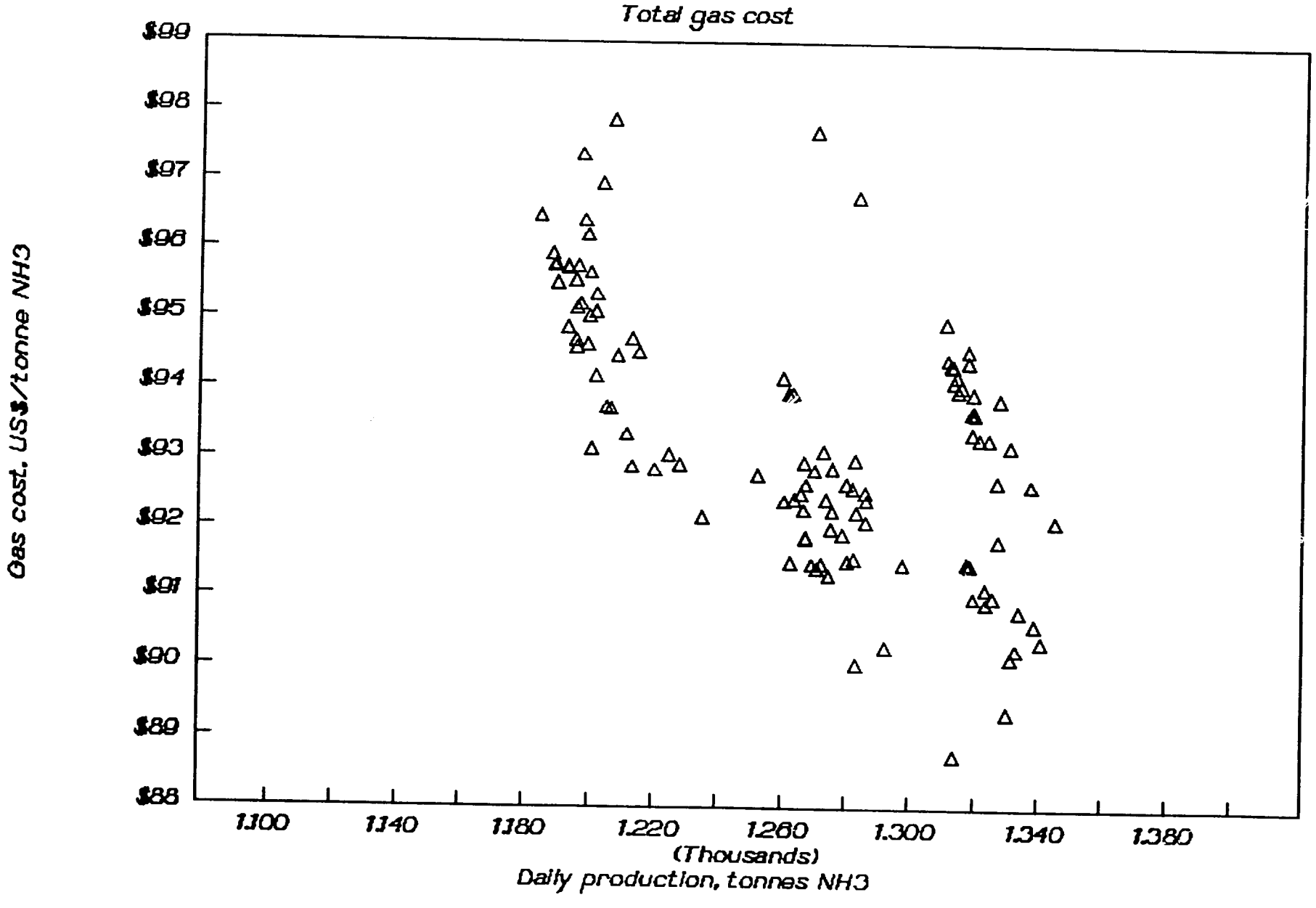
INA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



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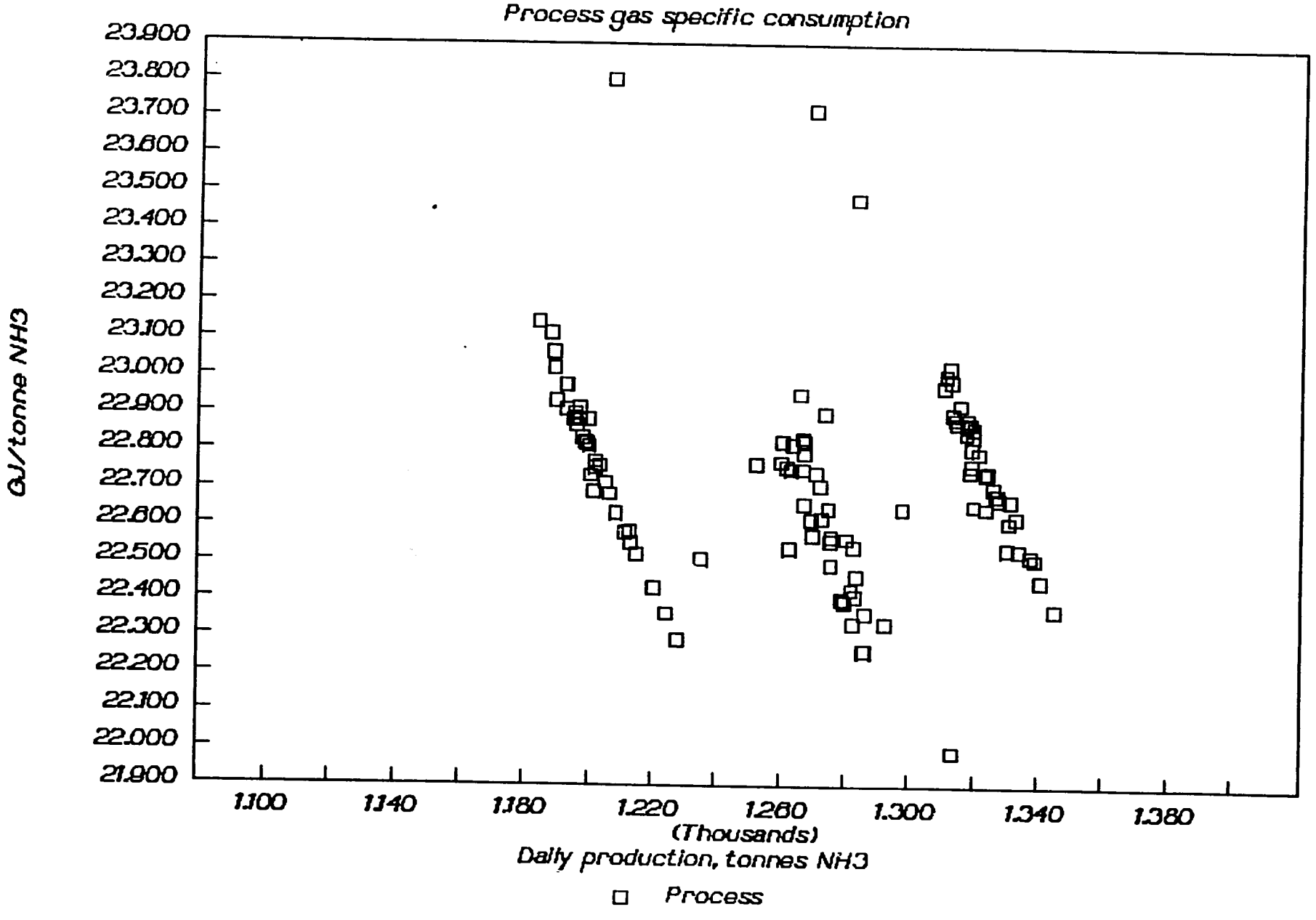
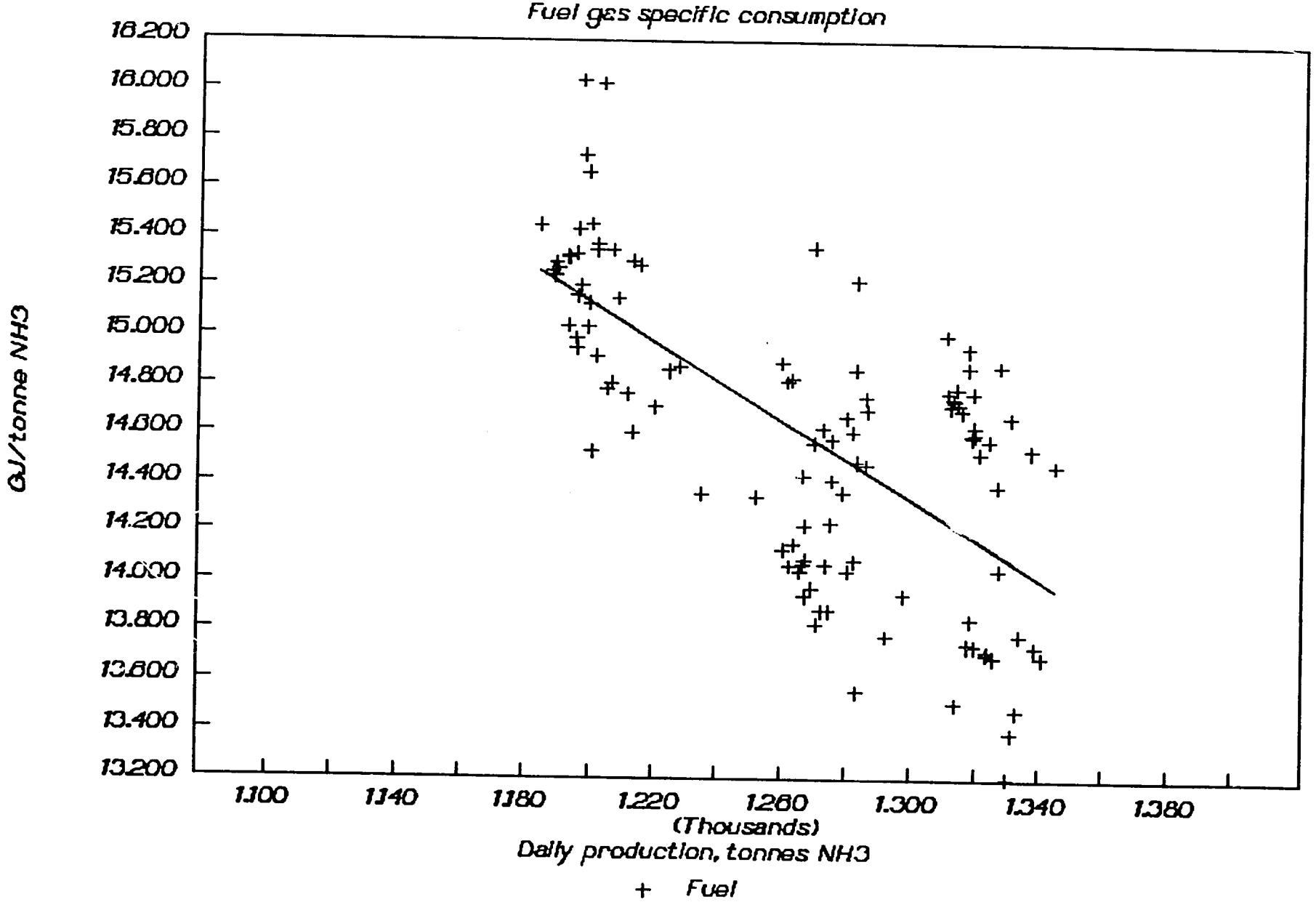
INA Petrokimija Kutina - Ammonia



INA Petrokimija Kutina - Ammonia



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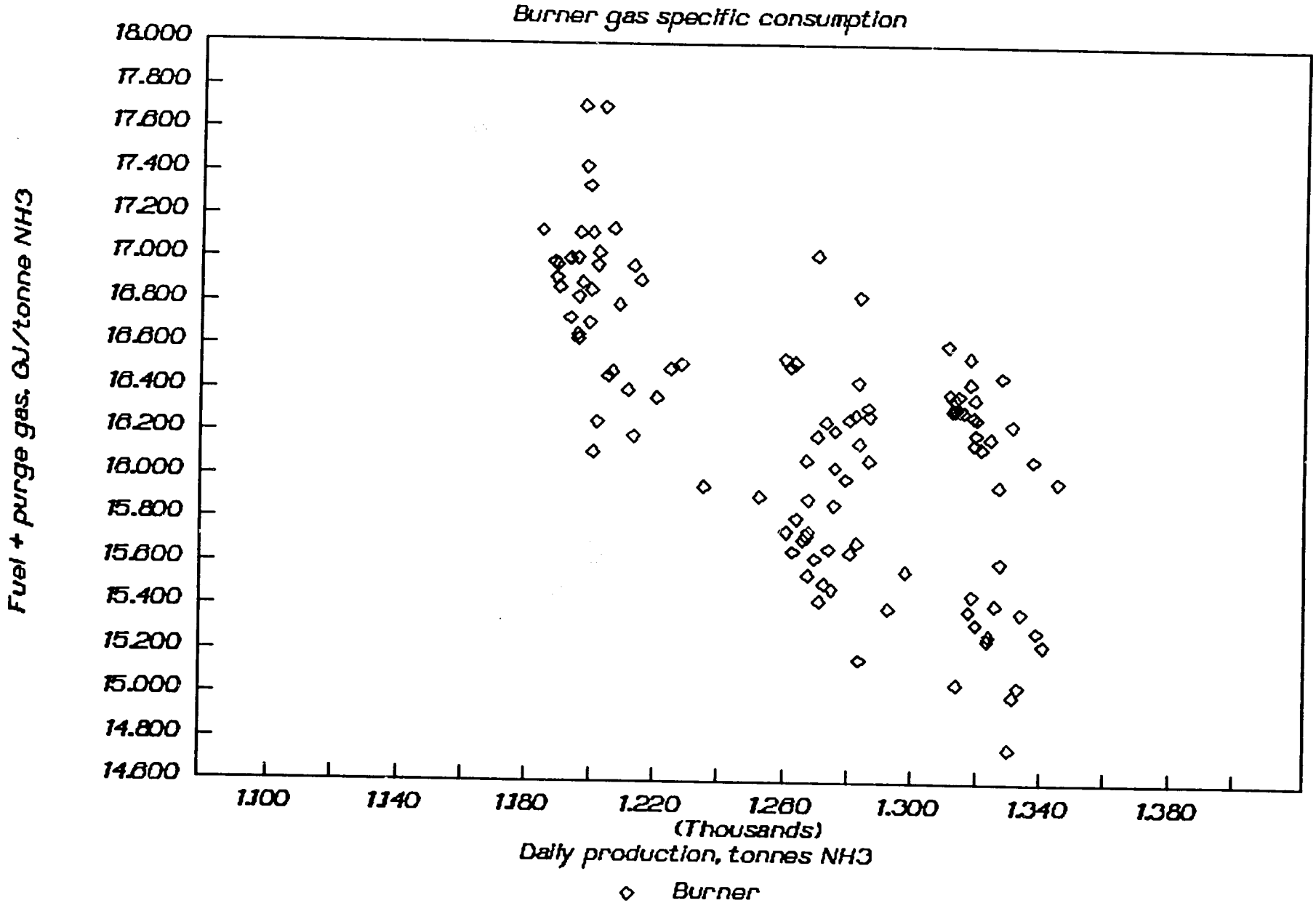
INA Petrokimija Kutina - Ammonia



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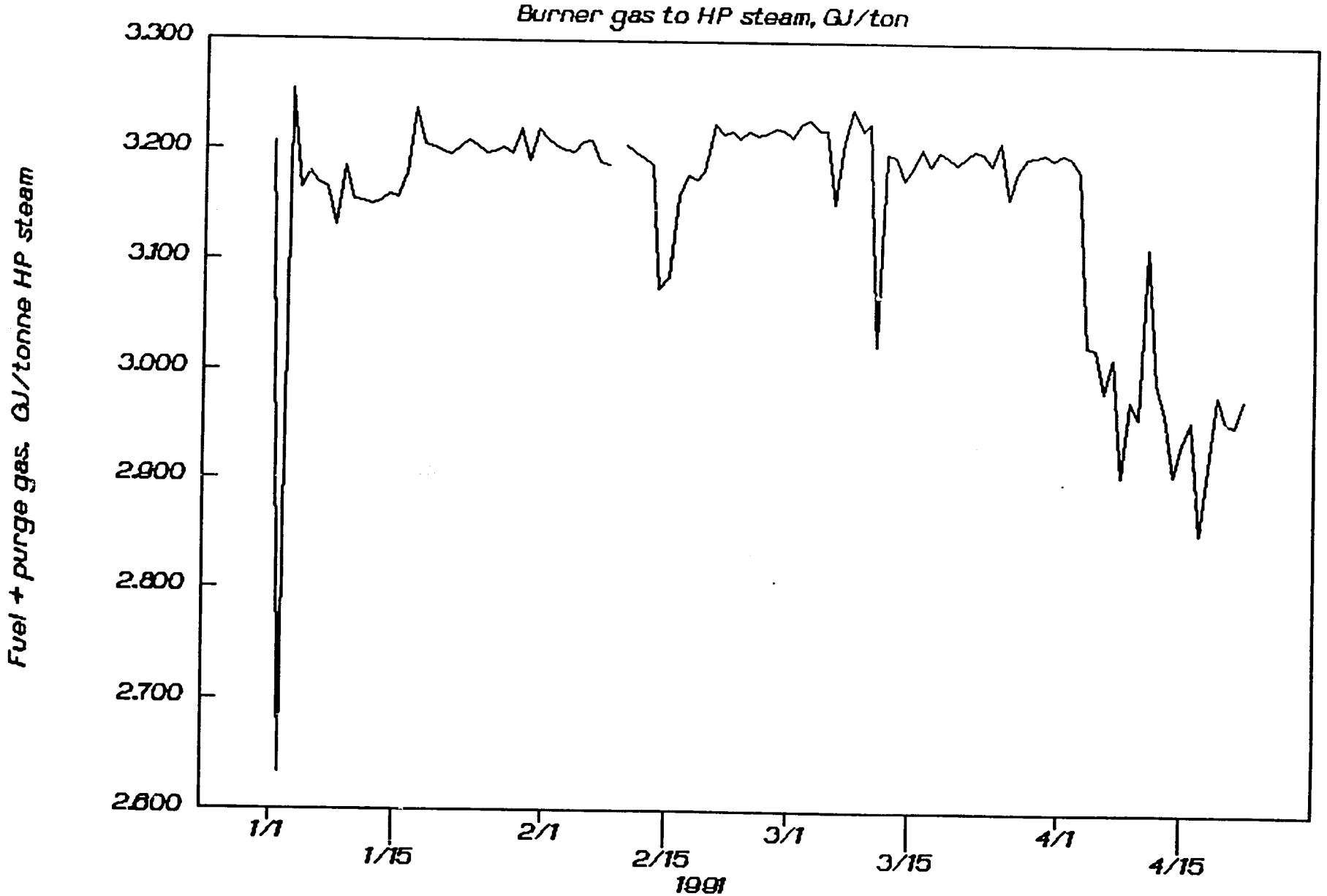

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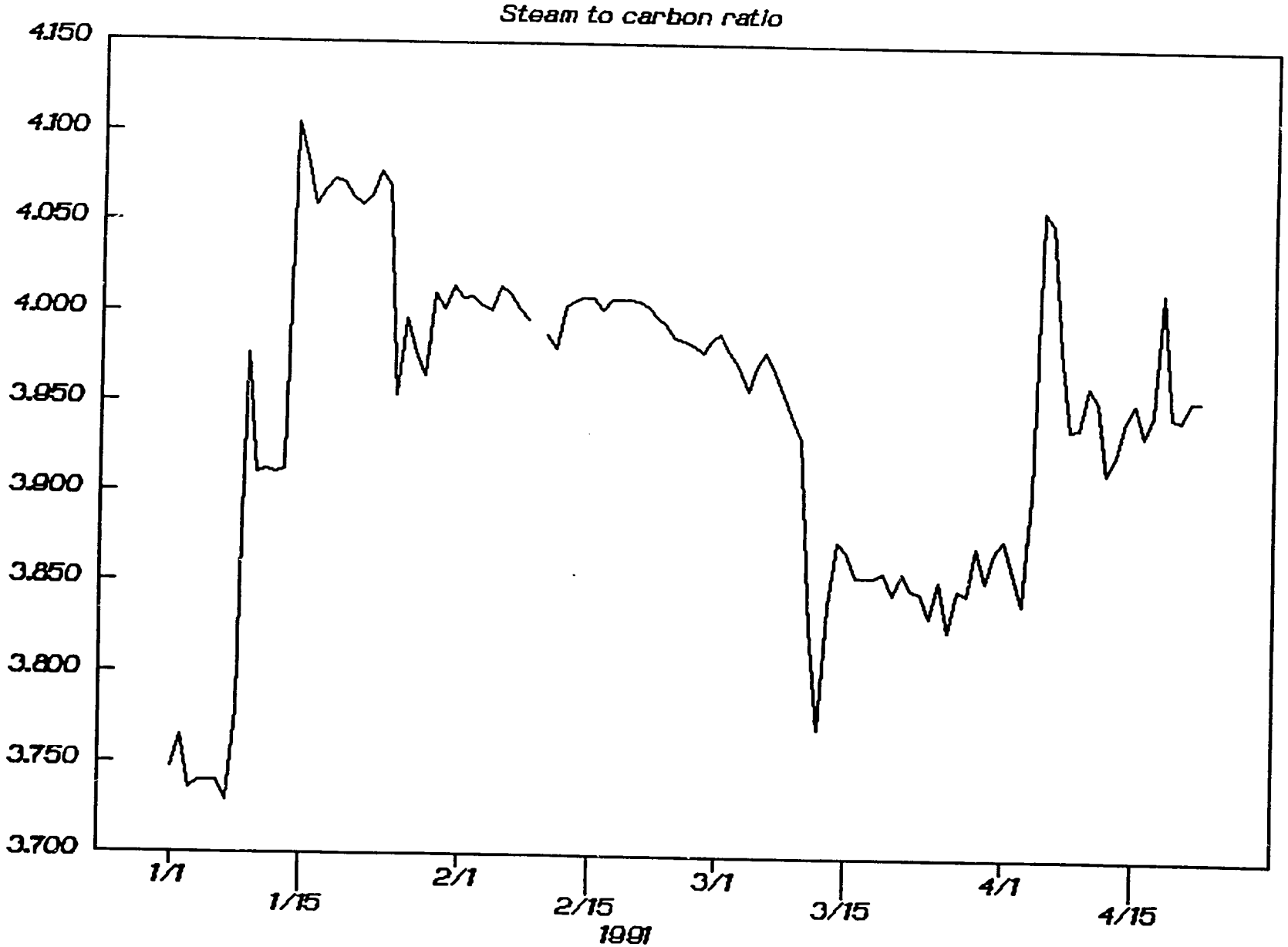

INA PETROKEMIJA, KUTINA

APPENDIX 4 -- AMMONIA II: COMBUSTION EFFICIENCY CALCULATIONS (PRIMARY REFORMER AND AUXILIARY BOILER)

INA Petrokemija Kutina – NH3 Exit ID fan
Combustion Calculations – Molal Basis

Date of test: 24 April 1991
Time of test: 1200

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	CO2 + SO	O2	N2	H2O	CO
	Fuel, O2, and Air per Unit of Fuel						Flue Gas Composition, Moles per Fuel Unit				
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.00				
4	C unburnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		132.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					3.70					
15	O2 (total) supplied = lines 13+14					15.25		3.70			
	Total Air (TA) = line 15/line 13					132.0%					
16	N2 supplied = 3.76*O2,line 15					57.34			57.34		
17	Air (dry) supplied = O2+N2					72.58					
18	H2O in air = moles dry air *A/(B-A)					1.54				1.54	
19	Air (wet) supplied = lines 17+18					74.12					
20	Flue gas constituents = lines 1 to 18, total						5.83	3.70	57.55	13.04	0.00

LINE					
		Nautral Gas			
a	Fuel analysis as fired (AF), % by wt or vol				
	C=	70.0%	CO=	0.0%	
	H2=	23.0%			
	S=	0.0%			
b	O2=	1.0%			
	N2=	6.0%			
	H2O=	0.0%			
	Ash=	0.0%			
	TOTAL=	100.00%			
	Flue gas analysis by test				
	CO2=	8.7%			
c	CO=	0 PPM, =	0.000%		
	O2=	5.4%	CMBSTBL	0.00%	
d	Total air (TA), based on above O2 test				
	TA=	132%			
e	Lines f,g,h for gaseous fuels only				
f	Wt, fuel unit + sum (moles each * mol wt), lb				
g	Mol wt of fuel + line f / 100				
h	Density of fuel = line g/394 (lb/cuft)				
i	Higher heat value, fuel	12197	, Btu/lb =		22000
j	%C in refuse				
k	Combustibles unburned, % of fuel				0.00%
l	Stack temp, degrees C				220
m	Ambient temp, dry bulb, degrees C				18

	Wet Flue Gas	Dry Flue Gas
Total Moles	80.118367	67.079585

21 Note: for air at 80F and 60%RH, A/(B-A)=0.0212 is used as a standard

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

								Conversion to metric units	
22	Fuel unit 100.00 lb	Flue gas constituents:	CO2 + SO	O2	N2	H2O	CO	Btu Total	kcal total	kJoules total
23	MCp, Molal specific heat, mean, t2 to t1		10.08	8.21	7.26	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)		21389	11041	151849		0.00	184279	46438	194414
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)					3964		3964	999	4182
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)					29628		29628	7466	31257
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18					215280		215280	54251	227120
28	Total in wet flue gas							433151	109154	456974
29	Due to unburned combustibles, line k*14,100 Btu/lb							0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb							0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30							433151	109154	456974
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels							2200000	554400	2321000
	= 394 * line i * 100 for gaseous fuels									
33	Stack and combustible loss, % of heat input, 100*line 31/line 32							19.7%	19.7%	19.7%
34	Combustion efficiency, HHV, % of heat input 100-line 33							80.3%	80.3%	80.3%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)							89.0%	89.0%	89.0%

INA Petrokemija Kutina – NH3 Exit ID fan
Combustion Calculations – Molal Basis

Date of test: REDUCE XS AIR
Time of test:

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Fuel, O2, and Air per Unit of Fuel							Flue Gas Composition, Moles per Fuel Unit				
Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	CO2 + SO	O2	N2	H2O	CO
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.00				
4	C unburnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		115.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					1.73					
15	O2 (total) supplied = lines 13+14					13.28		1.73			
	Total Air (TA) = line 15/line 13					115.0%					
16	N2 supplied = 3.76*O2,line 15					49.95			49.95		
17	Air (dry) supplied = O2+N2					63.24					
18	H2O in air = moles dry air *A/(B-A)					1.34				1.34	
19	Air (wet) supplied = lines 17+18					64.58					
20	Flue gas constituents = lines 1 to 18, total						5.83	1.73	50.17	12.84	0.00

LINE						
	Nautral Gas					
a	Fuel analysis as fired (AF), % by wt or vol					
	C=	70.0%	CO=	0.0%		
	H2=	23.0%				
	S=	0.0%				
b	O2=	1.0%				
	N2=	6.0%				
	H2O=	0.0%				
	Ash=	0.0%				
	TOTAL=	100.00%				
	Flue gas analysis by test					
	CO2=	10.7%				
c	CO=	0	PPM, =	0.000%		
	O2=	2.7%		CMBSTBL	0.00%	
d	Total air (TA), based on above O2 test					
	TA=	115%				
e	Lines f,g,h for gaseous fuels only					
f	Wt, fuel unit + sum (moles each * mol wt), lb					
g	Mol wt of fuel + line f / 100					
h	Density of fuel = line g/394 (lb/cuft)					
i	Higher heat value, fuel	12197	, Btu/lb =			22000
j	%C in refuse					
k	Combustibles unburned, % of fuel					0.00%
l	Stack temp, degrees C					230
m	Ambient temp, dry bulb, degrees C					18

	Wet Flue Gas	Dry Flue Gas
Total Moles	70.572245	57.731639

21 Note: for air at 80F and 60%RH, A/(B-A)=0.0212 is used as a standard

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

							Conversion to metric units	
22	Fuel unit 100.00 lb	Flue gas constituents:	CO2 + SO	O2	N2	H2O	CO	Btu Total	kcal total	kJoules total
23	MCp, Molal specific heat, mean, t2 to t1		10.12	8.22	7.27	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)		22526	5437	139125		0.00	167089	42106	176278
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)					3627		3627	914	3826
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)					31110		31110	7840	32821
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18					215260		215260	54251	227120
28	Total in wet flue gas							417106	105111	440046
29	Due to unburned combustibles, line k*14,100 Btu/lb							0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb							0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30							417106	105111	440046
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels							2200000	554400	2321000
	= 394 * line i * 100 for gaseous fuels									
33	Stack and combustible loss, % of heat input, 100*line 31/line 32							19.0%	19.0%	19.0%
34	Combustion efficiency, HHV, % of heat input 100-line 33							81.0%	81.0%	81.0%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)							89.8%	89.8%	89.8%

INA Petrokemija Kutina – NH3 Primary reformer
Combustion Calculations – Molal Basis

Date of test: 24 April 1991
Time of test: 1000

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	CO2 + SO	O2	N2	H2O	CO
	Fuel, O2, and Air per Unit of Fuel						Flue Gas Composition, Moles per Fuel Unit				
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.00				
4	C unburnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		142.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					4.85					
15	O2 (total) supplied = lines 13+14					16.40		4.85			
	Total air (dry) = line 15/line 13					142.0%					
16	N2 supplied = 3.76*O2,line 15					61.68			61.68		
17	Air (dry) supplied = O2+N2					78.08					
18	H2O in air = moles dry air *A/(B-A)					1.66				1.66	
19	Air (wet) supplied = lines 17+18					79.74					
20	Flue gas constituents = lines 1 to 18, total						5.83	4.85	61.89	13.16	0.00

LINE		Nautral Gas		
a	Fuel analysis as fired (AF), % by wt or vol			
	C=	70.0%	CO=	0.0%
	H2=	23.0%		
	S=	0.0%		
b	O2=	1.0%		
	N2=	6.0%		
	H2O=	0.0%		
	Ash=	0.0%		
	TOTAL=	100.00%		
	Flue gas analysis by test			
	CO2=	8.5%		
c	CO=	0 PPM, =	0.000%	
	O2=	8.5%	CMBSTBL	0.00%
d	Total air (TA), based on above O2 test			
	TA=	142%		
e	Lines f,g,h for gaseous fuels only			
f	Wt, fuel unit + sum (moles each * mol wt), lb			
g	Mol wt of fuel + line f / 100			
h	Density of fuel = line g/394 (lb/cuft)			
i	Higher heat value, fuel	12197	, Btu/lb =	22000
j	%C in refuse			
k	Combustibles unburned, % of fuel			0.00%
l	Stack temp, degrees C			220
m	Ambient temp, dry bulb, degrees C			15

	Wet Flue Gas	Dry Flue Gas
Total Moles	85.733733	72.578377

21 Note: for air at 60F and 60%RH, A/(B-A)=0.0212 is used as a standard

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

							Btu Total	Conversion to metric units kcal total	kJoules total
22	Fuel unit 100.00 lb	Flue gas constituents:	CO2 + SO	O2	N2	H2O	CO			
23	MCp, Molal specific heat, mean, t2 to t1		10.08	8.21	7.26	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)		21389	14491	163310		0.00	199190	50196	210145
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)					4265		4265	1075	4499
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)					29628		29628	7466	31257
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18					215280		215280	54251	227120
28	Total in wet flue gas							448362	112987	473022
29	Due to unburned combustibles, line k*14,100 Btu/lb							0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb							0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30							448362	112987	473022
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels							2200000	554400	2321000
	= 394 * line i * 100 for gaseous fuels									
33	Stack and combustible loss, % of heat input, 100*line 31/line 32							20.4%	20.4%	20.4%
34	Combustion efficiency, HHV, % of heat input 100-line 33							79.6%	79.6%	79.6%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)							88.3%	88.3%	88.3%

INA Petrokemija Kutina – NH3 Primary reformer
Combustion Calculations – Molal Basis

Date of test: REDUCE XS AIR
Time of test:

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	CO2 + SO	O2	N2	H2O	CO
	Fuel, O2, and Air per Unit of Fuel						Flue Gas Composition, Moles per Fuel Unit				
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.00				
4	C unburnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		117.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					1.96					
15	O2 (total) supplied = lines 13+14					13.52		1.96			
	Total Air (TA) = line 15/line 13					117.0%					
16	N2 supplied = 3.76*O2,line 15					50.82			50.82		
17	Air (dry) supplied = O2+N2					64.34					
18	H2O in air = moles dry air *A/(B-A)					1.36				1.36	
19	Air (wet) supplied = lines 17+18					65.70					
20	Flue gas constituents = lines 1 to 18, total						5.83	1.96	51.03	12.86	0.00

LINE					
		Nautral Gas			
a	Fuel analysis as fired (AF), % by wt or vol				
	C=	70.0%	CO=	0.0%	
	H2=	23.0%			
	S=	0.0%			
b	O2=	1.0%			
	N2=	6.0%			
	H2O=	0.0%			
	Ash=	0.0%			
	TOTAL=	100.00%			
	Flue gas analysis by test				
	CO2=	10.5%			
c	CO=	0 PPM, =	0.000%		
	O2=	3.0%	CMBSTBL	0.00%	
d	Total air (TA), based on above O2 test				
	TA=	117%			
e	Lines f,g,h for gaseous fuels only				
f	Wt, fuel unit + sum (moles each * mol wt), lb				
g	Mol wt of fuel + line f / 100				
h	Density of fuel = line g/394 (lb/cuft)				
i	Higher heat value, fuel	12197	, Btu/lb =		22000
j	%C in refuse				
k	Combustibles unburned, % of fuel				0.00%
l	Stack temp, degrees C				230
m	Ambient temp, dry bulb, degrees C				18

	Wet Flue Gas	Dry Flue Gas
Total Moles	71.695318	58.631396

21 Note: for air at 80F and 60%RH, A/(B-A)=0.0212 is used as a standard

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

								Conversion to metric units	
							Btu	kcal	kJoules
22	Fuel unit 100.00 lb	Flue gas constituents:	CO2 + SO	O2	N2	H2O	CO	Total	total	total
23	MCp, Molal specific heat, mean, t2 to t1		10.12	8.22	7.27	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)		22623	6162	141534		0.00	170223	42896	179585
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)					3690		3690	930	3893
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)					31110		31110	7840	32821
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18					215280		215280	54251	227120
28	Total in wet flue gas							420303	105916	443419
29	Due to unburned combustibles, line k*14,100 Btu/lb							0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb							0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30							420303	105916	443419
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels							2200000	554400	2321000
	= 394 * line i * 100 for gaseous fuels									
33	Stack and combustible loss, % of heat input, 100*line 31/line 32							19.1%	19.1%	19.1%
34	Combustion efficiency, HHV, % of heat input 100-line 33							80.9%	80.9%	80.9%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)							89.7%	89.7%	89.7%

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INA Petrokemija Kutina – NH3 Auxiliary Boiler
Combustion Calculations – Molal Basis

Date of test: 24 April 1991
Time of test: 1130

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	Flue Gas Composition, Moles per Fuel Unit: CO2 + SO	O2	N2	H2O	CO
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.00				
4	C unburnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		126.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					3.00					
15	O2 (total) supplied = lines 13+14					14.56		3.00			
	Total Air (TA) = line 15/line 13					126.0%					
16	N2 supplied = 3.76*O2,line 15					54.73			54.73		
17	Air (dry) supplied = O2+N2					69.28					
18	H2O in air = moles dry air *A/(B-A)					1.47				1.47	
19	Air (wet) supplied = lines 17+18					70.75					
20	Flue gas constituents = lines 1 to 18, total						5.83	3.00	54.94	12.97	0.00

21 Note: for air at 60F and 60%RH, A/(B-A)=0.0212 is used as a standard

LINE	Nautral Gas			
a	Fuel analysis as fired (AF), % by wt or vol			
	C=	70.0%	CO=	0.0%
	H2=	23.0%		
	S=	0.0%		
b	O2=	1.0%		
	N2=	6.0%		
	H2O=	0.0%		
	Ash=	0.0%		
	TOTAL=	100.00%		
	Flue gas analysis by test			
	CO2=	9.4%		
c	CO=	0 PPM. =	0.000%	
	O2=	4.2%	CMBSTBL	0.00%
d	Total air (TA), based on above O2 test			
	TA=	126%		
e	Lines f,g,h for gaseous fuels only			
f	Wt, fuel unit + sum (moles each * mol wt), lb			
g	Mol wt of fuel + line f / 100			
h	Density of fuel = line g/394 (lb/cuft)			
i	Higher heat value, fuel	12197	, Btu/lb =	22000
j	%C in refuse			
k	Combustibles unburned, % of fuel			0.00%
l	Stack temp, degrees C			220
m	Ambient temp, dry bulb, degrees C			18

	Wet Flue Gas	Dry Flue Gas
Total Moles	76.749147	63.780310

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

		CO2 + SO	O2	N2	H2O	CO	Btu Total	Conversion to metric units: kcal total	kJoules total
22	Fuel unit 100.00 lb — Flue gas constituents:								
23	MCp, Molal specific heat, mean, t2 to t1	10.08	8.21	7.26	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)	21389	8970	144972		0.00	175332	44184	184975
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)				3784		3784	954	3992
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)				29628		29628	7466	31257
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18				215280		215280	54251	227120
28	Total in wet flue gas						424024	106854	447345
29	Due to unburned combustibles, line k*14,100 Btu/lb						0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb						0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30						424024	106854	447345
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels						2200000	554400	2321000
	= 394 * line i * 100 for gaseous fuels								
33	Stack and combustible loss, % of heat input, 100*line 31/line 32						19.3%	19.3%	19.3%
34	Combustion efficiency, HHV, % of heat input 100-line 33						80.7%	80.7%	80.7%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)						89.5%	89.5%	89.5%

INA Petrokemija Kutina – NH3 Auxiliary Boiler
Combustion Calculations – Molal Basis

Date of test: REDUCE XS AIR
Time of test:

RCG/Hagler, Bailly, Inc.
Production rate: 97%

Line	Fuel Constit	Per Fuel Unit, lb	Mol. Wt Divisor	MolesFuel Constit	O2 Multiplr	O2 Moles TheoReqd	Flue Gas Composition, Moles per Fuel Unit: CO2 + SO	O2	N2	H2O	CO
1	C to CO2	70.00	12.00	5.83	1.00	5.83	5.83				
2	C to CO	0.00	12.00	0.00	0.50	0.00					0.00
3	CO to CO2	0.00	28.00	0.00	0.50	0.00	0.0				
4	C unbufnd	0.00	12.00	0.00	0.00	0.00					
5	H2	23.00	2.00	11.50	0.50	5.75				11.50	
6	S	0.00	32.00	0.00	1.00	0.00	0.00				
7	O2 deduct	-1.00	32.00	-0.03	1.00	-0.03					
8	N2	6.00	28.00	0.21		0.00			0.21		
9	CO2		44.00	0.00		0.00	0.00				
10	H2O	0.00	18.00	0.00		0.00				0.00	
11	Ash	0.00		0.00		0.00					
12	Sum	100.00		17.52		11.55					
	Total air =		110.0% (from stack test)								
13	O2 (theo) reqd = O2, line 12					11.55					
14	O2 (excess) = (Total air -1) * line 12					1.16					
15	O2 (total) supplied = lines 13+14					12.71		1.16			
	Total Air (TA) = line 15/line 13					110.0%					
16	N2 supplied = 3.76*O2,line 15					47.78			47.78		
17	Air (dry) supplied = O2+N2					60.49					
18	H2O in air = moles dry air *A/(B-A)					1.28				1.28	
19	Air (wet) supplied = lines 17+18					61.77					
20	Flue gas constituents = lines 1 to 18, total						5.83	1.16	47.99	12.78	0.00

Fuel, O2, and Air per Unit of Fuel

LINE — Nautral Gas

a Fuel analysis as fired (AF), % by wt or vol
C= 70.0% CO= 0.0%
H2= 23.0%
S= 0.0%
b O2= 1.0%
N2= 6.0%
H2O= 0.0%
Ash= 0.0%
TOTAL= 100.00%
Flue gas analysis by test
CO2= 10.5%
c CO= 0 PPM, = 0.000%
O2= 2.0% CMBSTBL 0.00%
d Total air (TA), based on above O2 test
TA= 110%
e Lines f,g,h for gaseous fuels only
f Wt, fuel unit + sum (moles each * mol wt), lb
g Mol wt of fuel + line f / 100
h Density of fuel = line g/394 (lb/cuft)
i Higher heat value, fuel 12197 , Btu/lb = 22000
j %C in refuse
k Combustibles unburned, % of fuel 0.00%
l Stack temp, degrees C 230
m Ambient temp, dry bulb, degrees C 18

	Wet Flue Gas	Dry Flue Gas
Total Moles	67.784562	54.962244

21 Note: for air at 60F and 60%RH, A/(B-A)=0.0212 is used as a standard

DETERMINATION OF FLUE GAS AND COMBUSTIBLE LOSSES IN BTU PER FUEL UNIT (AS FIRED)

22 Fuel unit 100.00 lb

	Flue gas constituents:	CO2 + SO	O2	N2	H2O	CO	Btu Total	Conversion to metric units: kcal total	kJoules total
23	MCp, Molal specific heat, mean, t2 to t1	10.12	8.22	7.27	7.09	7.13			
24	In dry flue gas, moles each, line 20*MCp*(t2-t1)	22526	3625	133102		0.00	159253	40132	168012
25	In H2O in air, moles H2O, line 18*MCp*(t2-t1)				3469		3469	874	3660
26	In sens heat, H2O in fuel, moles, lines (5+10)*MCp*(t2-t1)				31110		31110	7840	32821
27	In latent heat, H2O in fuel, moles, lines (5+10)*1040*18				215280		215280	54251	227120
28	Total in wet flue gas						409112	103096	431613
29	Due to unburned combustibles, line k*14,100 Btu/lb						0	0	0
30	Due to unburned CO in flue gas; moles C to CO*12*9755 Btu/lb						0	0	0
31	Total flue gas losses + unburned combustible = lines 28+29+30						409112	103096	431613
32	Higher heat value (HHV) of fuel unit= 100 * line i for solid & liquid fuels = 394 * line i * 100 for gaseous fuels						2200000	554400	2321000
33	Stack and combustible loss, % of heat input, 100*line 31/line 32						18.6%	18.6%	18.6%
34	Combustion efficiency, HHV, % of heat input 100-line 33						81.4%	81.4%	81.4%
35	Combustion efficiency, LHV basis (line 27 subtracted from heat value and losses)						90.2%	90.2%	90.2%

B.2