SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

ENGINEERING DIVISION REPORT

STATUS REPORT ON SELECTIVE CATALYTIC REDUCTION FOR GAS TURBINES

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BY

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I. INTRODUCTION

The South Coast Air Basin is nonattainment for both the state and federal ambient air quality standards for NO_2. NO_2 is a criteria pollutant and is also a precusor to ozone for which the Basin is also nonattainment. As a result of not achieving the NO_2 ambient air quality standards and projected shortfalls in attainment, the EPA has required a State Implementation Plan (SIP) revision which is due in February, 1985, to assure that air quality compliance will be attained by 1987.

A major problem jeopardizing the District's capability to comply with the NO_2 and ozone air quality standards is the current proliferation of cogeneration projects utilizing gas turbines. Cogeneration projects have been afforded certain regulatory relief to aid in their development. The Public Utility Regulatory Policy Act (PURPA) provided for purchase of cogeneration electricity by serving utilities and California legislation (Assembly Bill 1862) exempted cogeneration projects from most of the New Source Review requirements. Therefore, the cogeneration market has been extremely lucrative, especially in the South Coast Air Basin.

The District has either permitted or received applications for over 800 MW of cogeneration power. It has been estimated that there is over 1500 MW of cogeneration power planned for the Basin which would result in NOx emissions of over 40 tons per day.

There are several air quality issues associated with cogeneration including Basin emissions, double-counting and hot spots. One of the most important issues is the sheer magnitude of the NOx emissions, which are estimated to be over 33 tons per day by 1987. As cogeneration projects do not typically provide any offsets, all of their emissions would have to be offset by other sources. This is an almost impossible task in an air basin where all of the major and minor sources (including domestic water heaters) are being controlled for NO_x emissions.

In addition, the cogeneration project receives an emissions credit for the utility power which is displaced. This leads to two concerns. First, the cogeneration project is "dirtier" than the serving utility on a pounds of NOx per megawatt hour basis so that there is a net increase in Basin NOx due to cogeneration power. Secondly, the major utilities in the South Coast Air Basin have agreed to reduce their NOx emissions by 50 percent by 1990 using any means available, including displacement by cogeneration (Rule 1135.1 Settlement). Thus, it is possible for the cogenerator to receive an emissions credit by displacing the utility and the utility to take credit for reduced generation; thereby creating the "double-counting" issue.

Finally, cogeneration projects have a much greater impact on local air quality than utilities. A cogeneration project typically has a short stack which is subject to downwash and hence a relatively high ambient impact. Large utilities have a very tall stack which is not easily effected by downwash or fummigation conditions and consequently does not impact the immediate vicinity. Rather, the pollutants tend to be dispersed and have a much smaller impact.

In an effort to achieve air quality levels and accomodate cogeneration activity, the District initiated a Best Available Control Technology (BACT) review for cogeneration projects using gas turbines. The District is empowered to require BACT for new projects under state law and District Rules. The BACT review examined the application of Selective Catalytic Reduction (SCR). As part of the review, a trip was made to Japan to investigate SCR.

II. BACKGROUND

The South Coast Air Quality Management District arranged a trip to Japan to investigate and witness the use of Selective Catalytic Reduction (SCR) as applied to gas turbines operating with exhaust heat recovery systems. During the week of July 2, a District engineer met with representatives of Hitachi, Hitachi-Zosen, and Mitsubishi Heavy Industries and held several discussions with Dr. Jumpei Ando in Japan. Site visits to the Kawasaki Power Station Unit Number 1 of the Japanese National Railways, the Chita Steam Power Station of the Chubu Electric Power Company, and the Kure Works Manufacturing Facility of Babcock-Hitachi K.K. were also conducted.

Selective Catalytic Reduction (SCR) is a post-combustion process to reduce NOx present in flue gas. It involves the injection of ammonia and the use of a catalyst to promote the reaction. The reaction proceeds on the catalyst surface with the following reactions postulated to occur:

$$4\ NO + 4\ NH_3 + O_2 \ \text{---}\ 4\ N_2 + 6\ H_2O \quad (1)$$

$$6\ NO_2 + 8\ NH_3 \ \text{---}\ 7\ N_2 + 12\ H_2O \quad (2)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \ \text{---}\ 3\ N_2 + 6\ H_2O \quad (3)$$

As most of the NOx from a combustion device is in the form of NO, the stoichiometric reduction mole ratio of NH_3 to NOx is approximately 1:1 as shown in equation 1. In actual practice, these mole ratios may be lower based on the inlet NOx concentration and the desired outlet NOx concentration. For example, an 80 percent re-moval efficiency may require a NH_3 NOx mole ratio of between 0.80 to 0.85, assuming that sufficient catalyst volume has been provided to achieve this level of efficiency.

Several flue gas parameters can influence catalyst performance including temperature, oxygen concentration, water vapor concentration, and catalyst volume. Catalyst volume is typically normalized with respect to flue gas flow and expressed in terms of space velocity ($FT^3/HR-FT^3$) or area velocity ($FT^3/HR-FT^2$).

Research has indicated that the process is first order and thus dependent only on the gas residence time in the deNOx reactor (the vessel where the reaction occurs). Residence time is related to gas flow rate and catalyst volume. The latter parameters are included in the catalyst area velocity (AV). Catalyst efficiency is a function of AV, temperature (T) and NH_3/NOx mole ratio as shown by equation (4) (Reference 1).

$$\text{Efficiency } N = f(AV)(T)\,(NH_3/NOx) \quad (4)$$

Therefore, for a constant area velocity, temperature, and mole ratio, removal efficiency will not be dependent on inlet NOx concentration. A 90 percent efficient reactor will reduce a 500 ppm NO_x inlet gas to 50 ppm NOx or a 50 ppm NOx inlet gas to 5 ppm NOx (Reference 1).

Depending on the catalyst vendor, the ideal process temperature range is approximately 570 to 750°F, although some systems may be operated at a temperature of less than 570°F. Above 850°F, the catalyst may deteriorate by both chemical and mechanical parameters.

In order to provide the proper thermal environment for the deNOx reaction, the SCR catalyst vessel is located in the Heat Recovery Steam Generator. Although the exact location will vary with gas turbine manufacturers, SCR supplier and unit operational parameters, the SCR vessel will typically be located in the evaporator section of the waste heat boiler. This area provides the proper gas temperature for a wide range of loads as illustrated by Figure 1. Also shown in Figure 1 are economizer inlet gas temperature and economizer outlet gas temperature. These locations are above and below the proper operating temperature, respectively.

SCR systems have been installed on units burning natural gas, fuel oil, coal, LNG, and kerosene. In order to operate in high dust environments such as coal flue gas, parallel passage catalysts have been developed which are tolerant to the dust loading. For fuels containing sulfur, catalyst manufacturers supply low oxidation catalysts and limit the NH_3 slip. Unreacted NH_3 may combine with SO_3 in the flue gas and condense as ammonium bisulfate which can potentially plug the catalyst surface or deposit on heat transfer surfaces. The condensation temperature will be dependent on the amount of SO_3 and NH_3 present in the flue gas as shown in Figure 2.

FIGURE 1

FLUE GAS TEMPERATURE AS A FUNCTION OF LOAD

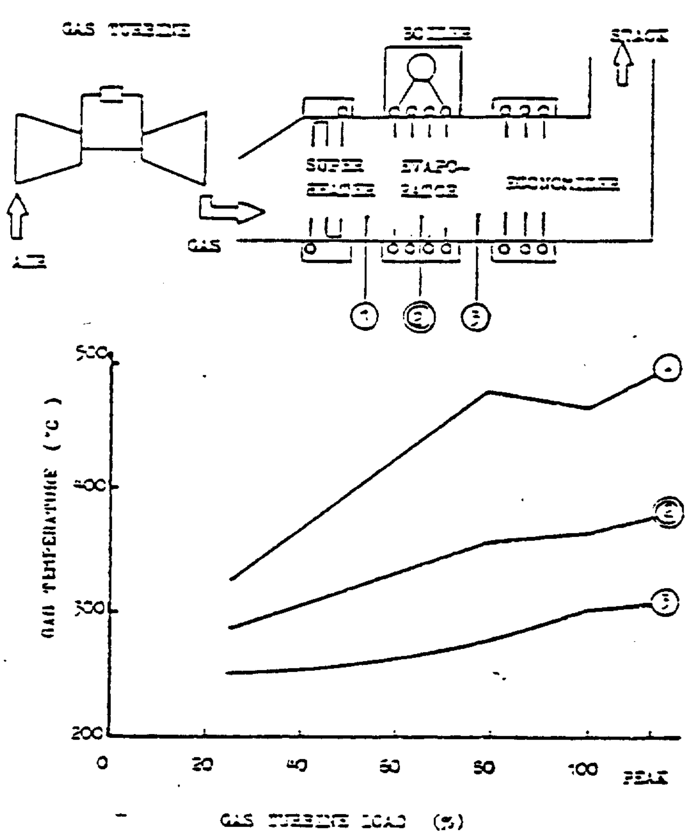
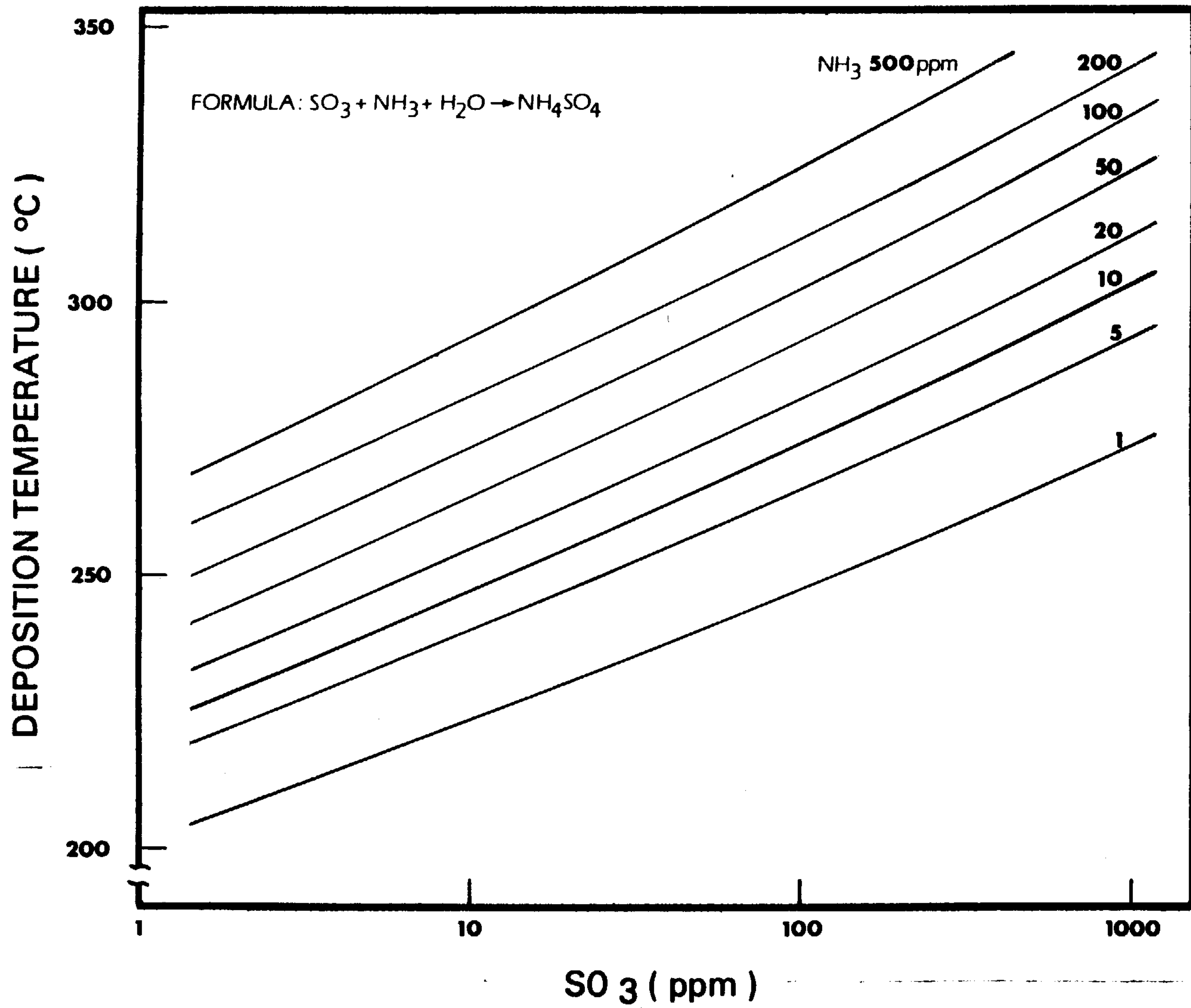


Figure 2



DEPOSITION TEMPERATURE OF AMMONIUM — BISULFATE ($NH_4 HSO_4$)

TABLE I
PARTIAL LISTING OF U.S. SCR INSTALLATIONS

U.S.

- The EPRI Arapanoe Test Facility at the Arapanoe Power Plant at the Public Service Company of Colorado
  Fuel - Coal
  Size - 5,000 SCFM (2.5 MW)
  Supplier - Kawasaki Heavy Industries

- The U.S. EPA Pilot Plant at the Mitchell Station, Georgia Power Company
  Fuel - Coal
  Size - 0.5 MW
  Supplier - Hitachi-Zosen

- The U.S. EPA Pilot Plant at the Big Bend Station at the Tampa Electric Company
  Fuel - Coal
  Size - 0.6 MW (combined SO_x/NO_x removal)
  Supplier - UOP, Inc.

- The Southern California Edison Company, Huntington Beach, Generating Station, Unit 2
  Fuel - Low sulfur fuel oil and natural gas
  Size - 112 MW
  Supplier - Kawasaki Heavy Industries

- Champlin Petroleum Company
  Fuel - Refinery gas
  Size - 125×10^6 Btu/hr
  Supplier - UOP

There are several SCR installations in the United States including three pilot scale facilities treating coal flue gas, a one-half scale demonstration project on a gas-or-oil fired utility boiler, and three installations at oil refineries. There are also over 100 installations of SCRs in Japan, including three gas turbine installations. A partial listing of the U.S. projects is given in Table 1.

III. JAPANESE SITE VISITS

On July 2, 1984, a site visit was made to the Kawasaki Power Station Unit Number 1 of the Japanese National Railways (JNR). Unit Number 1 is a combined cycle system consisting of a GE frame 9 gas turbine rated at 97 MW as the prime mover, a Heat Recovery Steam Generator (HRSG), and a 44 MW steam turbine for a total output rating of 141 MW. The system began commercial operation in April, 1981. A schematic of the system is shown in Figure 3. The turbine is fired with kerosene. A copy of the fuel analysis is given in Table 2.

Unit Number 1 operates approximately 14 to 16 hours per day, roughly from 7 a.m. until 9 p.m., Monday through Saturday. JNR stated that the unit is shutdown at night and restarted during the morning. This operation requires both cold and hot start-ups. The catalyst has thus undergone over 800 start-up and shut-down cycles. JNR reported that the catalyst has over 11,000 hours of operation on it and that over 24,000 hours is expected.

Shutdowns and start-ups subject the catalyst to thermal stress; rapid changes in temperature with respect to time. Thermal stress can cause cracking or spalling of the catalyst surface which reduces SCR efficiency. At the Kawasaki plant, the catalyst has undergone over three years of these cycles without any measurable decrease in activity or performance. The original catalyst is still in operation and has not required any maintenance. Catalyst performance in day-to-day operation has been verified.

The Frame 9 turbine is equipped with steam injection to reduce NOx formation in the gas turbine, which is used whenever the system is operational. The steam injection rate varies between 0.5 to 0.75 pounds of steam per pound of fuel, depending on the load.

As shown in Figure 3, the SCR unit is contained in the Heat Recovery Steam Generator (HRSG). The entire power plant, including the SCR system, was manufactured by Babcock-Hitachi. The catalyst is a proprietary formula but is believed to contain titanium dioxide and vanadium pentoxide on a alumina substrate. The SCR reactor contains 100 M^3 (3,531 ft^3) of catalyst pellets. The entire flue gas from the gas turbine passes through the reactor. The SCR system is utilized whenever the inlet reactor gas temperature is above 255°C. This temperature is achieved whenever the gas turbine is above 20 percent load.

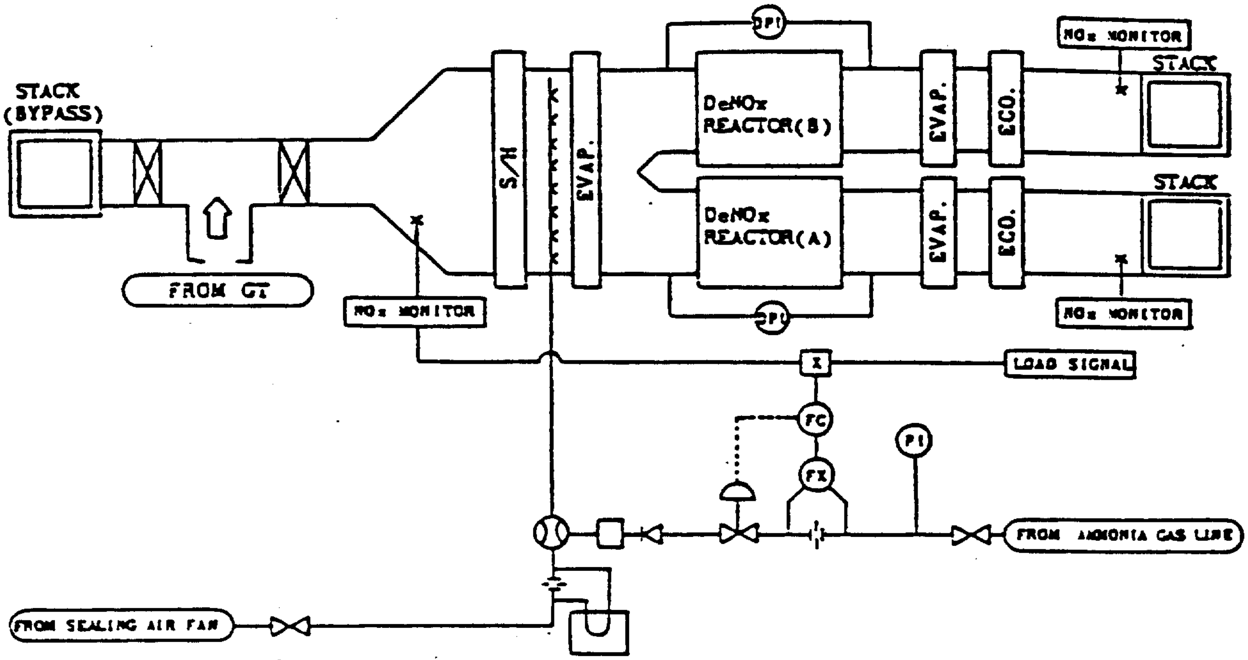
TABLE 2

FUEL ANALYSIS FOR KAWASAKI UNIT NUMBER 1

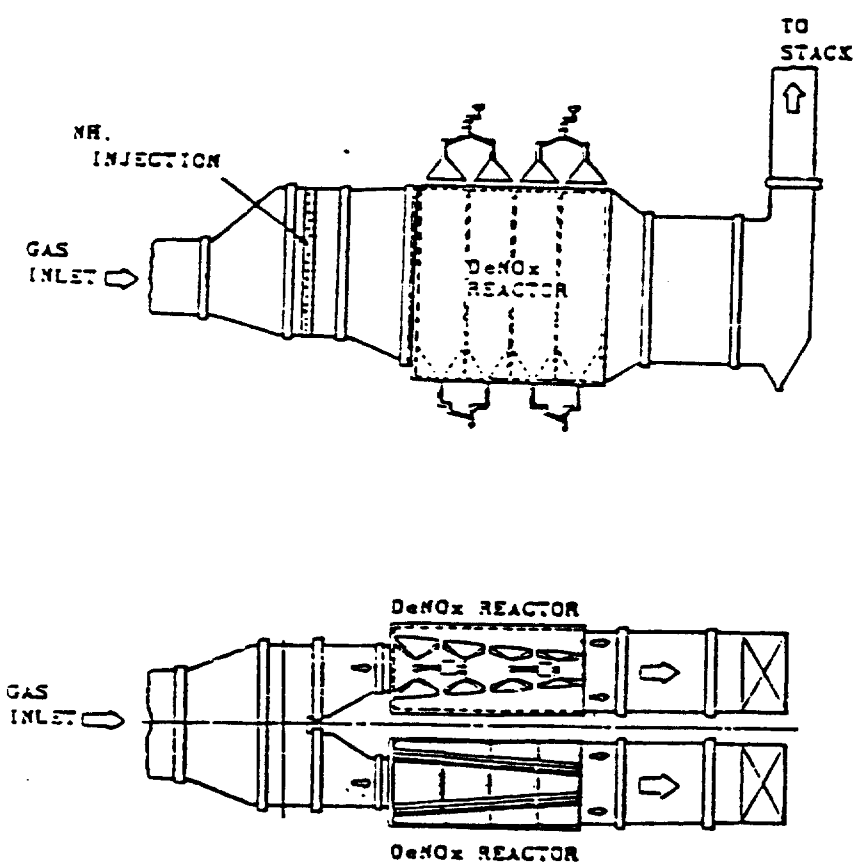
Date of Sample	6/15/84
Date Sample Received	6/22/84
Date of Report	6/25/84

Item	Result	Standard
Specific Gravity	0.8003	---
Reaction	Neutral	Neutral
Ignition Point °C	47.0	< 40
Distillation Temperature °C	154.5	<145
95% Distilled Temperature °C	247	<270
Wt. % Sulfur	.007	<.015
Copper Plate Reactivity (% wt. loss)	<1	< 1
Heating Value (kcal/kg)	11,000	---

FIGURE 3
(REF. 2)



A
PLANT FLOW DIAGRAM



B
OUTLINE OF SCR REACTOR

The SCR system was designed for an efficiency of 80 percent based on an inlet gas temperature to the reactor of 365°C (609°F), an inlet NO_x concentration of 75 ppm, and an outlet NH_3 concentration of less than 10 ppm (at actual conditions). These design parameters are summarized in Table 3.

The plant operates in accordance with an agreement between the local ministry and the plant regarding air emissions. The NOx limit for Unit Number 1 is 25 ppm NOx at 15 percent O_2, dry. The SCR system is operated at a mole ratio of approximately 0.4 (NH_3 to NOx) to achieve this level. Performance tests have indicated, however, that a NOx removal rate of over 85 percent can be achieved after more than 8,000 hours of operation.

This level of performance is demonstrated by test data given in Table 4 and Figures 4 and 5. As indicated by Figure 4, outlet NOx was reduced to less than 10 ppm (at 15% O_2, dry) for a load range of 25 percent to 100 percent+ (peak). Inlet NOx varied from 40 ppm to almost 80 ppm at peak load. NO_x efficiency of over 85 percent was achieved at peak load. Ammonia emissions from the reactor were less than 10 ppm for all data points.

Table 4 gives the performance test data obtained during plant guarantee tests. It can be seen that a deNOx efficiency of over 90 percent was achieved. As shown by Figure 5, catalyst performance has not substantially decreased with time. As previously mentioned, the data given in Figure 5 represent over 8,000 hours of operation.

During the time of the site visit, Unit Number 1 was operating at 97 MW (65 MW from the gas turbine and 32 MW from the steam turbine). An inspection was made of the control room, gas turbine, and heat recovery steam generator. All parameters observed indicated normal operation. No residual ammonia could be detected near the steam generator nor was there a visible plume. A summary of the control room operational data is given in Table 5.

Conversations with JNR officials indicated that there have not been any problems experienced with the catalyst. Due to the catalyst nature (pellets) and orientation (vertical plane) natural settling of the catalyst occurs. In order to alleviate this problem, approximately 10 percent of the catalyst is moved from the bottom of the SCR reactor to the top of the reactor once every three months. This operation is done on-line and requires about four hours using four laborers. The catalyst pellets are not cleaned or screened during the recycling operation.

The Chita Steam Power Station of the Chubu Electric Company was visited on Tuesday, July 3, 1984. Units 5 and 6 are Hitachi face-fired steam boilers burning LNG rated at 700 MW each. The units are also equipped with a full-scale Hitachi SCR system incorporating the same pellet catalyst used at Kawasaki.

TABLE 3
De NO_x SYSTEM DESIGN CONDITION
KAWASAKI UNIT 1
(Ref. 2)

Item	Unit	Design Data
Process	---	Selective catalytic reduction
Source of Gas	---	Gas turbine
G.T. load	---	Base
Number of reactors	---	2
Flue gas flowrate	m^3/h	982,000 (at 0°C, 1 ATM)
Flue gas temperature at reactor inlet	0°C	365
Flue gas composition at reactor inlet		
O_2 (wet basis)	vol %	14.4
H_2O (wet basis)	vol %	5.1
NO_x (dry basis)	ppm	75
SO_x (dry basis)	ppm	6
dust concentration	mg/m^3	5
Flue gas composition at reactor outlet		
NO_x (dry basis)	ppm	15 or less
NH_3 (dry basis)	ppm	10 or less
De NO_x efficiency	%	80 or more

Note: NO_x and NH_3 concentration values are based on actual O_2 concentration.

TABLE 4
PERFORMANCE TEST DATA
KAWASAKI UNIT 1
(Ref. 2)

Date Measured	Unit	11:00-15:00, 12th Feb, '81		11:00-15:00, 13th Feb, '81	
Design Value/ Measured Value	--	Design	Measured	Design	Measured
Gas Turbine Load	--	Base	Base	Peak	Peak
Water Injection	%	1	1.00	1	1.00
Ambient Pressure	atm	1.033	1.004	1.033	1.003
Ambient Temperature	°C	15	8.7	15	9.0
Total Generating Power	KW	118,900	126,720	133,700	141,720
Gas Turbine Output	KW	81,500	88,430	90,300	97,200
Steam Turbine Output	KW	37,400	38,290	43,400	44,520
Flue Gas Flow Rate (Wet)	Nm^3/h	982,000	1,008,000	984,000	999,000
Flue Gas Flow Rate (Dry)	Nm^3/h	932,000	951,000	930,000	946,000
Flue Gas Flow Temperature	°C	365	340	378	350
$[NH_3]/[NO_x]$ Mole Ratio	--	1.03	1.08	1.03	1.06
Inlet NO_x (G.T. Outlet)	ppm	75	62	88	77
Outlet NO_x (HRSG Outlet)	ppm	8	3.4	7	4.6
De-NO_x Efficiency	%	90	94.5	92	94
Slip NH_3	ppm	<10	2.3	<10	4
De-NO_x Draft Loss	mmAq	145	142	149	147

Notes:

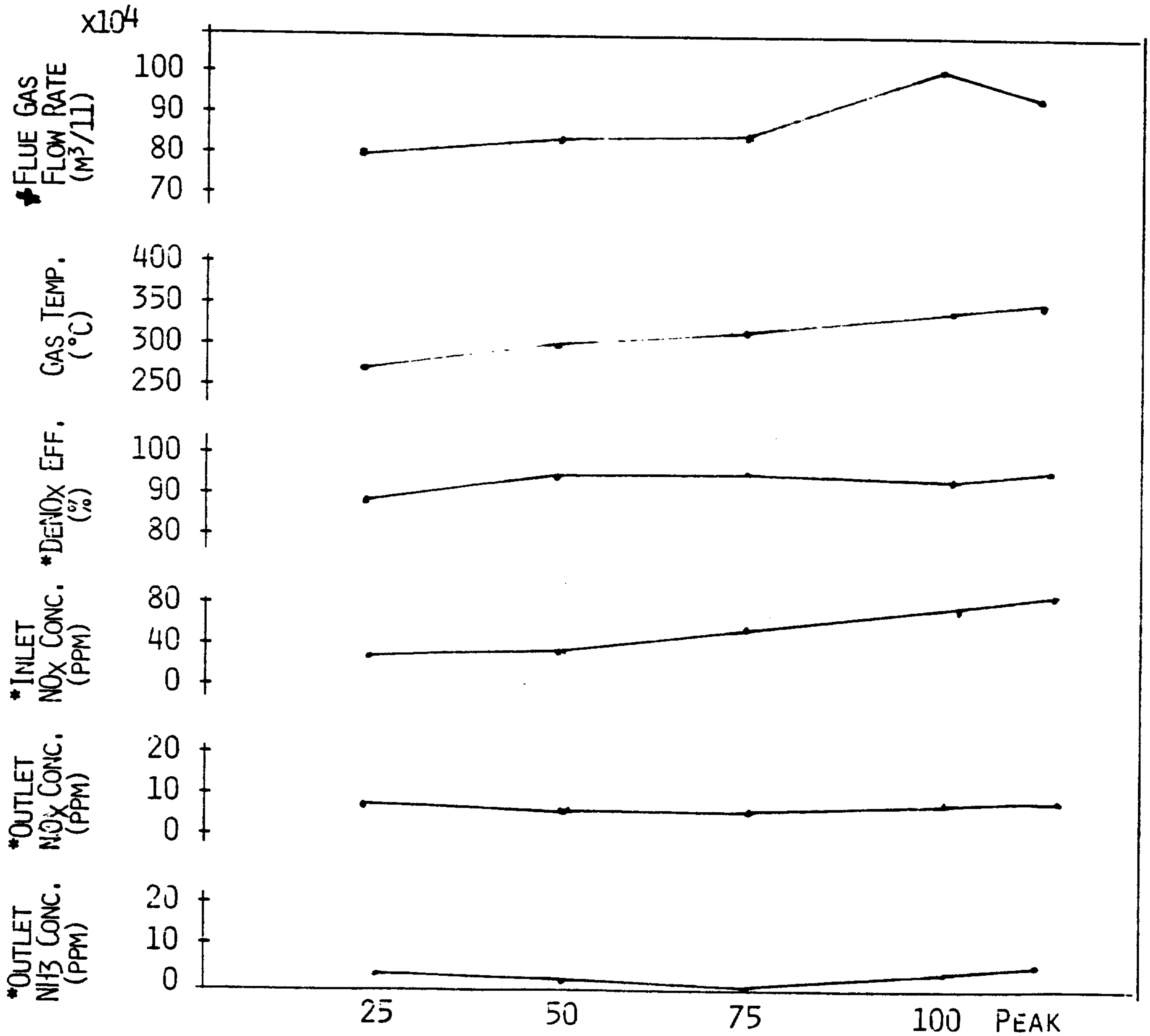
1. Above measured values are not corrected by ambient pressure, temperature, quantity of water injection, etc.
2. Values of Inlet NO_x, Outlet NO_x and Slip NH_3 are based on actual O_2%.
3. Values such as HRSG Outlet NO_x, $[NH_3]/[NO_x]$ Mole Ratio, $DeNo_x$ Efficiency, Slip NH_3, etc., are mean value between two $DeNO_x$ systems (A and B).
4. This application employs a pellet catalyst. For a plate-type catalyst, the pressure drop would be approximately 80 mm H_2O.

FIGURE 4
(REF. 2)

OPERATIONAL RESULTS OF SCR SYSTEM

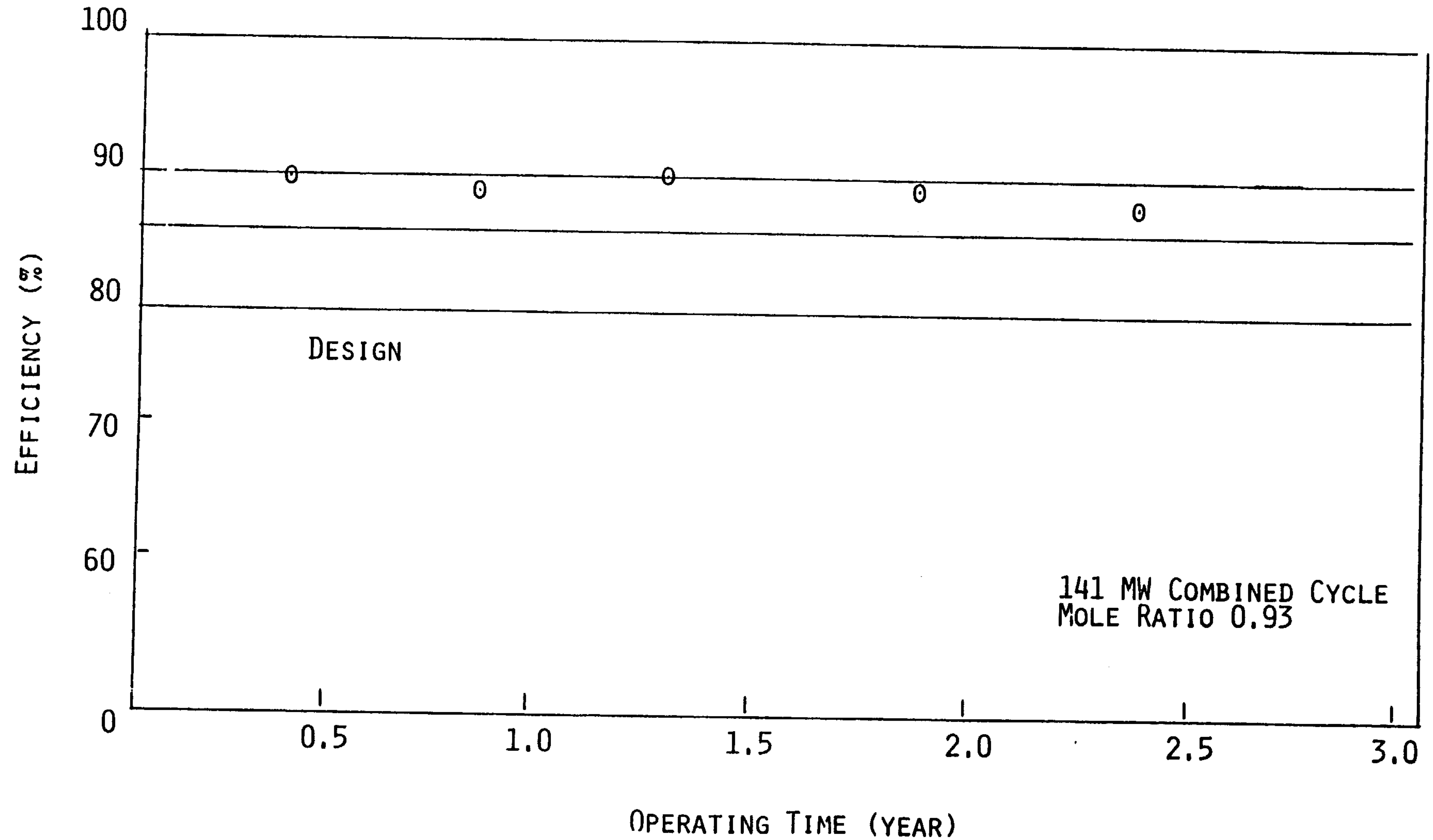
KAWASAKI UNIT NUMBER 1

$(NH_3)/(NO_X) = 1.03$
AMBIENT TEMP = 15°C



*ACTUAL O_2
✚AT 0°C AT 1 ATM

FIGURE 5
(REF. 2)



DENOX EFFICIENCY OF COMBINED CYCLE APPLICATION (141 MW)

TABLE 5
CONTROL ROOM DATA
KAWASAKI UNIT 1
JULY 2, 1984

Gas Turbine Output (MW)	65
Steam Turbine Output (MW)	32
Total Plant Output (MW)	97
Fuel Flow (kl/hr)	25
Excess Oxygen	13.3%
Inlet NO_x (Uncorrected) to SCR	48 ppm
Outlet NO_x (A/B, Corrected) from SCR	24/26 ppm
Gas Turbine Water Injection Rate (kl/hr)	12.0
Gas Turbine Exhaust	530°C
Boiler Outlet Temperature	195°C
Furnace Draft	300mm H_2O
Catalyst	135mm H_2O
Exhaust Gas Flow (wet)	85.5 X 10^4 NM^3/hr
" " " (dry)	82.6 X 10^4 NM^3/hr
NH_3/NO_x Mole Ratio	0.35

The units started up in 1978 and have operated for over 36,000 hours according to Mr. Masaru Iwama, Assistant Plant Superintendent. The deNOx reactor is operated at a NH_3/NOx rate ratio of 0.8 to achieve approximately an 80 percent reduction in NOx. The local NOx limitation is 10 ppm at five percent O_2, dry (equivalent to 11.25 ppm at three percent O_2, dry). The SCR system is always used whenever the boiler is on-line. There is no periodic maintenance requirement for the catalyst and the catalyst has not been changed or moved since start-up. The only activity associated with the SCR system has been catalyst sampling which is conducted twice a year.

After six years of operation, Chubu Electric estimates that the catalyst has had a decrease in efficiency of about five percent. There have been periodic tests to verify catalyst performance. These performance tests are, however, considered to be confidential by Chubu Electric. It is estimated that the catalyst will last over ten years before replacement is required.

Ammonia stack emissions are approximately 2-3 ppm. Although there are no local regulations governing the emission of ammonia, Chubu Electric limits NH_3 slip to less than 10 ppm for all units employing SCR. Ammonia emissions are measured periodically using wet chemical techniques.

Both units 5 and 6 were operating at full load during the time of the visit, 695 and 696 MW, respectively. The outlet NOx concentration from each unit was 9 ppm, corrected to 5% O_2, dry. The pressure drop across the SCR reactor is not measured but is estimated to be less than 100 mm H_2O (4" H_2O). A summary of units 5 and 6 operational parameters is given in Table 6.

On Wednesday, July 4, 1984, the Kure Works Manufacturing facility of Babcock-Hitachi (Babcock-Hitachi is the manufacturing group of Hitachi, Limited) was toured. Hitachi is a Manufacturers Associate of General Electric (GE) Company and as such builds Hitachi/General Electric industrial gas turbines (Frames 5, 6, 7, and 9) at this facility. The Hitachi plate-type catalyst is also made at the Kure Works.

During the time of the tour, the facility was in the process of building a GE Frame 9 gas turbine which will be used at the Futtsu power station of the Tokyo Electric Power Company (TEPCO). This turbine will be equipped with an SCR unit. In addition, a nuclear reactor vessel was also being fabricated.

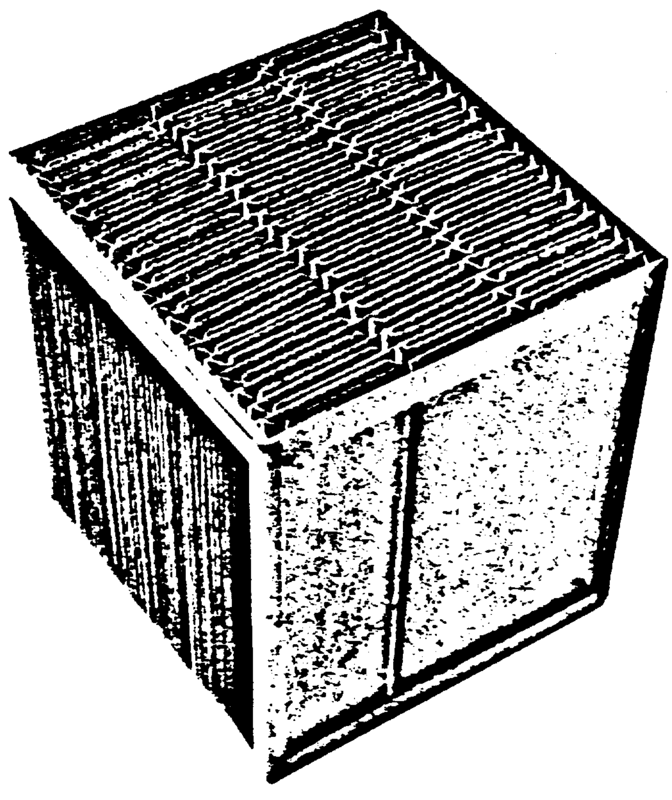
The plate-type catalyst manufacturing line was toured. The manufacturing line consists of several different operations. Metal plate is cut to the appropriate size, shaped, treated, covered with catalyst paste, heat treated, and then assembled into cubes using a metal frame to contain the catalyst plates. Each cube is approximately 500 X 500 X 500 (mm). Cubes are then assembled into a catalyst block which contains approximately 20 cubes. The exact shape of the block will depend upon the specific application. A picture of a catalyst cube is shown in Figure 6.

TABLE 6
UNIT 5 AND 6 OPERATING DATA
CHITA POWER STATION
CHUBU ELECTRIC COMPANY

	UNIT 6	UNIT 5
Load	695 MW	696 MW
Inlet NO_x	30/34	30/30
Outlet NO_x, Corrected, ppm	9	9
Stack O_2	3	3
NH_3 Flow (A/B) KG/hour	20/16	-
Furnace P	150 mm H_2O	-
Fuel Flow (Metric Tons/Hour)	118.2	-
Fuel HHV (cal/gram)	12,970	-

FIGURE 6
(REF. 2)

HITACHI PLATE TYPE CATALYST



According to Babcock-Hitachi, the influence of water vapor or excess oxygen does not appreciably impact deNOx efficiency for an SCR system. Data were prepared by Babcock-Hitachi to demonstrate the effect of water and oxygen, as well as other parameters on deNOx efficiency for a pellet-type catalyst. These results are shown in Figures 7, 8, 9, and 10. Mr. Hiroshi Kuroda, Department Manager, Kure Works, stated that identical results would be obtained for the plate-type catalyst.

Figure 7 illustrates the effect of water vapor on deNOx efficiency. For comparison, a typical uncontrolled (without water or steam injection) gas turbine has approximately eight percent by volume water in the exhaust and 10 percent by volume water controlled (using water or steam injection). The resulting change in de-NO_x performance is minimal between eight and ten percent water as shown in Figure 7.

Increasing the oxygen in the flue gas increases the deNOx efficiency. This relationship is presented in Figure 8. However, oxygen only influences the reaction efficiency if it is present in concentrations of less than one percent. Since turbines operate with 14 to 16% excess oxygen, varying concentrations should not impact performance.

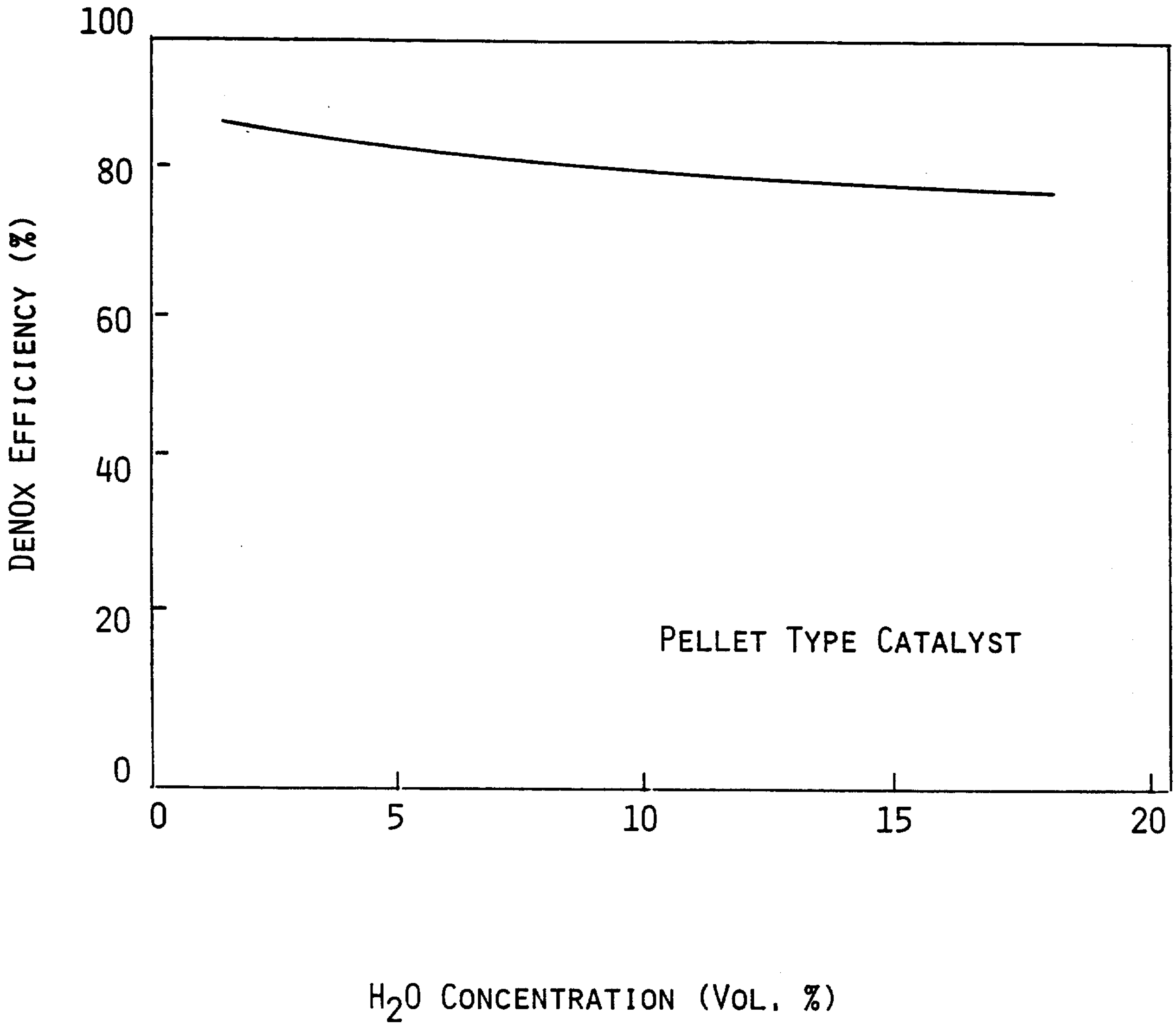
Figures 9 and 10 show the effect of space velocity and temperature on deNOx efficiency, respectively. Different catalysts will exhibit different characteristics with respect to temperature. Babcock-Hitachi stated that a space velocity of approximately 8,000 (hr^{-1}) would be used to obtain an 80 percent removal efficiency from a gas turbine.

IV. JAPANESE MEETINGS

On Thursday, July 5, and Friday, July 6, 1984, meetings were held with Hitachi, Mitsubishi, Hitachi Zosen and Dr. Jumpei Ando to discuss the installation of SCR systems on gas turbines. Dr. Ando is a consultant to the EPA and the Tennessee Valley Authority and has published reports on NO_x control in the United States and Japan. The results of those meetings are summarized below.

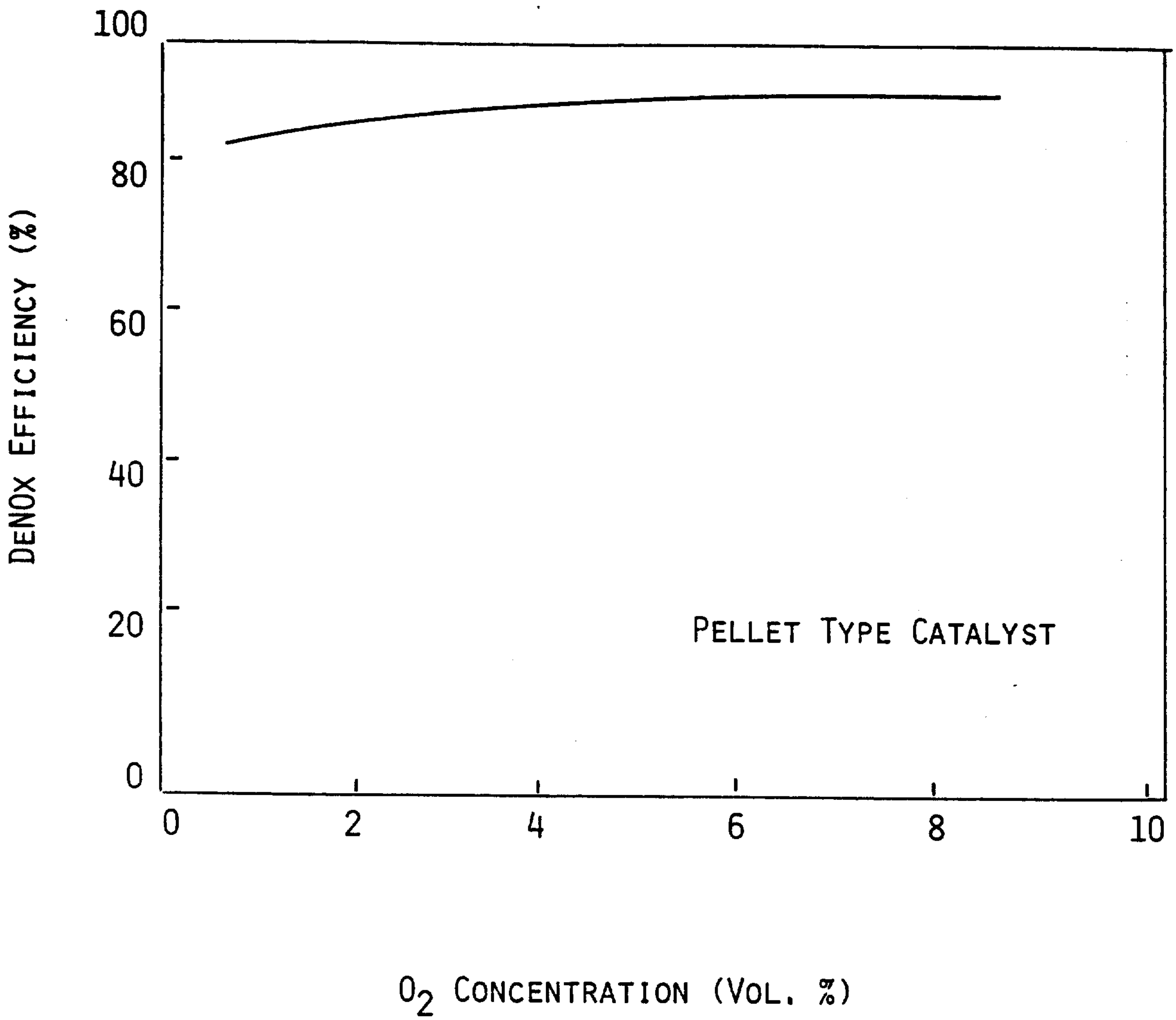
There are several firms which offer SCR systems in Japan. Most of these companies purchase catalysts from a manufacturer and then assemble the catalyst into an SCR system. Catalyst manufacturers include NGK; Catalyst and Chemicals, Inc.; Sakai Chemical; Babcock-Hitachi; and Hitachi-Zosen. Of these companies, only Babcock-Hitachi and Hitachi-Zosen also offer a complete SCR system. Other Japanese companies which offer SCR systems, such as Mitsubishi Heavy Industries (MHI), Ishekawajimon-Harima Heavy Industries (IHI), and Kawasaki Heavy Industries (KHI), incorporate catalysts obtained from another manufacturer.

FIGURE 7
(Ref. 3)



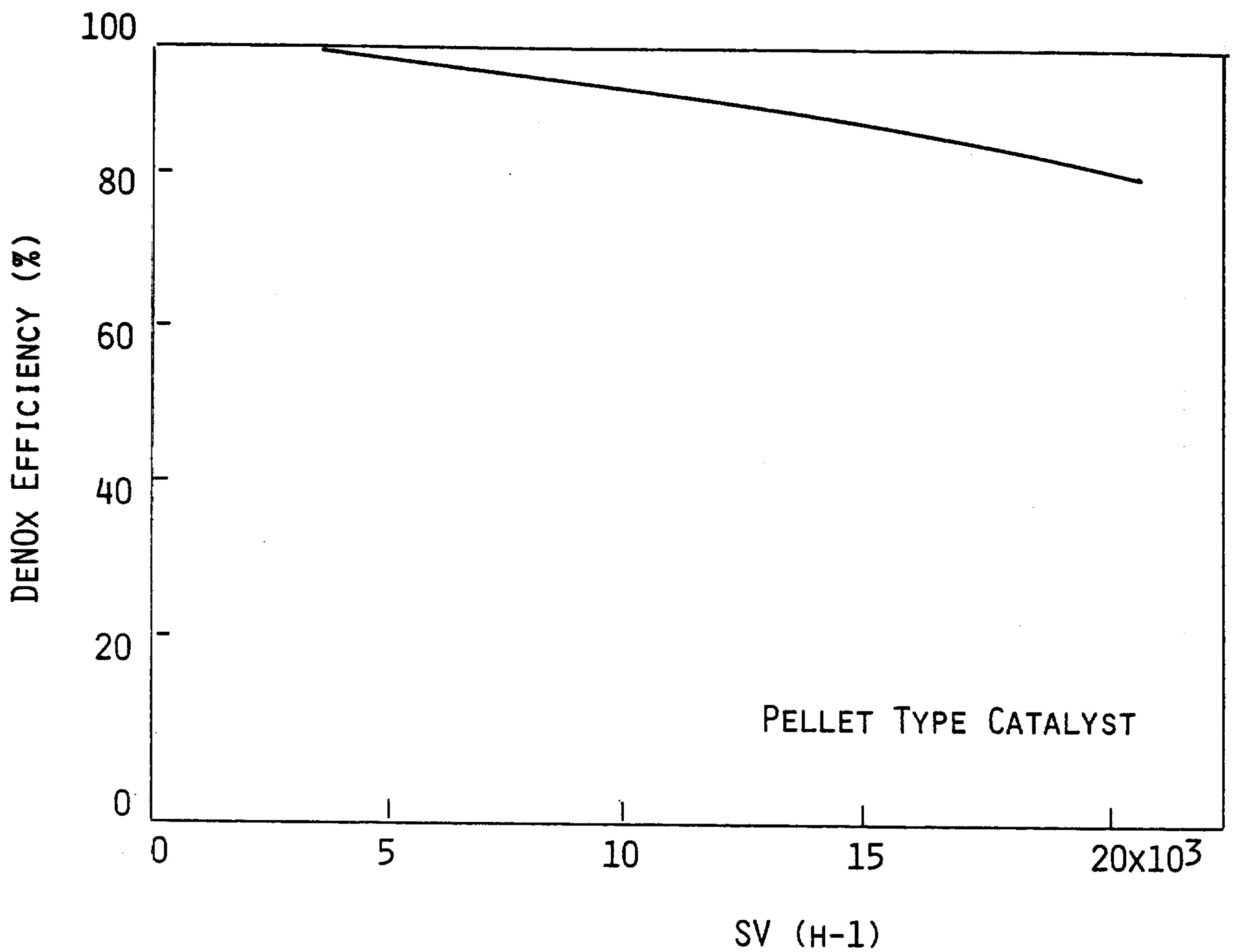
H_2O CONCENTRATION VS DENOX EFFICIENCY

FIGURE 8
(Ref. 3)



O_2 CONCENTRATION VS DENOX EFFICIENCY

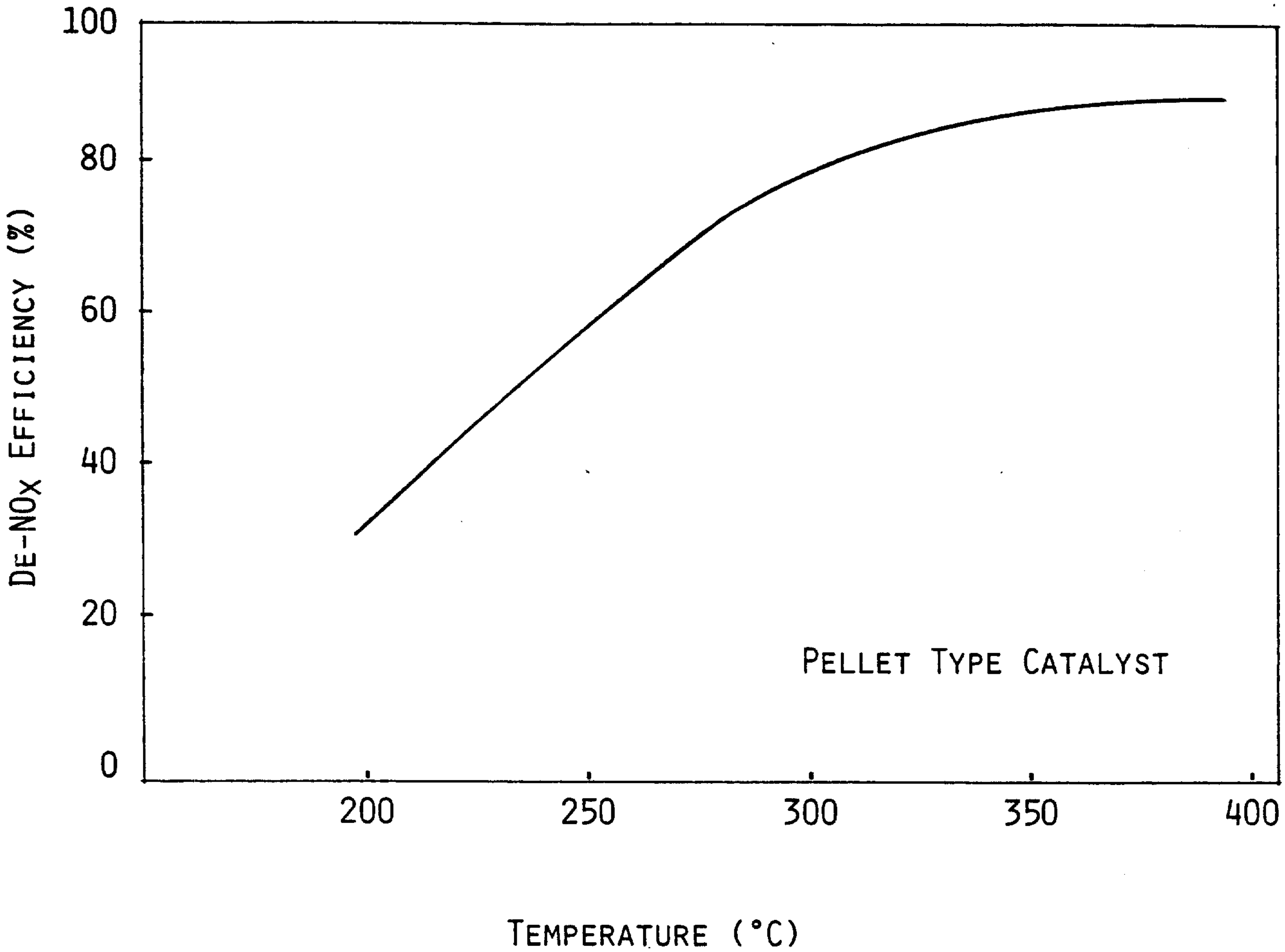
FIGURE 9
(Ref. 3)



SV VS DENOX EFFICIENCY

FIGURE 10

(Ref. 3)



GAS TEMPERATURE VS DENO$_X$ EFFICIENCY

In addition to the Kawasaski plant, there is one other installation of an SCR on a gas turbine. Hitachi-Zosen has installed a de NO_x system on a 3 MW gas turbine burning heavy oil. The unit became operational in 1984 and utilizes an Hitachi-Zosen NOXNON 600 catalyst. The flue gas contains approximately 100 ppm SO_2. Operational data on this system have been requested.

There are several combined cycle systems utilizing SCR that are either being built or planned in Japan. Table 7 gives partial listing of those projects. Over 5,600 MW of combined cycle generation utilizing SCR is planned at seven different locations.

The Higashi Niigata Plant Number 3 of the Tohoku Electric Power Company is currently undergoing performance tests and is scheduled for commercial operation at the end of July, 1984. This facility utilizes a MHI honeycomb catalyst with a 4.5 mm pitch. An example of the honeycomb catalyst is shown in Figure 11.

The Higashi Niigata plant consists of six gas turbines with a flue gas flow rate of 1,365,000 NM^3/hr (869,174 SCFM) per gas turbine. The inlet gas temperature to the SCR reactor is 297°C (567°F). The guarantee outlet NOx concentration is 15 ppm corrected to 15 percent O_2, dry using a NH_3/NOx mole ratio of approximately 1.0. The oxygen concentration is 14.13 percent. The space velocity of the SCR reactor is approximately 9,000-10,000 (hr^{-1}). The catalyst has been guaranteed for two years. The only planned maintenance for the SCR system is the taking of a catalyst sample annually. There are no other maintenance requirements.

The Futtsu Plant Number 1 of TEPCO will be comprised of seven GE Frame 9 gas turbines, each venting a two pressure level HRSG. The HRSG is unfired. Each combined cycle is rated at 142.8 MW at 32°C. The gas turbine fuel is liquid natural gas. The NOx control system consists of steam injection in the gas turbine and a Hitachi-Zosen SCR system in the HRSG. The required NOx outlet level is less than 4 ppm at 15 percent O_2, dry, which necessitates a deNOx efficiency of approximately 90 percent across the SCR system. The design NH_3/NOx ratio is 0.95. Outlet NH_3 is expected to be 3 ppm. Catalyst life is guaranteed for two years and estimated to be four years.

Hitachi-Zosen is currently fabricating catalyst for the Futtsu Plant. A NOXNON 500L catalyst will be used. This catalyst consists of alternating flat and undulating sheets of steel which have undergone a surface activation process. The catalyst is assembled in cubes that are 500 mm per side and then packaged into a 1 m^3 block of catalyst consisting of eight cubes. Each block weighs approximately 2,300 pounds. An example of the catalyst and its arrangement is given in Figure 12.

TABLE 7
COMBINED CYCLE GAS TURBINE INSTALLATIONS
IN JAPAN USING SCR

Power Company	Location	Plant	Output	$DeNO_x$ Supplier
Tokyo EPCO	Futsu	#1	1000 MW	Hitachi-Zosen*
Tokyo EPCO	Futsu	#2	1000 MW	Hitachi-Zosen
Tohoku EPCO	Niigata	#3	1090 MW	MHI
Chubu EPCO	Yokkaichi	#4	560 MW	Hitachi-Zosen
Kyushu EPCO	Shin-ota	#1	670 MW	Hitachi
Kyushu EPCO	Shin-ota	#2	870 MW	MHI
Hokuricu EPCO	Nanao	#1	550 MW	N/A#

*Currently under construction, start-up scheduled for 1985.
+Start-up scheduled for 7/84, currently undergoing performance tests.
#Not available.

FIGURE 11
(REF. 4)

MITSUBISHI HEAVY INDUSTRIES
HONEYCOMB TYPE CATALYST

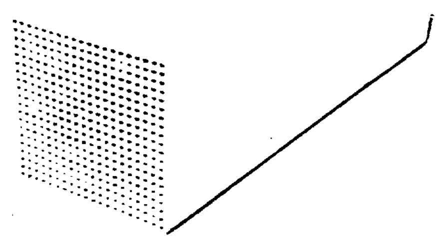
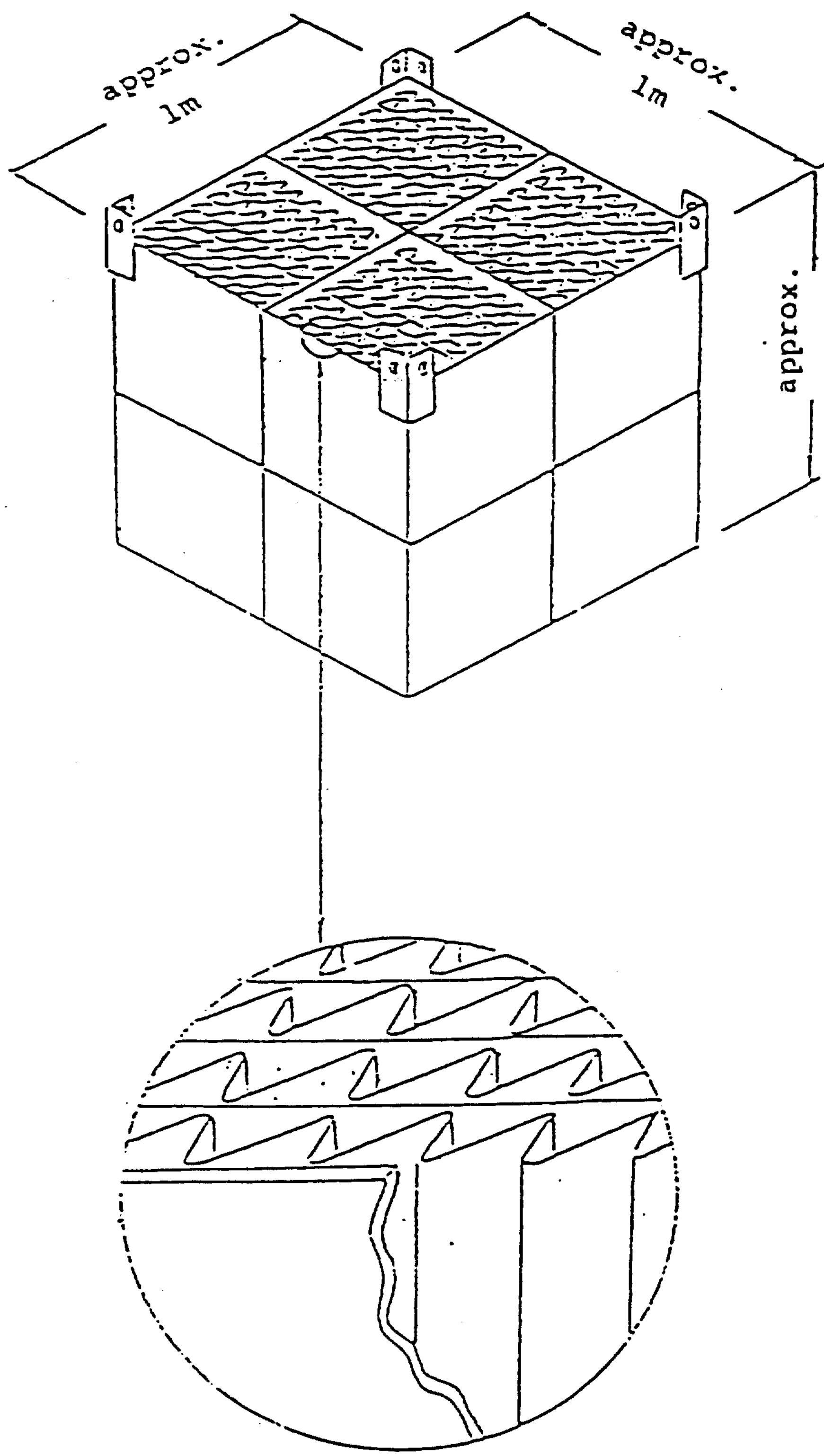


FIGURE 12
(REF. 5)

CONFIGURATION OF HITACHI-ZOSEN NOXNON 500L CATALYST



Tests have been conducted on the NOXNON 500L catalyst to determine its performance. The results of these tests are given in Figures 13 and 14. Figure 13 illustrates the effect of temperature on catalyst performance and Figure 14 indicates catalyst performance with respect to time.

An important consideration in the use of SCR on combined cycles is the thermal transients the catalyst may undergo during start-up, shut-down, and load ramping operations. In order to verify the mechanical integrity of the system, several thousand hours of testing have been conducted by GE (Reference 1) and Hitachi-Zosen. The Hitachi-Zosen NOXNON 500 catalyst has undergone over 15,000 cycles of controlled heating and cooling at T rates of up to 500°C/min. In addition, it has undergone very severe testing in which catalyst sample at 400°C was plunged into a bath of liquid nitrogen at -190°C. There was no visible damage to the catalyst surface (Reference 1).

As previously mentioned, the SCR system at Kawasaski Japan has undergone over 800 actual start-up and shut-down cycles without any measurable deterioration in catalyst performance. This SCR system has been on-line for over three years and has an expected life of an additional three years.

SCR systems for gas turbines are designed according to several factors including gas volume, required de NO_x efficiency, the temperature range at which the system will operate, the amount of ammonia slip, and the pressure drop. While all these factors and others are necessary to design a system, one of the more important parameters is gas volume. For a constant area velocity, the gas volume will be directly proportional to catalyst size.

Another consideration in the installation of SCR systems is pressure drop across the reactor and injection nozzles. Most SCR manu-facturers guarantee a pressure drop of 100 mm H_2O (about 4 inches H_2O) while the actual operation is estimated to be 80 mm H_2O (about 3 inches H_2O). For comparison, a GE Frame 5 gas turbine can handle about 30 inches H_2O back pressure and the total back pressure of a HRSG with SCR is about 20-24 inches H_2O.

V. SCR ECONOMICS

Conversations with deNOx suppliers indicated that SCR system cost would be divided between catalyst cost and peripheral system cost.

FIGURE 13

(Ref. 5)

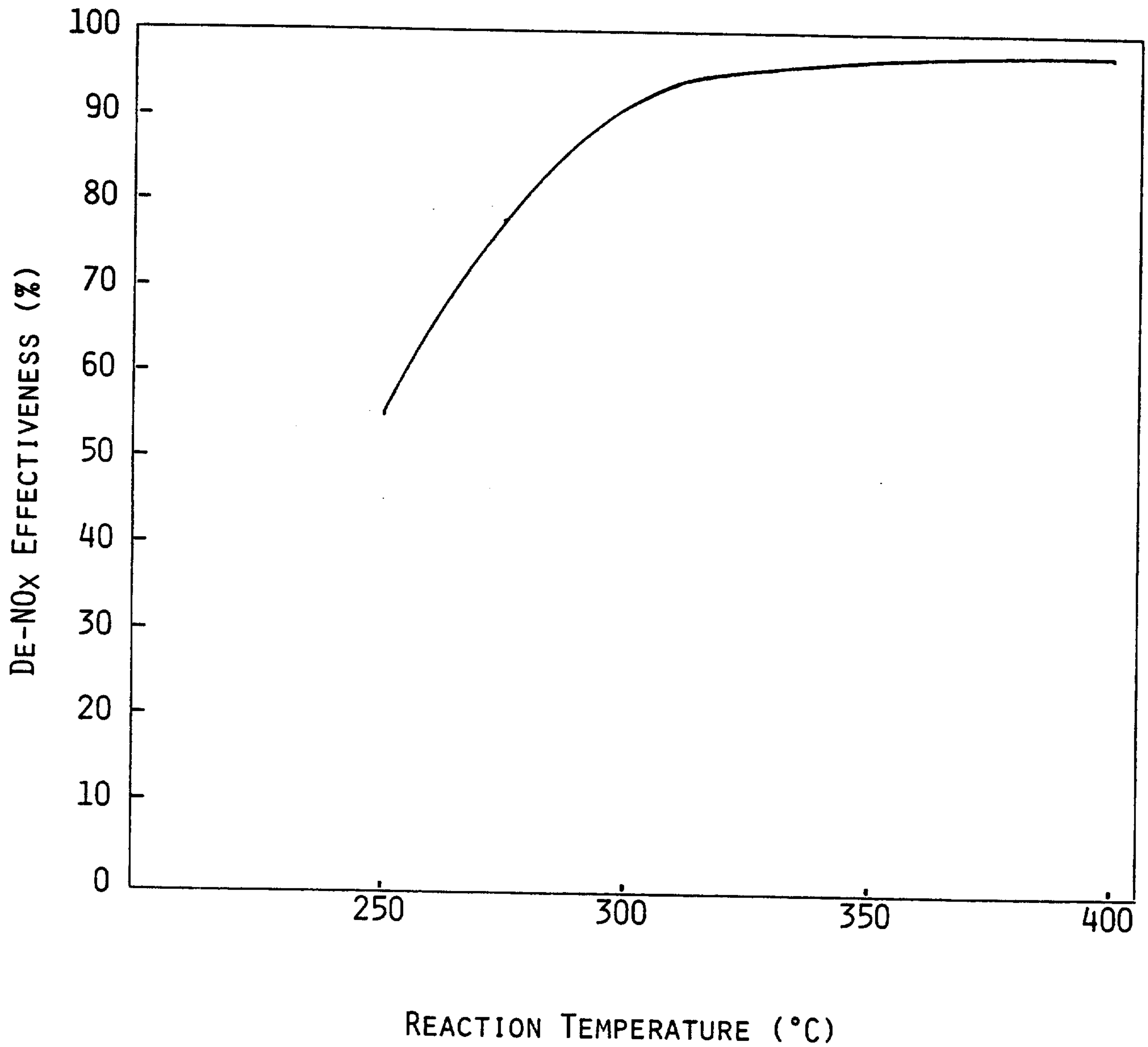


FIGURE **14**

(Ref. 5)

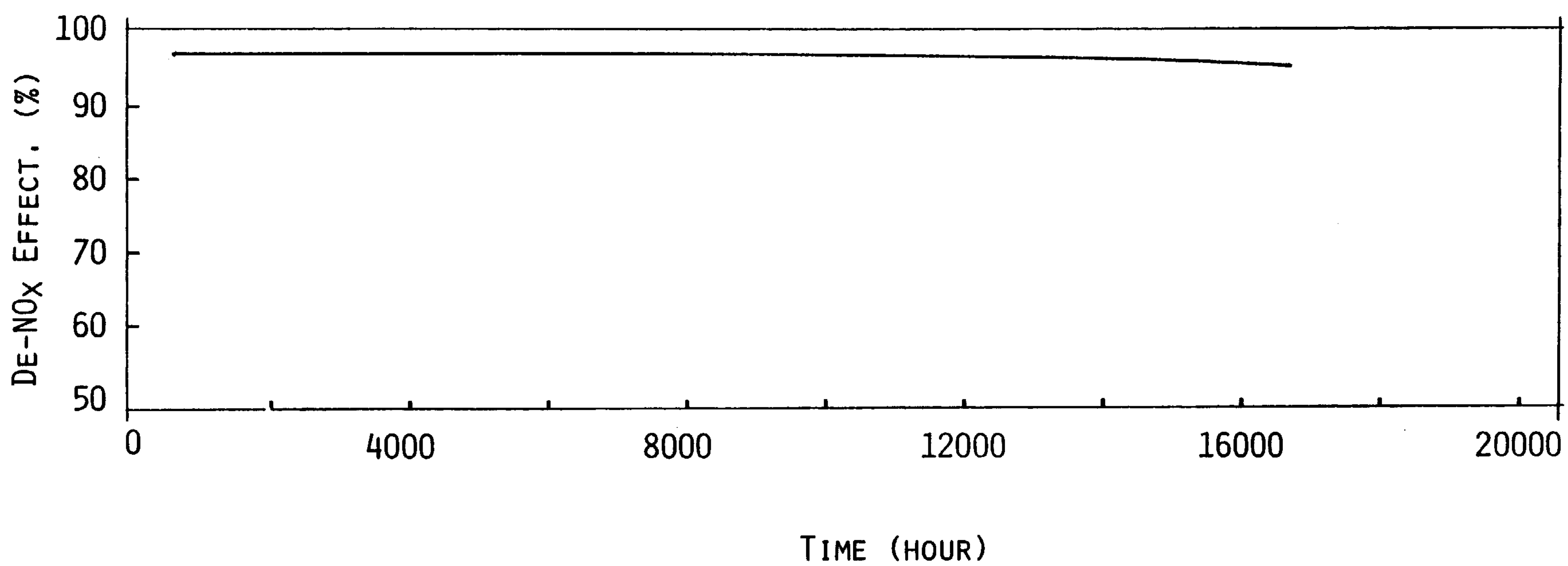
Life Test Data

(Test Condition)

Gas Rate	:	1,000 Nm^3/H
AV	:	7.1 Nm^3/m^2H
Reaction Temp	:	410°C
NH_3/NO_x	:	1

Gas Composition

NO_x:	30-40 ppm
O_2:	14 vol %
CO_2:	4 vol %
H_2O:	9 vol %
N_2:	Residual
Total:	100 vol %



The following cost information was obtained for an SCR system treating an LM 2500 exhaust(approximate flow rate of 125,000 SCFM) with steam or water injection in the gas turbine.

Catalyst Cost	$625,000
Ancilliary Cost*	472,000
TOTAL	$1,097,000

Costs not included in this estimate are the ammonia tank and ammonia vaporzation system. In addition, there are operating costs associated with the SCR system, including electricity (approximately 10 KVA), control air (about 150 cfm), purge nitrogen, service air, and ammonia.

The total cost for an SCR system treating approximately 600,000 SCFM (similar to a GE Frame 7 gas turbine or a Brown-Boveri Type 11 gas turbine) for 80 percent NO_x control is estimated to be between $3,900,000 and $4,500,000. This cost would include catalyst, transportation, and auxiliary requirements. Site installation, if required, would be additional.

VI. DATA VALIDATION

The General Electric Company has investigated the use of SCR for a combined cycle facility consisting of four GE Frame 6 gas turbines. To achieve a 90 percent reduction in NO_x, the estimated capital cost per gas turbine is $2,650,000 (1982 dollars). The operating cost, including direct costs (catalyst and ammonia), indirect costs, and incremental fuel cost is 1.25 mills/KW-hr (Reference 1). It is important to note that conversations with GE indicate that this price information may be high (Reference 6).

XII. SUMMARY

Selective Catalytic Reduction is a proven NOx control technology for gas turbines with heat recovery steam generators. There are currently two such installations operating and over 5,600 MW of combined cycle SCR systems either under construction or being planned in Japan. SCR system suppliers are guaranteeing a catalyst life of 16,000 hours and estimate a life of over 32,000 hours. A

*Ancilliary cost includes reactor vessel, ammonia injection nozzles, air fan, ammonia air mixer, control equipment (two NOx monitors, computers, piping valves, controllers).

guarantee of 80 percent NOx reduction is also being made although a 90 percent reduction has been demonstrated and is being commercially offered (Reference 1). Outlet levels as low as 4 pmm corrected to 15 percent O_2,dry are being guaranteed.

General Electric is currently commercially offering a combined cycle SCR package utilizing a Hitachi-Zosen catalyst in the United States for systems burning natural gas with fuel oil backup (Reference 7). This system is guaranteed for 16,000 hours. Hitachi of America is also offering a similar system incorporating a Babcock-Hitachi catalyst. Several other Japanese and American vendors offer SCR systems for gas turbines including KHI, MHI, IHI, Johnson-Maloney and UOP. (This list is not inclusive; there are several additional companies which offer SCR systems.)

REFERENCES

1. Flitner, D.P., Whitehead, A., Smith, R.W., "Catalytic Denitrification for Domestic Utility and Industrial Combined Cycle Applications", GE Publication, undated.

2. Babcock-Hitachi, NOx Removal System for Gas Turbine Application, June 1984.

3. Babcock-Hitachi data, July 1984.

4. Mitsubishi Dry Selective Catalytic NOx Removal System, Mitsubishi Heavy Industries.

5. Hitachi-Zosen data, July 1984.

6. Telephone conversation with Dr. Alan Whitehead, General Electric Company, July 1984.

7. Telephone Conversation with Duffy Wright, General Electric Company, July 1984