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THAILAND
PRIVATE SECTOR POWER PROJECT

FINAL REPORT

PREPARED UNDER

IQC PDC-5730-I-00-6110-00

DELIVERY ORDER NO. 9

PREPARED FOR

OFFICE OF PROJECT DEVELOPMENT AND SUPPORT

USAID/BANGKOK

AND THE

OFFICE OF TECHNICAL RESOURCES

BUREAU FOR ASIA AND NEAR EAST

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT

PREPARED BY

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SECTION 1

BACKGROUND

USAID/Thailand and ANE/TR/ENR arranged for the services of two consultants - an energy policy expert and an electric utility expert - through deLucia and Associates, to assist the Government of Thailand (RTG) in the development of policies to encourage private sector participation in power generation. Peter Borré, President, Boston Energy Associates (an affiliate of J. Makowski Associates), and John Levett, Manager, Alternate Energy Projects, New England Power Service Company, were selected as the Team for the assignment. The Team visited Thailand from February 5 through February 25, 1989.

The Team's Scope of Work (Annex 1) in summary consisted of the following:

- Analyze policy guidelines currently under consideration;

- Work with the RTG, including the National Energy Policy Office (NEPO), and the national utility (EGAT) to develop the basic elements of a private power program, including solicitation and selection procedures, model purchase agreements, and techniques for evaluating purchase prices;

- Work with EGAT on potential technical problem areas;

- Prepare procedures to implement a cogeneration and small power program;

- Analyze issues involved in implementing a larger-scale IPP program.

The Team's report follows.

SECTION 2

OVERVIEW

The RTG has recently made considerable progress in initiating a private power program for electricity generation. At a February 16 meeting of the National Energy Policy Committee (NEPC - the RTG's cabinet level oversight interagency group), the RTG made the policy decision to invite the private sector to participate in the production and distribution of electricity (press report, Annex 2).

Within this policy framework, the Team was able to accomplish the following:

1. Redrafting of regulations for cogeneration and small power (Annex 3), modifying to some degree the provisions of a previous draft (Annex 4);

2. Drafting of a Model Power Purchase Agreement for cogeneration and small power (Annex 5);

3. Providing NEPO with a modelling structure (through a Lotus - PC compatible program diskette) for the evaluation of tariffs, costs and profitability of a cogeneration project (sample pro forma printout, Annex 6);

4. Comments on EGAT's proposed expansion plan, Power Development Plan PDP 8802 (comments provided as Annex 7, PDP 8802 provided as Appendix A), and recommendations that selected EGAT expansion projects be identified as candidates for development by the private sector as larger-scale, so-called Independent Power Projects ("IPPs": defined as generating units which do not "cogenerate" steam for thermal applications);

5. Briefing on February 24 to the Privatization Working Group of the NEPC on the Team's redrafted regulations for cogeneration;

6. Presentation on February 23 to the Thailand Development Research Institute on private power in the U.S.;

7. Meetings with high level RTG officials on the U.S. private power program and its implications for Thailand;

8. Four meetings with EGAT officials, both at the senior management and at the working level, to describe the technical and reliability aspects of private power in the U.S.;

9. A recommendation for a Technical Conference, to brief the Thai private sector on the proposed regulations on cogeneration, and draw their comments before the regulations are made final (draft announcement of the conference prepared for NEPO is provided as Annex 8); RTG officials indicated they would hold the conference, and tentatively set it for March 27.

SECTION 3

SUMMARY

The following topics are described below in summary form:

- Privatization announcement;
- Team's draft regulations;
- Model power purchase agreement;
- Pro forma financial model;
- Introduction of larger-scale IPPs;
- EGAT Power Development Plan;
- Meetings with EGAT.

The Annexes noted above give a more comprehensive discussion on each of these topics.

3.1 Privatization Announcement

The NEPC policy decision appears to have come as a surprise ("striking and unexpected" as reported by the Bangkok Nation on February 17; see Annex 2). The driving pressures are (1) the dilemma created by EGAT's projections of negative reserve generating margins in May, 1990 (and thus the prospect of

electric capacity constraints well into the 1990s) and (2) the financial burden on public sector debt of financing the capacity expansion program needed to bring reserve margins back to more acceptable levels.

The National Economic and Social Development Board (NESDB) is well aware of the problem and sees the introduction of private power as a way of accomplishing some important public policy objectives: relieving the public sector of some future debt otherwise incurred through EGAT; and getting the benefits of competition in the electricity sector, both for project development and project operations.

The strategy for the time being is, apparently, to proceed in phases, first introducing cogeneration and small power, then going to larger-scale IPPs, and finally, perhaps, a partial flotation of EGAT shares.

3.2 Draft Regulations

The draft regulations prepared by the Team (Annex 3) are an important work product. The earlier version (Annex 4) might constrain the growth of cogeneration and small power, relegating it to a surplus power activity. Of the many modifications introduced into the draft regulations by the Team, the following are considered the most significant:

- Establishment of annual solicitations and a first level of 300 MWe (p. 2);

- Additional objective, "to meet the nation's growing needs" (p. 5);

- Expansion of residue fuel category to include renewables and solid waste; latitude to use conventional fuels up to 67% of annual needs (p. 6);

- Removal of size limit (50 MWe) for cogeneration facilities; definition of operating standard at 10% thermal energy against total energy output (p. 6);

- Substantially modified pricing provisions (pp. 9-12), including:

  - Fixed capacity charges averaging, based on preliminary analysis, 220 Baht per kilowatt per month ($8.8/KW month, $105.6/KW year);

  - Monthly (rather than yearly) nominations of stated capacity levels (to reflect the extensive seasonal and monthly "swings" in power available from agricultural waste cogenerators);

- Flexibility for EGAT to weight the monthly capacity payment to match its peaking needs, provided the average monthly value over the year is 220 Baht per kilowatt per month.

3.3 Model Power Purchase Agreement

Neither of the Team members is a lawyer. The Model Agreement (at Annex 5) is no more than a first draft, prepared by combining elements from purchase agreements currently in use by U.S. utilities with active programs for purchasing cogeneration and small power.

Before a Thai cogeneration program is launched, this draft agreement should be reviewed thoroughly for conformity with legal practices and other conditions in Thailand. Moreover, given how dynamic the PURPA industry has proven to be in the U.S., it is entirely possible that important new provisions may be developed and utilized in the U.S. in the near future, and might usefully by adapted and incorporated. Finally, it is almost certain to be the case that in any informed negotiation between prospective cogenerators and EGAT or other power purchasers, substantial modifications to this draft will be introduced, and trade-offs will be made.

3.4 Pro Forma Financial Model

The modelling format shown at Annex 6 is a simplified version of what will eventually be needed by NEPO to evaluate project financial returns from the viewpoint of the developer, power costs at the bus bar, and proposed tariff structures. This format is specific to an individual project. Key assumptions are entered, and a solution is run whereby the costs of power and the returns to the project are calculated.

NONE OF THE INPUT DATA SHOWN AT ANNEX 6 SHOULD BE UNDERSTOOD TO BE AN ACCURATE REPRESENTATION OF A REAL PROJECT IN THAILAND. The values shown were simply samples, plugged in to give the basis for running the model.

The model should be developed further in several important respects:

- More elaborate subroutines should be introduced, particularly to represent the value of cogeneration steam for process applications;

- The input values should be modified to reflect the specific project being analyzed;

- The structural description of fuel procurement should be modified to reflect the project being analyzed;

- The fiscal regime is based on U.S. rates, and should be modified to the Thailand provisions;

- Financing assumptions will have to be revised, to reflect local market conditions;

- No consideration has been given to the issue of foreign exchange risk for the non-Thai investor, and possible insurance mechanisms to contain this risk.

3.5 Introduction of Larger-Scale IPPs

The Team provided to NEPO some observations on the introduction of larger-scale IPPs in Thailand. The administrative structure for IPPs (including regulations, model purchase agreements, economic evaluation framework and solicitation procedures) will be different from what is being put in place for cogeneration and small power.

The key considerations are as follows:

1. The RTG should not get "stuck" in a cogeneration/small power phase; work should commence promptly on the administrative structure for larger-scale IPPs;

2. In the first stage of an IPP program, joint ventures between the IPP developer and EGAT may appropriate; however, independently-developed and operated generating units (bona-fide IPPs) would in theory provide the most active degree of competition;

3. The RTG should make an effort to identify sooner rather than later the larger-scale projects envisaged by EGAT in PDP 88-02 which are suitable candidates for development in the IPP mode.

3.6 EGAT Power Development Plan ("PDP 88-02")

Annex 7 presents the Team's comments on PDP 88-02, as conveyed to NEPO. In summary, PDP 88-02 presents a dilemma to the RTG: shortages of electricity going into the 1990s, or unacceptably rapid buildup of public sector debt to finance capacity expansion. Under these circumstances, privatizing the financial burden of some of the required expansion becomes an important goal of public policy.

EGAT might accept the building and financing of such plants by developers. In the event EGAT retained operating control over the units however, this would make it more difficult to introduce competition, transparency and efficiency improvements in the operating sector of the bulk power supply industry.

3.7 Meetings with EGAT

The Team held four meetings with EGAT. During the first meeting, on February 9, the Team described the U.S. experience with cogeneration and small power projects. The focus was on a description of how these projects are integrated into the utility's system, and ways to structure the power purchase contract for reliable operation. Pricing approaches used in the U.S. for energy and capacity purchases were also described.

EGAT described its objectives for cogeneration and small power projects. These objectives emphasize the maximization of cogeneration efficiency and use of residue fuels. Other, collateral objectives, such as reducing debt load, optimizing cogeneration economics (as opposed solely to efficiency) or increasing near term capacity by use of fossil fuels in residue-fired generators, are not emphasized.

EGAT brought up many issues concerning private power, based on shortcomings reported from U.S. experience. The Team described some of the shortcomings of PURPA in its early implementation, and the solutions that were employed to solve these problems.

EGAT and NEPO officials discussed at some length the National Petroleum Corporation (NPC) cogeneration project; NPC is selling electricity to downstream users through EGAT with a 1% markup.

EGAT indicated that it had under study the issue of IPPs beyond cogeneration and residue projects. EGAT anticipates completing a draft policy statement for the NEPC by March 31.

In the course of the second meeting with EGAT on February 13, the Team described U.S. approaches in dealing with private power, some of which may be applicable for Thailand. The Team and EGAT discussed EGAT's concerns in detail. EGAT described the risk of reduced operating flexibility, reduced system reliability and adverse impact on EGAT's least cost plan. The Team described various ways by which U.S. utilities had addressed these issues.

Discussion then moved on to the various options for private development of an IPP:

- Developer builds, owns and operates (BOO);
- Developer builds, owns, operates and eventually transfers the plant to EGAT (BOOT);
- Developer builds, owns and leases the plant to EGAT, who operates (BOL).

EGAT expressed a decided preference for BOL, whereby it would maintain operating control over the generating unit.

The third meeting, held on February 14, involved discussions of tariff matters, level of capacity payments, examples of PURPA problems in the U.S., and the appropriate objectives for the cogeneration and residue power program. The Team provided EGAT with ten illustrative documents currently in use in the U.S., including power purchase contracts, solicitations for power supply, interconnection requirements and an interconnection study.

The fourth meeting, on February 16, the day after the NEPC decision on private power, focused primarily on IPP options. EGAT reiterated its preference for joint ventures combined with the BOL option, and continued to express reservations on the BOO and BOOT options.

Based on the meetings with EGAT, the Team offers the following observations:

1. EGAT is cautious in considering the introduction of IPPs, and has concerns about operating control on its system. Cogeneration and residue power projects in small applications may be more acceptable since their impact on the system would probably be much more limited.

2. Continued government oversight on policy objectives and implementation will be needed. There will be early implementation issues that will need arbitration. NEPO is probably in the best position to do this. NEPO will need to build its staff, and may find continued USAID assistance helpful.

3. EGAT will likely seek maximum control over the operation of IPPs through the BOL option. A joint venture/BOL arrangement may provide a bridge, for projects put into development or construction in the near future, say the next 12-18 months. Private investment may be forthcoming under this regime, needed capacity will not be delayed, and EGAT can maintain operating control.

4. As the framework and implementing tools for the larger-scale IPPs are put in place, it would then be appropriate to put increased emphasis on independent development and operations by IPPs, through the BOO or BOOT options.

SECTION 4

COMMENT

In the Team's judgment, considerable progress has been made towards the introduction of private power in Thailand through a phased approach involving at the outset a cogeneration and small power program, to be followed by a larger-scale IPP program. Some of the basic tools for the cogeneration program, subject to further refinement, have been provided:

- Carefully devised draft regulations, aimed at stimulating development of reliable capacity while safeguarding the interests of the Thai rate-payer;

- A model purchase agreement reflecting U.S. experience which can be used as a realistic point of departure for serious negotiations between EGAT and the cogenerator/small power producer;

- A first-cut modelling structure which gives NEPO the basis to arbitrate financial issues that will arise between EGAT and the cogenerator/small power producer.

Moreover, the process for implementation has been established through the proposal for the Technical Conference, accepted by the RTG. Through the Technical Conference, it may be feasible to identify some of the candidate hosts or sponsors for cogeneration and small power projects.

The issues of larger-scale IPP development are more difficult to address, and solutions more difficult to put in place. In practical terms, the cogeneration/small power program means taking out of EGAT's expansion plan and privatizing some of the planned annual additions. This may ultimately be acceptable to since it can be viewed as part of a special purpose program with its own conservation rationale (cogeneration efficiencies). Moreover, capacity additions through cogeneration/small power backstop EGAT's ambitious expansion plan, PDP 88-02.

On the other hand, implementing a larger-scale IPP program means carving some discrete projects out of PDP 88-02, and ear-marking these for private development, a more ambitious and far-reaching change than merely introducing a cogeneration/small power program.

The Team concludes that it is important to maintain the momentum achieved on behalf of the introduction of private power in Thailand. Private power on the PURPA model, as it is now

evolving in the U.S. from cogeneration to IPPs, is a ten year learning experience - successes and failures - some of it relevant to the policy issues confronting the RTG going into the 1990s.

Important elements within the RGT have responded positively and energetically to the private power option, to the point of moving expeditiously with specific steps for implementation - namely the Technical Conference on cogeneration and small power.

Some of the implementing tools for the cogeneration program have been made available to the RTG. These tools - the regulations, the model agreement and the financial evaluation structure - must be refined further, since they will be the underpinning of a program which may eventually contribute significantly to Thailand's future generating capacity expansion needs.

Beyond the cogeneration program, as noted above the Team believes it is important to set in motion the development of the corresponding tools for follow on larger-scale IPP program. The launching of a vigorous private power program in Thailand, cogeneration/small power and larger-scale IPPs, could then progress rapidly, and serve as the model for other power generation privatization efforts in Southeast Asia.

As a concluding comment, the Team wishes to emphasize the excellent cooperation obtained from USAID/Thailand, and to underscore its view that an important ingredient in the Team's ability to work closely with the RTG - including NEPO, EGAT and NESDB - was the RTG's evident regard for, and confidence in, USAID/Thailand.

APPENDIX A

EGAT POWER DEVELOPMENT PLAN (PDP 88-02)

EGAT POWER DEVELOPMENT PLAN
(1988-2001)
(BASED ON JULY 1988 LOAD FORECAST)

VOLUME 1 : MAIN REPORT

PREPARED BY
ELECTRICITY GENERATING AUTHORITY OF THAILAND
SYSTEMS PLANNING DEPARTMENT
AUGUST 1988

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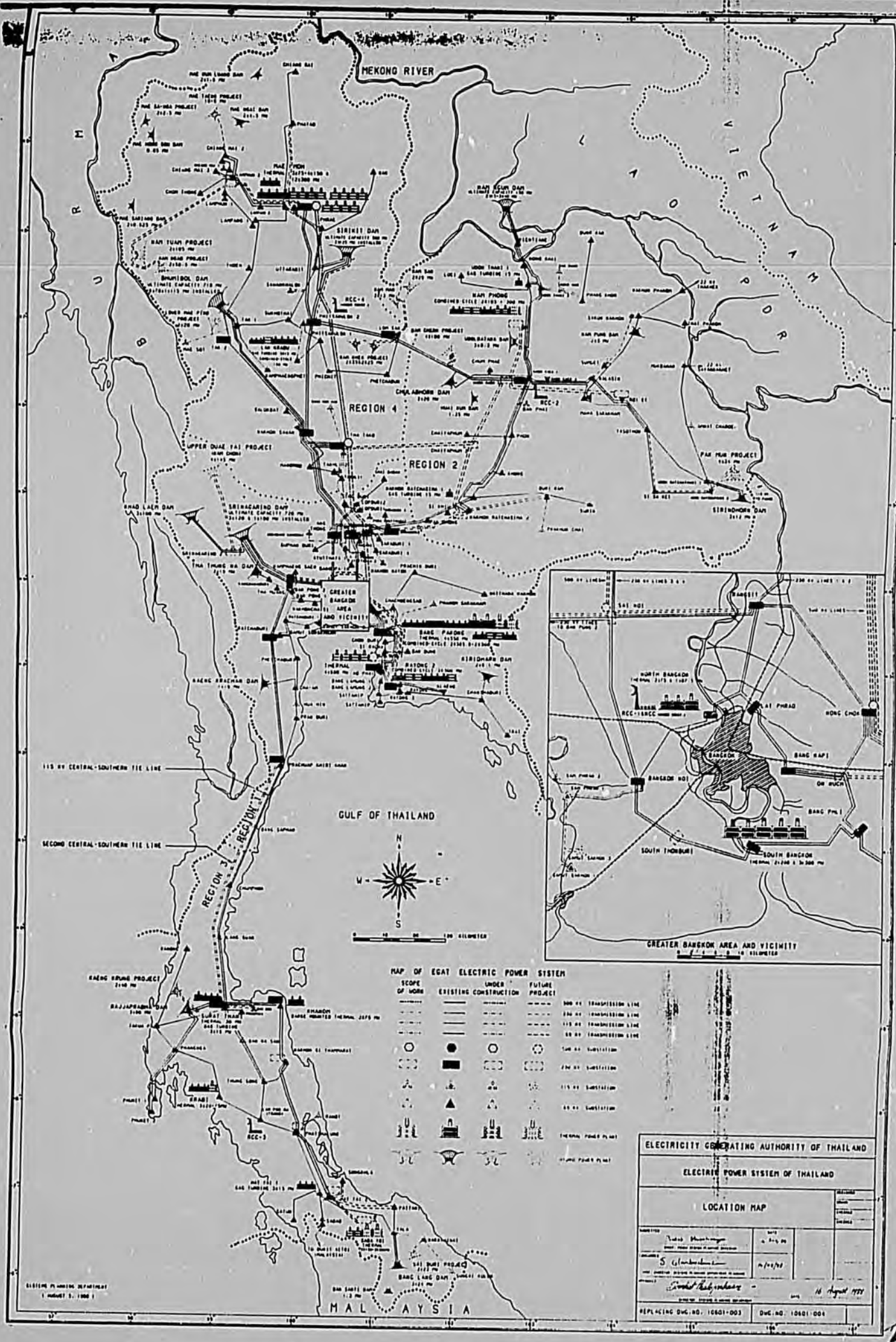
MEKONG RIVER
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1. INTRODUCTION

The former EGAT Power Development Plan (PDP 87-02), Report No. 10600-3004 dated November 1987 was submitted to the Government in December 1987 and approved by the National Energy Policy Committee on March 9, 1988. Also on April 5, 1988 the decision was made by the Government to shelve Nam Chon hydroelectric project.

In that PDP, the Working Group's October 1987 load forecast was used as a base in formulating the least-cost plan. The recommended PDP included 28 new projects to be implemented in the Sixth National Economic and Social Development Plan (NESDP). Four out of 28 projects were classified as urgent projects to prevent power shortage that would be encountered in mid 1990.

Since the favourable economic situation for Thailand in 1987 appears to continue in 1988, and the actual peak demand growth rate has risen to 13.4 percent on May 25,1988 and expected to be 15 percent by FY 1988, the Load Forecast Working Group urgently prepared a new load forecast which is called July 1988 Forecast.

To perform a revised PDP study, data and information used in the formulation were also revised and they were agreed upon by EGAT, NESDB, NEPO and PTT at the executive level meeting on June 29, 1988.

The new EGAT Power Development Plan (PDP 88-02), Report No. 10600-3106, dated August 1988 is the revised version which superseded the PDP proposed in PDP 87-02, Report No. 10600-3004, dated November 1987. The cause of revision was mainly due to the adoption of new official load forecast which was approved in July 1988.

The revision of EGAT PDP included the updating of data and information on : (1) the change in natural gas supply and demand, (2) the change in fuel prices, (3) the new candidate projects, (4) the projects cost and implementation schedule, and (5) the adoption of Base Case load forecast for a recommended PDP study and Low Case load forecast for a sensitivity analysis.

Formulation of the PDP 88-02 has been based on the same principle as used before. The optimization spans for the 14-year study horizon which will cover the 6th, 7th,and the 8th NESDP,and using the minimum reserve margin of 15 percent.

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2. SUMMARY AND RECOMMENDATION

2.1 As of July 1988, EGAT installed capacity is 6,894.2 MW of which 2,250.1 MW is hydropower; 3,607.5 MW is oil/gas and lignite-fired thermal; 771.6 MW is from combined cycle and 265.0 MW is of gas turbine plant. The length of transmission lines at 500, 230, 115 and 69 kV are 326, 6,122, 9,473 and 642 circuit-km respectively. The total number of high voltage substations is 151; comprising 31 of 230 kV, 110 of 115 kV and 10 of 69 kV. The total installed transformer capacity, excluding station service and generator unit transformers, is 13,054 MVA.

2.2 At present there are 8 power plant projects under construction/ implementation, with total capacity of 2,355 MW, i.e.,

Power Plant Projects	Rating (MW)	Commissioning Date
A) Project in the Fifth Plan		
1) Khanom Second Power Plant Barge	75	February 1989
2) Mae Moh Lignite-Fired Unit 8	300	July 1989
3) Mae Moh Lignite-Fired Unit 9	300	December 1990
B) Projects in the Sixth Plan		
4) Srinagarind Unit 5	180	April 1991
5) Bang Pakong Combined Cycle Block 3	300	Jun 1990-Jun 1991
6) Bang Pakong Combined Cycle Block 4	300	Aug 1990-Aug 1991
7) Mae Moh Lignite-Fired Unit 10	300	February 1992
8) Bang Pakong Thermal Unit 3	600	May 1992
Total Capacity of Power Plants Under Construction/Implementation	2,355	

2.3 It is estimated that there will be shortage of firm power during 1989-1990 period where the reserve margin of EGAT's generating system will be as low as 4.56% in May 1989 and -1.39% in May 1990. This will be the unacceptable situations. The Energy Policy Subcommittee has set up a working group to determine appropriate measures to cope with the situations. EGAT has also recommended the followings : (1) the reduction of electricity utilizations in EGAT's power plants and substations, (2) requesting the cooperation in the efficient use of electricity, reduction in the use of electricity especially the air-conditioners during peak load period, and requesting industries to adjust the production period to reduce

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the peak demand, (3) introduction of the time-of-day (TOD) metering rate to give incentive for the use of electric energy during the off-peak hours, and to persuate the industries to use standby power during peak hours if necessary, (4) enforcement measures that may be applied in the unavoided situations such as the shutdown of advertising electric signs, reduction in the use of street lighting, shifting the business hours of various services, night clubs, shutdown of T.V. broadcasting during the peak hours, reduction of system voltages and shutdown of electricity services for certain areas.

Besides the above mentioned measures, for the generation side EGAT has to accelerate the implementation of serveral projects, adjust the generation plan and maintenance scheduling, and may have to overload the generating units as far as possible to get additional capacity. These measures are necessary to help alleviate the short-term power shortage problems but can not be adopted for the long-term development. Together with several measures, the importation of electricity from Lao PDR (Nam Ngum hydro) will be maintained. For the case of power system interconnection with Malaysia, the power exchange is generally bi-directional but it is considered that the amount of power import from Malaysia will also be increased from 30 MW to the level of 60-80 MW.

As far as the above measures are concerned, cooperation from the end-users and various organizations are of utmost importance. The fast growing economy of Thailand at the present time encourages the use of electricity for residential, commercial, and industrial purposes. The demand management and other measures may proof to be valuable in the medium to long-term but still subject to further studies including how and when it is going to be applied in the future.

2.4 There were 28 projects included in the EGAT's Sixth Five-Year Plan (PDP 87-02) which were submitted and approved by the NEPC on March 9, 1988. Based on the new load forecast (Base Case-July 1988), the generation requirement will be 959 and 1,864 MW higher than the provious forecast by the years 1991 and 1996 respectively. The power shortage situations will occur if appropriate measures are not taken into serious consideration. EGAT has to revise the PDP by : (1) accelerate the implementation schedule of the already approved generation and transmission projects, (2) delay the

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uncertain projects including the power plant renovation, and postpone the retirement schedule of some power plants, and (3) provide additional generating capacity from new power plant projects. Table 2-2 shows the revised PDP (88-02) as compared to the previous PDP (87-02).

2.5 The additional generating capacity based on installed or nameplate rating of power plants upto the year 2001 is 11,910 MW but the power plants retirement will reduce the total system capacity by 435 MW.

2.6 Power generation projects consist of three categories: (1) urgent projects, (2) power plant renovation projects, and (3) various generation projects. These are summarized as follows :

(1) Urgent Projects

Thermal Power Plants				
Bang Pakong Combined Cycle Blocks 3-4[a]	2x300	=	600	MW
New Combined Cycle Blocks 1-3	3x300	=	900	MW
Mae Moh Lignite-Fired Units 10-11[b]	2x300	=	600	MW
Bang Pakong Thermal Units 3-4[c]	2x600	=	1,200	MW
Krabi Unit 4[d]	1x75	=	75	MW
Nam Phong Combined Cycle Blocks 1-2	2x105	=	210	MW
Subtotal		=	3,585	MW
Hydroelectric Plants				
Srinagarind Unit 5[e]	1x180	=	180	MW
Pak Mun Units 1-4[d]	4x34	=	136	MW
Kaeng Krung Units 1-2[d]	2x40	=	80	MW
Subtotal		=	396	MW
Transmission Systems				
230 kV Khon Kaen 3- Roi Et[f]				
230 kV Tha Tako-Khon Kaen 3[f]				
Accelerated Transmission Project (ATP)[d]				

Notes: a/ Tendering period.
b/ Letter of intent issued for Mae Moh#10. Mae Moh #11 is optional.
c/ Letter of intent issued for Bang Pakong #3. Bang Pakong #4 is optional.
d/ Project submitted to NESDB.
e/ Letter of intent issued.
f/ Projects approved.

(2) Power Plant Renovation Projects

Bhumibol Units 1-2f/	2x70	=	(140)	MW
North Bangkok Units 1-3	2x75+1x87.5	=	(237)	MW
South Bangkok Units 1-5	2x200+3x300	=	(1,300)	MW
	Subtotal	=	(1,677)	MW

(3) Other Projects

(A) Thermal Power Plants

Lan Krabu Combined Cycle (Steam Turbine)	1x50	=	50	MW
Mae Moh Lignite-Fired Units 12-19	8x300	=	2,400	MW
Saba Yoi Lignite-Fired Units 1-4	2x150+2x300	=	900	MW
New Thermal Units 1-5	5x600	=	3,000	MW
	Subtotal	=	6,350	MW

(B) Hydroelectric Plants

Mae Taeng Units 1-2	18+8	=	26	MW
Bhumibol Unit 8	1x178	=	178	MW
Sirikit Unit 4 and Lower Sirikit Unit 1	125+15	=	140	MW
Lower Mae Ping Units 1-2	2x20	=	40	MW
Nam Khek (1) and (2)	2x25+2x35	=	120	MW
Nam Chern Units 1-4	4x100	=	400	MW
	Subtotal	=	904	MW
Total Additional Generating Capacity		=	11,235	MW

Table 2-3 and Figure 2-1 show the list of projects and the installation schedule respectively.

2.7 EGAT's Sixth Five-Year Investment Plant (1987-1991) corresponding to the Sixth NESDP of the Government can be summarized as follows:

2.7.1 The total capital expenditure in the period 1987-1991 amounts to ฿ 100,000 million. Of this, the foreign currency requirement is ฿ 53,000 million (approximately US.$ 2.04 billion), and the local currency portion is ฿ 47,000 million.

Note : f/ Project approved.

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2.7.2 Projects in the Sixth Plan are classified into three categories: (i) Projects in the Fifth Plan to be commissioned in the Sixth Plan period, (ii) Projects in the Sixth Plan and commissioned in the Sixth Plan period, (iii) Projects in the Sixth Plan but will be commissioned in the Seventh Plan period.

2.7.3 There are 11 projects in the Fifth Plan that will be completed in the Sixth Plan period. These are committed projects which are already under construction. The capital expenditures for these projects amount to ฿ 18,474.7 million. Details are given in Section 11.2.

2.7.4 There are 11 projects in the Sixth Plan that will be commissioned in the Sixth Plan period. These consist of 1 hydro project, 5 thermal power plant projects, 1 mining project, 3 transmission projects and 1 miscellaneous transmission system expansion and construction work. Of these, 1 hydro project, 2 thermal projects, 1 mining project and 3 transmission projects have already been approved, and now under implementation stage. Total capital expenditure amounts to ฿ 35,948.2 million (foreign currency is equivalent to ฿ 17,349.0 million). Details are given in Section 11.3. The projects are listed as follows :

Projects	Project Approval
1) Srinagarind Unit 5 (180 MW)	Approved
2) Bang Pakong Combined Cycle Block 3 (300 MW)	Approved
3) Bang Pakong Combined Cycle Block 4 (300 MW)	Approved
4) New Combined Cycle Block 1 (300 MW)	-
5) New Combined Cycle Block 2 (300 MW)	-
6) Lan Krabu Combined Cycle (Steam Turbine-50 MW)	-
*7) Mae Moh Mine Expansion (Stage 1) for Mae Moh Units 8-9	Approved
*8) Second Central-Southern Tie Line	Approved
*9) Transmission System Expansion No.7	Approved
10) 230 kV Khon Kaen 3-Roi Et Transmission Line	Approved
11) Miscellaneous Transmission System Expansion and Construction Work	-

Note : * These projects were submitted in the Fifth plan period.

2.7.5 There are 25 projects in the Sixth Plan that will be commissioned in the Seventh Plan period. These consist of 4 hydro projects, 10 thermal power plant projects, 5 mining projects, and 6 transmission projects. Total capital expenditure amounts to ฿ 45,577.1 million (foreign currency is ฿ 24,310.6 million). Details are given in Section 11.4. The projects are listed as follows :

1) Bhumibol Hydro Plant Renovation
2) Pak Mun Units 1-4 (4x34 MW)
3) Kaeng Krung Units 1-2 (2x40 MW)
4) Bhumibol Unit 8 (178 MW)
5) Nam Phong Combined Cycle Blocks 1 and 2 (2x105 MW)
6) New Combined Cycle Block 3 (300 MW)
7) Mae Moh Unit 10 (300 MW)
8) Bang Pakong Thermal Unit 3 (600 MW)
9) Krabi Unit 4 (75 MW)
10) Mae Moh Unit 11 (300 MW)
11) Bang Pakong Thermal Unit 4 (600 MW)
12) Mae Moh Unit 12 (300 MW)
13) Mae Moh Unit 13 (300 MW)
14) Mae Moh Unit 14 (300 MW)
15) Mae Moh Mine Expansion for Mae Moh Unit 10
16) Mae Moh Mine Expansion for Mae Moh Unit 11
17) Mae Moh Mine Expansion for Mae Moh Unit 12
18) Krabi Mine Expansion for Krabi Unit 4
19) Saba Yoi Mine Development for Saba Yoi Units 1,2
20) EHV Transmission System for Mae Moh Unit 10
21) Accelerated Transmission Project (ATP)
22) 230 kV Tha Tako-Khon Kaen 3 Transmission Line
23) EHV Transmission System for Mae Moh Unit 11
24) Transmission System Expansion No.8 (TS 8)
25) EHV Transmission System for Mae Moh Unit 12

2.7.6 In summary, there are 33 projects that require capital expenditures in the period of the Sixth NESDP. The list of projects is given in Table 2-1.

TABLE 2-1

LIST OF PROJECTS IN THE SIXTH PLAN PERIOD

(1987-1991)

Name of Project	Capacity (MW)	Proposed Commissioning Date
Hydroelectric Projects		
1. Srinagarind Unit 5	1x180	April 1991
2. Bhumibol Hydro Plant Renovation	(2x70)	March 1992
3. Pak Mun Units 1-4	4x34	November 1993
4. Kaeng Krung Units 1-2	2x40	December 1993
*5. Bhumibol Unit 8	1x178	January 1996
Thermal Power Plant Projects		
1. Bang Pakong Combined Cycle Block 3	1x300	Jun 90 - Jun 91
2. Bang Pakong Combined Cycle Block 4	1x300	Aug 90 - Aug 91
*3. New Combined Cycle Block 1	1x300	Sep 90 - Sep 91
*4. New Combined Cycle Block 2	1x300	Oct 90 - Oct 91
5. Nam Phong Combined Cycle Blocks 1-2	2x105	Nov 90 - Dec 91
*6. New Combined Cycle Block 3	1x300	Jan 91 - Jan 92
*7. Lan Krabu Combined Cycle (Steam Turbine)	1x50	October 1991
8. Mae Moh Lignite Unit 10	1x300	February 1992
9. Bang Pakong Thermal Unit 3	1x600	May 1992
10. Krabi Unit 4	1x75	November 1992
11. Mae Moh Lignite Unit 11	1x300	February 1993
12. Bang Pakong Thermal Unit 4	1x600	May 1993
13. Mae Moh Lignite Unit 12	1x300	October 1993
14. Mae Moh Lignite Unit 13	1x300	April 1994
15. Mae Moh Lignite Unit 14	1x300	October 1994
Mining Projects		
1. Mae Moh Mine Expansion for Mae Moh Unit 10	-	February 1992
2. Krabi Mine Expansion for Krabi Unit 4	-	October 1992
3. Mae Moh Mine Expansion for Mae Moh Unit 11	-	February 1993
*4. Mae Moh Mine Expansion for Mae Moh Unit 12	-	October 1993
*5. Saba Yoi Mine Development for Saba Yoi Units 1-2	-	April 1996
Transmission Projects		
1. 230 kV Khon Kaen 3-Roi Et	-	January 1991
2. 230 kV Tha Tako-Khon Kaen 3	-	January 1992
3. EHV Transmission System for Mae Moh Unit 10	-	February 1992
4. Accelerated Transmission Project (ATP)	-	April 1992
5. EHV Transmission System for Mae Moh Unit 11	-	February 1993
6. Transmission System Expansion No.8	-	April 1993
7. EHV Transmission System for Mae Moh Unit 12	-	October 1993
Miscellaneous Transmission System Expansions and Construction Work	-	1987-1991

Note : Additional Projects.

TABLE 2-2
THE REVISED PDP COMPARED TO THE PREVIOUS PLAN

Project	Commissioning		Difference
	PDP 87-02 (November 1987)	PDP 88-02 (August 1988)	
1. Bang Pakong Combined Cycle Blocks 3-4 (2x300 MW)			
Gas Turbine Block 3	November 1990	June 1990	Advanced 5 months
Gas Turbine Block 4	February 1991	August 1990	Advanced 6 months
Steam Turbine Block 3	October 1991	June 1991	Advanced 4 months
Steam Turbine Block 4	January 1992	August 1991	Advanced 5 months
*2. New Combined Cycle Block 1 (300 MW)	-	Sep 90-Sep 91	Additional Project
*3. New Combined Cycle Block 2 (300 MW)	-	Oct 90-Oct 91	Additional Project
*4. New Combined Cycle Block 3 (300 MW)	-	Jan 91-Jan 92	Additional Project
5. Nam Phong Combined Cycle Blocks 1-2 (2x105 MW)			
Gas Turbine 4x35 MW	November 1989	November 1990	Delayed 12 months
Steam Turbine 2x35 MW	January 1991	December 1991	Delayed 11 months
6. Srinagarind #5 (180 MW)	April 1992	April 1991	Advanced 12 months
*7. Lan Krabu Combined Cycle (Steam Turbine-50 MW)	-	October 1991	Additional Project
8. Bhumibol Renovation #1-2 (2x70 MW)	January 1991	March 1992	Delayed 14 months
9. 230 kV Tha Tako-Khon Kaen	October 1992	January 1992	Advanced 9 months
10. Bang Pakong Thermal #3 (600 MW)	December 1992	May 1992	Advanced 7 months
11. Krabi #1,3 Retired	October 1990	October 1992	Delalyed 24 months
12. Mae Moh #11 (300 MW)	October 1993	February 1993	Advanced 8 months
13. Bang Pakong Thermal #4 (600 MW)	November 1995	May 1993	Advanced 30 months
14. Mae Moh #12 (300 MW)	April 1994	October 1993	Advanced 6 months
15. Mae Moh #13 (300 MW)	October 1994	April 1994	Advanced 6 months
16. Mae Moh #14 (300 MW)	April 1995	October 1994	Advanced 6 months
*17. Bhumibol #8 (178 MW)	-	January 1996	Additional Project
18. Accelerated Transmission Project	-	April 1992	1/

Note : 1/ Scope of the jobs are part of the Miscellaneous Tranmission System Expansion and Construction Work which have been taken for accelerated implementation.

TABLE 2-3

LIST OF PROJECTS IN PDP 88-02 (1988-2001) a/

(LONG TERM PROFILE)

	Power Plant	Fuel Type	Unit Number	Rating (MW)	Total (MW)	Commissioning Date
Under Construction	Khanom 2nd PPB	Oil/Gas	2	75	75	February 1989
	Mae Moh	Lignite	8	300	300	July 1989
	2nd CSTL	-	-	(270)	(270)	February 1990
	Mae Moh	Lignite	9	300	300	December 1990
	Srinagarind	Hydro	5	180	180	April 1991
	Bang Pakong CC	Gas	3	300	300	Jun 90 - Jun 91
	Bang Pakong CC	Gas	4	300	300	Aug 90 - Aug 91
	Mae Moh	Lignite	10	300	300	February 1992
	Bang Pakong Thermal	Oil/Gas	3	600	600	May 1992
	New Combined Cycle	Gas	1	300	300	Sep 90 - Sep 91
	New Combined Cycle	Gas	2	300	300	Oct 90 - Oct 91
	Nam Phong CC	Gas	1-2	105	210	Nov 90 - Dec 91
	New Combined Cycle	Gas	3	300	300	Jan 91 - Jan 92
	Lan Krabu CC (ST)	-	1	50	50	October 1991
	230 KV Tha Tako-Khon Kaen 3	-	-	(300)	(300)	January 1992
	Bhumibol Renovation	Hydro	1-2	(70)	(140) b/	March 1992
	Krabi	Lignite	4	75	75	November 1992
	Mae Moh	Lignite	11	300	300	February 1993
	Bang Pakong Thermal	Oil/Gas	4	600	600	May 1993
	North Bangkok Renovation	Oil	1-3	(2x75+87.5)	(237.5)	August 1993
	Mae Moh	Lignite	12	300	300	October 1993
	Pak Mun	Hydro	1-4	34	136	November 1993
	Kaeng Krung	Hydro	1-2	40	80	December 1993
	Mae Moh	Lignite	13	300	300	April 1994
	Mae Moh	Lignite	14	300	300	October 1994
	Mae Moh	Lignite	15	300	300	April 1995
	Mae Taeng	Hydro	1-2	18+8	26	June 1995
	Saba Yoi	Lignite	1	150	150	October 1995
	Mae Moh	Lignite	16	300	300	November 1995
	South Bangkok Renovation	Oil/Gas	1-5	(2x200+3x300)	(1,300)	December 1995
	Bhumibol	Hydro	8	178	178	January 1996
	Sirikit	Hydro	4	125	125	February 1996
	Lower Sirikit	Hydro	1	15	15	February 1996
	Saba Yoi	Lignite	2	150	150	April 1996
	Saba Yoi	Lignite	3	300	300	October 1996
	Mae Moh	Lignite	17	300	300	November 1996
	Mae Moh	Lignite	18	300	300	April 1997
	New Thermal	Coal	1	600	600	October 1997
	Mae Moh	Lignite	19	300	300	November 1997
	Lower Mae Ping	Hydro	1-2	20	40	July 1998
	New Thermal	Coal	2	600	600	October 1998
	Saba Yoi	Lignite	4	300	300	November 1998
	Nam Khek (1)	Hydro	1-2	25	50	January 1999
	Nam Khek (2)	Hydro	1-2	35	70	February 1999
	New Thermal	Coal	3	600	600	October 1999
	Nam Chern	Hydro	1-4	100	400	November 1999
	New Thermal	Coal	4	600	600	October 2000
	New Thermal	Coal	5	600	600	January 2001

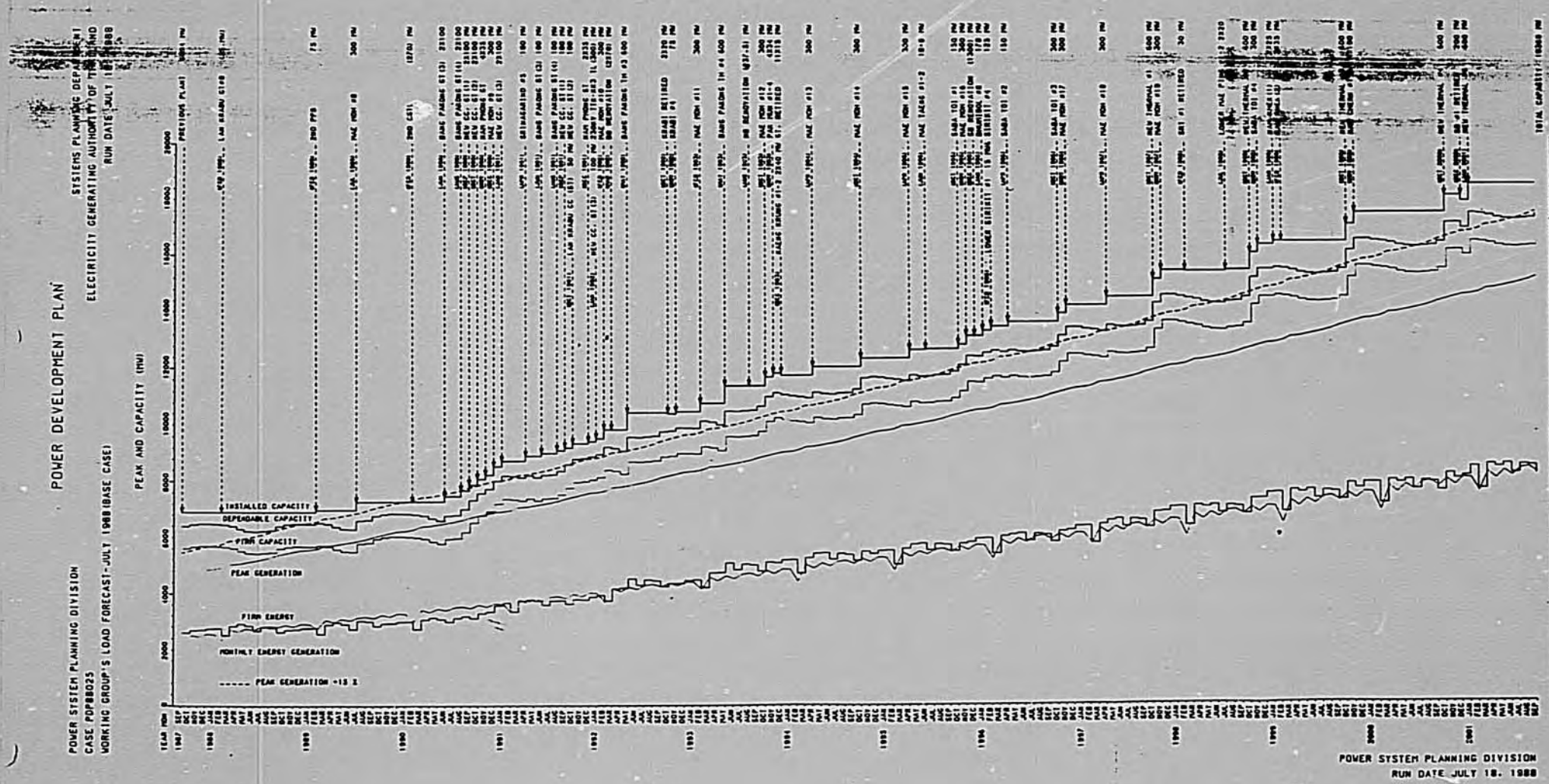
Existing Capacity by 1988	=	6,894.2	MW
Total Added Capacity (Up to 2001)	=	11,910.0	MW
Plant Retirement	=	435.0	MW
Total Capacity by Year 2001	=	18,369.2	MW

Notes : a/ This list is only for generation projects and inter-regional transmission projects.

b/ Rating after renovation is expected to be 2x75.4 or 150.8 MW.

EGAT POWER DEVELOPMENT PLAN (88-02)

FIGURE 2-1



3. FUNCTION AND RESPONSIBILITY OF EGAT

The Electricity Generating Authority of Thailand (EGAT) was formed in May 1969, pursuant to the Electricity Generating Authority of Thailand Act, B.E. 2511 (EGAT Act 1968), to rationalize and consolidate the functions and responsibilities of three independent state enterprises namely the Yanhee Electricity Authority (YEA), the Lignite Authority (LA) and the Northeast Electricity Authority (NEEA). Each of these enterprises was responsible for supplying electricity in the area specifically designated to it. The areas under the responsibility of YEA were in the North and Central Region, while those of LA were in the far North and the South, and the area in the Northeast fell under the responsibility of NEEA. Such territorial division for the enterprises was primarily dictated by geographical consideration, in spite of their similar operational functions; therefore, the Government finally decided to consolidate the entities of the three organizations into one so that the effectiveness of better performance and higher efficiency could be achieved.

EGAT has been entrusted to carry out the following objectives :

- To generate, acquire, transmit or distribute electric energy to: The Metropolitan Electricity Authority (MEA),the Provincial Electricity Authority (PEA), other electricity distribution authorities as prescribed, consumers directed by the Royal Decree, and neighbouring countries.

- To undertake the activities related to the production of electric energy such as developing energy sources from natural resources which could possibly be water, wind, natural heat, sunlight, oil, coal, oil shale, natural gas etc., including the nuclear power sources; other activities that will promote the objectives of EGAT are also undertaken.

- To carry out, individually or jointly with other bodies, the production and sale of lignite or lignite by-product.

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The Government of Thailand has entrusted EGAT with the following responsibilities:

- To construct and operate dams, reservoirs and other equipment in connection with electric power generation. The development of water resources for the purpose of power generation is also a responsible duty.

- To construct thermal, hydro, nuclear and other types of power plant.

- To improve and expand substation and transmission system including associated equipment for electric power transmission and distribution.

- To specify the standards, type and size of substations, transmission systems, power plants, lignite chemical plants and fuel for power production as well as associated equipment.

- To formulate policy in connection with the production and sales of electricity, lignite and lignite by-product.

The main policy which EGAT has consistently adhered to is to ensure that sufficient power is constantly available, the service is reliable, and the power is sold at the lowest possible rate. The achievement of this three-fold objective is complex and costly and not as simple as the general public seems to believe. The reliability of power supply has been in constant improvement, up until now, the standards of service and achievement are highly satisfactory.

EGAT sells bulk supply of electric power to the following entities:

1. The Metropolitan Electricity Authority (MEA) - The distributor of electric energy in the greater Bangkok area, Nonthaburi and Samut Prakan provinces.

2. The Provincial Electricity Authority (PEA) - The distributor of electric energy to all provinces except those in the MEA's area.

3. Industrial plants and other electricity consumers (EGAT's Direct Customers) - These are large-scale or specialized users prescribed by the 1969 Royal Decree Covering Power Users. At present EGAT's Direct Customers are :

Name of Direct Customers	Location/Province
1. Jalaprathan Cement Co., Ltd	Nakhon Sawan
2. Siam Cement Co., Ltd.	Saraburi
3. Siam Cement Co., Ltd.	Nakhon Si Thammarat
4. Sattahip Naval Station	Chonburi
5. Siam Iron and Steel Co., Ltd	Saraburi
6. VOA Broadcasting Station	Ayutthaya
7. Electricite Du Laos (EDL)	Nakhon Phanom and Mukdahan 1/
8. Padaeng Industry Co., Ltd.	Tak
9. Esso Standard Thailand Limited	Chonburi
10. Thai Oil Refinery Co., Ltd.	Chonburi

EGAT also purchases surplus energy from Nam Ngum Dam in Lao PDR, and the power exchange with Malaysia at Sadao has been in service since February 1, 1981.

Note : 1/ Supply power to Thakhek and Savannakhet in Lao PDR via 22 kV submarine cables.

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4. PRESENT FACILITIES

EGAT has been entrusted to generate and transmit electric power throughout Thailand. In order to accomplish this responsibility, the system of generating stations, transmission lines and substations have been extensively developed during the past 20 years. The following sections describe EGAT system that exists up to July 1988.

4.1 Generating Stations

As of July 1988, EGAT installed capacity is 6,894.2 MW, of which 2,250.1 MW is from hydro, 3,607.5 MW from oil/gas and lignite-fired thermal, 771.6 MW from combined cycle and 265.0 MW from gas turbine power plants. Table 4-1 shows detailed breakdown of the present installed capacity.

Figure 1 depicts the map of EGAT power system, in which the four regions1/ are illustrated. Each of the regions is presently interconnected through either 230 kV or 115 kV transmission lines.

The base load generation in Region 1 is mainly provided by the South Bangkok and Bang Pakong oil/gas-fired thermal plants and supplemented by Bang Pakong combined cycle power plants as an intermediate load plant while that in Region 4 is provided by lignite-fired power plants at Mae Moh. For peaking generation, capacities are obtained from Bhumibol, Sirikit, Srinagarind, Kang Krachan, Khao Laem and Tha Thung Na hydroelectric plants.

The power supply for base load in Region 2, the Northeast, is mainly obtained from the interconnection with Region 4 through a 230 kV tie line and a 115 kV tie line for interconnection with Region 1. Hydroelectric and gas turbine generations are used for peak load support. A part of the energy needed for this region has been supplemented by the purchase of surplus energy from Nam Ngum Dam in Lao PDR.

Note : 1/ Region 1: Greater Bangkok and 23 surrounding provinces.
Region 2: 17 provinces in the Northeast.
Region 3: 14 provinces in the South.
Region 4: 18 provinces in the North and the upper part of Central area.

The base load generation in Region 3, the South, is provided by the barge-mounted thermal power plant at Khanom, lignite-fired power plant at Krabi and oil-fired power plant at Surat Thani. The base load energy is obtained from the 115 kV Central-Southern tie line (1st CSTL) which has been in operation since August 1980. Peaking power are provided by Bang Lang and Rajjaprabha (Chiew Larn) hydroelectric plants and gas turbines. The power system in Region 3 is also interconnected with its neighbouring system in Malaysia via the 132 kV interconnector, through which part of Region 3 load during the peak period can be supplemented by the power import from Malaysia whenever it is considered necessary.

4.2 Transmission Lines and Substations

The standard voltages for power transmission in EGAT system are 500, 230, 115 and 69 kV at the frequency of 50 Hertz. Table 4-2 shows the installed transmission lines and substations as of July 1988. Figure 4-1 illustrates the total transmission line length classified by voltage levels over the period 1960-1995. As of July 1988, the circuit-km of EGAT transmission system are : 326 circuit-km of 500 kV1/, 6,122 circuit-km of 230 kV, 9,473 circuit-km of 115 kV and 642 circuit-km of 69 kV lines. For high voltage substation, there are thirty-one 230 kV, one-hundred and ten 115 kV and ten 69 kV, totalling 151 substations. The total installed transformer capacity, excluding station service and generator unit transformers, is 13,054 MVA.

Note : 1/ Presently energized at 230 kV and expected to be operated at 500 kV by 1989.

TABLE 4-1
EGAT EXISTING INSTALLED GENERATING CAPACITY
AS OF JULY 1988

Plant Type	Number of Units	Capacity (MW) Installed	Capacity (MW) Ultimate	Average Energy Capability (GWh/yr)
A. Hydroelectric Plant				
Bhumibol	7	535.0	710.0	1,200.0
Sirikit	3	375.0	500.0	1,000.0
Ubolratana	3	25.0	25.0	56.0
Sirindhorn	3	36.0	36.0	86.0
Chulabhorn	2	40.0	40.0	95.0
Kang Krachan	1	19.0	19.0	78.0
Nam Pung	2	6.0	6.0	15.0
Srinagarind	4	540.0	720.0	1,140.0
Bang Lang	3	72.0	72.0	200.0
Tha Thung Na	2	38.0	38.0	165.0
Khao Laem	3	300.0	300.0	760.0
Huai Kum	1	1.3	1.3	2.0
Ban Yang	3	0.12	0.12	0.3
Ban Santi	1	1.3	1.3	6.0
Ban Chong Klum	1	0.02	0.02	0.2
Ban Khun Klang	2	0.18	0.18	0.7
Mae Ngat	2	9.0	9.0	29.0
Huai Saphan Hin	2	12.2	12.2	27.0
Rajjaprabha	3	240.00	240.00	550.0
Total	48	2,250.12	2,730.12	5,410.2
B. Thermal Power Plant				
North Bangkok	3	237.5		1,250.0
South Bangkok	5	1,300.0		9,110.0
Mae Moh	7	825.0		5,420.0
Krabi	2	40.0		200.0
Surat Thani	1	30.0		210.0
Khanom PPB	1	75.0		525.0
Bang Pakong Thermal	2	1,100.0		7,710.0
Total	21	3,607.5		24,425.0
C. Combined Cycle Power Plant				
Bang Pakong Combined-Cycle Blocks 1 & 2	10	771.6		4,055.0
Total	10	771.6		4,055.0
D. Gas Turbine				
Nakhon Ratchasima	1	15.0		33.0
Udon Thani	1	15.0		33.0
Hat Yai	3	45.0		99.0
Surat Thani	3	45.0		99.0
Lan Krabu	7	145.0		888.0
Total	15	265.0		1,152.0
GRAND TOTAL	94	6,894.22		35,042.2

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TABLE 4-2
INSTALLED TRANSMISSION LINES AND SUBSTATIONS
AS OF JULY 1988

Region and System Voltage	Substations		Transmission Lines (Circuit - Kilometers)		
	Number	Transformer[a] Capacity (MVA)	Double-Circuit	Single-Circuit	Total
Region 1					
230 kV	19	6,060	2,750	18	2,768
115 kV	41	2,269	641	1,437	2,078
69 kV	1	40	-	128	128
Total	61	8,369	3,391	1,583	4,974
Region 2					
230 kV	1	400	290	-	290
115 kV	28	1,057	1,711	1,686	3,397
69 kV	4	47	-	327	327
Total	33	1,504	2,001	2,013	4,014
Region 3					
230 kV	3	400	806[b]	-	806
115 kV	21	976	1,149	1,137[c]	2,286
Total	24	1,376	1,955	1,137	3,092
Region 4					
500 kV	-	-	-	326[d]	326
230 kV	8	750	2,040	218	2,258
115 kV	20	930	640	1,072	1,712
69 kV	5	125	-	187	187
Total	33	1,805	2,680	1,803	4,483
All Regions					
500 kV	-	-	-	326	326
230 kV	31	7,610	5,886	236	6,122
115 kV	110	5,232	4,141	5,332	9,473
69 kV	10	212	-	642	642
Total EGAT	151	13,054	10,027	6,536	16,563

Notes : a/ Station service and generator unit transformers are excluded.
b/ Initially energized at 115 kV.
c/ Including 9 circuit-km of 132 kV transmission line.
d/ Presently energized at 230 kV.

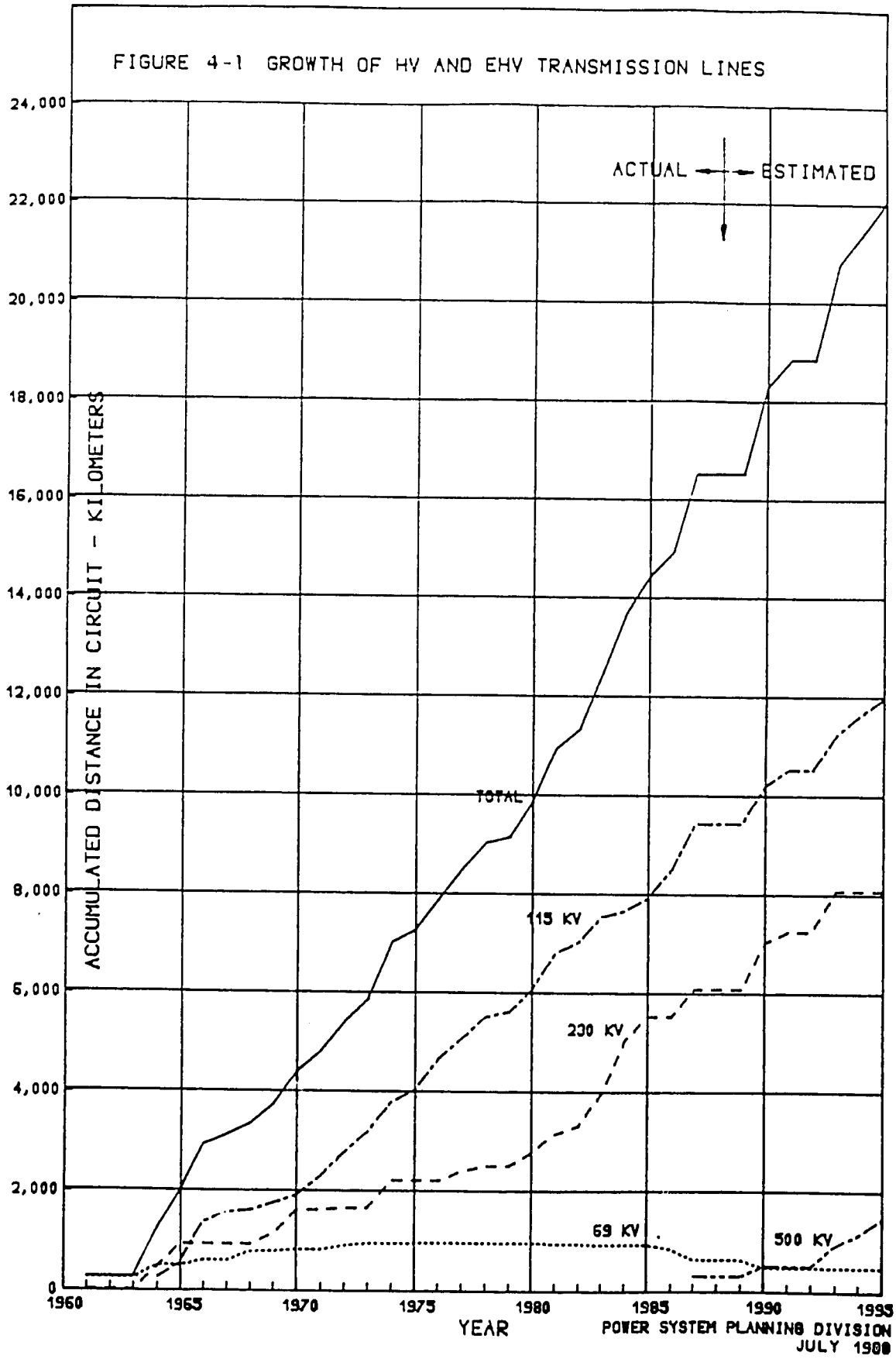
FIGURE 4-1 GROWTH OF HV AND EHV TRANSMISSION LINES
ACTUAL
ESTIMATED
ACCUMULATED DISTANCE IN CIRCUIT - KILOMETERS
24,000
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
TOTAL
115 KV
230 KV
69 KV
500 KV
1960
1965
1970
1975
1980
1985
1990
1995
YEAR
POWER SYSTEM PLANNING DIVISION
JULY 1988

5. LOAD FORECAST FOR EGAT SYSTEM

The peak generation of EGAT as recorded in 1987 was 4,733.9 MW and 28,193.2 GWh, representing 13.2% and 13.8% growth in power and energy over 1986. The high growth rate in 1987 resulted from the economic recovery of the country. The production of manufacturing industries has been activated due to the favorable economic situation, the lower oil price, lower interest rate, etc. The 1987 Visit Thailand Year has also attributed to the high growth in electricity consumption.

The high economic growth rate continues in 1988. Since the beginning of this year, the peak generation of EGAT has increased so rapidly and the peak load on May 25, 1988 reached 5,370.1 MW. This new peak is already 273.1 MW more than the peak demand estimated by the Load Forecast Working Group[1]/of October 1987, and represents a 13.44% growth over the peak of 1987. The alarming growth in power demand has activated the Working Group to review and urgently prepared a new set of forecasts.

The new load forecast is called the July 1988 Working Group Load Forecast. It consists of two cases : the Base Case and the Low Case which have been based on different GDP scenarios. The Base Case load forecast was recommended to be used for the formulation of Thailand power sector investment program. The EGAT's PDP 88-02 is based on the Base Case load forecast, while the Alternative PDP (88-02 A) is based on the Low Case load forecast.

Table 5-1 shows the Working Group's Base Case Load Forecast-July 1988 which was used to formulate the Base Case PDP and Table 5-2 shows the forecast of EGAT total generation and classification of sales.

Notes: 1/ The official Load Forecast Working Group consists of the representatives from NESDB, NEPO, NEA, MEA, PEA, EGAT, and including some experts from TDRI and NIDA. This Working Group, appointed in January 1987, is chaired by the Deputy Secretary General of NESDB and a representative from NEPO is the secretary.

The Low Case 1988 Load Forecast is given in Appendix 7. The same appendix also shows the comparison of the October 1987 with the July 1988 load forecasts. The comparison shows that the new load forecast (Base Case) will be 959 MW and 1,864 MW higher than the October 1987 load forecast by the end of the 6th and 7th National Economic and Social Development Plan respectively.

same
1988
Base
load
cial

TABLE 5-1

TOTAL EGAT GENERATION REQUIREMENT
(Base Case Load Forecast)

Fiscal Year	Peak Generation		Energy Generation		Load Factor
	MW	% Increase	GWh	% Increase	%
		Actual			
1973	1,199.30	16.57	6,872.84	20.34	65.42
1974	1,256.30	4.75	7,258.72	5.61	65.96
1975	1,406.60	11.96	8,211.57	13.13	66.64
1976	1,652.10	17.45	9,414.48	14.64	65.05
1977	1,873.40	13.40	10,950.62	16.32	66.73
1978	2,100.60	12.13	12,371.67	12.98	67.23
1979	2,255.00	7.35	13,964.55	12.88	70.69
1980	2,417.40	7.20	14,753.73	5.65	69.67
1981	2,588.70	7.09	15,959.97	8.18	70.38
1982	2,838.00	9.63	16,881.95	5.78	67.91
1983	3,204.30	12.91	19,066.30	12.94	67.92
1984	3,547.30	10.70	21,066.44	10.49	67.79
1985	3,878.40	9.33	23,356.57	10.87	68.75
1986	4,180.90	7.80	24,779.53	6.09	67.66
1987	4,733.90	13.23	28,193.16	13.78	67.99
Average Growth Rate % 1977-1987	-	10.04	-	10.49	-
		Forecast			
1988	5,444.00	15.00	32,596.00	15.62	68.35
1989	6,098.00	12.01	36,584.00	12.23	68.49
1990	6,759.00	10.84	40,746.00	11.38	68.82
1991	7,440.00	10.08	45,062.00	10.59	69.14
1992	8,173.00	9.85	49,793.00	10.50	69.55
1993	8,867.00	8.49	54,240.00	8.93	69.83
1994	9,578.00	8.02	58,964.00	8.71	70.28
1995	10,304.00	7.58	63,924.00	8.41	70.82
1996	11,066.00	7.40	69,065.00	8.04	71.25
1997	11,816.00	6.78	74,016.00	7.17	71.51
1998	12,596.00	6.60	79,170.00	6.96	71.75
1999	13,414.00	6.49	84,666.00	6.94	72.05
2000	14,271.00	6.39	90,568.00	6.97	72.45
2001	15,112.00	5.89	96,373.00	6.41	72.80
Average Growth Rate %					
1987-1991	-	12.22	-	12.71	-
1992-1996	-	8.26	-	8.92	-
1997-2001	-	6.43	-	6.89	-

Reference : Working Group Load Forecast
July 1988

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TABLE 5-2
FORECAST OF EGAT GENERATION AND SALES

Fiscal Year	Total Generation		Total Sales		Classification of Sales					
	Power	Energy	Power	Energy	MEA		PEA		Direct Customers	
	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)	(MW)	(GWh)
1988	5,444.00	32,596.00	5,454.78	29,959.16	2,468.45	14,846.65	2,804.60	13,927.80	181.73	1,184.71
1989	6,098.00	36,584.00	6,128.30	33,749.29	2,751.36	16,561.18	3,177.70	15,885.40	199.24	1,302.71
1990	6,759.00	40,746.00	6,806.86	37,727.45	3,016.33	18,309.12	3,589.30	18,070.00	201.23	1,348.33
1991	7,440.00	45,062.00	7,515.55	41,724.25	3,290.84	19,982.96	4,022.50	20,387.40	202.21	1,353.89
1992	8,173.00	49,793.00	8,255.24	46,104.18	3,583.02	21,935.05	4,469.00	22,809.50	203.22	1,359.63
1993	8,867.00	54,240.00	8,956.41	50,222.58	3,890.36	23,865.75	4,861.80	24,991.30	204.25	1,365.53
1994	9,578.00	58,964.00	9,674.46	54,596.17	4,205.96	25,969.24	5,263.20	27,255.30	205.30	1,371.63
1995	10,304.00	63,924.00	10,408.45	59,189.08	4,525.95	28,195.34	5,676.10	29,615.80	206.40	1,377.94
1996	11,066.00	69,065.00	11,177.54	63,949.09	4,875.41	30,520.12	6,094.60	32,044.50	207.53	1,384.47
1997	11,816.00	74,016.00	11,935.42	68,532.98	5,242.84	32,782.43	6,483.90	34,359.30	208.68	1,391.24
1998	12,596.00	79,170.00	12,723.68	73,479.68	5,621.90	35,269.65	6,891.90	36,811.80	209.88	1,398.23
1999	13,414.00	84,666.00	13,549.58	78,686.13	6,026.06	37,906.96	7,312.40	39,373.70	211.12	1,405.46
2000	14,271.00	90,568.00	14,414.99	84,170.58	6,454.30	40,695.92	7,748.30	42,061.70	212.39	1,412.95
2001	15,112.00	96,373.00	15,264.49	89,586.50	6,888.21	43,498.40	8,162.56	44,667.41	213.71	1,420.69
Average Growth Rate (%)										
1987-1991	12.22	12.71	12.16	13.03	10.67	11.90	14.08	14.88	3.59	5.48
1992-1996	8.26	8.92	8.26	8.92	8.18	8.84	8.67	9.47	0.52	0.45
1997-2001	6.43	6.89	6.43	6.97	7.16	7.34	6.02	6.87	0.59	0.52

1992-1996 1997-2001	8.26 6.43	8.92 6.89	8.26 6.43	8.92 6.97	8.18 7.16	8.04 7.34	6.02	6.87	0.59	0.52

6. GENERATION PLANNING CRITERIA AND ASSUMPTIONS

6.1 Reserve and Reliability Criteria

The EGAT PDP is formulated for adequate generating capacity in excess of anticipated peak loads. This excess capacity provides a margin of reserve to ensure continuous and reliable power supply under any operating conditions, i.e. with power plant shutdown due to either forced outage or scheduled shutdown for maintenance. Unit failure which is usually the dominant factor in establishing the required reserve margin has been determined from studies and analyses on actual records of power plant performances, capability and reliability for the past several years. In the EGAT's mixed hydro-thermal system, the dependable capacity of each power plant, especially hydroelectric power plants with seasonal output variation, has been carefully determined.

For generation planning purpose, the following criteria are adopted:

- Loss of Largest Unit (Contingency Criterion)
- Reserve Margin Criterion
- Loss-of-Load Probability

(a) Loss of Largest Unit

This is based on contingency principle that the system generating capacity must be capable of meeting the annual peak load with one or more units out of service. By this definition, EGAT has, at present, considered that the system firm generating capacity is as follows:

Firm Capacity = Total Dependable Capacity (Hydro and Thermal Plants) - Dependable Capacity of the First and the Second Largest Generating Units in the System.

(b) Reserve Margin Criterion

Reserve margin is a measure of the system generating capability above the amount required to meet the system load requirements. It is defined as the difference between the total dependable capacity and the

annual system peak load, divided by the system peak load, expressed in percentage.

Generally, the total EGAT system requires approximately 25% of reserve margin to ensure that the LOLP will not be more than 1 day/year. However, according to the Government policy and the limitation in foreign currency borrowing, the minimum reserve margin of EGAT has been reduced from 25% to 15% for the present planning purpose. This is considered to be the minimum acceptable level for the present situation.

(c) Loss of Load Probability (LOLP)

LOLP is one of the method in determining the generation reserve requirement. It makes use of probability mathematics and is currently most widely used. The LOLP criterion previously adopted was that LOLP for total EGAT system should not exceed 1 day/year, and this has been considered as a normal practice in power utilities which has mixed hydro-thermal generation.

There is a relationship between LOLP and reserve margin in generation planning program which can be analyzed by using computer software model. The LOLP will be lower (i.e. reliability level is higher) if the reserve margin is larger, and vice versa.

The recommended PDP shows that the LOLP during 1989-1990 will be 9.7-24.7 days/year which is too high due to power shortage situation and from 1992 to 2001 the LOLP will be in the range of 0.6 to 4.2 days/year.

6.2 Criteria for Determining the Peaking Capacity

The term dependable capacity has been mentioned in the reserve criterion. It can be explained as follows :

(a) Dependable Capacity of Hydroelectric Plants : The dependable capacity of hydroelectric plant is defined as the unit output at reservoir water level corresponding to 90% of the water level frequency based on long-term reservoir simulation, using past hydrological records.

(b) Dependable Capacity of Thermal Power Plants : For thermal power plants in the EGAT system, the records of the operations since 1975 showed that there were several occasions that thermal plants were not able to generate up to full-rated capacity. Therefore, dependable capacity of thermal power plants including gas turbines should be used as one of the generation planning criterion.

The dependable capacity of thermal plants, and gas turbines used in generation planning, are as follows:

Type of Power Plant	Averaged Figure of 1/ Dependable Capacity as a Percentage of Rated Capacity
1. All thermal plants (Oil/gas/lignite/coal)	95
2. Krabi lignite-fired (2x20 MW)	75
3. Combined cycle plants	95
4. Existing gas turbines (11x15 MW)	80
5. Gas turbines 4x25 MW	80

6.3 Gas Supply and Fuel Prices

The gas supply and the fuel prices assumptions were agreed upon at the meeting between the senior officials from NESDB, NEPO, PTT and EGAT on June 29, 1988. The present long-term gas supply projection is less than the previous one that was prepared on October 19,1987 by about 21-118 MMCFD. Appendix 8 shows the comparison of gas supply projections, and the gas supply and demand balance, and Appendix 9 shows fuel prices used in the study.

Note : 1/ The diversity of derated capacity of several power plants were taken into account.

7. THE POWER DEVELOPMENT PLAN

7.1 Power Shortage Situation due to Insufficient Reserve Margin

The power shortage situation will occur in the period of 1989 to 1990 due to low reserve and the commissioning date of projects can not be accelerated to keep pace with the growth of power demand.

To solve an immediate problem, EGAT has requested the Working Group to take on this problem and to study the temporary measures of demand and supply management.

7.2 The PDP in a Long-Term Profile

The EGAT PDP is the result of an optimization in term of the least-cost sequence of development following an extensive studies of the alternative generation and transmission projects. EGAT has formulated a comprehensive development program up to the year 2001. The studies have included a review and comparison of power plants alternatives such as lignite, gas and coal-fired power plants in different locations, including domestic hydroelectric sources. The sensitivity study of the recommended program related to deviation in load growth was also prepared.

The new PDP (88-02) has been formulated based on 2 different load forecasts i.e; Base Case load forecast as a recommended PDP and Low Case load forecast as a sensitivity analysis.

The recommended PDP up to the year 2001 is illustrated in Figure 2-1 and tabulated in Tables 2-3 and 7-1.

The development of power plants project, separated into each region are as follows:

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Region 1 Construction of Srinagarind Unit 5 rated 180 MW; Bang Pakong combined cycle blocks 3 and 4 rated 2x300 MW; new combined cycle blocks 1,2 and 3 rated 3x300 MW; Bang Pakong thermal power plant units 3 and 4 rated 2x600 MW; and new thermal power plant units 1 to 5 rated 5x600 MW. Total Region 1 additional capacity is 5,880 MW.

Region 2 Construction of Nam Phong combined cycle blocks 1 and 2 rated 2x105 MW; Pak Mun hydro power plant units 1 to 4 rated 4x34 MW; and Nam Chern hydro power plant units 1 to 4 rated 4x100 MW. Total Region 2 additional capacity is 746 MW.

Region 3 Construction of Krabi lignite-fired Unit 4 rated 75 MW; Kaeng Krung hydro power plant units 1 and 2 rated 2x40 MW; and Saba Yoi lignite-fired power plant units 1 to 4 rated 2x150 and 2x300 MW. Total Region 3 additional capacity is 1,055 MW.

Region 4 Construction of Lan Krabu steam turbine rated 50 MW; Mae Moh lignite-fired (2nd power plant site) units 10 and 11 rated 2x300 MW; Mae Moh lignite-fired (3rd power plant site) units 12 to 15 rated 4x300 MW; Mae Moh lignite-fired (4th power plant site) units 16 to 19 rated 4x300 MW; Mae Taeng hydro power plant units 1 and 2 rated 18 and 8 MW or 26 MW; Bhumibol Unit 8 rated 178 MW; Sirikit hydro power plant rated 125 and 15 MW or 140 MW; Lower Mae Ping hydro power plant units 1 and 2 rated 2x20 MW; and Nam Khek hydro rated 2x25 and 2x35 MW or 120 MW. Total Region 4 additional capacity is 3,554 MW.

The Alternative PDP (88-02A) was formulated based on the Low Case July 1988 load forecast. The least-cost development plan of the sensitivity case is given in Appendix 17.

TABLE 7-1
THE EGAT POWER DEVELOPMENT PLAN
(PDP 88-02)

Name of Project	Rating (MW)	Commissioning Date	LOLP (Days/Year)
2nd PPB	75	February 1989	17.279
Mae Moh #8	300	July 1989	19.355
2nd CSTL	(270)	February 1990	18.877
Bang Pakong GT (3)	2x100	June 1990	24.709
Bang Pakong GT (4)	2x100	August 1990	22.105
New CC GT (1)	2x100	September 1990	22.378
New CC GT (2)	2x100	October 1990	10.356
Nam Phong GT	4x35	November 1990	11.510
Mae Moh #9	300	December 1990	12.302
New CC GT (3)	2x100	January 1991	9.662
Srinagarind #5	180	April 1991	12.923
Bang Pakong ST (3)	100	June 1991	13.015
Bang Pakong ST (4)	100	August 1991	10.636
New CC ST (1)	100	September 1991	11.384
New CC ST (2)	100	October 1991	0.794
Lan Krabu CC (ST)	50	October 1991	0.794
Nam Phong ST	2x35	December 1991	0.809
New CC ST (3)	100	January 1992	0.758
230 kV Tha Tako-Khon Kaen 3	(300)	January 1992	0.758
Mae Moh #10	300	February 1992	0.738
Bhumibol Renovation	(2x70)	March 1992	0.734
Bang Pakong Thermal #3	600	May 1992	0.779
Krabi #4	75	November 1992	0.629
Mae Moh #11	300	February 1993	0.624
Bang Pakong Thermal #4	600	May 1993	0.610
North Bangkok Renovation	(2x75+87.5)	August 1993	0.686
Mae Moh #12	300	October 1993	1.693
Pak Mun #1-4	4x34	November 1993	1.678
Kaeng Krung #1-2	2x40	December 1993	2.367
Mae Moh #13	300	April 1994	1.572
Mae Moh #14	300	October 1994	3.859
Mae Moh #15	300	April 1995	3.548
Mae Taeng #1-2	18+8	June 1995	3.430
Saba Yoi #1	150	October 1995	2.106
Mae Moh #16	300	November 1995	2.125
South Bangkok Renovation	(2x200+3x300)	December 1995	2.204
Bhumibol #8	178	January 1996	2.292
Sirikit #4	125	February 1996	2.145
Lower Sirikit #1	15	February 1996	2.145
Saba Yoi #2	150	April 1996	2.333
Saba Yoi #3	300	October 1996	2.408
Mae Moh #17	300	November 1996	3.014
Mae Moh #18	300	April 1997	2.523
New Thermal #1	600	October 1997	3.909
Mae Moh #19	300	November 1997	3.598
Lower Mae Ping #1-2	2x20	July 1998	3.851
New Thermal #2	600	October 1998	2.670
Saba Yoi #4	300	November 1998	2.574
Nam Khek (1)	2x25	January 1999	2.836
Nam Khek (2)	2x35	Febuary 1999	2.514
New Thermal #3	600	October 1999	2.838
Nam Chern #1-4	4x100	November 1999	4.181
New Thermal #4	600	October 2000	3.217
New Thermal #5	600	January 2001	3.487
Additional Capacity in 1988-2001	=	11,910.0 MW	
Total Capacity Up to 2001a/	=	18,369.2 MW	
PV.@ 12% DR. (From 1988-2001 in Million Baht)			
Capital Expenditure		108,328.79	
Operation and Maintenance Cost		19,319.47	
Fuel Cost		256,529.55	
Total Present Value		384,178.00	

Notes : a/ With retirement of existing plants of 435 MW (see Appendix 14).

8. PROJECTS IN THE POWER DEVELOPMENT PLAN

8.1 Bang Pakong Combined Cycle Power Plant Project Blocks 3-4 (2x300 MW)

The project consists of two 300 MW combined cycle blocks which will be located at Bang Pakong thermal power plant site.

The Bang Pakong combined cycle, each block consists of two 100 MW heavy duty gas turbines with two waste heat boilers and one 100 MW steam turbine generating unit. The project was approved for construction and scheduled for completion in the period from June 1990 to August 1991.

The cost estimate of the project is ฿ 9,573.6 million, of which the foreign currency portion is ฿ 5,738.6 million (US.$ 220.7 million equivalent) and the local currency portion is ฿ 3,835.0 million.

8.2 Srinagarind Unit 5 Project (Reversible Pumped-Turbine) 180 MW

Srinagarind Unit 5 Project covers the installation of one 180 MW reversible pumped-turbine unit at the existing structure of Srinagarind power plant. The project also includes the construction of 230 kV substation at Sai Noi with the termination of transmission lines from Ban Pong 2, Ang Thong 2, Rangsit and from Bangkok Noi substations.

The purpose of the project is to provide peaking generation for the system. The unit can be installed in rather short period since the major structures have already been completed.

The Project was approved for construction and scheduled for completion by April 1991.

The project cost is estimated at ฿ 995.0 million, of which the foreign currency portion is ฿ 687.0 million (US.$ 26.4 million equivalent), and the local currency portion is ฿ 308.0 million.

8.3 New Combined Cycle Power Plant Project Blocks 1-3 (3x300 MW)

The project consists of three 300 MW combined cycle blocks which will be located adjacent to Rayong 2 Substation.

The new combined cycle block will consist of two 100 MW heavy duty gas turbine units with two waste heat boilers and one 100 MW steam turbine generating unit. The project is scheduled for completion in the period from September 1990 to January 1992.

The cost estimate of the project is ฿ 14,695.0 million, of which the foreign currency portion is ฿ 9,012.3 million (US.$ 346.6 million equivalent) and the local currency portion is ฿ 5,682.7 million.

8.4 Nam Phong Combined Cycle Power Plant Project Blocks 1-2(2x105 MW)

The project consists of two 105 MW combined cycle blocks which will be located at Nam Phong, Khon Kaen Province in the Northeast, close to ESSO gas field. Each combined cycle power plant consists of two 35 MW gas turbines with two waste heat boilers and one 35 MW steam turbine generating unit. After completion of the two blocks, the natural gas consumption from Nam Phong gas field will be approximately 30-40 MMCFD.

The project is expected to be on-line during November 1990 - December 1991. The cost estimate of the project is ฿ 4,355.0 million, of which the foreign currency portion is ฿ 2,874.8 million (US.$ 110.6 million equivalent) and the local currency portion is ฿ 1,480.2 million.

8.5 Lan Krabu Combined Cycle (Steam Turbine Part) 50 MW

At present three 15 MW and four 25 MW gas turbine are installed at Lan Krabu power plant . The associated gas from Sirikit oil field (Thai Shell concessionaire) has been used as fuel for base-load energy generation. The Lan Krabu combined cycle power plant project consists of the construction of waste heat boiler and turbine-generating unit with 50 MW capacity for the utilization of waste heat generated from the existing 4x25 MW gas turbines. The project is scheduled for completion by October 1991.

The cost estimate of the project is ฿ 1,302.1 million of which the foreign currency portion is ฿ 846.3 million (US.$ 32.6 million equivalent) and the local currency portion is ฿ 455.8 million.

8.6 Bhumibol Hydro Power Plant Renovation Project

Bhumibol hydro power plant has been in operation for more than 24 years. The recent inspection shows that some mechanical equipment such as runner, protection liner, grease bearing, etc. and most of electrical equipment such as generator, excitation system and unit control system are deteriorated. Thus renovation of Units 1 and 2 are necessary.

This project consists of the renovation /rehabilitation work for Units 1 and 2 to increase efficiency, reliability and generation capacity. The project was approved for implementation and expected to be completed in March 1992.

Cost estimate of the project is ฿ 609.7 million. The foreign currency requirement is ฿ 484.9 million (US.$ 18.6 million equivalent) and the local currency portion is ฿ 124.8 million.

8.7 Krabi Lignite-Fired Power Plant Project (75 MW)

The Krabi lignite power plant Unit 4 rated 75 MW is proposed to replace the existing 3x20 MW generating units which were put into operation from the period of 1964-1968 (Appendix 1). The new 75 MW unit will utilize the remaining lignite from the old Krabi lignite mine for base-load energy generation. The project is scheduled for completion in November 1991.

Cost estimate of the project is ฿ 3,112.9 million. The foreign currency requirement is ฿ 1,861.7 million (US.$ 71.6 million equivalent) and the local currency portion is ฿ 1,251.2 million.

8.8 Mae Moh Lignite-Fired Power Plant Project Units 10-19 (10x300 MW)

The proven lignite reserve at Mae Moh mine in the Northern part of Thailand has been estimated at about 812 million tons. This will be sufficient for power production of at least 4,500 MW for the life time of the power plants. At present, there are seven generating units in operation with a total capacity of 825 MW. Units 8, 9 and 10, each of 300 MW are under construction. Thus the total capacity will be 1,725 MW.

Additional power plant at Mae Moh site has been proposed to increase the generating capacity for EGAT system. The Unit 11 has been already approved for construction while the implementation of Units 12 to 19 have been proposed in PDP 88-02 for the period up to year 2001. The new power plant sites are required for Units 12 to 15 and Units 16 to 19 respectively.

The commissioning dates and cost estimates for Mae Moh Units 10 to 19 are summarized as follows:

	Commissioning Date	F.C (M฿)	L.C (M฿)	Total (M฿)
Mae Moh Unit 10	February 1992	4,335.3	3,323.9	7,659.2
Mae Moh Unit 11	February 1993	3,788.3	2,746.3	6,534.6
Mae Moh Unit 12	October 1993	4,139.0	3,192.5	7,331.5
Mae Moh Unit 13	April 1994	4,172.0	3,227.0	7,399.0
Mae Moh Unit 14	October 1994	4,172.0	3,227.0	7,399.0
Mae Moh Unit 15	April 1995	4,205.5	3,256.5	7,462.0
Mae Moh Unit 16	November 1995	4,205.5	3,256.5	7,462.0
Mae Moh Unit 17	November 1996	4,239.0	3,319.5	7,558.5
Mae Moh Unit 18	April 1997	4,273.0	3,422.5	7,695.5
Mae Moh Unit 19	November 1997	4,273.0	3,422.5	7,695.5

8.9 Bang Pakong Thermal Power Plant Project Units 3-4 (2x600 MW)

Two conventional steam turbine units, (rated 600 MW each), located adjacent to the existing Bang Pakong thermal power plant Units 1-2 are proposed. The units are planned to be dual-fired (oil/natural gas). In case if the natural gas would not be available in sufficient quantity in the future, then heavy oil can be used. The project was approved for construction and scheduled for completion by May 1992 and May 1993 respectively.

The total project cost is estimated at B 21,871.5 million. The foreign currency portion is B 10,223.7 million (US.$ 393.2 million equivalent) and the local currency portion is B 11,647.8 million.

The project cost estimate for Bang Pakong Units 3 and 4 are as follows :

	F.C (MB)	L.C (MB)	Total (MB)
Bang Pakong Thermal Unit 3	5,223.7	5,925.8	11,149.5
	(US.$ 200.9 million)		
Bang Pakong Thermal Unit 4	5,000.0	5,722.0	10,722.0
	(US.$ 192.3 million)		

8.10 North Bangkok Power Plant Renovation Project

The three generating units at North Bangkok power plant (2x75 and 1x87.5 MW) have been in operation since 1961, 1963 and 1968 respectively. Base upon the average economic life time of thermal power plant of 25 years, and the conditions of the plant, these units are considered possible for renovation. Study is being conducted by a consultant to determine the method and cost of renovating the three units. Heavy oil will be used as the main fuel for this plant, but if natural gas is available in sufficient amount and proved to be economical, then the natural gas-firing can be adopted. The schedule for renovation will be determined when the study is completed. However, it is expected that the recommissioning of this plant after the renovation will be August 1993.

The cost estimate for the renovation work of the three units is B 1,267.3 million. Of this amount, the foreign currency requirement is B 745.0 million (US.$ 28.7 million equivalent), and the local currency portion is B 522.3 million.

8.11 Pak Mun Hydroelectric Project (4x34 MW)

Pak Mun hydroelectric project is located on the Nam Mun River, approximately 70 km east of Ubon Ratchathani town in Northeast Thailand. Theproject site is 6 km from the confluence of the Mekong River. The average annual inflow at the damsite is approximately 23,300 million cubic meters. The benefits of Pak Mun project are : irrigation, power generation and fisheries. Brief description and scope of work are as follows :

(a) A rockfill dam 17 m high, 255 m crest length at the elevation of 111.0 m.(MSL) and the dam volume is approximately 104,000 cubic meters.

(b) A power plant which will be located on the right abutment to accommodate four horizontal bulb type 34 MW generating units. The plant capacity will be 136 MW with the average annual energy production of 280 GWh.

(c) A 115 kV double circuit transmission line, 70 km long, linking Pak Mun switchyard with the new Ubon Ratchathani 2 Substation, and stringing of one 115 kV circuit on the existing steel towers from Ubon Ratchathani 1 to Ubon Ratchathani 2 and Si Sa Ket substations. Additional substation expansions are required at Si Sa Ket and Ubon Ratchathani 1.

The proposed commissioning date of Pak Mun hydroelectric project is November 1993.

The project cost is estimated at ฿ 3,880.0 million. The foreign currency portion is ฿ 1,940.0 million (US.$ 74.6 million equivalent) and the local currency portion is ฿ 1,940.0 million.

8.12 Kaeng Krung Hydroelectric Project (2x40 MW)

Kaeng Krung Project is located on the Khlong Yan River at Ban Ta Kuk Nua, Khiri Rathanikhom District, Surat Thani Province. The average annual inflow at Kaeng Krung damsite is approximately 800 million cubic meters. Brief description of major works are as follows :

(a) Main concrete faced rockfill dam with a crest elevation of 158.76 m.(MSL) and maximum height of about 107 m is proposed. The embankment volume is approximately 3.5 million cubic meters.

(b) The diversion tunnel of 8.5 m diameter through the ridge on the left bank to serve as irrigation and bottom outlet.

(c) The spillway, open chute type with three radial gates 6.0 m wide 10.0 m high each located on the right abutment.

(d) The power intake and power tunnel of 5.3 m diameter are located on the right abutment.

(e) The powerhouse, shaft type, with 2 generating units of 40 MW each.

(f) 115 kV double circuit transmission line, 42 km long, linking Kaeng Krung and Chiew Larn Switchyard.

The power plant of Kaeng Krung project can supply 178 GWh/Yr to the system. The irrigation area for Tapi-Phum Duang Basin are totally 270,000 rai which are supported by the Chiew Larn and Kaeng Krung reservoirs. The annual fishery benefit from Kaeng Krung reservoir is about ฿ 21 million.

It is expected that the Kaeng Krung project will be completed by December 1993.

The project cost is estimated at ฿ 2,890.0 million of which ฿ 1,255.0 million (US.$ 48.3 million equivalent) is required in foreign currency and ฿ 1,635.0 million in local currency.

8.13 Mae Taeng Hydroelectric Project (18+8 MW)

Mae Taeng hydroelectric project is located on the Mae Taeng River, a tributary of the Mae Ping River, approximately 50 km north of Chiang Mai Province. The average annual inflow at the damsite is approximately 687 million cubic meters. The benefit of Mae Taeng project is mainly for power generation. Brief description and scope of works are as follows :

(a) An intake dam, a concrete gravity dam, 26 m high, 68 m crest length at the elevation of 448 m (MSL) is proposed and the concrete volume is approximately 10,000 cubic meters.

(b) A headrace tunnel, located on the left bank comprises 880 m long unlined tunnel followed by 270 m long steel lined tunnel and a 60 m long steel penstock.

(c) A power plant which will be located on a paddy field near the foot of the mountain ridge running between the Mae Taeng River and Mae Ta Man River to accomodate two vertical Francis type 18+8 MW generating units. The total plant capacity will be 25 MW with the average annual energy production of 112 GWh.

(d) 115 kV single circuit transmission line, 45 km long, linking between Mae Taeng Switchyard and Chiang Mai 2 Substation.

The proposed commissioning date of the project is June 1995.

The project cost is estimated at ฿ 935.0 million. The foreign currency portion is ฿ 485.0 million (US.$ 18.7 million equivalent) and the local currency portion is ฿ 450.0 million.

8.14 Saba Yoi Lignite-Fired Power Plant Project Units 1-4 (2x150+2x300 MW)

The proven lignite reserve at Saba Yoi mine in the southern part of Thailand has been initially estimated at approximately 137 million tons. This will be sufficient for power production of at least 900 MW for the life time of the power plants.

The power plant project at Saba Yoi has been proposed to increase the generating capacity for EGAT system. Construction of Units 1 and 2, each of 150 MW and Units 3 and 4, each of 300 MW have been proposed in the PDP for the period up to year 2001. The power plant site is under preliminary study. The commissioning dates of Units 1,2,3 and 4 will be October 1995, April 1996, October 1996 and November 1998 respectively.

The cost estimates for Saba Yoi Power Plant Units 1-4 are summarized as follows:

	F.C (M฿)	L.C (M฿)	Total (M฿)
Saba Yoi Lignite Unit 1	2,773.0 (US.$ 106.7 million)	2,135.0	4,908.0
Saba Yoi Lignite Unit 2	2,434.0 (US.$ 93.6 million)	1,799.0	4,233.0
Saba Yoi Lignite Unit 3	4,250.0 (US.$ 163.5 million)	3,328.0	7,578.0
Saba Yoi Lignite Unit 4	5,025.5 (US.$ 193.3 million)	4,166.0	9,191.5

8.15 South Bangkok Power Plant Renovation

South Bangkok Power Plant Units 1-5 have been in service since 1971, 1972, 1974, 1975, and 1978 respectively. According to general practice, these 5 units should be retired from the system after their economic lives are reached. Therefore, by 1996, 1997, 1999, 2000 and 2003, all these five units should be shutdown starting from 1996 for Unit 1 and 2003 for the last unit. However, it is observed from recent inspection that the operating condition of these five units remains in good level and it will be worth performing plant renovation to extend the operating function for future years. The renovation is expected to be completed for recommissioning by December 1995.

The cost estimate for the renovation of these 5 units is ฿ 1,528.5 million. The foreign currency requirement is ฿ 1,001.5 million (US.$ 38.5 million equivalent) and the local currency portion is ฿ 527.0 million.

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8.16 Bhumibol Unit 8 Project (Reversible Pumped-Turbine, 178 MW)

Bhumibol Unit 8 Project is located adjacent to the existing Bhumibol power plant at Tak Province. The project consists of a Lower Mae Ping Barrage and Bhumibol Unit 8 power plant. Brief description and scope of works are as follows :

a) Lower Mae Ping concrete barrage, 8 m high, 293 m crest length at the elevation of 140 m (MSL), will be located on the Mae Ping River at Chad San village, Sam Ngao District, Tak Province, approximately 9.5 km downstream of existing power plant.

b) Bhumibol Unit 8 power plant will be located on the right bank of the Mae Ping River, approximately 70 m downstream of the existing power plant to accommodate one reversible pumped-turbine type, rated 178 MW generating unit.

The proposed commissioning date of Bhumibol Unit 8 project is January 1996.

The project cost is estimated at ฿ 2,150.0 million. The foreign currency portion is ฿ 1,248.0 million (US.$ 48.0 million in equivalent) and the local currency portion is ฿ 902.0 million.

8.17 Sirikit Hydroelectric Project Stage 3 (125+15 MW)

Sirikit Dam is located on the Nan River at Ta Pla District, Uttaradit Province, approximately 60 km upstream from Uttaradit.

Sirikit hydroelectric project stage 1 covers the construction of power plant to accommodate four 125 MW generating units. The installation of Units 1 and 2 were completed in January 1974 and March 1974 respectively. The present transmission system consists of two circuits of 230 kV from Sirikit Swithyard to Nakhon Sawan via Phitsanulok 2 substations. For stage 2, the installation of Unit 3 were completed in July 1974.

For Stage 3, the installation of Unit 4 at the existing power plant, including the afterbay structure with a new power plant are proposed. The brief description and scope of work are as follows :

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(a) Installation of one 125 MW Francis type generating unit at the existing Unit 4 Bay.

(b) A lower dam, earthfill type, 13 m high, 90 m crest length at the elevation of 83 m (MSL) with the total volume of approximately 29,710 cubic meters.

(c) A service spillway with three radial gates (10.5 m wide and 7.0 m high) with the discharge capacity of 1,850 cubic meters.

(d) A single unit power plant will be located on the left bank of the Nan River abutting the earthfill dam. The generating unit is a low head, open pit, double regulated unit, The installed capacity will be 15 MW with the average annual energy production of 65 GWh.

(e) A 230 kV single circuit transmission line, 117 km long, linking between Sirikit Switchyard and Phitsanulok 2 Substation,and a termination of existing 115 kV Sirikit-Uttaradit line, 1 km long to Lower Sirikit Switchyard.

The proposed commissioning date of the project is February 1996.

The project cost is estimated at ฿ 2,050.0 million. The foreign currency portion is ฿ 1,375.0 million.(US.$ 52.9 million equivalent) and local currency portion is ฿ 675.0 million.

8.18 New Thermal Power Plant Project Units 1-5 (5x600 MW)

The future large base-load thermal power generation from new thermal power plants Units 1-5 each rated 600 MW has been included in the PDP. The proposed plan is expected to have the first unit in operation by October 1997 and other units by October 1998, October 1999, April 2000 and October 2000 respectively.

The project cost is estimated at ฿ 19,409.0 million for the first unit, ฿ 18,740.5 million for the second unit, ฿ 19,348.5 million for the third unit, ฿ 20,799.5 million for the fourth unit, and ฿ 21,779.5 million for the fifth unit. The foreign and local currency requirements are summarized as follows:

	F.C (MB)	L.C (MB)	Total (MB)
Unit 1 (600 MW)	9,087.1 (US.$ 349.5 million)	10,321.9	19,409.0
Unit 2 (600 MW)	8,564.0 (US.$ 329.4 million)	10,176.5	18,740.5
Unit 3 (600 MW)	8,634.8 (US.m 332.1 million)	10,713.7	19,348.5
Unit 4 (600 MW)	9,273.8 (US.$ 356.7 million)	11,525.7	20,799.5
Unit 5 (600 MW)	9,960.1 (US.$ 383.1 million)	11,819.4	21,779.5

8.19 Lower Mae Ping Hydroelectric Project (2x20 MW)

Lower Mae Ping hydroelectric project is located on the Mae Ping River at Amphoe Sam Ngao, Tak Province, approximately 26.5 km downstream of existing Bhumibol Dam. Brief description of major works are as follows:

(a) A power canal, concrete lining type 20.68 km long, can supply the discharge of 260 cubic meters per second.

(b) A power plant will be located on the right bank, 17 km downstream of the Lower Mae Ping Barrage to accommodate two 20 MW generating units. The total plant capacity will be 40 MW with the average annual energy production of 207 GWh.

(c) A termination of existing 115 kV Bhumibol-Tak 1 transmission line, 4 km long to Lower Mae Ping Switchyard.

The commissioning date of the project is expected to be in July 1998.

The project cost is estimated at ฿ 2,130.0 million. The foreign portion is ฿ 985.0 million (US.$ 37.9 million equivalent) and the local portion is ฿ 1,145.0 million.

8.20 Nam Khek Hydroelectric Project (2x25+2x35 MW)

Nam Khek hydroelectric project is a multipurpose project, located on the Nam Khek River, a tributary of the Nan River at Wang Thong and Nakorn Thai Districts, Phitsanulok Province. The project consists of Upper Huai Ngaet rockfill dam and lower concrete weir. Two power plants will be constructed at downstream of the dam and weir, consequently. Brief descriptions of the project are as follows:

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Upper Huai Ngaet Dam and Power Plant No.1

(a) Upper Huai Ngaet dam, concrete faced rockfill dam, will be located on Nam Khek River, downstream from the confluence of Khlong Khek Noi and Khlong Khek Yai at Nakorn Thai District, Phitsanulok Province. The dam with 125 m high 470 m crest length at the elevation of 580 m(MSL), willhave the total volume of 5.26 million cubic meters.

(b) Power plant No. 1 will be located at downstream of the Upper Huai Ngaet dam to accommodate two 25 MW generating units. The plant capacity will be 50 MW with the average annual energy production of 137 GWh.

A 115 kV double circuit transmission line, 40 km long, is required from Huai Ngaet Switchyard to Lom Sak Substation.

Lower Weir and Power Plant No. 2

(a) Lower Weir, a concrete gravity type, is located on Nam Khek River, about 55 km downstream from the Upper Huai Ngaet dam at Wang Thong District, Phitsanulok Province. This concrete gravity weir is 12 m high and has 65 m crest length at the elevation of 415 m (MSL).

(b) Power plant No.2 will be located at downstream of the lower weir to accommodate two 35 MW generating units. The plant capacity is 70 MW with the average annual energy production of 176 GWh.

A 115 kV single circuit transmission line, 10 km long is required from the Lower Weir Switchyard to the Upper Huai Ngaet Switchyard.

The total plant capacity of the project is 120 MW and the average annual energy production is 313 GWh. The irrigation area in Amphoe Wang Thong and Phitsanulok Stage II-irrigation project, totalling 58,750 rai are supported by the Upper Huai Ngaet Reservoir.

The proposed commissioning date of the power plants No.1 & No.2 are January 1999 and February 1999 respectively.

The project cost is estimated at ฿ 4,498.5 million. The foreign currency portion is ฿ 2,021.8 million (US.$ 77.8 million, equivalent) and local currency portion is ฿ 2,476.7 million.

8.21 Nam Chern Hydroelectric Project (4x100 MW)

Nam Chern project is a hydroelectric power development on the upper Nam Pong basin in Northeastern Thailand. The project is located at Ban Na Pho Song, Nam Now district, Petchabun Province.

The project is a pumped storage type consisting of the upper and lower reservoirs which are formed by the dam located on Huai Chan and Nam Chern River. The average annual inflow at the upper and lower damsites are approximately 31 and 4 million cubic meters respectively. Water will be released and pumped up between the upper and lower reservoirs but some amount of water will be released to supply downstream irrigation area approximately 50,000 rai. Brief description of major works are as follows:

(a) An upper dam is rockfill concrete faced type, 40 m high, with 365 m crest length at the elevation of 785 m (MSL).

(b) A lower dam is rockfill concrete faced type, 38 m high, with 224 m crest length at the elevation of 413 m (MSL).

(c) A tunnel waterway consists of the low pressure tunnel of 6.20 m diameter and 1,420 m long, surge tank of 14 m diameter and 62 m high, pressure tunnel of 6.0 m diameter and 552 m long connecting from the intake of upper reservoir to the underground power plant.

(d) A power plant, underground type, will be equipped with four 100 MW reversible pumped-turbine units. The plant capacity is 400 MW.

(e) A termination of the existing 230 kV Lamsak-Khon Kaen 1 transmission line, 3 km long, to Nam Chern Swithyard.

The project is expected to be commissioned in November 1999.

The total project cost is estimated at ฿ 4,660.5 million. The foreign currency portion is ฿ 2,473.1 million (US.$ 95.1 million equivalent) and the local currency portion is ฿ 2,187.4 million.

9. TRANSMISSION SYSTEM DEVELOPMENT

EGAT transmission system development in the future will cover the expansion of 500, 230 and 115 kV transmission lines and substations to all provinces of Thailand. The 500 kV Extra High Voltage (EHV) transmission system is being developed for long distance bulk power transmission and to superimpose the 230 kV system. The long-term plan for power development in Thailand up to the year 2001 will be concentrated in five areas, namely : Eastern area (Bang Pakong/Ao Phai), Western area (Quae Yai and Quae Noi Rivers); Northern area (Mae Moh), Northeastern area (Nam Phong), and Southern area (Rajjaprabha, Khanom, and Saba Yoi). Transmission voltages of 230 kV and 500 kV have been considered for most of the future projects.

The large scale generation development of lignite-fired power plants at Mae Moh minemouth for additional capacity of up to 2,700 MW in the period up to year 2001 will require long distance EHV transmission lines to transmit bulk power to load center at the Greater Bangkok area. Presently, it is envisaged that 500 kV AC lines will be required from the new Mae Moh power plant (the 3rd power plant site) to Tha Tako intermediate substation, and from Tha Tako to Nong Chok Substation. Integration of power generation between Mae Moh 2 and Mae Moh 3 power plant sites are also required.

Power system expansion will require the construction of 500 kV double circuit line from Nong Chok to Sai Noi Substation in the future. The existing 230 kV transmission system in the greater Bangkok area will have to be reinforced or modified to provide sufficient capacity for the MEA. New 230 kV substations are planned to be located at South Thonburi and On Nuch with commissioning dates of September 1991 and May 1992 respectively.

In the northeastern area, the discovery of natural gas at Nam Phong District, Khon Kaen Province, has provided the opportunity to construct more power generation close to the load center. The Nam Phong combined cycle power plant project has been proposed and additional transmission lines are required to provide reliable power supply in the region. One of the most urgently needed project is the construction of a 230 kV double circuit transmission line from Khon Kaen to Roi Et to

reinforce and provide more transmission capacity to serve the eastern part of Region 2. Additional power supply to Region 2 will be provided by the new 230 kV double circuit Tha Tako-Khon Kaen 3 transmission project, proposed for commissioning in January 1992.

With regard to the southern system development, 230 kV transmission system has already been in operation from Rajjaprabha (Chiew Larn) hydroelectric plant to Surat Thani, and from Surat Thani to Khanom power plant. The transmission lines from Khanom to Nakhon Si Thammarat, Phatthalung and Hat Yai 2 Substation have been designed and constructed for 230 kV operation but being energized at 115 kV, and will be converted to 230 kV by 1989 together with the commissioning of the Khanom 2nd power plant barge project. To reinforce and increase the power transmission capacity of the Central-Southern interconnection, the Second Central-Southern tie line project (2nd CSTL) is under construction stage. Hence, the transmission system development for Region 3 has largely been improved in recent years resulting in better voltage control and lower system losses.

Besides the transmission system for generation expansion, EGAT has also planned and implemented the transmission system expansion project (TS Project) which consists of several transmission lines and substations combined into a package. The project will enable EGAT to maintain continuity of service and provide sufficient electric supply as well as for system reinforcement. So far, EGAT has implemented six transmission system expansion projects, namely Transmission System Expansion Project Nos.1, 2, 3, 4, 5 and 6. At present, the Transmission System Expansion Project No.7 is under implementation and Transmission System Expansion Project No.8 is under study.

In conjunction with the higher growth in power demand than expected, the transmission system expansion programs being implemented in the TS.7 will not be sufficient to maintain the continuity and reliability of supply. EGAT, therefore decided to adopt an accelerated transmission program to keep abreast of the increasing demand during the TS. 7 period as well as the period which is considered to be the gap between TS.7 and TS. 8. The Accelerated Transmission Project (ATP) is therefore formulated.

The power system interconnection between Thailand and Malaysia (EGAT-LIN) has been in operation since February 1981. The power exchanges between the two power utilities are useful in many circumstances such as to prevent power shortage when some of the power stations have to be shutdown due to scheduled and unscheduled maintenances and outages, and during maintenance work of transmission system. In the context of ASEAN Cooperation, the study on EGAT-LIN Stage II Interconnection is still ongoing. The study covers the Stage II power exchange in the range of 100, 200 and 300 MW. The HVDC back-to-back system is one of the most promising alternatives to solve the inherent power swing and stability problems. The EGAT-LIN Stage II Interconnection project will be studied at feasibility level and expected to be incorporated in PDP in the near future.

10. PROJECT WORK SCHEDULE

Project work schedule is arranged in accordance with the recommended PDP. The schedule consists of feasibility study and proposed period for approval, engineering and construction periods and indication of the project commissioning date.

Table 10-1 and shows tentative work schedule of projects in the PDP.

No.	
1	New C
2	New C
3	Nam P
4	New C
5	Lam K
6	Krabi
7	Mae Mo
8	Bang P
9	Mae Mo
10	Pak Mu
11	Kaeng
12	Mae Mo
13	Mae Mo
14	Mae Mo
15	Mae Ta
16	Saba Y
17	Mae Mo
18	Bhumibo
19	Sirikit Lower S

Legend : ===
##
P

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TABLE 10-1

PROJECT WORK SCHEDULE

No.	Name of Projects	Installed Capacity (MW)	Fiscal Year 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1	New Combined Cycle Block 1	300														
2	New Combined Cycle Block 2	300														
3	Nam Phong CC. Blocks 1-2	2x105														
4	New Combined Cycle Block 3	300														
5	Lan Krabu CC (ST)	50														
6	Krabi Unit 4	75														
7	Mae Moh #11	300														
8	Bang Pakong #4	600														
9	Mae Moh #12	300														
10	Pak Mun #1-4	136 (4x34)														
11	Kaeng Krung #1-2	80 (2x40)														
12	Mae Moh #13	300														
13	Mae Moh #14	300														
14	Mae Moh #15	300														
15	Mae Taeng #1-2	26 (18+8)														
16	Saba Yoi #1	150														
17	Mae Moh #16	300														
18	Bhumibol #8	178														
19	Sirikit #4 and Lower Sirikit #1	140 (125+15)														

Legend :
- ==== Feasibility Study and Propose for Approval
- #### Engineering
- ▬▬ Preliminary , Manufacturing , Construction and Installation Works
- ▶ Commissioning Date

Power System Planning Division
July 25,1988

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TABLE 10-1 (CONTINUED)

PROJECT WORK SCHEDULE

No.	Name of Projects	Installed Capacity (MW)	Fiscal Year 1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
20	Saba Yoi #2	150														
21	Saba Yoi #3	300														
22	Mae Moh #17	300														
23	Mae Moh #18	300														
24	New Thermal #1	600														
25	Mae Moh #19	300														
26	Lower Mae Ping #1-2	40 (2x20)														
27	New Thermal #2	600														
28	Saba Yoi #4	300														
29	Nam Khek (1)-(2)	50+70 (2x25+2x35)														
30	New Thermal #3	600														
31	Nam Chern #1-4	400 (4x100)														
32	New Thermal #4	600														
33	New Thermal #5	600														

Legend : ==== Feasibility Study and Propose for Approval
Engineering
▬▬ Preliminary , Manufacturing , Construction and Installation Works
Commissioning Date

Power System Planning Division
July 25,1988

11. EGAT'S SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)

11.1 Time-Frame of the National Economic and Social Development Plan

The National Economic and Social Development Plans (NESDP) which are related in the present EGAT's long-term PDP are :

The Fifth NESDP.....1982-1986
The Sixth NESDP.....1987-1991
The Seventh NESDP.....1992-1996

The main objective of the present PDP is to stress on the capital investment and expenditure schedules for EGAT's projects in the period 1987-2001, but with emphasis on the expenditures in the Sixth Plan period.

11.2 Capital Expenditure of Projects in the Fifth Plan but will be Commissioned in the Sixth Plan

There are still 11 projects of the Fifth Plan that will be completed in the Sixth Plan period. These are the projects which are under construction, or already in operation in 1987, summarized in Table 11-1.

The total expenditure required for 11 projects remaining from the Fifth Plan is estimated at ฿ 18,474.7 million. Of this the foreign currency exchange is equivalent to ฿ 11,340.4 million, and the local currency portion is ฿ 7,134.3 million. Details are given in Table 11-4.

11.3 Capital Expenditures of Projects in the Sixth Plan and will be Commissioned in the Sixth Plan

There are 11 projects which will require capital expenditures during the period 1987-1991. Some of these projects have already been approved by the Cabinet i.e. the Second Central-Southern Tie Line Project, the Transmission System Expansion Project No.7 (TS.7), and Mae Moh Mine Expansion for Mae Moh Units 8 and 9. The total capital expenditure requirement is estimated at ฿ 35,948.2 million. The foreign currency exchange is ฿ 17,349.0 million equivalent and the local currency portion is ฿ 18,599.2 million. Table 11-2 summarizes the capital expenditures requirement for projects which will be constructed and commissioned in the Sixth Plan period. Table 11-5 shows the details.

11.4 Capital Expenditures of Projects in the Sixth Plan but will be Commissioned in the Seventh Plan

There are 25 projects which will require capital expenditures during the period 1988-1991 of the Sixth Plan but these projects will be commissioned after 1991, or in the Seventh Plan period. The total capital expenditure requirement is estimated at ฿ 45,577.1 million. The foreign currency exchange is ฿ 24,310.6 million equivalent and the local currency portion is ฿ 21,266.5 million. Table 11-3 gives a summary of projects and capital expenditures in the Sixth Plan period. Table 11-6 shows the details.

11.5 Total Capital Expenditure of EGAT for the Sixth Plan (1987-1991)

EGAT's total capital expenditure in the period 1987-1991, based on Load Forecast of July 1988 amounts to ฿ 100,000 million. The foreign exchange requirement is equivalent to ฿ 53,000 million or approximately US.$ 2.04 billion. The local currency portion is ฿ 47,000 million or 46 per cent of total expenditure. Heavy investment will be required in FY 1989, 1990 and 1991 due to additional generating capacities, transmission systems and mining expansions. Table 11-7 gives a summary of total EGAT's capital expenditure in the Sixth Plan period.

TABLE 11-1

PROJECTS OF THE FIFTH PLAN BUT TO BE COMMISSIONED IN THE SIXTH PLAN

Name of Project	Expenditure Period	Commissioning Date	Estimated Expenditure (Million Baht)
Hydroelectric Projects			
1. Flood Protection of Ubol Ratana Dam	1987	March 1987	28.0
2. Rajjaprabha Units 1,2,3 (240 MW)	1987	June 1987	683.2
Thermal Power Plant Projects			
1. Khanom Second Power Plant Barge (75 MW)	1987-1989	February 1989	2,107.9
2. Mae Moh Unit 8 (300 MW)	1987-1989	July 1989	5,513.5
3. Mae Moh Unit 9 (300 MW)	1987-1991	December 1990	5,988.7
Mining Project			
1. Mae Moh Mine Expansion for Mae Moh Units 5,6,7	1987-1989	October 1989	807.9
Transmission Projects			
1. EHV Transmission System Stage 1 (For Mae Moh Unit 7)	1987-1988	December 1986	182.8
2. 230 kV Phatthalung-Hat Yai 2	1987	June 1987	40.4
3. Transmission System Expansion No.6	1987-1988	October 1987	427.4
4. EHV Transmission System Stage 2 (For Mae Moh Unit 8)	1987-1989	April 1989	746.2
5. EHV Transmission System Stage 3 (For Mae Moh Unit 9)	1987-1990	April 1990	1,948.7
Total Expenditures			18,474.7
Foreign Currency Exchange			11,340.4
Local Currency Portion			7,134.3

TABLE 11-2

PROJECTS OF THE SIXTH PLAN AND TO BE COMMISSIONED IN THE SIXTH PLAN PERIOD

Name of Project	Expenditure Period	Commissioning Date	Estimated Expenditure (Million Baht)
Hydroelectric Project			
1. Srinagarind Unit 5 (180 MW)	1989-1991	April 1991	995.0
Thermal Power Plant Projects			
1. Bang Pakong Combined Cycle Block 3 (300 MW)	1988-1991	Jun 90-Jun 91	5,15[illegible].6
2. Bang Pakong Combined Cycle Block 4 (300 MW)	1989-1991	Aug 90-Aug 91	4,4[illegible].0
3. New Combined Cycle Block 1 (300 MW)	1989-1991	Sep 90-Sep 91	5,395.7
4. New Combined Cycle Block 2 (300 MW)	1989-1991	Oct 90-Oct 91	4,435.1
5. Lan Krabu Combined Cycle	1989-1991	October 1991	1,302.1
Mining Project			
1. Mae Moh Mine Expansion (Stage 1) for Mae Moh Units 8,9	1987-1991	October 1991	4,529.4
Transmission Projects			
1. Second Central-Southern Tie Line	1987-1990	February 1990	1,170.0
2. Transmission System Expansion No.7	1987-1990		
Part A		April 1990	2,410.0
Part B		October 1990	777.0
3. 230 kV Khon Kaen 3-Roi Et	1989-1991	January 1991	582.0
Miscellaneous Transmission System Expansions and Construction Work	1987-1991	1987-1991	4,778.3
Total Expenditures			35,948.2
Foreign Currency Exchange			17,349.0
Local Currency Portion			18,599.2

TABLE 11-3
PROJECTS OF THE SIXTH PLAN BUT TO BE COMMISSIONED IN THE SEVENTH PLAN PERIOD

Name of Project	Expenditure Period	Commissioning Date	Estimated Expenditure (Million Baht)
Hydroelectric Projects			
1. Bhumibol Hydro Plant Renovation	1990-1991	March 1992	528.0
2. Pak Mun Units 1-4 (4x34 MW)	1989-1991	November 1993	1,055.7
3. Kaeng Krung Units 1-2 (2x40 MW)	1988-1991	December 1993	1,344.2
4. Bhumibol Unit 8 (178 MW)	1991	January 1996	44.8
Thermal Power Plant Projects			
1. Nam Phong Combined Cycle Blocks 1 and 2 (2x105 MW)	1989-1991	Nov 90-Dec 91	4,148.3
2. New Combined Cycle Block 3 (300 MW)	1989-1991	Jan 91-Jan 92	3,650.8
3. Mae Moh Unit 10 (300 MW)	1989-1991	February 1992	5,891.2
4. Bang Pakong Thermal Unit 3 (600 MW)	1989-1991	May 1992	6,595.9
5. Krabi Unit 4 (75 MW)	1989-1991	November 1992	2,166.4
6. Mae Moh Unit 11 (300 MW)	1989-1991	February 1993	3,167.8
7. Bang Pakong Thermal Unit 4 (600 MW)	1989-1991	May 1993	5,319.5
8. Mae Moh Unit 12 (300 MW)	1990-1991	October 1993	2,154.2
9. Mae Moh Unit 13 (300 MW)	1991	April 1994	735.0
10. Mae Moh Unit 14 (300 MW)	1991	October 1994	735.0
Mining Projects			
1. Mae Moh Mine Expansion for Mae Moh Unit 10	1990-1991	February 1992	733.0
2. Mae Moh Mine Expansion for Mae Moh Unit 11	1991	February 1993	164.0
3. Krabi Mine Expansion for Krabi Unit 4	1989-1991	October 1992	43.2
4. Mae Moh Mine Expansion for Mae Moh Unit 12	1991	October 1993	433.0
5. Saba Yoi Mine Development for Saba Yoi Units 1,2	1990-1991	April 1996	994.0
Transmission Projects			
1. EHV Transmission System for Mae Moh Unit 10	1989-1991	February 1992	1,900.6
2. Accelerated Transmission Project	1989-1991	April 1992	2,122.9
3. 230 kV Tha Tako-Khon Kaen 3	1989-1991	January 1992	810.3
4. EHV Transmission System for Mae Moh Unit 11	1990-1991	February 1993	228.1
5. Transmission System Expansion No. 8	1989-1991	April 1993	605.6
6. EHV Transmission System for Mae Moh Unit 12	1991	October 1993	5.6
Total Expenditures			45,577.1
Foreign Currency Exchange			24,310.6
Local Currency Portion			21,266.5

TABLE 11-4
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

1. Projects in the Fifth Plan and Commissioning in the Sixth Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
HYDROELECTRIC PROJECTS																
1. Flood Protection of Ubol Ratana Dam	19.3	8.7	-	-	-	-	-	-	-	-	19.3	8.7	28.0	188.9	170.5	359.4
2. Rajjaprabha Units 1,2,3	269.9	413.3	-	-	-	-	-	-	-	-	269.9	413.3	683.2	2042.4	2602.9	4645.3
Subtotal	289.2	422.0	-	-	-	-	-	-	-	-	289.2	422.0	711.2	2231.3	2773.4	5004.7
THERMAL POWER PLANT PROJECTS																
1. Khanom Second Power Plant Barge	819.3	307.0	347.0	262.2	339.4	33.0	-	-	-	-	1505.7	602.2	2107.9	1687.4	622.2	2309.6
2. Mae Moh Unit 8	1135.1	788.8	1551.8	941.0	758.0	338.8	-	-	-	-	3444.9	2068.6	5513.5	4467.0	2531.0	6998.0
3. Mae Moh Unit 9	652.3	144.6	336.4	354.6	1865.9	853.1	864.0	613.0	296.3	8.5	4014.9	1973.8	5988.7	4014.9	2111.1	6126.0
Subtotal	2606.7	1240.4	2235.2	1557.8	2963.3	1224.9	864.0	613.0	296.3	8.5	8965.5	4644.6	13610.1	10169.3	5264.3	15433.6
MINING PROJECT																
1.Mae Moh Mine Expansion for Mae Moh Units 5,6,7	13.4	91.2	74.9	204.4	263.7	160.3	-	-	-	-	352.0	455.9	807.9	747.8	1264.6	2012.4
Subtotal	13.4	91.2	74.9	204.4	263.7	160.3	-	-	-	-	352.0	455.9	807.9	747.8	1264.6	2012.4

TABLE 11-4 (CONTINUED)
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

Projects in the Fifth Plan and Commissioning in the Sixth Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
TRANSMISSION PROJECTS																
1. 230 kV Phatthalung-Hat Yai 2	18.8	21.6	-	-	-	-	-	-	-	-	18.8	21.6	40.4	129.1	69.1	198.2
2. Transmission System Expansion No.6	170.0	246.3	-	11.1	-	-	-	-	-	-	170.0	257.4	427.4	878.3	1033.1	1911.4
3. EHV Transmission System Stage 1 (For Mae Moh Unit 7)	26.9	143.3	-	12.6	-	-	-	-	-	-	26.9	155.9	182.8	820.8	970.5	1791.3
4. EHV Transmission System Stage 2 (For Mae Moh Unit 8)	34.0	26.3	380.9	201.0	45.5	58.5	-	-	-	-	460.4	285.8	746.2	460.4	300.2	760.6
5. EHV Transmission System Stage 3 (For Mae Moh Unit 9)	65.2	49.7	276.9	196.6	715.5	412.8	-	232.0	-	-	1057.6	891.1	1948.7	1061.4	893.6	1955.0
Subtotal	314.9	487.2	657.8	421.3	761.0	471.3	-	232.0	-	-	1733.7	1611.8	3345.5	3350.0	3266.5	6616.5
Total (Projects in the Fifth Plan and Commissioning in the Sixth Plan)	3224.2	2240.8	2967.9	2183.5	3908.0	1856.5	864.0	845.0	296.3	8.5	11340.4	7134.3	18474.7	16408.4	12508.8	29057.2

TABLE 11-5
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

2. Projects in the Sixth Plan and Commissioning in the Sixth Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
HYDROELECTRIC PROJECT																
1. Srinagarind Unit 5	-	-	-	-	6.6	5.5	604.9	190.2	75.5	112.3	687.0	308.0	995.0	687.0	308.0	995.0
Subtotal	-	-	-	-	6.6	5.5	604.9	190.2	75.5	112.3	687.0	308.0	995.0	687.0	308.0	995.0
THERMAL POWER PLANT PROJECTS																
1. Bang Pakong Combined Cycle Block 3	-	-	19.5	1.0	440.2	282.9	1343.1	1053.5	1183.3	831.1	2986.1	2168.5	5154.6	2986.1	2168.5	5154.6
2. Bang Pakong Combined Cycle Block 4	-	-	-	-	394.4	163.4	1244.7	808.4	1113.4	694.7	2752.5	1666.5	4419.0	2752.5	1666.5	4419.0
3. New Combined Cycle Block 1	-	-	-	-	310.5	239.0	2104.1	1353.2	789.2	599.7	3203.8	2191.9	5395.7	3203.8	2191.9	5395.7
4. New Combined Cycle Block 2	-	-	-	-	272.1	54.0	1905.5	957.7	705.2	[illegible]	2882.8	1552.3	4435.1	2882.8	1552.3	4435.1
5. Lan Krabu Combined Cycle (Steam Turbine)	-	-	-	-	129.5	12.4	560.0	335.3	156.8	108.1	846.3	455.8	1302.1	846.3	455.8	1302.1
Subtotal	-	-	19.5	1.0	1546.7	751.7	7157.4	4508.1	3947.9	2774.2	12671.5	8035.0	20706.5	12671.5	8035.0	20706.5
MINING PROJECT																
1. Mae Moh Mine Expansion (Stage 1) for Mae Moh Units 8,9	-	55.1	-	262.6	150.1	615.8	523.2	1302.1	366.8	1253.7	1040.1	3489.3	4529.4	1040.1	3489.3	4529.4
Subtotal	-	55.1	-	262.6	150.1	615.8	523.2	1302.1	366.8	1253.7	1040.1	3489.3	4529.4	1040.1	3489.3	4529.4
TRANSMISSION PROJECTS																
1. Second Central-Southern Tie Line	-	32.0	277.0	91.4	100.4	167.4	59.6	362.2	-	-	517.0	653.0	1170.0	517.0	653.0	1170.0
2. Transmission System Expansion No.7																
Part A	-	25.4	259.2	214.2	547.5	568.1	363.3	432.3	-	-	1170.0	1240.0	2410.0	1170.0	1240.0	2410.0
Part B	-	1.5	3.9	25.3	94.9	60.7	306.2	284.5	-	-	405.0	372.0	777.0	405.0	372.0	777.0
3. 230 kV Khon Kaen 3-Roi Et	-	-	-	-	124.6	73.1	125.2	177.4	32.2	49.5	282.0	300.0	582.0	282.0	300.0	582.0
Subtotal	-	58.9	540.1	330.9	947.4	869.3	854.3	1256.4	32.2	49.5	2374.0	2565.0	4939.0	2374.0	2565.0	4939.0

3. 230 kV Khon Kaen 3-Roi Et	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Subtotal	-	58.9	540.1	330.9	947.4	869.3	854.3	1256.4	32.2	49.5	2374.0	2565.0	4939.0	2374.0	2565.0	4939.0

TABLE 11-5 (CONTINUED)
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

Projects in the Sixth Plan and Commissioning in the Sixth Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
Miscellaneous Transmission System Expansions and Construction Work	37.7	728.4	10.6	742.6	128.1	1130.9	200.0	800.0	200.0	800.0	576.4	4201.9	4778.3	-	-	-
Subtotal	37.7	728.4	10.6	742.6	128.1	1130.9	200.0	800.0	200.0	800.0	576.4	4201.9	4778.3	-	-	-
Total (Projects in the Sixth Plan and Commissioning in the Sixth Plan)	37.7	842.4	570.2	1337.1	2778.9	3373.2	9339.8	8056.8	4622.4	4909.7	17349.0	18599.2	35948.2	16772.6	14397.3	31169.9

TABLE 11-6
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

3. Projects in the Sixth Plan and Commissioning in the Seventh Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
HYDROELECTRIC PROJECTS																
1. Kaeng Krung Units 1,2	-	-	-	7.1	25.0	212.3	142.5	226.7	352.8	377.8	520.3	823.9	1344.2	1255.0	1635.0	2890.0
2. Pak Mun Units 1,2,3,4	-	-	-	-	18.0	43.8	17.3	184.7	297.9	494.0	333.2	722.5	1055.7	1940.0	1940.0	3880.0
3. Bhumibol Hydro Plant Renovation	-	-	-	-	-	-	80.1	14.6	345.8	87.5	425.9	102.1	528.0	484.9	124.8	609.7
4. Bhumibol Unit 8	-	-	-	-	-	-	-	-	4.3	40.5	4.3	40.5	44.8	1248.0	902.0	2150.0
Subtotal	-	-	-	7.1	43.0	256.1	239.9	426.0	1000.8	999.8	1283.7	1689.0	2972.7	4927.9	4601.8	9529.7
THERMAL POWER PLANT PROJECTS																
1. Bang Pakong Thermal Unit 3	-	-	-	-	743.5	178.5	1271.3	1000.2	1152.8	2269.6	3147.6	3448.3	6595.9	5223.7	5925.8	11149.5
2. Bang Pakong Thermal Unit 4	-	-	-	-	168.0	55.0	611.1	609.4	1881.3	1994.7	2660.4	2659.1	5319.5	5000.0	5722.0	10722.0
3. Krabi Lignite Unit 4	-	-	-	-	171.7	83.8	286.0	166.1	880.0	578.8	1337.7	828.7	2166.4	1861.7	1251.2	3112.9
4. Nam Phong Combined Cycle Blocks 1-2	-	-	-	-	30.8	35.3	1932.4	771.4	786.1	592.3	2749.3	1399.0	4148.3	2874.8	1480.2	4355.0
5. New Combined Cycle Block 3	-	-	-	-	272.1	38.0	1224.6	897.2	622.4	596.5	2119.1	1531.7	3650.8	2925.7	1938.5	4864.2
6. Mae Moh Unit 10	-	-	-	-	526.8	308.6	2403.4	1210.3	531.0	911.1	3461.2	2430.0	5891.2	4335.3	3323.9	7659.2
7. Mae Moh Unit 11	-	-	-	-	-	-	527.8	296.3	1439.8	903.9	1967.6	1200.2	3167.8	3788.3	2746.3	6534.6
8. Mae Moh Unit 12	-	-	-	-	-	-	506.3	220.3	788.5	639.1	1294.8	859.4	2154.2	4139.0	3192.5	7331.5
9. Mae Moh Unit 13	-	-	-	-	-	-	-	-	510.4	224.6	510.4	224.6	735.0	4172.0	3227.0	7399.0
10. Mae Moh Unit 14	-	-	-	-	-	-	-	-	510.4	224.6	510.4	224.6	735.0	4172.0	3227.0	7399.0
Subtotal	-	-	-	-	1912.9	699.2	8762.9	5171.2	9082.7	8935.2	19758.5	14805.6	34564.1	38492.5	32034.4	70526.9

TABLE 11-6 (CONTINUED)
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

TABLE 1: 6 (CONTINUED)
EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

Projects in the Sixth Plan and Commissioning in the Seventh Plan

(Unit : Million Baht)

Projects	Capital Expenditures										Total Expenditures (1987-1991)			Total Project Cost		
	1987		1988		1989		1990		1991							
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total	F.C.	L.C.	Total
MINING PROJECTS																
1. Krabi Mine Expansion for Krabi Lignite Unit 4	-	-	-	-	-	15.1	-	0.4	-	27.7	-	43.2	43.2	326.3	239.7	566.0
2. Mae Moh Mine Expansion for Mae Moh Unit 10	-	-	-	-	-	-	112.0	248.0	109.0	264.0	221.0	512.0	733.0	256.0	570.0	826.0
3. Mae Moh Mine Expansion for Mae Moh Unit 11	-	-	-	-	-	-	-	-	-	164.0	-	164.0	164.0	518.0	663.0	1181.0
4. Mae Moh Mine Expansion for Mae Moh Unit 12	-	-	-	-	-	-	-	-	182.0	251.0	182.0	251.0	433.0	1853.0	1143.0	2996.0
5. Saba Yoi Mine Development for Saba Yoi Units 1,2	-	-	-	-	-	-	-	134.0	-	860.0	-	994.0	994.0	1498.0	4221.0	5719.0
Subtotal	-	-	-	-	-	15.1	112.0	382.4	291.0	1566.7	403.0	1964.2	2367.2	4451.3	6836.7	11288.0
TRANSMISSION PROJECTS																
1. Accelerated Transmission Project	-	-	-	-	1.0	8.9	550.4	379.7	613.6	569.3	1165.0	957.9	2122.9	1230.0	980.0	2210.0
2. 230 kV Tha Tako-Khon Kaen 3	-	-	-	-	-	66.6	240.9	110.2	164.7	227.9	405.6	404.7	810.3	430.0	460.0	890.0
3. Transmission System Expansion No.8	-	-	-	-	-	9.4	-	41.8	273.0	281.4	273.0	332.6	605.6	1298.3	1274.7	2573.0
4. EHV Transmission System for Mae Moh Unit 10	-	-	-	-	60.6	78.5	402.3	180.8	506.4	672.0	969.3	931.3	1900.6	1101.0	1132.1	2233.1
5. EHV Transmission System for Mae Moh Unit 11	-	-	-	-	5.1	6.9	-	8.9	47.4	159.8	52.5	175.6	228.1	707.0	892.1	1599.1
6. EHV Transmission System for Mae Moh Unit 12	-	-	-	-	-	-	-	-	-	5.6	-	5.6	5.6	714.3	592.7	1307.0
Subtotal	-	-	-	-	66.7	170.3	1193.6	721.4	1605.1	1916.0	2865.4	2807.7	5673.1	5480.6	5331.6	10812.2
Total (Projects in the Sixth Plan and Commissioning in the Seventh Plan)	-	-	-	7.1	2022.6	1140.7	10308.4	6701.0	11979.6	13417.7	24310.6	21266.5	45577.1	53352.3	48801.5	102156.8

TABLE 11-7
SUMMARY EGAT SIXTH FIVE-YEAR INVESTMENT PLAN (1987-1991)
PDP 88-02

(Unit : Million Baht)

Description	Capital Expenditures										Total Expenditures (1987-1991)		
	1987		1988		1989		1990		1991				
	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	F.C.	L.C.	Total
1. Projects in the Fifth Plan and Commissioning in the Sixth Plan	3,224.2	2,240.8	2,967.9	2,183.5	3,908.0	1,856.5	864.0	845.0	296.3	8.5	11,340.4	7,134.3	18,474.7
2. Projects in the Sixth Plan and Commissioning in the Sixth Plan	37.7	842.4	570.2	1,337.1	2,778.9	3,373.2	9,339.8	8,056.8	4,622.4	4,989.7	17,349.0	18,599.2	35,948.2
3. Projects in the Sixth Plan and Commissioning in the Seventh Plan	-	-	-	7.1	2,022.6	1,140.7	10,300.4	6,701.0	11,979.6	13,417.7	24,310.6	21,266.5	45,577.1
Total Capital Expenditures	3,261.9	3,083.2	3,538.1	3,527.7	8,709.5	6,370.4	20,512.2	15,602.8	16,898.3	18,415.9	53,000.0	47,000.0	100,000.0
	6,345.1		7,065.8		15,159.9		36,115.0		35,314.2				

Note : Fifth Plan 1982-1986
Sixth Plan 1987-1991
Seventh Plan 1992-1996

A P P E N D I X E S

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LIST OF EXISTING POWER PLANTS AND IN-SERVICE DATES-AS OF JULY 1988

Plants	Fuel Type	Unit No.	Rating (MW)	Total (MW)	In-Service Date
Hydro Power Plants					
Bhumibol	Hydro	1	70	535	May 17, 1964
		2	70		Jun 15, 1964
		3	70		May 11, 1967
		4	70		Aug 9, 1967
		5	70		Oct 25, 1968
		6	70		Aug 18, 1969
		7	115		Oct 18, 1982
Sirikit	Hydro	1	125	375	Jan 12, 1974
		2	125		Mar 18, 1974
		3	125		Jul 3, 1974
Ubolratana	Hydro	1	8.3	25	Mar 13, 1966
		2	8.3		Mar 13, 1966
		3	8.3		Jun 19, 1968
Sirindhorn	Hydro	1	12	36	Nov 1, 1971
		2	12		Oct 31, 1971
		3	12		Mar 28, 1984
Chulabhorn	Hydro	1	20	40	Oct 29, 1972
		2	20		Nov 6, 1972
Kang Krachan	Hydro	1	19	19	Aug 7, 1974
Nam Pung	Hydro	1	3	6	Oct 20, 1965
		2	3		Oct 20, 1965
Srinagarind	Hydro	1	120	540	Feb 12, 1980
		2	120		Feb 26, 1980
		3	120		Mar 19, 1980
		4	180		Nov 23, 1985
Bang Lang	Hydro	1	24	72	Jul 7, 1981
		2	24		Aug 10, 1981
		3	24		Oct 25, 1981
Tha Thung Na	Hydro	1	19	38	Dec 24, 1981
		2	19		Feb 10, 1982
Khao Laem	Hydro	1	100	300	Feb 13, 1985
		2	100		Feb 7, 1985
		3	100		Dec 5, 1984
Ban Yang	Hydro	1	0.0125	0.12	Feb , 1974
		2	0.0560		
		3	0.0560		
Huai Kum	Hydro	1	1.3	1.3	Feb 11, 1982
Ban Santi	Hydro	1	1.3	1.3	Oct 19, 1982
Ban Chong Klum	Hydro	1	0.02	0.02	Sep 3, 1984
Ban Khun Klang	Hydro	1	0.09	0.18	Dec 5, 1983
		2	0.09		
Mae Ngat	Hydro	1	4.50	9.00	Oct 19, 1985
		2	4.50		Sep 25, 1985
Huai Saphan Hin	Hydro	1	6.1	12.2	Oct 7, 1986
		2	6.1		Oct 11, 1986
Rajjaprabha	Hydro	1	80.0	240	Jun 6, 1987
		2	80.0		Apr 8, 1987
		3	80.0		Dec 23, 1986
Total		48		2,250.12	

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LIST OF EXISTING POWER PLANTS AND IN-SERVICE DATES-AS OF JULY 1988
(CONTINUED)

Plants	Fuel Type	Unit No.	Rating (MW)	Total (MW)	In-Service Date
Thermal Power Plants					
North Bangkok	Heavy Oil	1	75.0		Mar 25, 1961
		2	75.0	237.5	Jun 26, 1963
		3	87.5		Dec 31, 1968
South Bangkok	Heavy Oil	1	200.0		Dec 18, 1970
		2	200.0		Nov 16, 1971
	Gas/Heavy Oil	3	300.0	1,300.0	Jun 11, 1974
		4	300.0		Sep 22, 1975
		5	300.0		Nov 11, 1977
Mae Moh	Lignite	1	75.0		Mar 31, 1978
		2	75.0		Dec 22, 1978
		3	75.0	825.0	Feb 17, 1981
		4	150.0		Mar 17, 1984
		5	150.0		Sep 1, 1984
		6	150.0		Mar 13, 1985
		7	150.0		Sep 2, 1985
Krabi a/	Lignite	1	20.0	40.0	Jun 26, 1964
		3	20.0		Jun 6, 1968
Surat Thani	Heavy Oil	1	30.0	30.0	Feb 26, 1973
Khanom PPB	Heavy Oil	1	75.0	75.0	Jan 6, 1981
Bang Pakong Thermal	Gas/Heavy Oil	1	550.0	1,100.0	Aug 4, 1983
		2	550.0		May 21, 1984
Total		21		3,607.5	
Combined Cycle Power Plants					
Bang Pakong Combined Cycle-Block 1					
- Bang Pakong Gas Turbine	Gas/Diesel b/ Oil	11	62.2		Oct 29, 1980
		12	62.2	248.8	Dec 2, 1980
		13	62.2		Jan 30, 1981
		14	62.2		Jul 2, 1981
- Bang Pakong Steam Turbine	-	10	137.0	137.0	Dec 28, 1982

Notes : a/ The turbine of Krabi Unit 2 has broken down since November 19, 1985
b/ Also treated heavy oil can be used.

LIST OF EXISTING POWER PLANTS AND IN-SERVICE DATES-AS OF JULY 1988
(CONTINUED)

Plants	Fuel Type	Unit No.	Rating (MW)	Total (MW)	In-Service Date
Combined Cycle Power Plants (Continued)					
Bang Pakong Combined Cycle-Block 2					
- Bang Pakong Gas Turbine	Gas/Diesel Oil	21	62.2	248.8	Sep 23, 1981
		22	62.2		Oct 29, 1981
		23	62.2		Jan 15, 1982
		24	62.2		Mar 5, 1982
- Bang Pakong Steam Turbine	-	02	137.0	137.0	Jul 15, 1983
Total		10		771.6	
Gas Turbine Power Plants					
Nakhon Ratchasima	Diesel Oil	1	15.0	15.0	Jan 14, 1968
Udon Thani	Diesel Oil	1	15.0	15.0	Jun 10, 1969
Hat Yai	Diesel Oil	1	15.0	45.0	Aug 16, 1971
		2	15.0		Jan 2, 1969
		3	15.0		Jan 20, 1970
Surat Thani	Diesel Oil	3	15.0	45.0	Jan 8, 1970
		4	15.0		May 8, 1969
		5	15.0		Jan 9, 1970
Lan Krabu	Gas	1 c/	15.0	145.0	Feb 24, 1970
		2 c/	15.0		May 30, 1969
		3 c/	15.0		Apr 13, 1969
		5 d/	25.0		Mar 30, 1981
		6 d/	25.0		Apr 1, 1981
		7 e/	25.0		Mar 25, 1981
		8 f/	25.0		Mar 25, 1981
Total		15		265.0	
GRAND TOTAL		94		6,894.2	

Notes: c/ Shifted from Surat Thani GT Units 1, 2 and Ao Phai GT Unit 1 to Lan Krabu for Units 1, 2 and 3 commissioned on April 11, 1983, August 3, 1983 and August 14, 1984 respectively.

d/ Shifted from South Bangkok GT Units 3 and 2 to Lan Krabu Units 5 and 6 commissioned on June 28, 1983 and Oct 10, 1984 respectively.

e/ Shifted from South Bangkok GT Unit 4 on February 18, 1985.

f/ Shifted from Songkhla and commissioning on February 14, 1988.

LIST OF UNDER CONSTRUCTION AND COMMITTED POWER PLANTS WITH ASSOCIATED TRANSMISSION SYSTEMS

Name of Project	Scope of Work for Power Plant	Scope of Work for Associated Transmission System
1. Mae Moh Lignite-Fired Unit 8	One 300 MW lignite-fired	- Conversion of 326 km Mae Moh-Tha Tako Line from 230 kV to 500 kV and related substations.
2. Mae Moh Lignite-Fired Unit 9	One 300 MW lignite-fired	- 500 kV Tha Tako-Nong Chok, 4x795 MCM, ACSR, SC/ST 210 km and related substations.
3. Khanom Second Power Plant Barge	One 75 MW oil-fired	- Conversion of Khanom-Nakhon Si Thammarat-Phatthalung-Hat Yai 2 from 115 kV to 230 kV and related substations. - Termination of 115 kV Hat Yai 1-Sadao Line to Hat Yai 2 Substation, DC/ST, 477 MCM ACSR, 6 km.
4. Lan Krabu Gas Turbine Unit 8	Addition of one 25 MW gas turbine (shifted from Songkhla Substation)	- 115 kV Lan Krabu-Phitsanulok 2, 477 MCM, SC/ST, 52 km.

LIST OF UNDER CONSTRUCTION AND COMMITTED POWER PLANTS WITH ASSOCIATED TRANSMISSION SYSTEM
(CONTINUED)

Name of Project	Scope of Work for Power Plant	Scope of Work for Associated Transmission System
5. Bang Pakong Combined Cycle Blocks 3-4	Four units of 100 MW gas turbines and two steam turbines	- Modification of 230 kV DC/ST Bang Pakong-Bang Phli Line from 1x1,272 to 2x1,272 MCM ACSR conductor/phase 44.5 km. - Installation of two bus sectionalizer circuit breakers at Bang Pakong Switchyard.
6. Srinagarind Unit 5	One 180 MW, reversible pumped turbine	- Construction of new 230 kV Sai Noi Substation.
7. Mae Moh Lignite-Fired Unit 10	One 300 MW, lignite-fired	- 500 kV Mae Moh-Tha Tako, 4x795 MCM, ACSR, SC on DC/ST, 326 km and related substations.
8. Bang Pakong Thermal Unit 3	One 600 MW, oil/gas-fired	- Modification of 230 kV DC/ST Bang Kapi-Lat Phrao line from 1x1,272 to 2x1,272 MCM ACSR conductor/phase, 10.4 km. - Modification of 230 kV DC/SC Bang Phli-South Bangkok line from 1x1,272 to 2x1,272 MCM ACSR conductor/phase, 15.9 km.

LEVEL OF GENERATION, TRANSMISSION AND DISTRIBUTION LOSSES

Year	Energy Generation (GWh)	Generating losses		Transmission and Substation losses1/		Distribution losses (MEA and PEA)		Total Losses (EGAT MEA and PEA)	
		GWh	%	GWh	%	GWh	%	GWh	%
1980	14,753.73	590.45	4.00	583.95	3.96	845.13	5.73	2,019.52	13.69
1981	15,959.97	612.29	3.84	842.06	5.28	870.24	5.45	2,324.59	14.57
1982	16,881.95	602.49	3.57	917.49	5.43	870.52	5.16	2,390.49	14.16
1983	19,066.30	659.05	3.46	901.17	4.73	1,157.17	6.07	2,717.38	14.25
1984	21,066.44	830.10	3.94	931.63	4.42	1,336.86	6.35	3,098.58	14.71
1985	23,356.74	1,022.81	4.38	1,167.20	5.00	1,392.43	5.96	3,582.44	15.34
1986	24,779.53	1,010.03	4.08	1,335.38	5.39	1,483.63	5.99	3,829.04	15.45
1987	28,193.16	1,154.68	4.10	1,211..46	4.30 2/	1,714.43	6.08	4,080.52	14.47

Notes : 1/ Including MEA and PEA Sub-Transmission, street lighting, mining and construction used.
2/ Reduction of about 1 percent transmission loss was due to the commissioning of Mae Moh-Tha Tako 500 kV line (4x795 MCM ACSR conductor per phase), which is being energized at 230 kV; the installations of reactive power compensation equipment such as static VAr control (SVC) at Chumphon and shunt capacitor banks.

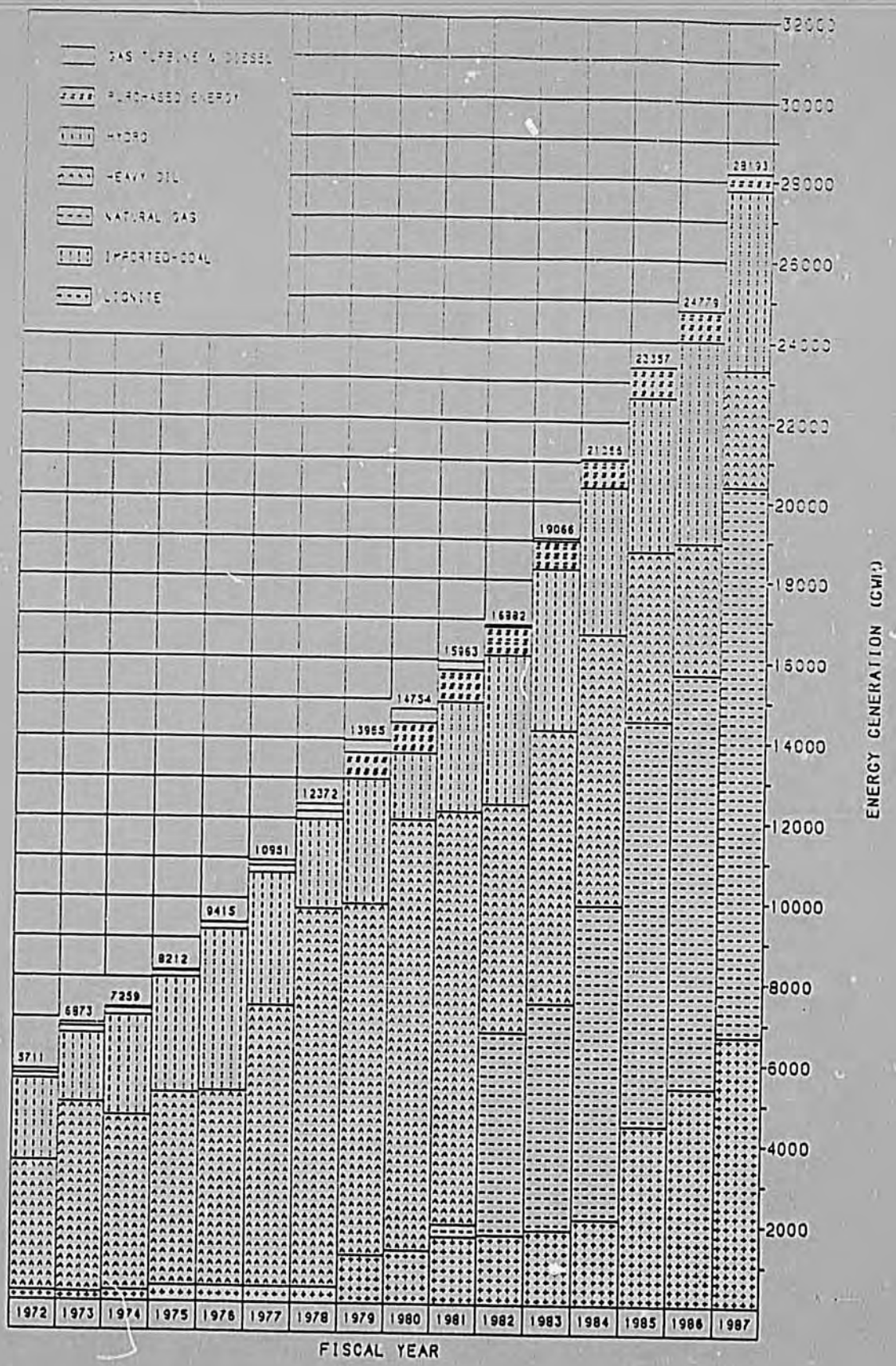
RECORD OF ELECTRICITY GENERATION AND SALES

Year	Generation				Sales		GDP Growth Rate (% p.a.)	Population Electrified as a Percentage of Total Population	No. of Consumers
	Power (MW)	Growth Rate (%)	Energy (GWh)	Growth Rate (%)	Energy (GWh)	Growth Rate (%)			
1980	2,417.40	7.20	14,753.73	5.66	13,006.97	5.64	5.8	36.61	2,624,303
1981	2,588.70	7.09	15,959.97	8.18	13,892.52	6.81	6.3	41.42	3,064,135
1982	2,838.00	9.63	16,881.95	5.78	14,772.17	6.33	4.1	46.25	3,560,846
1983	3,204.30	12.91	19,066.30	12.94	16,455.97	11.40	5.8	50.57	4,062,423
1984	3,547.30	10.70	21,066.44	10.49	18,039.45	9.62	6.2	53.52	4,533,951
1985	3,878.40	9.33	23,356.57	10.87	19,814.19	9.84	4.0	56.74	5,016,084
1986	4,180.90	7.80	24,779.53	6.09	21,013.84	6.05	3.4	60.76	5,543,315
1987	4,733.90	13.23	28,193.16	13.78	24,170.85	15.02	6.6	63.51	6,121,373
Average Growth Rate (%) 1980-1987		9.71		9.18		7.97			

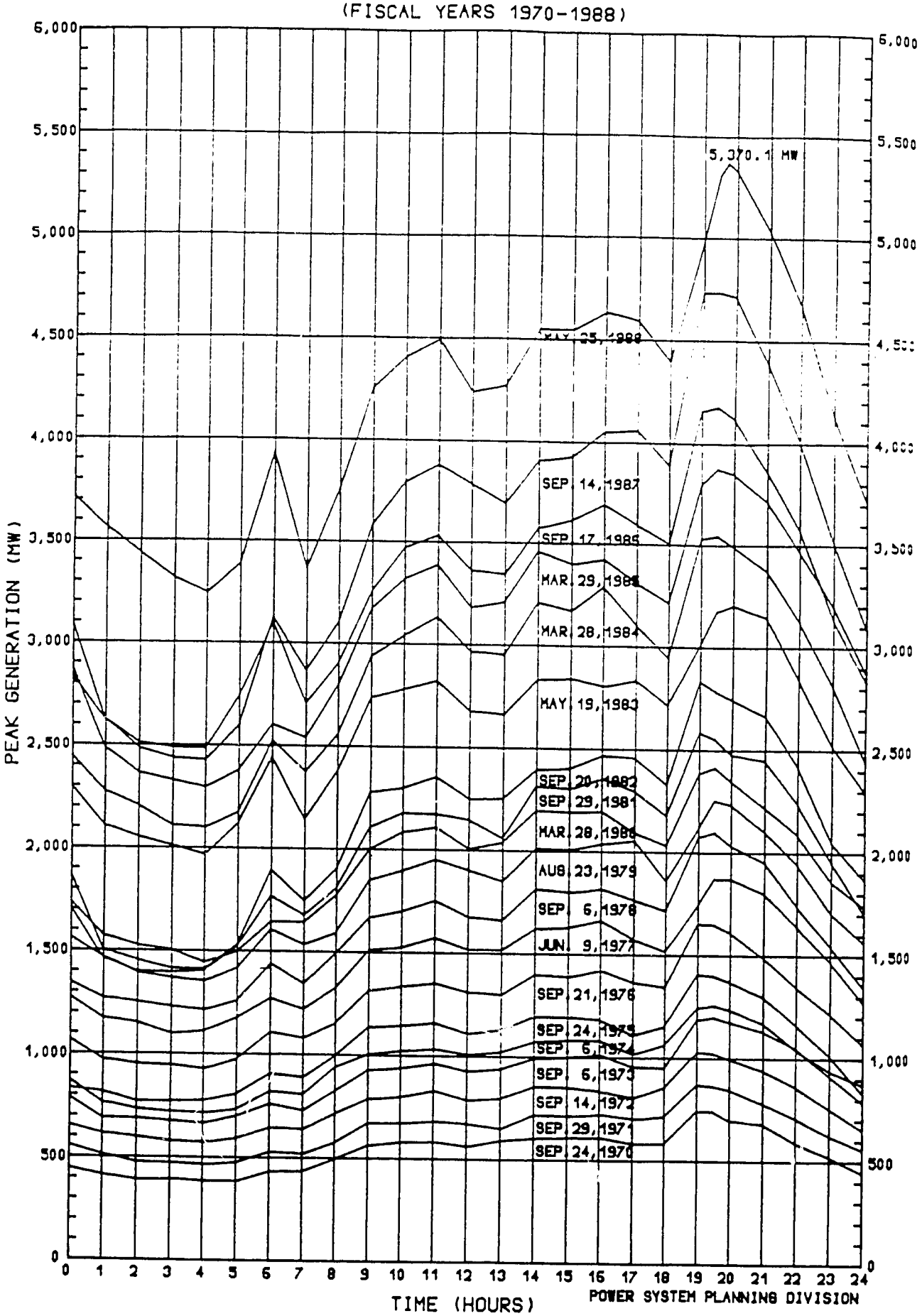
EGAT RECORDED ENERGY GENERATION FOR EXISTING POWER PLANTS

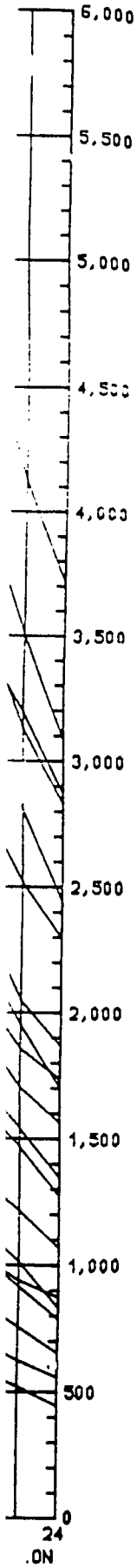
Type of Power Plant	Units	Fiscal Year															
		1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
1. Hydro	GWh	2,020	1,698	2,466	2,846	3,985	3,295	2,212	3,099	1,653	2,720	3,699	4,015	3,682	3,871	5,051	4,460
	%	35.4	24.7	34.0	34.7	42.3	30.1	17.9	22.2	11.2	17.0	21.9	21.1	17.4	16.6	20.4	15.8
2. Natural Gas	GWh	-	-	-	-	-	-	-	-	-	305	4,629	5,613	7,780	10,049	10,270	14,109
	%	-	-	-	-	-	-	-	-	-	1.9	27.4	29.4	36.9	43.0	41.5	50.0
	MMCFD	-	-	-	-	-	-	-	-	-	39	121	138	190	255	258	356
3. Heavy Oil	GWh	3,199	4,683	4,319	4,770	4,829	6,950	9,358	8,694	10,672	10,243	6,066	6,795	6,751	4,223	3,281	2,509
	%	56.0	68.1	59.5	58.1	51.3	63.5	75.6	62.3	72.3	64.2	35.9	35.6	32.1	18.1	13.2	8.9
	10^6 Litres	826	1,193	1,124	1,244	1,273	1,834	2,420	2,307	2,821	2,674	1,603	1,743	1,720	1,100	858	667
4. Diesel Oil	GWh	121	105	26	41	32	130	199	307	349	229	60	80	32	8	11	2
	%	2.1	1.5	0.3	0.5	0.3	1.2	1.6	2.2	2.4	1.4	0.4	0.4	0.2	0.0	0.0	0.0
	10^6 Litres	63	52	16	20	17	60	101	153	172	104	25	27	22	3	5	1
5. Lignite	GWh	251	230	282	408	405	402	415	1,206	1,327	1,671	1,726	1,850	2,126	4,451	5,402	6,682
	%	4.4	3.4	3.9	5.0	4.3	3.7	3.4	8.6	9.0	10.5	10.2	9.7	10.1	19.1	21.8	23.7
	10^6 Tons	0.321	0.314	0.361	0.472	0.429	0.409	0.388	1.164	1.239	1.547	1.566	1.630	1.797	3.853	4.522	5.970
6. Purchase	GWh	120	157	166	147	164	174	188	659	753	795	702	713	695	755	764	431
	%	2.1	2.3	2.3	1.7	1.8	1.5	1.5	4.7	5.1	5.0	4.2	3.8	3.3	3.2	3.1	1.6
Total	GWh	5,711	6,873	7,259	8,212	9,415	10,951	12,372	13,965	14,754	15,963	16,882	19,066	21,066	23,357	24,779	28,193
	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

EGAT RECORDED ENERGY GENERATION AND PURCHASED
(FISCAL YEARS 1972-1987)



EGAT RECORDED DAILY LOAD CURVES ON PEAK DAY
(FISCAL YEARS 1970-1988)





COMPARISON OF LOAD FORECASTS

The new official load forecast (July 1988) was presented by the Load Forecas Working Group in July 1988 divided into 2 cases; i.e., Base Case and Low Case.

The new load forecast seems to be very high in growth rate compared to the previous forecast presented in October 1987 as reason indicated in chapter 5.

To compare the Working Group's-July 1988 to the October 1987 load forecasts, the observation can be summarized as follows :

For the Base Case load forecast, the growth rates for the peak and energy in the 6th, 7th and 8th plan will be 3.06, 1.00, 1.27 and 3.30, 1.07, 1.26 percent higher.

For the Low Case load forecast, the growth rates for the peak and energy in the consequent plans will be 2.49, 0.12, 0.66 and 2.68, 0.09,0.66 percent higher.

The Low Case load forecast and the comparison of them are shown in the following pages.

However, after the Working Group has completed the data collection from MEA, PEA and NESDB, including improvement of the methodology, this load forecast will be revised accordingly and expected to represent by October 1989.

TOTAL EGAT GENERATION REQUIREMENT
(LOW CASE LOAD FORECAST)

Fiscal Year	Peak Generation		Energy Generation		Load Factor
	MW	% Increase	GWh	% Increase	%
		Actual			
1973	1,199.30	16.57	6,872.84	20.34	65.42
1974	1,256.30	4.75	7,258.72	5.61	65.96
1975	1,406.60	11.96	8,211.57	13.13	66.64
1976	1,652.10	17.45	9,414.48	14.64	65.05
1977	1,873.40	13.40	10,950.62	16.32	66.73
1978	2,100.60	12.13	12,371.67	12.98	67.23
1979	2,255.00	7.35	13,964.55	12.88	70.69
1980	2,417.40	7.20	14,753.73	5.65	69.67
1981	2,588.70	7.09	15,959.97	8.18	70.38
1982	2,838.00	9.63	16,881.95	5.78	67.91
1983	2,204.30	12.91	19,066.30	12.94	67.92
1984	3,547.30	10.70	21,066.44	10.49	67.79
1985	3,878.40	9.33	23,345.57	10.87	68.75
1986	4,180.90	7.80	24,779.53	6.09	67.66
1987	4,733.90	13.23	28,193.16	13.78	67.99
Average Growth Rate % 1977-1987	-	10.04	-	10.49	-
		Forecast			
1988	5,417.00	14.43	32,497.00	15.27	68.48
1989	6,022.00	11.17	36,182.00	11.34	68.59
1990	6,642.00	10.30	39,966.00	10.46	68.69
1991	7,255.00	9.23	43,841.00	9.70	68.98
1992	7,901.00	8.90	47,991.00	9.47	69.34
1993	8,495.00	7.52	51,779.00	7.89	69.58
1994	9,095.00	7.06	55,775.00	7.72	70.01
1995	9,712.00	6.78	59,922.00	7.44	70.43
1996	10,359.00	6.66	64,250.00	7.22	70.80
1997	10,994.00	6.13	68,456.00	6.55	71.08
1998	11,645.00	5.92	72,939.00	6.55	71.50
1999	12,323.00	5.82	77,454.00	6.19	71.75
2000	13,030.00	5.74	82,224.00	6.16	72.04
2001	13,732.00	5.39	87,130.00	5.97	72.43
Average Growth Rate %					
1987-1991	-	11.65	-	12.09	-
1992-1996	-	7.38	-	7.94	-
1997-2001	-	5.80	-	6.28	-

Reference : Working Group Load Forecast
(Low Case) July 1988

COMPARISON OF LOAD FORECASTS

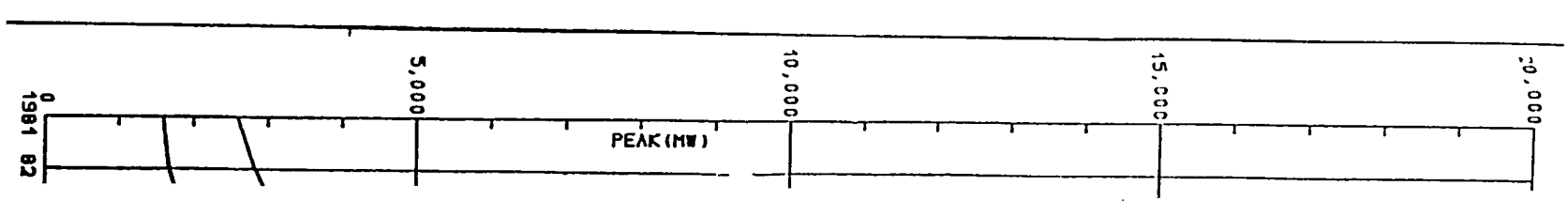
FISCAL YEAR	OCTOBER 1987		JULY 1988 (BASE CASE)		DIFFERENCE			
	MW	GWH	MW	GWH	MW	%	GWH	%
1988	5,097.00	30,467.00	5,444.00	32,596.00	347.00	6.81	2,129.00	6.99
1989	5,508.00	32,982.00	6,098.00	36,584.00	590.00	10.71	3,602.00	10.92
1990	5,980.00	35,826.00	6,759.00	40,746.00	779.00	13.03	4,920.00	13.73
1991	6,481.00	38,854.00	7,440.00	45,062.00	959.00	14.80	6,208.00	15.98
1992	7,082.00	42,667.00	8,173.00	49,793.00	1,091.00	15.41	7,126.00	16.70
1993	7,611.00	46,097.00	8,867.00	54,240.00	1,256.00	16.50	8,143.00	17.66
1994	8,137.00	49,570.00	9,578.00	58,964.00	1,441.00	17.71	9,394.00	18.95
1995	8,674.00	53,157.00	10,304.00	63,924.00	1,630.00	18.79	10,767.00	20.26
1996	9,202.00	56,702.00	11,066.00	69,065.00	1,864.00	20.26	12,363.00	21.80
1997	9,731.00	60,263.00	11,816.00	74,016.00	2,085.00	21.43	13,753.00	22.82
1998	10,255.00	63,795.00	12,596.00	79,170.00	2,341.00	22.83	15,375.00	24.10
1999	10,766.00	67,360.00	13,414.00	84,666.00	2,638.00	24.48	17,306.00	25.69
2000	11,294.00	70,949.00	14,271.00	90,568.00	2,977.00	26.36	19,619.00	27.65
2001	11,821.00	74,546.00	15,112.00	96,373.00	3,291.00	27.84	21,827.00	29.28
Average Growth Rate (%)								
1987-1991	9.16	9.41	12.22	12.71	3.06	-	3.30	-
1992-1996	7.26	7.85	8.26	8.92	1.00	-	1.07	-
1997-2001	5.14	5.62	6.43	6.89	1.27	-	1.26	-

July 1988

COMPARISON OF LOAD FORECASTS

FISCAL YEAR	OCTOBER 1987		JULY 1988 (LOW CASE)		DIFFERENCE			
	MW	GWH	MW	GWH	MW	%	GWH	%
1988	5,097.00	30,467.00	5,417.00	32,497.00	320.00	6.28	2,030.00	6.66
1989	5,508.00	32,982.00	6,022.00	36,182.00	514.00	9.33	3,200.00	9.70
1990	5,980.00	35,826.00	6,642.00	39,966.00	662.00	11.07	4,140.00	11.56
1991	6,481.00	38,854.00	7,255.00	43,841.00	774.00	11.94	4,987.00	12.84
1992	7,082.00	42,667.00	7,901.00	47,991.00	819.00	11.56	5,324.00	12.48
1993	7,611.00	46,097.00	8,495.00	51,779.00	884.00	11.61	5,682.00	12.33
1994	8,137.00	49,570.00	9,095.00	55,775.00	958.00	11.77	6,205.00	12.52
1995	8,674.00	53,157.00	9,712.00	59,922.00	1,038.00	11.97	6,765.00	12.73
1996	9,202.00	56,702.00	10,359.00	64,250.00	1,157.00	12.57	7,548.00	13.31
1997	9,731.00	60,263.00	10,994.00	68,456.00	1,263.00	12.98	8,193.00	[illegible]
1998	10,255.00	63,795.00	11,645.00	72,939.00	1,390.00	13.55	9,144.00	[illegible]
1999	10,766.00	67,360.00	12,323.00	77,454.00	1,547.00	14.36	10,094.00	14.99
2000	11,294.00	70,949.00	13,030.00	82,224.00	1,736.00	15.37	11,275.00	15.89
2001	11,821.00	74,546.00	13,732.00	87,130.00	1,911.00	16.17	12,584.00	16.88
Average Growth Rate (%)								
1987-1991	9.16	9.41	11.65	12.09	2.49	-	2.68	-
1992-1996	7.26	7.85	7.38	7.94	0.12	-	0.09	-
1997-2001	5.14	5.62	5.80	6.28	0.66	-	0.66	-

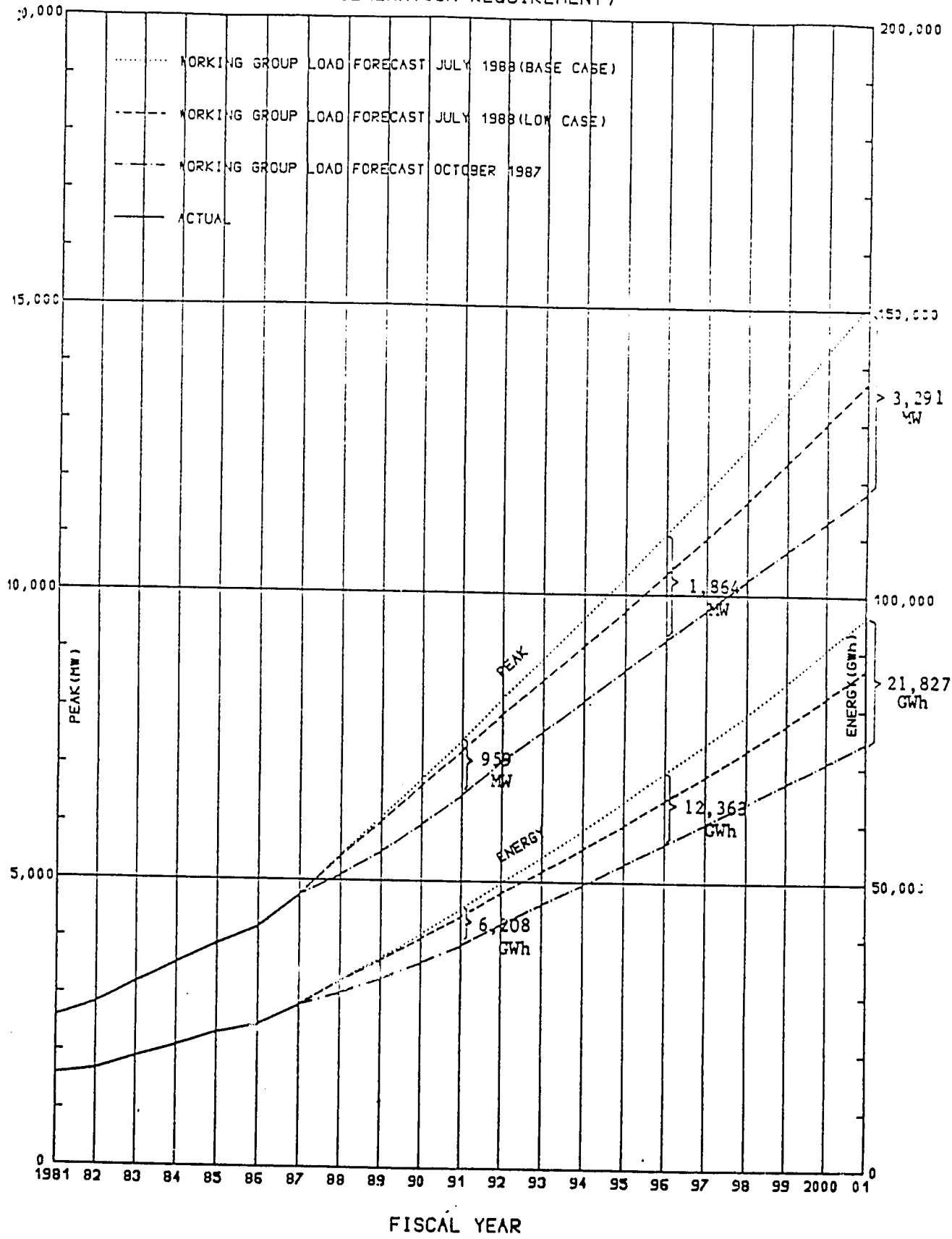
July 1988



July 1988

COMPARISON OF LOAD FORECASTS

(GENERATION REQUIREMENT)



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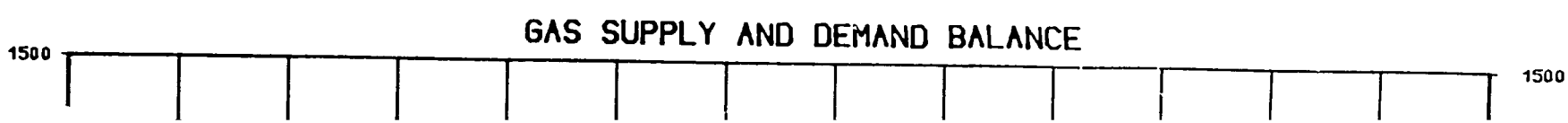
GAS SUPPLY AND DEMAND BALANCE
(PDP 88-02)

(UNIT :MMCFD)

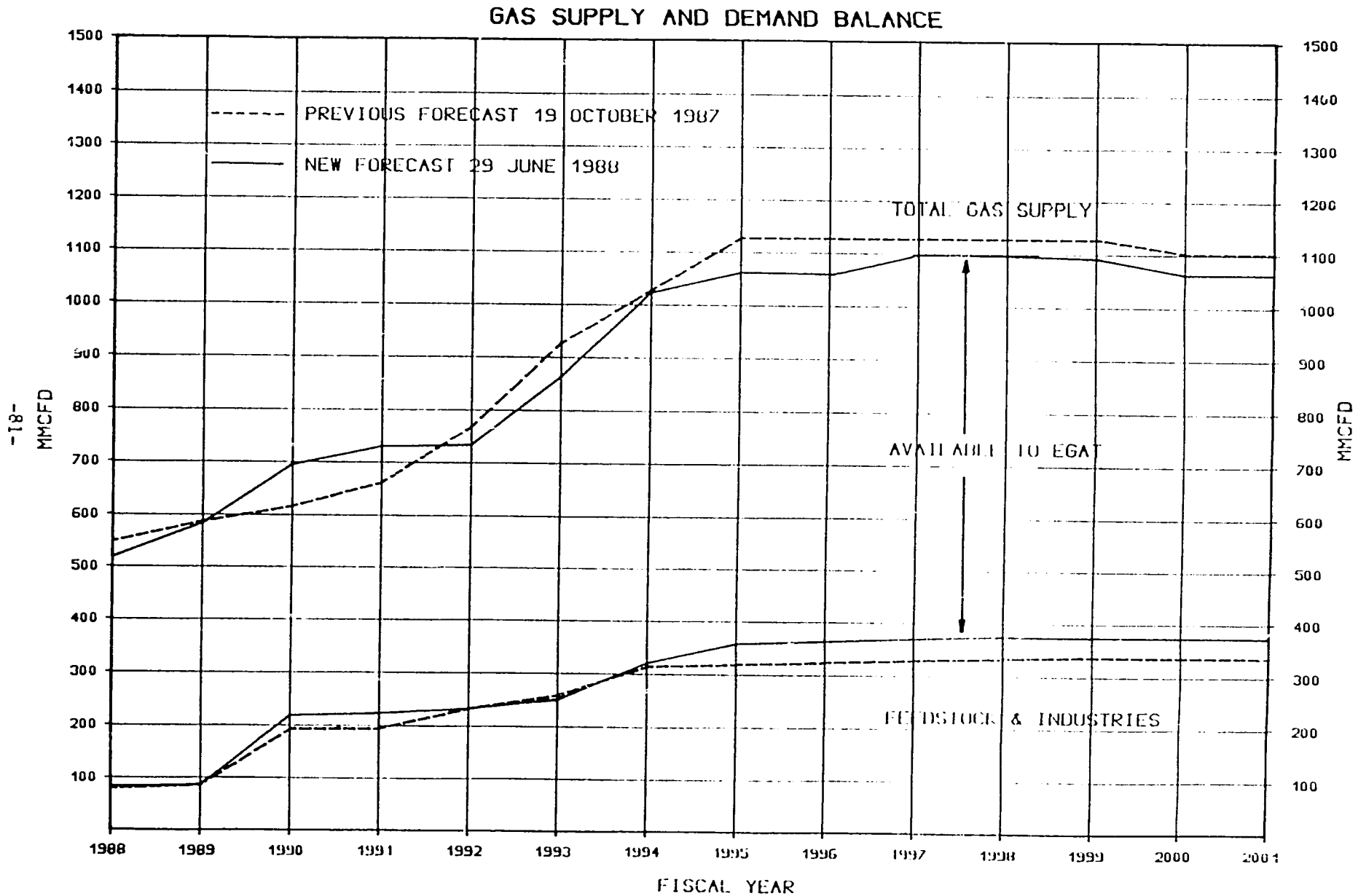
Source	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Supply														
UNOCAL	557	557	679	678	677	675	672	619	615	610	607	603	601	601
PTTEP	–	–	–	–	–	131	175	219	219	263	263	263	263	263
Subtotal Offshore	557	557	679	678	677	806	847	838	834	873	870	866	864	864
Esso	–	–	–	30	30	30	148	197	197	197	197	197	197	197
ES1 1/	28	26	16	22	27	27	18	18	18	18	18	18	–	–
Total Gas Supply	585	583	695	730	734	863	1,013	1,053	1,049	1,088	1,085	1,081	1,061	1,061
Demand														
Feedstock	75	75	179	179	179	179	222	254	254	254	254	254	254	254
Industries	7	10	38	43	53	70	97	102	108	113	119	119	119	119
Available to EGAT	503	498	478	508	502	614	694	697	687	721	712	708	688	688
Maximum EGAT's Gas Requirement	503	558	614	737	775	828	841	867	880	869	825	805	864	834
Surplus (+)	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Deficit (-)	–	-60	-136	-229	-273	-214	-147	-170	-193	-148	-113	-97	-176	-146

Source : PTT, as of June 29, 1988.

Notes : 1/ Thai Shell Exploration and Production Company Limited, July 30, 1987.



Source : PTT, as of June 29, 1988.
Notes : 1/ Thai Shell Exploration and Production Company Limited, July 30, 1987.



COMPARISON OF PTT'S GAS SUPPLY FOR EGAT 1/

(Unit : MMCFD)

Fiscal Year	Former October 1987	Present June 1988	Difference
1988	470	503	33
1989	471	498	27
1990	426	478	52
1991	470	508	38
1992	535	502	-33
1993	670	614	-56
1994	715	694	-21
1995	810	697	-113
1996	805	687	-118
1997	800	721	-79
1998	795	712	-83
1999	790	708	-82
2000	763	688	-75
2001	763	688	-75

Note : 1/ Including natural gas from Sirikit field.

TABLE FUEL PRICE FOR OPTIMIZATION OF EGAT PDP
(ECONOMIC 1988 PRICE LEVEL)

Year	Fuel Oil a/			Natural Gas b/			Nuclear c/		Imported Coal d/			Opportunity Cost of Lignite e/		
									f/			g/		
	US.$/MBtu	฿/Litre	% Increase	US.$/MBtu	฿/MBtu	% Increase	US.$/MBtu	% Increase	US.$/Ton	US.$/MBtu	% Increase	US.$/Ton	US.$/MBtu	% Increase
1988	2.20	2.21	-	2.44	63.66	-	0.69		37.60	1.42	-	14.26	1.38	-
1989	2.27	2.29	3.66	2.35	61.06	-3.92	0.69	0.00	37.97	1.44	1.26	14.32	1.39	0.42
1990	2.35	2.37	3.51	2.26	58.86	-3.60	0.69	0.00	38.46	1.46	1.26	14.39	1.39	0.49
1991	2.44	2.45	3.60	2.17	56.61	-3.99	0.69	0.00	38.94	1.47	1.27	14.45	1.40	0.42
1992	2.58	2.60	6.00	2.09	54.29	-3.93	0.69	0.00	40.26	1.52	3.38	14.55	1.41	0.69
1993	2.74	2.75	6.00	2.16	56.24	3.59	0.69	0.00	41.63	1.58	3.41	14.65	1.42	0.69
1994	2.90	2.92	6.00	2.21	57.36	1.99	0.69	0.00	43.05	1.63	3.42	14.76	1.43	0.75
1995	3.07	3.09	6.00	2.24	58.36	1.73	0.69	0.00	44.53	1.69	3.44	14.87	1.44	0.75
1996	3.26	3.28	6.00	2.28	59.21	1.47	0.69	0.00	46.08	1.75	3.46	14.98	1.45	0.74
1997	3.39	3.41	4.00	2.27	59.07	-0.24	0.69	0.00	46.88	1.78	1.74	15.08	1.46	0.67
1998	3.52	3.54	4.00	2.27	58.89	-0.30	0.69	0.00	47.69	1.81	1.74	15.19	1.47	0.73
1999	3.67	3.69	4.00	2.26	58.66	-0.39	0.69	0.00	48.53	1.84	1.75	15.31	1.48	0.79
2000	3.81	3.83	4.00	2.22	57.83	-1.41	0.69	0.00	49.38	1.87	1.75	15.43	1.50	0.78
2001	3.97	3.99	4.00	2.19	57.01	-1.42	0.69	0.00	50.26	1.90	1.76	15.57	1.51	0.91

Notes : a/ Assumed to be 85% of crude oil price (based on CIF price estimated by NEPO on June 29,1988).
b/ Estimated by PTT on July 7,1988 (Based on crude oil price estimated by NEPO on June 29,1988).
c/ Estimated by Thermal Engineering Department on July 1,1988 .
d/ Based on CIF price estimated by NEPO on June 29,1988 but including US.$ 6/Ton of inland transportation cost.
e/ Based on production cost of US.$ 6.66/Gcal in 1988, estimated by Mine Engineering Department on July, 1988
f/ Based on heating value of 6,653 kcal/kg (12,000 Btu/lb).
g/ Based on heating value of 2,600 kcal/kg.
h/ US.$ 1 = 26.0 Baht

GROWTH OF EGAT'S GENERATING CAPACITY

Description	Year							
	1980	1981	1982	1983	1984	1985	1986	1987
Installed Capacity (MW)								
Hydro Plant	1,269.31	1,317.31	1,380.61	1,514.91	1,515.11	1,813.63	1,998.13	2,250.33
Thermal Plant								
-Gas-Fired	-	900.00	900.00	1,450.00	2,000.00	2,000.00	2,000.00	2,000.00
-Oil-Fired	1,567.50	742.50	742.50	742.50	742.50	742.50	742.50	742.50
-Lignite-Fired	210.00	285.00	285.00	285.00	585.00	885.00	865.00	865.00
Combined Cycle	-	300.00	580.00	720.00	720.00	720.00	720.00	771.60
Gas Turbine	165.00	165.00	180.00	250.00	265.00	265.00	265.00	267.35
Diesel	27.60	27.60	29.60	29.60	31.60	31.60	31.60	31.60
Total	3,239.41	3,737.41	4,097.71	4,992.01	5,859.21	6,457.73	6,622.23	6,928.38
Net Capacity Increase(MW)	Base	498.00	360.30	894.30	867.20	598.52	164.50	306.15
Percent Increase (%)	Base	15.37	9.64	21.82	17.37	10.22	2.55	4.62

Note : Average generating capacity increased from 1980 to 1987 $= \frac{3,688.97}{7} = 527.00$ MW/yr

PERCENTAGE DISTRIBUTION OF EGAT GENERATING CAPACITY

Note : Average generating capacity increased from 1980 to 1987 $= \frac{3,688.97}{7} = 527.00$ MW/yr

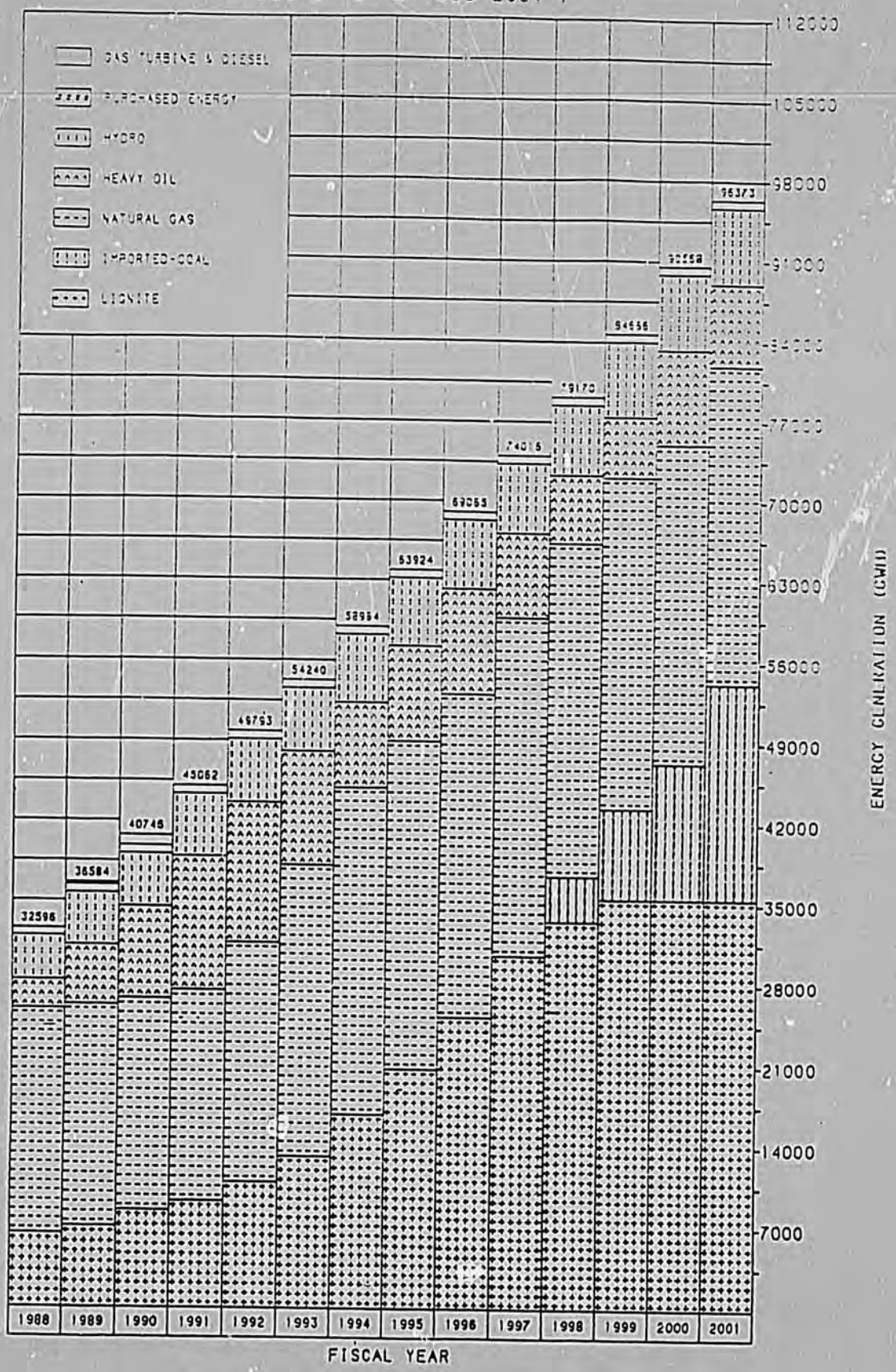
PERCENTAGE DISTRIBUTION OF EGAT GENERATING CAPACITY

Types of Power Plant	Unit	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Hydroelectric	MW	2,250.1	2,250.1	2,250.1	2,430.1	2,430.1	2,430.1	2,646.1	2,672.1	2,990.1	2,990.1	3,030.1	3,150.1	3,550.1	3,550.1
	%	32.6	31.0	29.3	26.7	23.3	21.4	22.1	21.2	22.1	20.7	19.7	19.2	20.4	19.3
Oil-Fired	MW	542.5	817.5	817.5	1,717.5	1,717.5	1,717.5	1,717.5	1,717.5	1,717.5	1,717.5	1,687.5	1,687.5	1,687.5	1,487.5
	%	7.9	11.2	10.7	18.9	16.5	15.1	14.3	13.6	12.7	11.9	11.0	10.3	9.7	8.1
Gas-Fired	MW	2,200.0	2,000.0	2,000.0	1,100.0	1,700.0	2,300.0	2,300.00	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0	2,300.0
	%	31.9	27.5	26.1	21.1	16.3	20.3	19.2	18.2	17.0	15.9	15.0	14.1	13.2	12.5
Lignite-Fired	MW	865.0	1,165.0	1,165.0	1,465.0	1,765.0	2,100.0	2,700.0	3,300.0	3,900.0	4,800.0	5,100.0	5,400.0	5,400.0	5,400.0
	%	12.5	16.0	15.2	16.1	17.0	18.5	22.5	26.1	28.8	33.2	33.2	33.0	31.1	29.4
Coal-Fired	MW	–	–	–	–	–	–	–	–	–	–	600.0	1,200.0	1,800.0	3,000.0
	%	–	–	–	–	–	–	–	–	–	–	3.9	7.3	10.4	16.3
Combined Cycle	MW	771.6	771.6	1,171.6	2,111.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6	2,531.6
	%	11.2	10.6	15.3	23.2	24.3	22.3	21.1	20.1	18.7	17.5	16.5	15.5	14.6	13.8
Peaking Gas Turbine	MW	265.0	265.0	265.0	265.0	265.0	265.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	%	3.8	3.6	3.5	3.0	2.5	2.3	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.5
Total	MW	6,894.2	7,269.2	7,669.2	9,089.2	10,409.2	11,344.2	11,995.2	12,621.2	13,539.2	14,439.2	15,349.2	16,369.2	17,369.2	18,369.2
	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

SUMMARY OF EGAT'S FUEL REQUIREMENT AND ENERGY GENERATION CLASSIFIED BY TYPES OF FUEL (PDP 88-02)

Type of Power Plant	Units	Fiscal Year													
		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1. Hydro	GWh	3,807	4,518	4,571	5,410	5,410	5,410	5,905	5,942	6,060	6,082	6,132	6,506	6,599	6,599
	%	11.7	12.3	11.2	12.0	10.9	10.0	10.0	9.3	8.8	8.2	7.7	7.7	7.3	6.8
2. Natural Gas	GWh	19,296	19,106	18,238	18,132	20,646	25,116	28,269	28,384	28,092	29,302	28,958	28,805	27,697	27,697
	%	59.2	52.2	44.8	40.2	41.5	46.3	47.9	44.4	40.5	39.6	36.6	34.0	30.6	28.7
	MMCFD	503	498	478	508	502	614	694	697	687	721	712	708	688	688
3. Heavy Oil	GWh	2,476	5,073	7,910	11,569	12,161	9,899	7,350	8,218	9,108	7,402	5,945	5,300	8,267	7,160
	%	7.6	13.9	19.4	25.7	24.4	18.3	12.5	12.9	13.2	10.0	7.5	6.3	9.1	7.4
	10^6 Litres	644	1,321	2,026	2,927	3,025	2,466	1,847	2,065	2,281	1,873	1,500	1,333	2,070	1,794
4. Diesel Oil	GWh	7	173	916	–	–	–	–	–	–	–	–	–	–	–
	%	0.0	0.5	2.2	–	–	–	–	–	–	–	–	–	–	–
	10^6 Litres	3	85	451	–	–	–	–	–	–	–	–	–	–	–
5. Lignite	GWh	6,396	7,014	8,421	9,236	10,866	13,110	16,735	20,675	25,190	30,525	33,480	35,450	35,450	35,450
	%	19.6	19.2	20.7	20.5	21.8	24.2	28.4	32.3	36.5	41.2	42.3	41.9	39.1	36.8
	10^6 Tons	6.419	7.012	8.323	9.079	10.617	12.648	16.070	19.708	24.068	29.094	31.868	33.698	33.698	33.698
6. Imported Coal	GWh	–	–	–	–	–	–	–	–	–	–	3,950	7,900	11,850	18,762
	%	–	–	–	–	–	–	–	–	–	–	5.0	9.3	13.1	19.5
	10^6 Tons	–	–	–	–	–	–	–	–	–	–	1.517	3.033	4.550	7.204
7. Purchase	GWh	614	700	690	715	710	705	705	705	705	705	705	705	705	705
	%	1.9	1.9	1.7	1.6	1.4	1.3	1.2	1.1	1.0	1.0	0.9	0.8	0.8	0.7
Total	GWh	32,596	36,584	40,746	45,062	49,793	54,240	58,964	63,924	69,065	74,016	79,170	84,666	90,568	96,373
	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

FORECAST OF ENERGY GENERATION AND PURCHASES
(FISCAL YEARS 1988-2001)



CAPABILITY OF EXISTING, UNDER CONSTRUCTION AND FUTURE POWER PLANTS

Plants	Power (MW)		Energy (GWh)	
	Installed	Dependable	Average	Firm
Existing Power Plants				
Hydro Power Plants				
Bhumibol Units 1-7	535.0	423.2	1,200.0	915.0
Sirikit Units 1-3	375.0	232.0	1,000.0	760.0
Ubolratana Units 1-3	25.0	16.8	56.0	27.0
Sirindhorn Units 1-3	36.0	31.7	86.0	53.0
Chulabhorn Units 1-2	40.0	40.0	93.0	59.0
Kang Krachan Unit 1	19.0	11.9	78.0	61.0
Nam Pung Units 1-2	6.0	5.3	15.0	10.0
Srinagarind Units 1-4	540.0	540.0	1,140.0	1,100.0
Bang Lang Units 1-3	72.0	61.3	200.0	114.0
Khao Laem Units 1-3	300.0	257.0	760.0	540.0
Tha Thung Na Units 1-2	38.0	38.0	165.0	136.0
Huai Kum	1.3	1.1	2.0	-
Ban Yang	0.12	0.12	0.3	-
Ban Santi	1.3	1.3	6.0	-
Klong Chong Klum	0.02	0.02	0.2	-
Ban Khun Klang	0.18	0.18	0.7	-
Mae Ngat Units 1-2	9.0	-	29.0	18.0
Huai Saphan Hin Units 1-2	12.2	11.80	27.0	22.0
Rajjaprabha Units 1-3	240.0	183.60	550.0	475.0
Subtotal	2,250.1	1,855.3	5,408.2	4,380.0
Thermal Power Plants				
North Bangkok Units 1-3	237.5	225.6	1,250.0	1,250.0
South Bangkok Units 1-5	1,300.0	1,235.0	9,110.0	9,110.0
Krabi Units 1,3	40.0	30.0	200.0	200.0
Surat Thani Unit 1	30.0	28.5	210.0	210.0
Mae Moh Units 1-3	225.0	213.9	1,480.0	1,480.0
Mae Moh Units 4-7	600.0	570.0	3,940.0	3,940.0
Khanom PPB Unit 1	75.0	71.3	525.0	525.0
Bang Pakong Thermal Units 1-2	1,100.0	1,045.0	7,710.0	7,710.0
Subtotal	3,607.5	3,419.3	24,425.0	24,425.0
Combined Cycle Power Plants				
Bang Pakong Combined Cycle Blocks 1-2	771.6	684.0	4,055.0	4,055.0
Subtotal	771.6	684.0	4,055.0	4,055.0
Gas Turbine Power Plants				
Nakhon Ratchasima Unit 1	15.0	12.0	33.0	33.0
Udon Thani Unit 1	15.0	12.0	33.0	33.0
Hat Yai Units 1-3	45.0	36.0	99.0	99.0
Surat Thani Units 3-5	45.0	36.0	99.0	99.0
Lan Krabu Units 1-3	45.0	36.0	276.0	276.0
Lan Krabu Units 5-8	100.0	80.0	612.0	612.0
Subtotal	265.0	212.0	1,152.0	1,152.0
Total Existing Plants (upto July 1988)	6,894.2	6,170.6	35,040.2	34,012.0

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CAPABILITY OF EXISTING, UNDER CONSTRUCTION AND FUTURE POWER PLANTS
(CONTINUED)

Plants	Power (MW)		Energy (GWh)	
	Installed	Dependable	Average	Firm
Power Plants Under Construction				
Hydro Power Plant				
Srinagarind Unit 5 (Reversible Pumped Turbine)	180.0	180.0	111.0	111.0
Subtotal	180.0	180.0	111.0	111.0
Thermal Power Plants				
Mae Moh Unit 8	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 9	300.0	285.0	1,970.0	1,970.0
Khanom PPB Unit 2	75.0	71.3	525.0	525.0
Bang Pakong Combined Cycle Block 3	300.0	285.0	1,577.0	1,577.0
Bang Pakong Combined Cycle Block 4	300.0	285.0	1,577.0	1,577.0
Mae Moh Unit 10	300.0	285.0	1,970.0	1,970.0
Bang Pakong Thermal Unit 3	600.0	570.0	3,940.0	3,940.0
Subtotal	2,175.0	2,066.3	13,529.0	13,529.0
Total Under Construction	2,355.0	2,246.3	13,640.0	13,640.0
Future Power Plants				
Hydro Power Plants				
Pak Mun Units 1-4	136.0	41.5	317.0	220.0
Kaeng Krung Units 1-2	80.0	73.7	178.0	156.0
Mae Taeng Units 1-2	26.0	26.0	111.0	91.0
Sirikit Unit 4 and Lower Sirikit Unit 1	140.0	98.1	65.0	51.0
Lower Mae Ping Units 1-2	40.0	40.0	210.0	155.0
Nam Khek (1) and (2)	120.0	120.0	310.0	230.0
Bhumibol Unit 8 (Reversible Pumped Turbine)	178.0	178.0	260.0	260.0
Nam Chern Units 1-4 (Reversible Pumped Turbine)	400.0	400.0	910.0	910.0
Subtotal	1,120.0	1 977.3	2,361.0	2,073.0
Thermal Power Plants				
Mae Moh Unit 11	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 12	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 13	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 14	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 15	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 16	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 17	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 18	300.0	285.0	1,970.0	1,970.0
Mae Moh Unit 19	300.0	285.0	1,970.0	1,970.0
Bang Pakong Thermal Unit 4	600.0	570.0	3,940.0	3,940.0
Krabi Unit 4	75.0	71.3	490.0	490.0

CAPABILITY OF EXISTING, UNDER CONSTRUCTION AND FUTURE POWER PLANTS
(CONTINUED)

Plants	Power (MW)		Energy (GWh)	
	Installed	Dependable	Average	Firm
Saba Yoi Unit 1	150.0	142.5	985.0	985.0
Saba Yoi Unit 2	150.0	142.5	985.0	985.0
Saba Yoi Unit 3	300.0	285.0	1,970.0	1,970.0
Saba Yoi Unit 4	300.0	285.0	1,970.0	1,970.0
New Thermal Unit 1	600.0	570.0	3,940.0	3,940.0
New Thermal Unit 2	600.0	570.0	3,940.0	3,940.0
New Thermal Unit 3	600.0	570.0	3,940.0	3,940.0
New Thermal Unit 4	600.0	570.0	3,940.0	3,940.0
New Thermal Unit 5	600.0	570.0	3,940.0	3,940.0
Subtotal	7,275.0	6,911.3	47,770.0	47,770.0
Combined Cycle Power Plants				
Nam Phong Combined Cycle Block 1	105.0	100.0	550.0	550.0
Nam Phong Combined Cycle Block 2	105.0	100.0	550.0	550.0
New Combined Cycle Block 1	300.0	285.0	1,577.0	1,577.0
New Combined Cycle Block 2	300.0	285.0	1,577.0	1,577.0
New Combined Cycle Block 3	300.0	285.0	1,577.0	1,577.0
Lan Krabu Combined Cycle (ST)	50.0	47.5	260.0	260.0
Subtotal	1,160.0	1,102.5	6,091.0	6,091.0
Total Future Plants	9,555.0	9,991.1	56,222.0	55,934.0
Grand Total Capacity (Up to 2001)	18,804.2 a/	18,408.0	104,902.2	103,586.0

Note : a/ After retirement of some existing plants of 435.0 MW, the total generating capacity of the system will be reduced to 18,369.2 MW.

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POWER PLANTS RETIREMENT SCHEDULE

Some existing power plants in EGAT system have been in operation for more than 20 years and should be retired or mothballed. The retirement of power plants are due to : (1) damaged component of the power plant that replacement or repairment are not technically viable, (2) rehabilitation or renovation is not economical, (3) Economic disadvantage to further operate the plant as a result of poor efficiency and obsolescence.

At present, EGAT has the plan for power plant renovation which covers the renovations of Bhumibol generating Units 1 and 2 (2x70 MW), the North Bangkok thermal power plant Units 1-3 (237.5 MW), and the South Bangkok thermal power plant Units 1-5 (1,300 MW).

However, there are certain number of generating units that will have to be retired amounting to 435 MW in the period 1990-2000, as listed below :

Name of Power Plant	Unit No.	Rating (MW)	Retirement Date
1. Krabi Lignite-fired	1 and 3	2x20	October 1992
2. Existing Gas Turbines	1-11	11x15	December 1993
3. Surat Thani Thermal	1	1x30	February 1998
4. South Bangkok Thermal	1	1x200	December 2000
Total Retired Capacity Up to Year 2001		435 MW	

Note : Due to expected power shortage in the period 1989-1990, it may be necessary to replace some of the gas turbine components to prolong the service life until sufficient generating capacity is available.

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POWER SYSTEM PLANNING DIVISION
CASE PDP88025W
LOAD WIGPLAN - JULY 1988(BASE)

SYSTEMS PLANNING DEPARTMENT
ELECTRICITY GENERATING AUTHORITY OF THAILAND
RUN DATE JULY 18, 1988

TABLE 2 MONTHLY RESERVE MARGIN

IN-SERVICE DATE	NAME OF POWER PLANT	RATED CAPACITY (MW)	ACCUMULATED CAPACITY INSTALLED (MW)	ACCUMULATED CAPACITY DEPENDABLE (MW)	ACCUMULATED CAPACITY FIRM (MW)	PEAK GENERATION REQUIREMENT (MW)	RESERVE MARGIN (MW)	RESERVE MARGIN (%)
BY SEP 1987	EXISTING		6894.2	6392.5	5585.0	4733.9	1658.6	35.04
FY 1988								
OCT 1987			6894.2	6451.3	5643.8	4702.1	1749.2	37.20
NOV 1987			6894.2	6479.5	5672.0	4886.8	1592.7	32.59
DEC 1987			6894.2	6473.5	5666.0	4589.9	1883.6	41.04
JAN 1988			6894.2	6461.9	5654.4	5003.3	1458.6	29.15
FEB 1988	LAN KRABU GT#8 (25 MW)		6894.2	6437.8	5630.3	5011.2	1426.6	28.47
MAR 1988			6894.2	6393.9	5586.4	5210.5	1183.4	22.71
APR 1988			6894.2	6293.4	5485.9	5249.1	1044.3	19.90
MAY 1988			6894.2	6218.1	5410.6	5370.1	848.1	15.79
JUN 1988			6894.2	6202.8	5395.3	5242.2	960.6	18.33
JUL 1988			6894.2	6225.1	5417.6	5287.6	937.5	17.73
AUG 1988			6894.2	6250.9	5443.4	5366.9	884.0	16.47
SEP 1988			6894.2	6392.5	5585.0	5444.0	948.5	17.42
FY 1989								
OCT 1988			6894.2	6451.3	5643.8	5267.0	1184.3	22.49
NOV 1988			6894.2	6479.5	5672.0	5473.9	1005.6	18.37
DEC 1988			6894.2	6473.5	5666.0	5141.3	1332.2	25.91
JAN 1989			6894.2	6461.9	5654.4	5604.4	857.5	15.30
FEB 1989	2ND PPB 75 MW	75.0	6969.2	6509.1	5701.6	5613.2	895.9	15.96
MAR 1989			6969.2	6465.2	5657.7	5836.5	628.8	10.77
APR 1989			6969.2	6364.7	5557.2	5879.7	485.0	8.25
MAY 1989			6969.2	6289.4	5481.9	6015.2	274.3	4.56
JUN 1989			6969.2	6274.1	5466.6	5872.0	402.2	6.85
JUL 1989	MAE MOH #8 300 MW	300.0	7269.2	6581.4	5773.9	5922.8	658.6	11.12
AUG 1989			7269.2	6607.2	5799.7	6011.6	595.5	9.91
SEP 1989			7269.2	6748.8	5941.3	6098.0	650.8	10.67
FY 1990								
OCT 1989			7269.2	6807.6	6000.1	5837.9	969.7	16.61
NOV 1989			7269.2	6835.8	6028.3	6067.2	768.6	12.67
DEC 1989			7269.2	6829.8	6022.3	5698.6	1131.2	19.85
JAN 1990			7269.2	6818.2	6010.7	6211.9	606.3	9.76
FEB 1990	2ND CSTL (270) MW		7269.2	6794.1	5986.6	6221.7	572.4	9.20
MAR 1990			7269.2	6750.2	5942.7	6469.1	281.1	4.35
APR 1990			7269.2	6649.7	5842.2	6517.0	132.7	2.04
MAY 1990			7269.2	6574.4	5766.9	6667.2	-92.8	-1.39
JUN 1990	BANG PAKONG GT(3) 2X100	200.0	7469.2	6749.1	5941.6	6508.4	240.7	3.70
JUL 1990			7469.2	6771.4	5963.9	6564.8	206.6	3.15
AUG 1990	BANG PAKONG GT(4) 2X100	200.0	7669.2	6987.2	6179.7	6663.3	323.9	4.86
SEP 1990	NEW CC. GT(1) 2X100 MW	200.0	7869.2	7318.8	6511.3	6759.0	559.8	8.28

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MAR 1990			9.2	6750.2	5942.7	6469.1	281.1	4.3[illegible]
APR 1990			7269.2	6649.7	5842.2	6517.0	132.7	2.04
MAY 1990			7269.2	6574.4	5766.9	6667.2	-92.8	-1.39
JUN 1990	BANG PAKONG GT(3) 2X100	200.0	7469.2	6749.1	5941.6	6508.4	240.7	3.70
JUL 1990			7469.2	6771.4	5963.9	6564.8	206.6	3.15
AUG 1990	BANG PAKONG GT(4) 2X100	200.0	7669.2	6987.2	6179.7	6663.3	323.9	4.86
SEP 1990	NEW CC. GT(1) 2X100 MW	200.0	7869.2	7318.8	6511.3	6759.0	559.8	8.28

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TABLE 2 MONTHLY RESERVE MARGIN

IN-SERVICE DATE	NAME OF POWER PLANT	RATED CAPACITY (MW)	ACCUMULATED CAPACITY INSTALLED (MW)	DEPENDABLE (MW)	FIRM (MW)	PEAK GENERATION REQUIREMENT (MW)	RESERVE MARGIN (MW)	(%)
FY 1991								
OCT 1990	NEW CC. GT(2) 2X100 MW	200.0	8069.2	7567.6	6760.1	6426.1	1141.5	17.76
NOV 1990	NAM PHONG GT 4X35 MW	140.0	8209.2	7720.8	6913.3	6678.5	1042.3	15.61
DEC 1990	MAE MOH #9 300 MW	300.0	8509.2	7999.8	7192.3	6272.7	1727.0	27.53
JAN 1991	NEW CC. GT(3) 2X100 MW	200.0	8709.2	8178.2	7370.7	6837.7	1340.5	19.60
FEB 1991			8709.2	8154.1	7346.6	6848.5	1305.6	19.06
MAR 1991			8709.2	8110.2	7302.7	7120.9	989.3	13.89
APR 1991	SRINAGARIND #5 180 MW	180.0	8889.2	8189.7	7382.2	7173.6	1016.1	14.16
MAY 1991			8889.2	8114.4	7306.9	7339.0	775.5	10.57
JUN 1991	BANG PAKONG ST(3) 100 MW	100.0	8989.2	8194.1	7386.6	7164.2	1029.9	14.38
JUL 1991			8989.2	8216.4	7408.9	7226.3	990.1	13.70
AUG 1991	BANG PAKONG ST(4) 100 MW	100.0	9089.2	8337.2	7529.7	7334.6	1002.5	13.67
SEP 1991	NEW CC. ST(1) 100 MW	100.0	9189.2	8573.8	7766.3	7440.0	1133.8	15.24
FY 1992								
OCT 1991	NEW CC. ST(2) 100 MW	100.0	9289.2	8727.6	7920.1	7059.2	1668.4	23.63
OCT 1991	LAN KRABU CC (ST) 50 MW	50.0	9339.2	8775.1	7967.6	7059.2	1715.9	24.31
NOV 1991			9339.2	8803.3	7995.8	7336.5	1466.8	19.99
DEC 1991	NAM PHONG ST 2X35 MW	70.0	9409.2	8863.8	8056.3	6890.7	1973.0	28.63
JAN 1992	230KV TTK-KK3 TL(300) MW		9409.2	8852.2	8044.7	7511.4	1340.8	17.85
JAN 1992	NEW CC. ST(3) 100 MW	100.0	9509.2	8947.2	8139.7	7511.4	1435.8	19.12
FEB 1992	MAE MOH #10 300 MW	300.0	9809.2	9208.1	8400.6	7523.3	1684.8	22.40
MAR 1992	BB RENOVATION (2X70) MW		9809.2	9164.2	8356.7	7822.5	1341.8	17.15
APR 1992			9809.2	9063.7	8256.2	7880.4	1183.3	15.02
MAY 1992	BANG PAKONG TH #3 600 MW	600.0	10409.2	9558.4	8703.4	8062.0	1496.4	18.56
JUN 1992			10409.2	9543.1	8688.1	7870.0	1673.1	21.26
JUL 1992			10409.2	9565.4	8710.4	7938.2	1627.2	20.50
AUG 1992			10409.2	9591.2	8736.2	8057.3	1533.9	19.04
SEP 1992			10409.2	9732.8	8877.8	8173.0	1559.8	19.08
FY 1993								
OCT 1992	KRABI RETIRED 2X20 MW	-40.0	10369.2	9761.6	8906.6	7658.6	2103.0	27.46
NOV 1992	KRABI #4 75 MW	75.0	10444.2	9860.8	9005.8	7959.5	1901.3	23.89
DEC 1992			10444.2	9854.8	8999.8	7475.9	2378.9	31.82
JAN 1993			10444.2	9843.2	8988.2	8149.2	1694.0	20.79
FEB 1993	MAE MOH #11 300 MW	300.0	10744.2	10104.1	9249.1	8162.1	1942.0	23.79
MAR 1993			10744.2	10060.2	9205.2	8486.7	1573.5	18.54
APR 1993			10744.2	9959.7	9104.7	8549.6	1410.2	16.49
MAY 1993	BANG PAKONG TH #4 600 MW	600.0	11344.2	10454.4	9599.4	8746.6	1707.8	19.53
JUN 1993			11344.2	10439.1	9584.1	8538.3	1900.8	22.26
JUL 1993			11344.2	10461.4	9606.4	8612.3	1849.1	21.47
AUG 1993	ND RENOVATION (237.5) MW		11344.2	10487.2	9632.2	8741.4	1745.7	19.97
SEP 1993			11344.2	10620.8	9773.8	8867.0	1761.8	19.87

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TABLE 2 MONTHLY RESERVE MARGIN

SERVICE	NAME OF POWER PLANT		RATED CAPACITY (MW)	ACCUMULATED CAPACITY INSTALLED (MW)	DEPENDABLE (MW)	FIRM (MW)	PEAK GENERATION REQUIREMENT (MW)	RESERVE MARGIN (MW)	(%)
FY 1994									
OCT 1993	MAE MOH #12	300 MW	300.0	11644.2	10972.6	10117.6	8272.7	2699.9	32.64
NOV 1993	PAK MUN #1-4	4X34 MW	136.0	11780.2	11108.9	10253.9	8597.7	2511.2	29.21
DEC 1993	GT. RETIRED	11X15 MW	-165.0	11615.2	10956.1	10101.1	8075.3	2880.8	35.67
DEC 1993	KAENG KRUNG #1-2	2X40 MW	80.0	11695.2	11036.1	10181.1	8075.3	2960.8	36.66
JAN 1994				11695.2	10989.8	10134.8	8802.7	2187.2	24.85
FEB 1994				11695.2	10960.7	10105.7	8816.5	2144.2	24.32
MAR 1994				11695.2	10917.9	10062.9	9167.2	1750.7	19.10
APR 1994	MAE MOH #13	300 MW	300.0	11995.2	11111.6	10256.6	9235.1	1876.5	20.32
MAY 1994				11995.2	11057.8	10202.8	9447.9	1609.8	17.04
JUN 1994				11995.2	11041.3	10186.3	9222.9	1818.3	19.72
JUL 1994				11995.2	11086.3	10231.3	9302.8	1783.4	19.17
AUG 1994				11995.2	11097.5	10242.5	9442.4	1655.2	17.53
SEP 1994				11995.2	11210.7	10355.7	9578.0	1632.7	17.05
FY 1995									
OCT 1994	MAE MOH #14	300 MW	300.0	12295.2	11590.4	10735.4	8899.8	2690.6	30.23
NOV 1994				12295.2	11626.9	10771.9	9249.4	2377.5	25.70
DEC 1994				12295.2	11606.1	10751.1	8687.4	2918.7	33.60
JAN 1995				12295.2	11559.8	10704.8	9469.9	2089.9	22.07
FEB 1995				12295.2	11530.7	10675.7	9484.8	2045.9	21.57
MAR 1995				12295.2	11487.9	10632.9	9862.1	1625.8	16.49
APR 1995	MAE MOH #15	300 MW	300.0	12595.2	11681.6	10826.6	9935.1	1746.5	17.58
MAY 1995				12595.2	11627.8	10772.8	10164.1	1463.7	14.40
JUN 1995	MAE TAENG #1-2	18+8 MW	26.0	12621.2	11637.1	10782.1	9922.0	1715.1	17.29
JUL 1995				12621.2	11682.1	10827.1	10008.0	1674.1	16.73
AUG 1995				12621.2	11693.3	10838.3	10158.1	1535.3	15.11
SEP 1995				12621.2	11806.5	10951.5	10304.0	1502.5	14.58
FY 1996									
OCT 1995	SABA YOI #1	150 MW	150.0	12771.2	12043.7	11188.7	9557.9	2485.8	26.01
NOV 1995	MAE MOH #16	300 MW	300.0	13071.2	12365.2	11510.2	9933.4	2431.8	24.48
DEC 1995	SB RENOVATION	(1300) MW		13071.2	12344.4	11489.4	9329.9	3014.5	32.31
JAN 1996	BHUMIBOL #8	178 MW	178.0	13249.2	12476.1	11621.1	10170.2	2305.9	22.67
FEB 1996	SIRIKIT #4	125 MW	140.0	13389.2	12556.3	11701.3	10186.3	2370.1	23.27
FEB 1996	LOWER SIRIKIT #1	15 MW&		13389.2	12556.3	11701.3	10186.3	2370.1	23.27
MAR 1996				13389.2	12502.3	11647.3	10591.4	1910.9	18.04
APR 1996	SABA YOI #2	150 MW	150.0	13539.2	12563.4	11708.4	10669.8	1893.6	17.75
MAY 1996				13539.2	12517.1	11662.1	10915.7	1601.3	14.67
JUN 1996				13539.2	12504.4	11649.4	10655.8	1848.6	17.35
JUL 1996				13539.2	12528.4	11673.4	10748.1	1780.3	16.56
AUG 1996				13539.2	12556.7	11701.7	10909.3	1647.4	15.10
SEP 1996				13539.2	12602.4	11827.4	11066.0	1616.4	14.61

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MAR 1996				[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
APR 1996	SABA YOI #2	150 MW	150.0	13539.2	12502.3	11647.3	10591.4	1910.9	18.04
MAY 1996				13539.2	12563.4	11708.4	10669.8	1893.6	17.75
JUN 1996				13539.2	12517.1	11662.1	10915.7	1601.3	14.67
JUL 1996				13539.2	12504.4	11649.4	10655.8	1848.6	17.35
AUG 1996				13539.2	12528.4	11673.4	10748.1	1780.3	16.56
SEP 1996				13539.2	12556.7	11701.7	10909.3	1647.4	15.10
				13539.2	12682.4	11827.4	11066.0	1616.4	14.61

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TABLE 2 MONTHLY RESERVE MARGIN

IN-SERVICE DATE	NAME OF POWER PLANT		RATED CAPACITY (MW)	ACCUMULATED CAPACITY INSTALLED (MW)	DEPENDABLE (MW)	FIRM (MW)	PEAK GENERATION REQUIREMENT (MW)	RESERVE MARGIN (MW)	(%)
FY 1997									
OCT 1996	SABA YOI #3	300 MW	300.0	13839.2	13065.8	12210.8	10205.7	2860.1	28.02
NOV 1996	MAE HOH #17	300 MW	300.0	14139.2	13356.2	12501.2	10606.6	2749.6	25.92
DEC 1996				14139.2	13353.5	12498.5	9962.2	3391.3	34.04
JAN 1997				14139.2	13299.9	12444.9	10859.5	2440.4	22.47
FEB 1997				14139.2	13268.8	12413.8	10876.6	2392.2	21.99
MAR 1997				14139.2	13214.8	12359.8	11309.2	1905.6	16.85
APR 1997	MAE HOH #18	300 MW	300.0	14439.2	13418.4	12563.4	11393.0	2025.4	17.78
MAY 1997				14439.2	13372.1	12517.1	11655.5	1716.5	14.73
JUN 1997				14439.2	13359.4	12504.4	11378.0	1981.4	17.41
JUL 1997				14439.2	13383.4	12528.4	11476.5	1906.8	16.62
AUG 1997				14439.2	13411.7	12556.7	11648.7	1763.1	15.14
SEP 1997				14439.2	13537.4	12682.4	11816.0	1721.4	14.57
FY 1998									
OCT 1997	NEW THERMAL #1	600 MW	600.0	15039.2	14205.8	13350.8	10879.4	3326.4	30.58
NOV 1997	MAE HOH #19	300 MW	300.0	15339.2	14496.2	13641.2	11306.8	3189.4	28.21
DEC 1997				15339.2	14493.5	13638.5	10619.8	3873.6	36.48
JAN 1998				15339.2	14439.9	13584.9	11576.3	2863.6	24.74
FEB 1998	SRT #1 RETIRED	30 MW	-30.0	15309.2	14380.3	13525.3	11594.6	2785.7	24.03
MAR 1998				15309.2	14326.3	13471.3	12055.8	2270.5	18.83
APR 1998				15309.2	14244.9	13389.9	12145.1	2099.9	17.29
MAY 1998				15309.2	14198.6	13343.6	12425.0	1773.6	14.27
JUN 1998				15309.2	14185.9	13330.9	12129.1	2056.8	16.96
JUL 1998	LOWER MAE PING #1-2	2X20	40.0	15349.2	14249.9	13394.9	12234.1	2015.7	16.48
AUG 1998				15349.2	14278.2	13423.2	12417.6	1860.6	14.98
SEP 1998				15349.2	14403.9	13548.9	12596.0	1807.9	14.35
FY 1999									
OCT 1998	NEW THERMAL #2	600 MW	600.0	15949.2	15072.3	14217.3	11585.9	3486.4	30.09
NOV 1998	SABA YOI #4	300 MW	300.0	16249.2	15362.7	14507.7	12041.1	3321.6	27.59
DEC 1998				16249.2	15360.0	14505.0	11309.5	4050.5	35.81
JAN 1999	NAM KHEK(1)	2X25 MW	120.0	16369.2	15417.4	14562.4	12328.1	3089.3	25.06
FEB 1999	NAM KHEK(2)	2X35 MW		16369.2	15386.3	14531.3	12347.6	3038.7	24.61
MAR 1999				16369.2	15332.3	14477.3	12838.7	2493.6	19.42
APR 1999				16369.2	15250.9	14395.9	12933.8	2317.1	17.92
MAY 1999				16369.2	15204.6	14349.6	13231.8	1972.7	14.91
JUN 1999				16369.2	15191.8	14336.8	12916.7	2275.1	17.61
JUL 1999				16369.2	15215.3	14360.3	13028.6	2186.7	16.78
AUG 1999				16369.2	15242.6	14387.6	13224.1	2018.6	15.26
SEP 1999				16369.2	15368.5	14513.5	13414.0	1954.6	14.57

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TABLE 2 MONTHLY RESERVE MARGIN

IN-SERVICE DATE	NAME OF POWER PLANT	RATED CAPACITY (MW)	ACCUMULATED CAPACITY INSTALLED (MW)	DEPENDABLE (MW)	FIRM (MW)	PEAK GENERATION REQUIREMENT (MW)	RESERVE MARGIN (MW)	(%)
FY 2000								
OCT 1999	NEW THERMAL #3 600 MW	600.0	16969.2	16038.3	15103.3	12326.2	3712.1	30.12
NOV 1999	NAM CHERN #1-4 4X100 MW	400.0	17369.2	16443.7	15508.7	12810.4	3633.3	28.36
DEC 1999			17369.2	16441.0	15506.0	12032.0	4408.9	36.64
JAN 2000			17369.2	16387.4	15532.4	13115.8	3271.7	24.94
FEB 2000			17369.2	16356.3	15501.3	13136.5	3219.9	24.51
MAR 2000			17369.2	16302.3	15447.3	13658.9	2643.4	19.35
APR 2000			17369.2	16220.9	15365.9	13760.1	2460.8	17.88
MAY 2000			17369.2	16174.6	15319.6	14077.2	2097.4	14.90
JUN 2000			17369.2	16161.8	15306.8	13742.0	2419.9	17.61
JUL 2000			17369.2	16185.3	15330.3	13861.0	2324.3	16.77
AUG 2000			17369.2	16212.6	15357.6	14068.9	2143.7	15.24
SEP 2000			17369.2	16338.5	15483.5	14271.0	2067.6	14.49
FY 2001								
OCT 2000	NEW THERMAL #4 600 MW	600.0	17969.2	17008.3	16153.3	13052.5	3955.8	30.31
NOV 2000			17969.2	17013.7	16158.7	13565.3	3448.4	25.42
DEC 2000	SB #1 RETIRED 200 MW	-200.0	17769.2	16821.0	15966.0	12741.1	4079.9	32.02
JAN 2001	NEW THERMAL #5 600 MW	600.0	18369.2	17337.4	16482.4	13888.7	3448.7	24.83
FEB 2001			18369.2	17306.3	16451.3	13910.6	3395.7	24.41
MAR 2001			18369.2	17252.3	16397.3	14463.8	2788.4	19.28
APR 2001			18369.2	17170.9	16315.9	14571.0	2599.9	17.84
MAY 2001			18369.2	17124.6	16269.6	14906.8	2217.8	14.88
JUN 2001			18369.2	17111.8	16256.8	14551.8	2560.0	17.59
JUL 2001			18369.2	17135.3	16280.3	14677.8	2457.5	16.74
AUG 2001			18369.2	17162.6	16307.6	14898.0	2264.6	15.20
SEP 2001			18369.2	17288.6	16433.6	15112.0	2176.6	14.40

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DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM
(AS OF JULY 1988)

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.	TRANSMISSION SYSTEM EXPANSION ASSOCIATED WITH GENERATION PROJECTS					
A.1	ON-GOING PROJECTS					
	HYDROELECTRIC PROJECT					
A.1.1	Srinagarind Unit 5 Project (180 MW)					
	a) Srinagarind Switchyard Addition	-	-	230	-	1991
	b) Sai Noi Substation 1/	-	-	230	-	1991
	THERMAL POWER PLANT PROJECTS					
A.1.2	Khanom 2nd Barge (75 MW)					
	a) Conversion of Khanom-Nakhon Si Thammarat-Phatthalung-Hat Yai 2 from 115 kV to 230 kV	-	-	230	-	1989
	b) Termination of 115 kV Hat Yai 1-Sadao Line to Hat Yai 2 Substation	6	2	115	477	1989
A.1.3	Mae Moh Unit 8 (300 MW)					
	a) Conversion of Mae Moh 3-Tha Tako Line from 230 kV to 500 kV	(326)	1	500	4x795	1989
A.1.4	Mae Moh Unit 9 (300 MW)					
	a) Mae Moh 3 Switchyard Expansion	-	-	500	-	1990
	b) Tha Tako-Nong Chok	212	1	500	4x795	1990

Note : 1/ New Substation.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.1.5	Lan Krabu Unit 8 (25 MW)					
	a) Lan Krabu-Phitsanulok 2	52	1	115	477	1990
A.1.6	Bang Pakong Combined Cycle Blocks 3&4 (2x300 MW)					
	a) Modification of 230 kV Bang Pakong-Bang Phli	(44.5)	2	230	2x1,272	1991
A.1.7	Mae Moh Unit 10 (300 MW)					
	a) Mae Moh 3-Tha Tako (2nd Circuit) 1/	326	1	500	4x795	1992
A.1.8	Bang Pakong Thermal Power Plant Unit 3 (600 MW)					
	a) Modification of Bang Kapi-Lat Phrao	(10.4)	2	230	2x1,272	1992
	b) Modification of Bang Phli-South Bangkok	(15.9)	2	230	2x1,272	1992
	c) Bang Pakong Switchyard Expansion	-	-	230	2x1,272	1992
	Subtotal	596 km (or 602 circuit-kilometers) and 1 New Substation				

Note : 1/ Single Circuit on Double Circuit Steel Towers.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.2	PROJECTS IN SIXTH FIVE-YEAR DEVELOPMENT PLAN					
	HYDROELECTRIC PROJECTS					
A.2.1	Pak Mun Project (4x34 MW)					
	a) Pak Mun 1/ - Ubon Ratchathani 2	70	2	115	477	1993
	b) Ubon Ratchathani 1 - Ubon Ratchathani 2 1/,2/	25	1	115	477	1993
	c) Ubon Ratchathani 2 - Si Saket 2/	65	1	115	477	1993
A.2.2	Kaeng Krung Project (2x40 MW)					
	a) Kaeng Krung 1/ - Rajjaprabha	42	2	115	477	1993
	THERMAL POWER PLANT PROJECTS					
A.2.3	New Combined Cycle Blocks 1,2 & 3 (3x300 MW)					
	a) Rayong 2 - Ao Phai 1	54	2	230	1x1,272	1991
A.2.4	Nam Phong Combined Cycle Blocks 1 & 2 (2x105 MW)					
	a) Termination of 115 kV Khon Kaen 1-Udon Thani 2 Line to Nam Phong Switchyard 3/	6	4	115	477	1990
	b) Nam Phong - Khon Kaen 1	30 2/ /1	1/2	115	95 mm²	1990
	c) Termination of 115 kV Ubolratana - Nam Phong Junction Line to Nam Phong Switchyard	1	4	115	95 mm²	1990
	d) Nam Phong - Udon Thani (Rebuild)	7 4/ /(95)	1	115	477	1990

Notes : 1/ New Substation.
2/ Line Stringing only.
3/ Relocated Substation.
4/ Construction on new Rights-of-Way.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.2.5	New Krabi Lignite (75 MW)					
	a) Krabi Switchyard (Reconstruction)	-	-	115	-	1992
A.2.6	Mae Moh Unit 11 (300 MW)					
	a) Mae Moh 3 Switchyard Addition	-	-	500	-	1993
	b) Tha Tako - Nong Chok (2nd Circuit) 1/	212	1	500	4x795	1993
A.2.7	Bang Pakong Thermal Power Plant Unit 4 (600 MW)					
	a) Ao Phai Substation Addition	-	-	230	-	1993
	b) Bang Pakong - On Nuch 2/	45	2	230	2x1,272	1992
A.2.8	Mae Moh Unit 12 (300 MW)					
	a) Mae Moh 3 - Mae Moh 4 1/,2/	5	1	500	4x795	1993
	b) Mae Moh 4 - Tha Tako (3rd Circuit) 3/	326	1	500	4x795	1993
	Subtotal	889 km (or 1,122 circuit-kilometers) and 5 New Substations				

Notes : 1/ Single Circuit on Double Circuit Steel Towers.
2/ New Substation.
3/ Line Stringing.

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DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.3	FUTURE PROJECTS					
	HYDROELECTRIC PROJECTS					
A.3.1	Mae Taeng Project (26 MW)					
	a) Mae Taeng 1/ - Chiang Mai 2	45	1	115	477	1995
A.3.2	Lower Sirikit Unit 1 (15 MW) & Sirikit Unit 4 (125 MW)					
	a) Sirikit - Phitsanulok 2	118	1	230	1,272	1996
	b) Termination of 115 kV Sirikit - Uttaradit Line to Lower Sirikit Switchyard 1/	1	2	115	477	1996
A.3.3	Lower Mae Ping Units 1-2 (2x20 MW)					
	a) Termination of 115 kV Bhumibol - Tak 1 Line to Lower Mae Ping Switchyard 1/	4	2	115	477	1998
A.3.4	Nam Khek Project (120 MW)					
	a) Huai Ngaet 1 1/ - Huai Ngaet 2 1/	10	1	115	477	1999
	b) Huai Ngaet 1 - Lom Sak	40	2	115	477	1999
A.3.5	Nam Chern Project (4x100 MW)					
	a) Termination of 230 kV Lom Sak - Khon Kaen 3 Line to Nam Chern Switchyard 1/	3	4	230	1,272	1999

Notes : 1/ New Substation.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
	THERMAL POWER PLANT PROJECTS					
A.3.6	Mae Moh Unit 13 (300 MW))					
	a) Mae Moh 4 Switchyard Addition	-	-	500	-	1994
	b) Tha Tako Substaton Addition	-	-	230	-	1994
	c) Nong Chok Substation Addition	-	-	500	-	1994
A.3.7	Mae Moh Unit 14 (300 MW)					
	a) Mae Moh 4 Switchyard Addition	-	-	500	-	1994
	b) Tha Tako - Nong Chok (3rd Circuit) 1/	212	1	500	4x795	1994
A.3.8	Mae Moh Unit 15 (300 MW)					
	a) Mae Moh 4 - Tha Tako (4th Circuit) 2/	326	1	500	4x795	1995
A.3.9	Saba Yoi Unit 1 (150 MW)					
	a) Saba Yoi 3/ - Hat Yai 2	77	2	230	2x1,272	1995
	b) Termination of 115 kV Hat Yai 2 - Yala Line to Saba Yoi Switchyard	13	2	115	336.4	1995
A.3.10	Mae Moh Unit 16 (300 MW)					
	a) Mae Moh 4 - Mae Moh 5 (1st Circuit) 2/, 3/	5	1	500	4x795	1995
	b) Tha Tako - Nong Chok (4th Circuit)	212	1	500	4x795	1995
A.3.11	Saba Yoi Units 2 & 3 (150+300 MW)					
	a) Saba Yoi Switchyard Addition	-	-	230	-	1996
A.3.12	Mae Moh Unit 17 (300 MW)					
	a) Mae Moh 5 - Tha Tako (5th Circuit) 1/	326	1	500	4x795	1996

Notes : 1/ Line Stringing.
2/ Single Circuit on Double Circuit Steel Towers.
3/ New Substation.

Notes : 1/ Line Stringing.
2/ Single Circuit on Double Circuit Steel Towers.
3/ New Substation.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
A.3.13	Mae Moh Unit 18 (300 MW))					
	a) Mae Moh 5 Switchyard Addition	-	-	500	-	1997
A.3.14	New Thermal Unit 1 (600 MW)					
	a) Ao Phai 1 - Ao Phai 2 1/	3	2	230	2x1,272	1997
A.3.15	Mae Moh Unit 19 (300 MW)					
	a) Mae Moh 5 Switchyard Addition	-	-	500	-	1997
	b) Tha Tako Substation Addition	-	-	500	-	1997
A.3.16	New Thermal Unit 2 (600 MW)					
	a) Ao Phai 2 - Nong Chok	97	2	500	4x795	1998
A.3.17	Saba Yoi Unit 4 (300 MW)					
	a) Hat Yai 2 - Phatthalung	90	2	230	1,272	1998
	b) Thung Song - Surat Thani 2/	(120)	2	115	266.8	1998
	c) Phatthalung - Surat Thani (via Thung Song)	208	2	230	1,272	1998
A.3.18	New Thermal Unit 3 (600 MW)					
	a) Ao Phai 2 Switchyard Addition	-	-	500	-	1999
A.3.19	New Thermal Unit 4 (600 MW)					
	a) Ao Phai 2 Switchyard Addition	-	-	500	-	2000
	Subtotal	1,790 km (or 2,332 circuit-kilometers) and 9 New Substations				

Notes : 1/ New Substation.
2/ Line Dismantling Only.

DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
B.	TRANSMISSION SYSTEM EXPANSION PROJECTS					
B.1	ON GOING PROJECTS					
B.1.1	Transmission System Expansion Project No.7 (Part A)					
(1)	Saraburi 2-Nakhon Ratchasima 2	120	2	230 2/	1,272	1990
(2)	Bang Pakong-Chachoeng Sao	19	1	115	477	1990
(3)	Ang Thong 2-Ayutthaya 1	38 3/	1	115	477	1990
(4)	Ayutthaya 1-Bang Pa-In (Reconstruction)	(21)	2	115	477	1990
(5)	Ao Phai-Si Racha	5	1	115	477	1990
(6)	Conversion of Lampang 1-Lamphun 1-Chiang Mai 1-Chiang Mai 2 from 69 kV to 115 kV	-	-	115 4/	-	1990
(7)	Tha Tako-Takhli 2 & Reconstruction of Singburi-Takhli 2	44/(45)	2/1	115	477	1990
(8)	Mae Moh 3-Phayao	114	1	115	477	1990
(9)	Tak 1-Mae Sot 1/	79	1	115	477	1990
(10)	Ban Phai Substation 1/ and Line Termination	2	2	115	477	1990
(11)	Khong Substation 1/ and Line Termination	2	2	115	477	1990
(12)	Sam Phran 2 Substation 1/	-	-	115	-	1990
(13)	Sawankhalok Substation 1/ and Line Termination	11	2	115	477	1990
(14)	Ang Thong 2-Doembang Nangbuat 1/	34	1	115	477	1990

Notes :
1/ New Substation
2/ Initially Energized at 115 kV
3/ Line Stringing Only
4/ Conversion of Substation Equipment from 69 kV to 115 kV only

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DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
	(15) Nakhon Sawan-Salokbat 1/	49	1	115	477	1990
	(16) Thalan 1-Phra Phutthabat 1/	19	1	115	477	1990
	(17) Saraburi 4-Nakhon Nayok 1/	30	1	115	477	1990
	(18) Surat Thani-Ban Don 1/	17	1	115	477	1990
	(19) Ayutthaya 2 Substation 1/	-	-	69	-	1990
	(20) Addition of Transformer at Existing Substations	-	-	-	-	1990
	(21) Reactive Power Compensation	-	-	-	-	1990
	(22) Miscellaneous System Expansions	-	-	-	-	1990
B.1.2	Transmission System Expansion Project No.7 (Part B)					
	(1) Upgrading of EGAT System Control Centre	-	-	-	-	1990
	Subtotal	583 km (or 783 circuit-kilometers) and 11 New Substations				
B.1.3	Other Transmission System Expansion Projects					
	(1) Nong Han 1/ - Ban Dung 1/	40	1	115	477	1990
	(2) Second Central - Southern Tie Line					
	(a) Prachuap Khiri Khan - Surat Thani	350	2	230	1,272	1990
	(3) Khon Kaen 3 1/ - Roi Et	115	2	230	1,272	1991
	Subtotal	505 km (or 970 circuit-kilometers) and 3 New Substation				

Note : 1/ New Substation

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DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date
B.2	PROJECTS IN SIXTH FIVE-YEAR DEVELOPMENT PLAN					
B.2.1	Transmission System Expansion Project No.8 (Tentative Program)					
	(1) Kalasin-Sakon Nakon	113	1	115	477	1992
	(2) Tha Tako-Bang Mun Nak 1/	51	1	115	477	1992
	(3) Narathiwat-Sungai Kolok 1/	48	1	115	477	1992
	(4) Ban Na San Substation 1/	-	-	115	-	1992
	(5) Bang Pakong-Phanom Sarakham 1/	52	1	115	477	1992
	(6) Kabin Buri Substation 1/	-	-	115	-	1992
	(7) Ao Phai-Bang Lamung (No.2)	22	1	115	477	1992
	(8) Phatthalung-Ranot 1/	48	1	115	477	1992
	(9) Chiang Rai-Thoeng 1/	61	1	115	477	1992
	(10) Amnat Charoen Substation 1/	-	-	115	-	1992
	(11) Mae Moh 3-Lamphun 2	107	2	230	1,272	1992
	(12) Chumphon-Surat Thani Line Termination to Lang Suan 1/	3	2	115	477	1992
	(13) Buri Ram-Prakhon Chai 1/	46	1	115	477	1992
	(14) Prachuap Khiri Khan-Chumphon Line Termination to Bang Saphan 1/	2	2	115	477	1992
	(15) Hua Hin Substation 1/	-	-	115	-	1992
	(16) Addition of Transformer at Existing Substations	-	-	-	-	1992
	(17) Reactive Power Compensation	-	-	-	-	1992
	(18) Miscelleneous System Expansions	-	-	-	-	1992
	Subtotal	553 km (or 665 circuit-kilometers) and 12 New Substations				

Notes : 1/ New Substation.
2/ Line Stringing only.

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DETAIL OF TRANSMISSION SYSTEM EXPANSION PROGRAM

No.	Name of Transmission Lines and Substations	Length in km	Number of Circuit	Voltage (kV)	Conductor Size (MCM)	Commissioning Date (Fiscal Year)
B.2.2	Accelerated Transmission System Expansion Projects					
(1)	South Bangkok - South Thonburi 1/ - Bangkok Noi Line	(23.2)	2	230	2x1,272	1991
(2)	Sam Phran 1 - Samut Sakhon 1 - Samut Sakhon 3 1/ Line	16.9	2	115	477	1991
(3)	Hat Yai 2 - Pattani Line	90.0	1 2/	115	477	1991
(4)	Yasothon - Ubon Ratchathani Line 3/	(95.5)	1	115	477	1991
(5)	Nakhon Ratchasima 2 - Buri Ram Line	120	2	115	477	1991
(6)	Transformer Additions	-	-	-	-	1990-1991
(7)	Reactive Power Compensation Equipment Installations	-	-	-	-	1990-1991
(8)	Miscellaneous System Expansions	-	-	-	-	1990-1991
	Subtotal	226.9 km (or 363.8 circuit-kilometers) and 2 New Substation				
B.2.3	Other Transmission System Expansion Projects					
(1)	Tha Tako - Khon Kaen 3	300	2	230	1272	1992
	Subtotal	300 km (or 600 circuit-kilometers)				
	GRAND TOTAL (TRANSMISSION SYSTEM EXPANSION PROJECT)	5,442.9 km (or 7,437.8 circuit-kilometers) and 43 New Substations				

Note : 1/ New Substation.
2/ Single Circuit on Double Circuit Steel Towers.
3/ Line Reconductoring.

SENSITIVITY ANALYSIS OF EGAT PDP

The sensitivity analysis of EGAT PDP, formulated based on Working Group's load forecast-July 1988 (Low Case), is considered as an alternative PDP (88-02A).

The differences in the sequence of projects selected in the alternative PDP compared to that in the recommended PDP are classified into 4 categories as follows:

1. Common Projects

- Bang Pakong Combined Cycle Blocks 3-4 (2x300 MW)
- New Combined Cycle Blocks 1-2 (2x300 MW)
- Nam Phong Combined Cycle Blocks 1-2 (2x105 MW)
- Srinagarind Unit 5 (180 MW)
- Lan Krabu Combined Cycle (Steam Turbine-50 MW)
- Mae Moh Units 10-11 (2x300 MW)
- Bang Pakong Thermal Unit 3 (600 MW)
- Krabi Unit 4 (75 MW)
- Pak Mun Units 1-4 (4x34 MW)
- Kaeng Krung Units 1-2 (2x40 MW)
- Mae Taeng Units 1-2 (18 and 8 MW)
- Saba Yoi Units 1-3 (2x150 and 1x300 MW)

2. Delayed Projects

Projects	Delayed Schedule
Bang Pakong Thermal Unit 4 (600 MW)	5 months
Mae Moh Units 12-19 (8x300 MW)	1 Year
Saba Yoi Unit 4 (300 MW)	1 Year
Bhumibol Unit 8 (178 MW)	1 Year
New Thermal Units 1-3 (3x600 MW)	1 Year
Nam Khek (1)and (2)	2 Years

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3. Accelerated Project

Sirikit Unit 4 and Lower Sirikit Unit 1 (125 and 15 MW) would be accelerated for one year.

4. Noncommissioned Projects

Noncommissioned Projects	Replaced by
New Combined Cycle Block 3 (300 MW)	-
Lower Mae Ping Units 1-2 (2x20 MW)	Nam San and Nam Man (2x26 and 2x16 MW) one year ahead in commission
Nam Chern Units 1-4 (4x100 MW)	-
New Thermal Units 4-5 (2x600 MW)	-

List of projects of the Alternative PDP, LOLP and the comparison of sequence of projects are shown in the following pages.

LIST OF ALTERNATIVE PDP (88-02A)
(Based on Low Load Forecast)

Name of Project	Rating (MW)	Commissioning Date	LOLP (Days/Year)
2nd PPB	75	February 1989	12.506
Mae Moh #8	300	July 1989	13.507
2nd CSTL	(270)	February 1990	13.567
Bang Pakong GT (3)	2x100	June 1990	16.830
Bang Pakong GT (4)	2x100	August 1990	15.086
New CC GT (1)	2x100	September 1990	14.861
New CC GT (2)	2x100	October 1990	5.293
Nam Phong GT	4x35	November 1990	6.311
Mae Moh #9	300	December 1990	6.840
Srinagarind #5	180	April 1991	6.780
Bang Pakong ST (3)	100	June 1991	5.617
Bang Pakong ST (4)	100	August 1991	5.261
New CC ST (1)	100	September 1991	6.219
New CC ST (2)	100	October 1991	0.845
Lan Krabu CC (ST)	50	October 1991	0.845
Nam Phong ST	2x35	December 1991	0.731
230 kV Tha Tako-Khon Kaen 3	(300)	January 1992	0.886
Mae Moh #10	300	February 1992	0.850
Bhumibol Renovation	(2x70)	March 1992	0.685
Bang Pakong Thermal #3	600	May 1992	0.792
Krabi #4	75	November 1992	2.176
Mae Moh #11	300	February 1993	2.287
North Bangkok Renovation	(2x75-87.5)	August 1993	2.307
Bang Pakong Thermal #4	600	October 1993	4.198
Pak Mun #1-4	4x34	November 1993	3.968
Kaeng Krung #1-2	2x40	December 1993	5.358
Mae Moh #12	300	October 1994	3.646
Sirikit #4	125	February 1995	3.571
Lower Sirikit #1	15	February 1995	3.571
Mae Moh #13	300	April 1995	3.850
Mae Taeng #1-2	18+8	June 1995	4.048
Saba Yoi #1	150	October 1995	1.815
Mae Moh #14	300	November 1995	1.930
South Bangkok Renovation	(2x200+3x300)	December 1995	1.841
Saba Yoi #2	150	April 1996	1.708
Mae Moh #15	300	May 1996	2.061
Saba Yoi #3	300	October 1996	2.234
Mae Moh #16	300	November 1996	2.471
Bhumibol #8	178	January 1997	2.230
Mae Moh #17	300	October 1997	3.204
Nam San #1-2	2x26	November 1997	3.307
Nam Man #1-2	2x16	December 1997	2.969
Mae Moh #18	300	April 1998	3.334
New Thermal #1	600	October 1998	2.044
Mae Moh #19	300	November 1998	2.232
New Thermal #2	600	October 1999	2.740
Saba Yoi #4	300	November 1999	3.324
New Thermal #3	600	October 2000	5.515
Nam Khek (1)	2x25	January 2001	5.319
Nam Khek (2)	2x35	Febuary 2001	5.650
Additional Capacity in 1988-2001	=	10,054 MW	
Total Capacity Up to 2001a/	=	16,513 MW	
PV.@ 12% DR.(From 1988-2001 in Million Baht)			
Capital Expenditure		91,162.08	
Operation and Maintenance Cost		7,648.67	
Fuel Cost		238,489.48	
Total Present Value		337,300.00	

Notes : With retirement of existing plants of 435.0 MW (see Appendix 14).

COMPARISON OF PROJECTS
BASE CASE AND ALTERNATIVE PDP

Calendar Year	Month	PDP 88-02 (Base Case)	MW	PDP 88-02A (Low Case)	MW
1988		Existing Capacity	6,894	Existing Capacity	6,894
1989	Feb	2nd PPB	75	2nd PPB	75
	Jul	Mae Moh #8	300	Mae Moh #8	300
1990	Jun	Bang Pakong GT (3)	2x100	Bang Pakong GT (3)	2x100
	Aug	Bang Pakong GT (4)	2x100	Bang Pakong GT (4)	2x100
	Sep	New CC. GT (1)	2x100	New CC. GT (1)	2x100
	Oct	New CC. GT (2)	2x100	New CC. GT (2)	2x100
	Nov	Nam Phong GT	4x35	Nam Phong GT	4x35
	Dec	Mae Moh #9	300	Mae Moh #9	300
1991	Jan	New CC. GT (3)	2x100	-	-
	Apr	Srinagarind #5	180	Srinagarind #5	180
	Jun	Bang Pakong ST (3)	100	Bang Pakong ST (3)	100
	Aug	Bang Pakong ST (4)	100	Bang Pakong ST (4)	100
	Sep	New CC. ST(1)	100	New CC. ST(1)	100
	Oct	Lan Krabu CC.(ST)	50	Lan Krabu CC.(ST)	50
		New CC.ST (2)	100	New CC.ST (2)	100
	Dec	Nam Phong ST	2x35	Nam Phong ST	2x35
1992	Jan	New CC.ST (3)	100	-	-
	Feb	Mae Moh #10	300	Mae Moh #10	300
	Mar	Bhumibol Renovation	(2x70)	Bhumibol Renovation	(2x70)
	May	Bang Pakong TH #3	600	Bang Pakong TH #3	600
	Nov	Krabi #4	75	Krabi #4	75
1993	Feb	Mae Moh #11	300	Mae Moh #11	300
	May	Bang Pakong TH #4	600	-	-
	Aug	North Bangkok Renovation	(237.5)	North Bangkok Renovation	(237.5)
	Oct	Mae Moh #12	300	Bang Pakong TH #4	600
	Nov	Pak Mun #1-4	4x34	Pak Mun #1-4	4x34
	Dec	Kaeng Krung #1-2	2x40	Kaeng Krung #1-2	2x40
1994	Apr	Mae Moh #13	300	-	-
	Oct	Mae Moh #14	300	Mae Moh # 12	300
1995	Feb	-	-	Lower Sirikit #1	15
		-	-	Sirikit #4	125
	Apr	Mae Moh #15	300	Mae Moh #13	300
	Jun	Mae Taeng #1-2	18+8	Mae Taeng #1-2	18+8
	Oct	Saba Yoi #1	150	Saba Yoi #1	150
	Nov	Mae Moh #16	300	Mae Moh #14	300
	Dec	South Bangkok Renovation	(1,300)	South Bangkok Renovation	(1,300)
1996	Jan	Bhumibol #8	178	-	-
	Feb	Lower Sirikit #1	15	-	-
		Sirikit #4	125	-	-
	Apr	Saba Yoi #2	150	Saba Yoi #2	150
	May	-	-	Mae Moh #15	300
	Oct	Saba Yoi #3	300	Saba Yoi #3	300
	Nov	Mae Moh #17	300	Mae Moh #16	300
1997	Jan	-	-	Bhumibol #8	178
	Apr	Mae Moh #18	300	-	-
	Oct	New Thermal #1	600	Mae Moh #17	300
	Nov	Mae Moh #19	300	Nam San #1-2	2x26
	Dec	-	-	Nam Man #1-2	2x16
1998	Apr	-	-	Mae Moh #18	300
	Jul	Lower Mae Ping #1-2	2x20	-	-
	Oct	New Thermal #2	600	New Thermal #1	600
	Nov	Saba Yoi #4	300	Mae Moh #19	300
1999	Jan	Nam Khek (1)	2x25	-	-
	Feb	Nam Khek (2)	2x35	-	-
	Oct	New Thermal #3	600	New Thermal #2	600
	Nov	Nam Chern #1-4	4x100	Saba Yoi #4	300
2000	Oct	New Thermal #4	600	New Thermal #3	600
2001	Jan	New Thermal #5	600	Nam Khek (1)	2x25
	Feb	-	-	Nam Khek (2)	2x35
Additional MW (1988-2001)			11,910		10,054
Difference			Base		-1,856

THAILAND
PRIVATE SECTOR POWER STUDY

ANNEXES

ANNEXES

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ANNEX 1

SCOPE OF WORK

SCOPE OF WORK

BACKGROUND

The Government of Thailand is developing policies and guidelines to encourage the participation of the private sector in power generation. In November 1988 the Government established a policy framework and in December the electric utility, EGAT, developed draft procedures for cogeneration and small scale generation. Larger scale private power generation is a separate but related issue that is under consideration and analysis. The Government has requested USAID assistance on the cogeneration guidelines and examination of the issue of large private power producers.

CONSULTANTS

The Contractor will provide two consultants, an electric utility expert and an energy policy expert, to provide the scope of work described below.

SCOPE OF WORK

1. Analyze the policy statements and guidelines that are under consideration by the Government (RTG) and utility (EGAT).

2. Work closely with the RTG and EGAT in the design and initiation of development of a "private power program". This will include options for key elements of such a program including but not limited to (a) planning for the amount, type and timing of private power plants and coordination with the system expansion plan, (b) procedures for solicitation of proposals, (c) criteria and process for selection, (d) contracting for private power including, if possible, model power purchase agreements and purchase price methodologies, and (e) implementation of private power projects including technical interconnection, reliability and dispatchability issues.

3. Work closely with EGAT on analysis of potential technical problems and technical constraints which are of concern to EGAT, such as reliability and dispatchability. Identify options for dealing with problems and constraints.

4. In collaboration with RTG and EGAT prepare workplan and schedule for full development of a private power program incorporating cogeneration and small scale generation.

5. Consult with RTG and EGAT on broader private power issues including potential for and implications of large scale private power generation; prepare guidance, workplan or related documents if requested by RTG.

REPORTS

The consultants will prepare a final report of activities, findings and recommendations for the RTG, USAID/Thailand and ANE/TR/ENR.

REF: ATTACH1

ANNEX 2

PRESS RELEASE: PRIVATIZATION

NATION
2/17/89

EGAT asked to seek listing on stock exchange

Govt approves private venture in electricity

By Duangkamol Chotana

THE National Energy Policy Committee has approved an ambitious plan in which the private sector will be invited to participate in production and distribution of electricity in what is considered as the first major decision on privatization under the Chatichai administration.

The committee, under the chairmanship of Premier Chatichai and holding a Cabinet status, has also agreed to push the Electricity Generating Authority of Thailand for its shares to be listed on the Securities Exchange of Thailand as part of its divestiture.

The move, initiated by the prime minister, is aimed at reducing the huge financial risks shouldered by the electricity generating agency at the time when it is heading towards a period of major expansion to meet the sharp increase in energy demand.

The approval was striking and unexpected since the EGAT's privatization plan was not included in the agenda of the meeting yesterday. This episode might also shock EGAT's officials, who have all along cast doubts over privatization. Furthermore, nobody expected that the decision would come this fast, jumping over routine scrutiny and procedure because the national energy policy subcommittee previously ordered EGAT to submit its privatization plan for consideration in March.

But concern is mounting that the committee's decision might spark a strong opposition from the EGAT labour union, which previously and successfully rallied against the National Petrochemical Corporation's request to sell electricity from its new cogeneration facilities at Mab Ta Put.

NPC finally gave in, being forced to agree to sell its electricity through EGAT once its operation comes on line late this year. EGAT will stand to earn a one per cent margin in revenue from this agreement. It is estimated that the value of electricity which NPC sells to

CONTINUED PAGE 24

Chatichai...spearheads the partial privatization move

Pisit...happy with decision

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▶▶▶ Electricity

the downstream petrochemical companies will amount to some Bt100 million a year.

In fact, the committee was intended to review electricity development programmes towards the end of the Sixth Plan, during which six projects will be added to the EGAT's expansion programme that will require the investment size to jump from Bt85 billion to Bt138.10 billion. This will double EGAT's assets, now standing at Bt108 billion, by the end of the Sixth Plan in 1992.

That huge amount of money was apparently viewed as a burden to the government by most committee members, who shared the opinion that the money could otherwise be allocated to other needed sectors, so they did not hesitate to endorse EGAT's privatization.

Dr Pisit Pakkasem, deputy secretary general of the National Economic and Social Development Board and a secretary of the National Energy Policy Committee, said the private sector, under the broad guideline, will be invited to participate in either the cogeneration or joint ventures of all the approved electricity generating projects.

He said the committee has assigned the Finance Ministry, NESDB and EGAT to conduct a joint study outlining details and procedures of the private participation in the power generation sector within 30 days. The Finance Ministry will concentrate on EGAT's divestiture plan to float shares in the stock market.

Dr Piyasvasti Amranand, director of the Office of the National Energy Policy, supported the privatization plan saying that privatization of the power generation sector is the worldwide prevailing practice, which helps increase the production efficiency while reducing the government's financial burden.

He said projects that the private sector might participate are thermal plants at newly-discovered Saba Yoi lignite deposits in Songkhla, the thermal power projects in the Eastern Seaboard using imported coals as fuel, and the thermal power units at Mae Moh, Lampang.

Projects that the private sector might not be able to participate at the moment because of the tedious negotiations that involve are the gas turbine plants at Bang Pakong, Rayong, Namphong in Khon Kaen.

Piyasvasti said the private investors have been involved in the cogeneration process for quite some time, such as sugar refineries, the scale of which remains small because the refineries stay opened for only four months a year. Only a small amount of excess supply is sold to EGAT or to other companies.

Cogeneration is a process by which sequential production of electricity and heat is generated from one fuel source for the purpose of performing useful work. If cogeneration is implemented by a private company, it can then be considered a special form of private power generation.

A source said EGAT has been voicing objection all along for the privatization of the agency, arguing that the private participation will not efficiently be worked out largely because the Thai investors lack adequate financial and technological support. The government's green-light, EGAT viewed, will open a wide door to foreign participation, hence biting into profits of the agency at the time when the agency is subsidizing the electricity bills in the upcountry.

EGAT only agrees to private participation at the cogeneration level, but not at other levels, at least at this particular juncture. Still, the agency has come up with four forms of privatizations, yet to be presented for official endorsements: cogeneration, build own operate transfer (the private sector sets up its own power generation operation), partial divestiture of EGAT's shares, EGAT's setting up a subsidiary in which private participation is invited.

Pisit said the committee has also agreed to reduce the electricity bills by 10 per cent for manufacturing plants located within the designated industrial estates for a period of five years. Exception will be made for the industrial estates situated in Bangkok, Nonthaburi, Samut Prakarn, Samut Sakhon and the Eastern Seaboard.

EGAT in fiscal 1988 posted Bt108.39 billion in assets and a net income of Bt7.06 billion. The agency has the generating capacity of 6,896,845 kilowatts from 33 power stations.

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ANNEX 3

RECOMMENDED DRAFT REGULATIONS

(Proposed by Team)

PROPOSED MODIFICATIONS TO
REGULATIONS ON THE PURCHASE OF ELECTRICITY FROM INDEPENDENT POWER PRODUCERS
(For power generated from residue fuel or cogeneration only)

THE NATIONAL ENERGY POLICY OFFICE

February 1989

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FOREWORD

At the National Energy Policy Committee (NEPC) meeting on October 24, 1988, the Committee approved a policy guideline that would allow the private sector to generate and sell electricity to the electric utilities. The committee also established a time frame for the implementation of the policy guideline. The first step was to establish, by the end of 1988, regulations on the purchase of electric power generated from residue fuels or cogeneration processes from private power producers.

A draft of the regulations, which has now been completed, was a joint effort between the Electricity Generating Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA), and the Provincial Electricity Authority (PEA). The major points covered in the regulations include the encouragement of private sector participation in power generation, the encouragement of increasing the use of primary energy by-products and the improved efficient utilization of primary energy in power generation. The regulations also specify the characteristics of the electricity generation process, the procedures for the purchase of electricity from cogeneration or residue power producers and the criteria for establishing purchase prices. The draft regulations will be discussed in a technical conference to provide an opportunity for comment before the final regulations are issued. The target date for final regulations to be published is March 31, 1989.

Applications for the sale of electricity by cogeneration or residue power producers to the electric utilities will be accepted three months after the official announcement of the regulations and for such period after that date until the amount of power offered to the electricity authorities equals the amount solicited. EGAT will issue solicitations for such power on an annual basis. EGAT will request 300 MW in its first solicitation. The applications submitted will be reviewed by EGAT, coordinating with MEA and PEA, with recommendations presented to the NEPC.

(SAMPLE)

ANNOUNCEMENT

Reference : REGULATIONS FOR THE PURCHASE OF ELECTRIC POWER FROM PRIVATE COGENERATION OR RESIDUE POWER PRODUCERS

Following the National Energy Policy Committee (NEPC) resolution to promote energy efficiency through the generation of electricity from the efficient utilization of residue fuels or cogeneration processes and NEPC review, the electricity authorities have established regulations and procedures for the purchase of electricity from such power producers.

The Electricity Generating Authority of Thailand, in conjunction with the Metropolitan Electricity Authority and the Provincial Electricity Authority , hereby announces that private entities interested in selling electricity to the electricity utilities are required to follow the procedures and guidelines as per the attached announcement.

Effective on .....

Date of announcement .....

.....

(Mr. Paopat Chavanalikikorn)

The Electricity Generating Authorit, of Thailand

.....

(Mr. Anant Atilaksana)

The Metropolitan Electricity Authority

.....

(Mr. Veera Pitrachart)

The Provincial Electricity Authority

REGULATIONS FOR THE PURCHASE OF ELECTRICITY FROM COGENERATION OR RESIDUE POWER PRODUCERS

Contents

Definition

A. The objectives of purchasing electricity from cogeneration or residue producers

B. Characteristics of cogeneration or residue power producers

C. The standard requirements of privately owned power systems

D. Power purchasing procedures

E. Criteria for power purchase

F. Purchasing point

G. Expenses of cogeneration or residue power producers

H. Criteria for determining the purchase price

I. Terms of payment

J. Damage to electrical systems

Attached Application form for the sale of electricity

REGULATIONS FOR THE PURCHASE OF ELECTRICITY FROM COGENERATION OR RESIDUE POWER PRODUCERS

Definitions

" Cogeneration or Residue Power Producer" (CR) refers to an entity which gener and sells electricity in accordance with the standards of power generating processes as stated in B.

"Electricity Authorities" (EA) refers to :

The Electricity Generating Authority of Thailand (EGAT)

The Metropolitan Electricity Authority (MEA)

The Provincial Electricity Authority (PEA)

A. Objectives of Purchasing Electricity from Cogeneration or Residue Power Producers

are as follows :

1. To encourage greater private sector participation in power generation.
2. To encourage the utilization of primary energy by-products in the generation of electricity.
3. To stimulate more efficient utilization of primary energy for power generation.
4. To meet the nation's growing needs for generating capacity.

B. Characteristics of Cogeneration or Residue Power Producers

The Electricity Authorities will buy from the following categories of power producers, subject to the limitations described later in these regulations:

1. Electricity generated by utilizing renewable, waste or residue fuel from facilities sized less than 50 MW. Renewable, waste and residue fuels include but are not limited to agricultural waste (such as sugar and rice harvesting and processing products) dendrothermal projects, wood, municipal garbage biogas, hydro, wind and any other fuel except oil, coal, lignite or natural gas. Electricity generated using oil, gas coal or lignite from these renewable, waste and residue facilities will also be purchased under these regulations provided that generation from residue or waste fuel represents at least 33 percent of the annual generation of kilouatthours at the facility.

2. Cogenerated power from facilities using any fuel where the ratio of useful thermal output (thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application) to total energy output is no less than 10 percent on an annual basis.

C. The Standard Requirements of Privately-Owned Power Systems

Cogeneration or Residue Power Producers wishing to generate and distribute electricity to the state-owned electricity utilities are required to abide by the established safety standards. In addition, their power lines, when connected to the public utility system, must adhere to the technical specifications as set by each electricity authority accordingly. Interconnection requirements are appended to these regulations.

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D. Power Purchasing Procedures

The procedures for purchasing electricity from Cogeneration or Residue Power Producers are as follows:

1. CRs wishing to sell electricity to the electricity authorites must submit their applications at the Electricity Generating Authority of Thailand's headquarters at Tambon Bangruey, Amphoe Bangruey, Nonthaburi Province.

2. In addition to the application form, other documents detailing the following information are also required :

2.1 The juristic entity registration and the prospectus.

2.2 Maps showing the location of the plant and its layout.

2.3 A description of the power generating site.

2.4 Details of thermal utilization in the production process of the plant and the characteristics of the power generation process.

2.5 Descriptions of details of electricity generators, prime movers and their technical specifications.

2.6 Single line diagrams and metering and relaying diagrams illustrating how the plant is to be connected to the public power system.

2.7 The amount of power consumption and the proposed procedure for supplying power into the public power system.

2.8 The number of power generator operators the facility will employ, and the requirements for operator educational levels and engineering licenses.

3. The result of the application will be announced within 90 days after the submission of all the required documents.

4. EGAT will make the standard contract attached to these regulations available to CRs approved to sell electricity to the EA. CRs may, at their option, negotiate non-price terms of the standard contract with EGAT to suit the requirements of the facility. CRs approved to sell electricity to the EA are required to sign a contract with EGAT within one year after the date of approval.

E. Criteria for Power Purchase

The criteria for purchasing electricity from the CR are established as follows:

1. EGAT will be the sole purchaser of electricity. unless the CR, EGAT and MEA or PEA as appropriate agree otherwise.
2. The electricity authorities will purchase electricity from facilities that meet the characteristics of a CR as described in Section B in an amount up to the amount solicited.
3. CRs may not sell electricity to the electric authorities without a contract for the sale of that power.
4. The CR is required to submit permits for plant construction, equipment installation, and electricity production and distribution no more than eighteen months after the signing of the contract.
5. In the event more electrical capacity is offered to the electricity authorities than the amount solicited (300 MW in its first solicitation), the electricity authorities reserve the right to select those CR proposals that best meet the requirements of the electricity authorities.
6. The electricity authorities retain the right to inspect the CR's electricity distribution equipments and to request the correction of defective equipment if does not meet the requirements of these regulations.

F. Electricity Purchasing Point

The purchasing point is designated as the connecting point between the CR's lines and the main public power system.

G. Expenses of CR

1. Main system power connection costs.

The total cost of connecting power to the main system, namely, the costs associated with electricity distribution, metering, safety measures, and additional operating expenses incurred by the electricity authorities must be incurred by the CR.

2. Equipment inspection costs.

The CR is required to pay all inspection costs as stated in E.7, whether the inspections are prescribed by the electricity authorities or requested by the CR. The CR is required to pay for such costs within 30 days of receiving payment notification from the electricity authorities.

H. Criteria for Deterimining the Purchase Price

Prior to its solicitation for purchases of electricity from CRs, EGAT will establish a level for capacity payments to projects accepted in that solicitation. The level of capacity payments will be established based on the estimated capacity costs of new generation units planned by EGAT in the time period covered by the solicitation . For the purpose of its first solicitation, the level for capacity payments will equal 2640 Baht per Kilowatt per year. The capacity value, in kilowatts, will be allocated in a manner shown in the capacity payments section below.

The energy price will be announced on a yearly basis, and will commence on the first day of each calendar year. The calculation will be performed in a consistent manner each year.

During the peak and partial load periods, the price will be calculated by adding 25% to the average energy costs and operating and maintenance costs incurred by EGAT's thermal power plants during the prior fiscal year.

During the light load period, the price will be calculated by adding 25% to EGAT's average energy cost incurred by EGAT's thermal power plants during the prior fiscal year.

If, however, EGAT estimates that the energy costs it will avoid by purchasing from cogeneration and residue plants in the calendar year exceeds the values specified above, then EGAT will pay CRs the energy costs it estimates it will avoid by purchasing from such facilities for the calendar year. EGAT shall provide its estimates of the energy costs it will avoid and the details of its calculation to the National Energy Policy Committee for review prior to each calendar year. Such avoided energy costs will be calculated on a bahts per kilowatthour basis for Peak, Partial peak and Light Load Periods.

Capacity Payment

The Annual Capacity Value of the term of the agreement will equal _____Baht per Kilowatt per year (2640 Baht for the first solicitation). [Explanatory note : the annual figure of 2640 baht proposed for the first solicitation is equivalent to 220 baht per Kilowatt per month ; attachment A outlines the method used to derive this figure.] The Monthly Capacity Value

will equal the Annual Capacity Value multiplied by the Monthly Ratio for each month, where the Monthly Ratio is EGAT's peak electric demand for the corresponding month in the prior year divided by the sum of EGAT's twelve monthly peak electric demands for the prior year.

The monthly capacity payment for the term of the agreement will equal the Monthly Capacity Value multiplied by the Net Dependable Capacity of the facility. The Net Dependable Capacity of the facility shall be defined as the lesser of :

(i) The Monthly Stated Capacity ; or

(ii) Monthly Peak Capacity minus [10% x (Monthly Stated Capacity minus Monthly Peak Capacity)]

where :

Monthly Stated Capacity is the amount of dependable capacity that the CR intends to provide to EGAT. The CR will specify Monthly Stated Capacity in kilowatts for each month in the year at the time of contract signing. The CR may respecify Monthly Stated Capacity at three year intervals following the contract signing based on the actual experience of the facility

Monthly Peak Capacity is equal to the sum of : (i) .7x [Peak Period kwh deliveries in month/ (.8x hours in Peak Period in month)]; and (ii) .3x [Partial Peak Period kwh deliveries in month/ (.8x hours in Partial Peak Period in month)].

EGAT may propose allocation factors other than 70% Peak Period and 30% Partial Peak period in subsequent solicitations.

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Losses

The energy and capacity payments described above shall be increased by a percentage value (loss factor) equal to the estimated reduction in system losses that the CR will provide. The loss factor for CRs delivering power to the transmission or subtrancmission system (above 15000 votts) will be 4.30% in 1989. The loss factor for CRs delivering at distribution voltages (at or below 15000 votts) will be 10.38% in 1989. [Explanatory note : attachment B shows EGAT's tabulation of transmission and distribution losses; the 1987 values have been used in this proposal.] EGAT may however, conduct a loss study for any CR that it believes will reduce losses by less than these loss factors. If the loss study shows a lower value of loss reduction then EGAT may employ such lower loss factor. The loss factor will be adjusted annually based on EGAT, MEA and PEA average transmission, subtransmission and distribution losses for the prior year.

1/ NOTE

Peak and Partial Peak

Purchase Price = (Energy Cost + Operating Costs + Maintenance Cost of EGAT's thermal plants) + 25%

Light Load

Purchase Price = Energy Cost of thermal plants + 25%

Note that the 3 periods are

Peak	18.30-21.30
Partial Peak	08.00-18.30
Light	21.30-08.00

I. Terms of payment

Montnly payments for the purchase of electricity will be made within 30 days upon the receipt of payment notifications.

J. Damages to the main power system

The CR will be held responsible for all damage done to their own power system if the cause of damage originates from within their own plant.

The CR will also be held responsible for all damage done to the main public power system if the damage is caused by the CR's operating error or by a failure of the CR's own equipment.

Note Any CR wishing to purchase electricity from the electricity authorities must follow the normal procedures established by the authorities for all prospective users. The purchase price from the electricity authorities is the same as for other customers.

Form EGAT RF-1

Economic Policy Division

The Electricity Generating Authority of Thailand

Receipt No.....

Date Received.....

Signed.....

(Receiver)

APPLICATION FOR ELECTRICITY SALE

Address .....

Date.....Month.....Year.....

Name ..... Age ..... Nationality .....

Race ..... Home address number ..... Trok/Soi .....

Province ..... Telephone number .....

I am submitting the application in the capacity of .....

Name of the company .....

Headquaters address ..... Telephone number .....

Plant location ..... Telephone number .....

I hereby submit this application form for the sale of electricity to the state electricity authorities. The following additional documents are attached.

1. The Juristic entity registration and the prospectus
2. Maps showing the location of the plant and its layout.
3. A description of the power generating site.
4. Details of thermal utilization in the production process of the plant and the characteristics of the power generation process.
5. Descriptions of details of electricity generators, prime movers and their technical specifications.

6. Single line diagrams and metering and relaying diagrams illustrating how the plant is to be connected to the public power system.
7. The amount of power consumption and the proposed procedure for supplying power into the public power system.
8. The number of power generator operators the facility will employ, and the requirements for operator's educational levels and their engineering licenses.

I hereby certify that the above information and the documents attached are true and correct.

Signed.....Applicant

(.....)

Position .....

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Attached documents

Descriptions of Details of Electricity Generators and Prime Movers

1. Power generator

- Type of electricity generator
- Capacity (Kilowatt per unit)
- Rated Voltage
- Rate Current
- Rotation (Round per minute)
- System (phase, line number)
- Frequency (Round per minute)
- Power factor (%)
- Engine condition
- Manufacturer
- Serial number

2. Prime mover

- Type (combustion, thermal gas turbine, steam turbine)
- Horse power
- Rotation
- Fuel (Diesel, natural gas, etc.)
- Number of piston or stage
- Engine condition (%)
- Manufacturer
- Serial number

Detail of the Safety System

1. Metering and safety equipment

- Amp. Meter
- Volt meter
- Demand meter
- Frequency and Kilowatt hour meters
- Fuse
- Cut-out
- Circuit Breaker
- Relay

(Sample)

(EGAT Trademark)

ANNOUNCEMENT

THE PURCHASE PRICE OF ELECTRICITY FROM
COGENERATION ON RESIDUE POWER PRODUCERS

With reference to the regulation for the purchase of electricity from Cogeneration or Residue Power Producers, the Electricity Generation Authority of Thailand will buy electricity, during the 1989 fiscal year, based on the following rates.

A. Energy price

A.1 During the peak load period	00.80 Baht/kwh
A.2 During the partial peak load period	00.80 Baht/kwh
A.3 During the light load period	00.75 Baht/kwh
Capacity Price	220 Baht/Kw/month

The above prices are effective as of October 1, 1988.

Announcement date : September 30, 1988

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(Mr. Paophat Chaovanalikikorn)

General Manager

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Attachment A:

Method for Derriving

Avoided Capacity Cost

Source: PDP 88-02 p 35-36 Summary of Sources of Financing 1989 Commitments

Bang Pakong Combined Cycle Block3	(300 MW)	$198.25 million U.S.
Bang Pakong Combine Cycle Block4	(300)	169.96
Krabi Lignite Unit 4	(75)	119.72
Nam Phong Combined Cycle Blocks 1-2	(210)	167.50
Mae Moh Unit 11	(300)	251.33
Lan Krabu Combined Cycle (steam turbine)	(50)	50.08
New Combined Cycle Block 1	(300)	207.52
New Combined Cycle Block 2	(300)	170.58
New Combined Cycle Block 3	(300)	187.09
Bang Pakong Thermal Unit 4	(600)	412.39
Total	2735 MW	$1934.36 million

Average cost/KW = $ 1,934.36 million/2,735 MW = $707/KW

For Thailand Power Tariff Structure study, a 12% annuity over 25 years is used, or a.1275 annual factor. Adding operation and maintenance cost to this (note no taxes in calculation) gives about a 15% annual charge rate.

$$\$707 \times .15 \times 25 \frac{\text{Baht}}{\text{dollar}} \quad 12\text{mo/yr} = 220 \text{ Baht/kw-month}$$

Operation and Maintenance - 1988 " Other Generating Expenses"/Installed MW

= 2,593,000,000 Baht/6,894,200 kw

= 376 Baht/kw-yr

Operation and Maintenance /Capacity cost = 376/(220x12) = 14.2%

Annual charge rate = .1275 x 1.142 = .146, or approximately 15%

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LEVEL OF GENERATION, TRANSMISSION AND DISTRIBUTION LOSSES

Year	Energy Generation (GWh)	Generating losses		Transmission and Substation losses1/		Distribution losses (MEA and PEA)		Total Losses (EGAT MEA and PEA)	
		GWh	%	GWh	%	GWh	%	GWh	%
1980	14,753.73	590.45	4.00	583.95	3.96	845.13	5.73	2,019.52	13.69
1981	15,959.97	612.29	3.84	842.06	5.28	870.24	5.45	2,324.59	14.57
1982	16,881.95	602.49	3.57	917.49	5.43	870.52	5.16	2,390.49	14.16
1983	19,066.30	659.05	3.46	901.17	4.73	1,157.17	6.07	2,717.38	14.25
1984	21,066.44	830.10	3.94	931.63	4.42	1,336.86	6.35	3,098.58	14.71
1985	23,356.74	1,022.81	4.38	1,167.20	5.00	1,392.43	5.96	3,582.44	15.34
1986	24,779.53	1,010.03	4.08	1,335.38	5.39	1,483.63	5.99	3,829.04	15.45
1987	28,193.16	1,154.68	4.10	1,211..46	4.30 2/	1,714.43	6.08	4,080.52	14.47

Notes : 1/ Including MEA and PEA Sub-Transmission, street lighting, mining and construction used.
2/ Reduction of about 1 percent transmission loss was due to the commissioning of Mae Moh-Tha Tako 500 kV line (4x795 MCM ACSR conductor per phase), which is being energized at 230 kV; the installations of reactive power compensation equipment such as static VAr control (SVC) at Chumphon and shunt capacitor banks.

Source : PDP 8802-Vol.1

0267C

MASSACHUSETTS ELECTRIC COMPANY

REQUIREMENTS FOR INTERCONNECTION OF QUALIFYING SMALL POWER PRODUCERS AND COGENERATORS WITH MASSACHUSETTS ELECTRIC COMPANY

Any Small Power Producer or Cogenerator ("QF") wishing to interconnect with the Company's electrical distribution system must meet the requirements set forth in this policy before the Company will interconnect with the QF. Once interconnected, the Company may disconnect from the QF if the QF departs from this policy's requirements. The QF must return to full compliance with this policy prior to reconnecting.

I. To prevent inadvertent and unwanted re-energization of a dead Company line or bus, the QF must install and maintain the following equipment:

A. A circuit breaker must be installed to isolate the QF's generation from the Company's system whenever the Company side of the interconnection is dead. A voltage transformer must be connected either phase to phase, or phase to ground, on the Company side of the circuit breaker. The voltage transformer must supply an undervoltage relay that will open the circuit breaker when voltage is at 75% or less of normal voltage and prevent

the closing of the circuit breaker until Company voltage is restored to normal. If the voltage transformer is connected phase to ground, it must be rated for phase to phase voltage and have a loading resistor to prevent ferroresonance. The voltage relay must have time delay. B using suitable interlocks, the QF may disable the undervoltage relay whenever the generator is not running, so that the QF's load will remain connected to the Company during abnormal voltage conditions on the Company's system. For 120V systems, the voltage transformer may be omitted.

B. The Company shall have the right to open the interconnection at any time to maintain the line. The QF may continue to generate to meet its own loads, but must have an open switch at the interconnection. The open switch must have a visible air break that can be locked open, tagged, and grounded on the Company side by Company personnel.

C. QFs operating induction generators do not require the protection described in this paragraph I unless the Company specifically finds that protection is required during its interconnection inspection.

II. To prevent interconnection while out of synchronization, the QF must install and maintain the following equipment:

A. Two voltage transformers with correct polarity and phasing must be installed to synchronize the generator with the Company's system. One shall be installed on each side of

the circuit breaker. They shall supply a synchroscope monitoring the primary system that must be energized before the circuit breaker can be closed.

B. Non-directional overcurrent relays supplied by current transformers in the generator circuit must be installed with a setting suitable to detect an out-of-phase connection. The relays shall be designed to trip the circuit breaker.

C. The circuit breaker used for synchronizing the generator must be capable of withstanding at least twice the circui voltage. Also, it must be capable of interrupting the current produced when the generator, at full voltage, is connected to the Company's line 180° out of phase, which may produce more current than a short circuit.

D. This paragraph II shall not apply to QFs operating induction generators.

III. To detect and prevent ground faults, the QF must install and maintain the following equipment:

A. For interconnections having a transformer between the generator and the Company with an ungrounded winding at the Company voltage, a voltage transformer must be installed and connected phase to ground on the Company side of the transformer or the Company side of a circuit breaker. The voltage transformer must be rated for the circuit phase to phase voltage, and have a loading resistor to prevent ferroresonance. This may be the same

voltage transformer used under paragraph IA. One undervoltage relay and one overvoltage relay supplied by this voltage transformer must be installed to detect ground faults and trip the appropriate circuit breaker, as under paragraph IA. The voltage relays must have time delay. The requirements of this paragraph IIIA shall not apply to single phase interconnections connected phase to phase.

B. For interconnections having a transformer between the generator and the Company with a grounded winding at the Company voltage:

(i) Three Phase Interconnection: A study must be performed to determine whether a voltage or a current method of ground fault detection must be used.

(ii) Single Phase Interconnection: No special ground fault detection method is needed as it is provided under paragraph IA as dead line detection.

C. For interconnections having no transformer between the generator and the Company:

(i) 480/277V Systems: A voltage transformer must be installed on each phase connected phase to ground with an undervoltage relay on each transformer. The relays shall be designed to trip the appropriate circuit breaker after a time delay.

(ii) 208/120V Systems: An undervoltage relay must be installed on each phase connected phase to ground. The

relays shall be designed to trip the appropriate circuit breaker after a time delay.

(iii) 120/240V Single Phase Systems: When the generator is 240V, two undervoltage relays must be installed and connected from each side to ground. When the generator is 120V, one undervoltage relay must be installed and connected to the same 120V side as the generator. These relays shall be designed to trip the appropriate circuit breaker after a time delay.

D. This paragraph III shall not apply to QFs operating induction generators.

IV. To prevent frequency outside permissible limits, the QF shall install and maintain the following equipment:

A. A voltage transformer with 115V or 120V normal output, connected to either the generator voltage or the Company voltage, must be installed to supply an underfrequency relay and an overfrequency relay. These relays shall be designed to trip the appropriate interconnection circuit breaker after a time delay. The permissible limits are approximately 59Hz to 61Hz.

The frequency relays are not expected to operate while the QF is interconnected with the Company. They should not be connected to the generator side of the circuit breaker used for synchronizing.

B. Induction generators do not require frequency relays.

V. To prevent voltage generated outside permissible limits, the QF

shall install and maintain the following equipment:

A. (i) Three Phase Generators: A voltage transformer connected phase to phase or phase to ground at the Company voltage must be installed to supply voltage relays when a three phase generator is used. If the voltage transformer is connected phase to ground, it must be rated for the phase to phase voltage and have a loading resistor to prevent ferroresonance. It may be the same voltage transformer installed to meet the requirements of paragraph IA. An undervoltage and an overvoltage relay must be installed to trip the appropriate interconnection circuit breaker after a time delay. The permissible voltage limits are approximately 114V to 126V when 120V is the normal.

The voltage relays are not expected to operate while the QF is interconnected with the Company.

By using suitable interlocks, the QF may disable the voltage relays whenever the generator is not running so that the QF's load will remain connected to the Company during abnormal voltage conditions on the Company's system.

The voltage transformers may be connected to the generator voltage level with suitable adjustment in the relay settings to compensate for the power transformer ratio.

(ii) Single Phase Generators: When the generator

is single phase, the voltage measurement will be made on the phase used by the generator.

B. No voltage transformer is needed when the interconnection is at 120V.

C. The voltage relays must be frequency compensated to have the same calibration at frequencies 30Hz to 90Hz.

D. An undervoltage relay must be installed for induction generators, but the overvoltage relay is not required. The undervoltage relay is not ordinarily required for induction

generators having a capacity of 30KW or less.

VI. Additional Information and Requirements:

A. The Company may require the QF to discontinue generating or to disconnect from the Company's system whenever other customers complain about poor electrical service and the Company believes that the QF's generation may be the cause. Interconnection may be resumed when it is determined that the QF has not caused the condition or when the QF has taken corrective action satisfactory to the Company.

B. The Company will assist communication companies in determining the source and type of interference caused by the QF interconnection with the electrical circuit.

C. The Company shall have the right to automatically reclose circuit breakers after they have tripped open without determining whether the QF is keeping the circuit energized.

D. The Company reserves the right to refuse to interconnect, or to discontinue an interconnection, with a QF if:

(i) The anticipated voltage flicker will be objectionable to other customers.

(ii) The anticipated voltage regulation will be objectionable to other customers.

(iii) The anticipated harmonic generation and waveform distortion will affect communication facilities.

(iv) The limits of toleration for flicker, voltage regulation and waveform distortion, as defined by appropriate standards, have already been reached on the circuit due to previous interconnections with QFs or other customers.

E. The QF must not reduce the reliability or the power factor of the circuit below the level that existed prior to the QF's interconnection.

F. The Company shall have the right to review and approve the interconnection plans and the specifications for equipment proposed to be used by a QF before effecting an interconnection.

G. Before the initial interconnection and as required thereafter, the Company shall have the right to calculate or check the relay settings and either test or witness the testing of the relays. The relays must be tested by the QF on a periodic basis, not less than once every four years.

H. The QF must not add generators or replace generators with

a different type or larger size without first notifying the Company and complying with this policy's requirements. The QF may, however, reduce generation without notice.

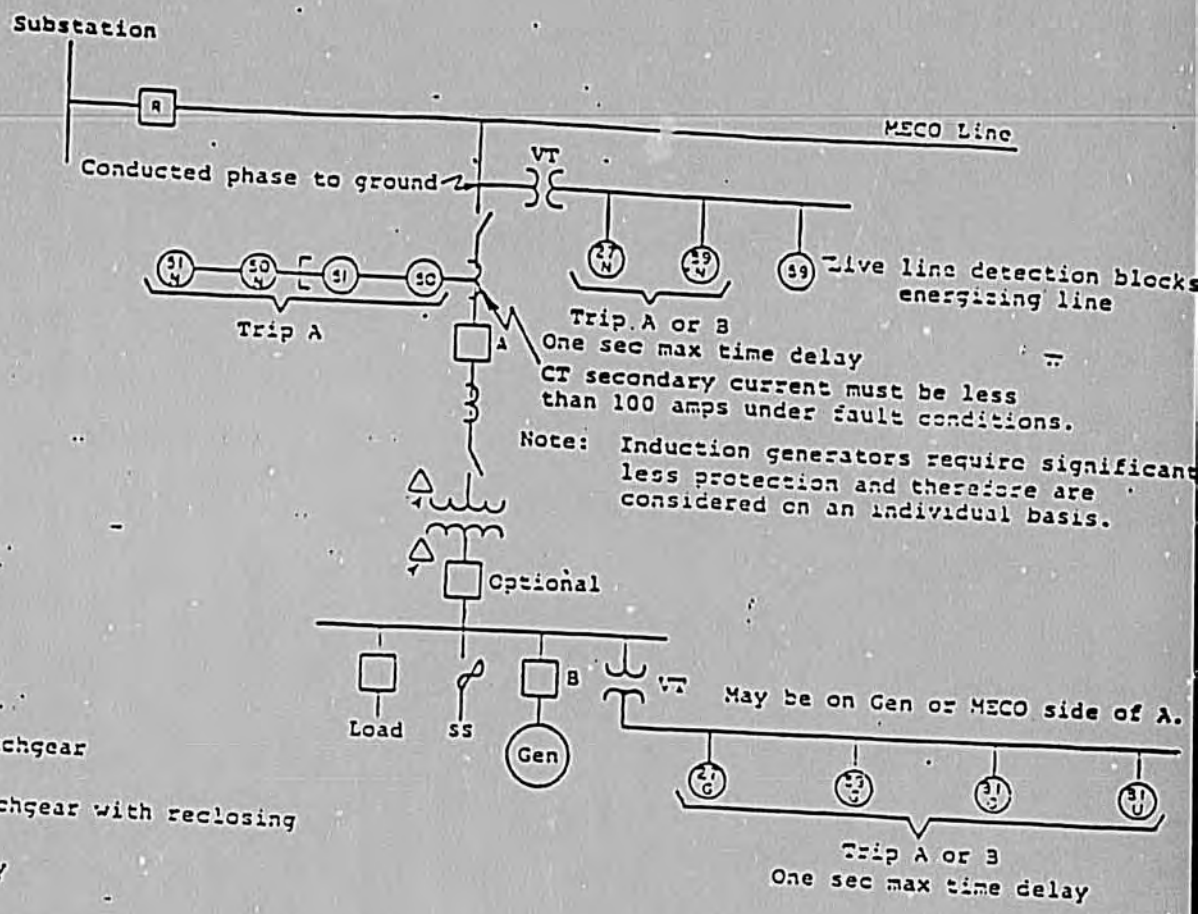
I. The Company may transfer the distribution circuit to a different substation, change voltage levels or use the circuit for underfrequency load shedding after providing the QF with notice.

J. The QF must coordinate its protective relaying with the protective devices on the distribution circuit, and if necessary, install special relays and communication, such as pilot wire protection.

K. The QF must provide protection for its equipment and remove all faults from the Company circuit in a manner that coordinates with the circuit protection. The QF shall be solely responsible for the protection of its own equipment.

L. The attached diagram provides an example of the minimum protective requirements for interconnection with and operation of a QF's generators. Note that small induction generators require significantly less protection and are considered on an individual basis.

TYPICAL MINIMUM PROTECTION REQUIREMENTS FOR INTERCONNECTION AND OPERATION OF CUSTOMER'S GENERATORS



SYMBOLS

- Switchgear
- Switchgear with reclosing
- Relay
- Transformer
- CTs
- Fuses
- 27 Undervoltage-Gen (1)
- 27 N Undervoltage-MECO Line ground fault (1)
- 50 Overcurrent-Instantaneous, phase (2 or 3)
- 50 N Overcurrent-Instantaneous, ground (1)
- 51 Overcurrent-Inverse Time, phase (2 or 3)
- 51 N Overcurrent-Inverse Time, ground (1), Optional
- 59 Overvoltage-Instantaneous, blocking (1)
- 59 G Overvoltage-Gen (1)
- 59 N Overvoltage-MECO Line ground fault (1)
- 81 O Overfrequency (1)
- 81 U Underfrequency (1)
- 62 Timer-if necessary

NOTES

Synchronizing not shown

Fuses may be used in place of switchgear under certain conditions

Additional relays may be required by MECO

Customer relay protection is not shown

Surge voltage protection is not shown

Metering is not shown

Effective Date: March 1, 1984

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ANNEX 4

EGAT DRAFT REGULATIONS

REGULATIONS ON THE PURCHASE OF ELECTRICITY FROM INDEPENDENT POWER PRODUCERS

(For power generated from residue fuel or cogeneration only)

THE ELECTRICITY GENERATING AUTHORITY OF THAILAND
THE METROPOLITAN ELECTRICITY AUTHORITY
THE PROVINCIAL ELECTRICITY AUTHORITY

December 1988

FORWARD

At the 1/1988 National Energy Policy Committee meeting on October 24, 1988, the Committee approved a policy guideline that would allow the private sector to generate and sell electricity to the electric utilities. The committee also established a time frame for the implementation of the policy guideline. The first step was to establish, by the end of 1988, regulations on the purchase of electric power generated from residue fuels or cogeneration processes from private independent power producers.

A draft of the regulations, which has now been completed, was a joint effort between the Electricity Generating Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA), and the Provincial Electricity Authority (PEA). The major points covered in the regulations include the encouragement of private sector participation in power generation, the encouragement of increasing the use of primary energy by-products and the improved efficient utilization of primary energy in power generation. The regulations also specify the characteristics of the electricity generation process, the procedures for the purchase of electricity from the independent power producers and the criteria for establishing purchase prices. When finalized, the regulations would be announced to the public.

Applications for the sale of electricity by independent power producers to the electric utilities will be accepted six mounths after the official announcement of the regulations. The applications submitted will be jointly reviewed by all three electricity authorities.

(SAMPLE)

ANNOUNCEMENT

Reference : REGULATIONS FOR THE PURCHASE OF ELECTRIC POWER FROM PRIVATE INDEPENDENT POWER PRODUCERS

Following the National Energy Policy Committee resolution to promote energy efficiency through the generation of electricity from the efficient utilization of residue fuels or cogeneration processes, the the electricity authorities have established regulations and procedures for the purchase of electricity from independent power producers.

The Electricity Generating Authority of Thailand, the Metropolitan Electricity Authority and the Provincial Electricity Authority hereby announce that private entities interested in selling electricity to the electricity utilities are required to follow the procedures and guidelines as per the attached announcement.

Effective on .....

Date of announcement .....

.....

(Mr. Paopat Chavanalikikorn)

The Electricity Generating Authority of Thailand

.....

(Mr. Anant Atilaksana)

The Metropolitan Electricity Authority

.....

(Mr. Veera Pitrachart)

The Provincial Electricity Authority

REGULATIONS FOR THE PURCHASE OF ELECTRICITY FROM THE PRIVATE INDEPENDENT POWER PRODUCERS

(For power generated from residue fuel or cogeneration only)

Contents

Definition

A. The objectives of purchasing electricity from independent power producers

B. Characteristics of independent power producers

C. The standard requirements of privately owned power systems

D. Power purchasing procedures

E. Criteria for power purchase

F. Purchasing point

G. Expenses of independent power producers

H. Criteria for Determining the purchase price

I. Terms of payment

J. Damage to electrical systems

Attached Application form for the sale of electricity

REGULATIONS FOR THE PURCHASE OF ELECTRICITY FROM INDEPENDENT POWER PRODUCERS

(For power generated from residue fuel or cogeneration only)

Definition

"Independent Power Producer" (IPP) refers to an entity which generates and sells electricity in accordance with the standards of power generating processes as stated in B.

"Electricity Authorities" (EA) refers to :

The Electricity Generating Authority of Thailand (EGAT)

The Metropolitan Electricity Authority (MEA)

The Provincial Electricity Authority (PEA)

A. **Objectives of Purchasing Electricity from Independent Power Producers**

are as follows :

1. To encourage greater private sector participation in power generation.
2. To encourage the utilization of primary energy by-products in the generation of electricity.
3. To stimulate more efficient utilization of primary energy for power generation.

B. **Characteristics of Independent Power Producers**

The Electricity Authorities will consider buying from the following categories of power producers :

1. Electricity generated by utilizing residue fuel ;
2. Cogenerated power optimizing the ratio between waste heat and electricity generation by taking into consideration the heating requirements of that private entity.

C. The Standard Requirements of Privately-Owned Power Systems

Independent power producers wishing to generate and distribute electricity to the state-owned electricity utilities are required to abide by the established safety standards. In addition, their power lines, when connected to the public utility system, must adhere to the technical specifcations as set by each electricity authority accordingly.

D. Power Purchasing Procedures

The procedures for purchasing electricity from independent power producers are as follows:

1. IPPs wishing to sell electricity to the electricity authorites must submit their applications at the Electricity Generating Authority of Thailand's headquarters at Tambon Bangruey, Amphoe Bangruey, Nonthaburi Province.

2. In addition to the application form, other documents detailing the following information are also required :

2.1 The juristic entity registration and the prospectus.

2.2 Maps showing the location of the plant and its layout.

2.3 A description of the power generating site.

2.4 Details of thermal utilization in the production process of the plant and the characteristics of the power generation process.

2.5 Descriptions of details of electricity generators, prime movers and their technical specifications.

2.6 Single line diagrams and metering and relaying diagrams illustrating how the plant is to be connected to the public power system.

2.7 The amount of power consumption and the proposed procedure for supplying power into the public power system.

2.8 The number of power generator operators, and the operator's educational records and engineering licenses.

3. The result of the application will be announced within 90 days after the submission of all the required documents.

4. IPP approved to sell electricity to the EA are required to sign a contract with EGAT within one year after the date of approval

E. Criteria for Power Purchase

The criteria for purchasing electricity from the IPP are established as follows:

1. EGAT will be the sole purchaser of electricity.
2. The electricity authorities will purchase electricity from licensed IPP only.
3. The generating capacity and the amount of electricity supplied to the main grid by the IPP must receive prior approval from EA and must not exceed 50 MW.
   The amount of electricity purchased will be determined by system capability and security (in accordance with the authorities' technical standards).
4. IPP is required to submit permits for plant construction, equipment installation, and electricity production and distribution on the day of the signing of the contract.

5. The electricity authorities reserve the right to determine the starting date for the purchase of electricity from IPP.
6. Officials of the electricity authorites are entitled to operate the switching system in the IPP's power plant, though IPP may be allowed to operate the system themselves. In the latter case, private producers must observe the authorities' switching orders to ensure the maximum safety of both party's operators.
7. The electricity authorities retain the right to inspect the IPP's electricity distribution equipments and to request the correction of defective equipments if necessary.

F. Electricity Purchasing Point

The purchasing point is designated as the connecting point between the IPP's lines and the main public power system.

G. Expenses of IPP

1. Main system power connection costs.
   The total cost of connecting power to the main system, namely, the costs associated with electricity distribution, metering, safety measures, and additional operating expenses incurred by the electricity authorities must be incurred by the IPP.

2. Equipment inspection costs.
   IPP is required to pay all inspection costs as stated in E.7, whether inspections are prescribed by the electricity authorities or requested by the IPP in addition to all additional operating costs incurred by the electricity authorities. IPP

is required to pay for such costs within 30 days of receiving payment notification from the authorities.

H. Criteria for Determining the Purchase Price

The purchase price will be announced on a yearly basis, and will commence from the first day of each fiscal year. The criteria for determining the purchase price are based on the ways power is discharged into the public power system; these can be classified into 2 types.

Type 1 If the amounts of electricity and the time periods of discharging power from IPP into the public power system are unreliable the purchase price will be calculated by adding 25% to the average energy cost incurred by EGAT's thermal power plant during that particular year:

Purchase price = Average Energy Cost of EGAT'S thermal Plant + 25%

Type 2 If the power to be discharged has high degree of reliability during the peak load period and if the amount discharged remains fairly regular the purchse price will be calculated according to 3 separate time periods as follows:

1. During the peak load period, the price will be calculated by adding 25% to the combined total of the energy costs, operating costs, maintenance costs, and depreciation costs incurred by EGAT's thermal power plant during that particular year.

2. During the partial peak load period, the price will be calculated by adding 25% to the combined total of the energy costs and the average operating costs incurred by EGAT thermal power plant during that year. However, the amount of electricity priced at the partial peak load rate must not exceed the average hourly peak load

demand. The amount of electricity supplied that exceeds the average hourly peak load demand level will be priced at the light load rate.

3. The purchasing price during the light load rate will be priced at the same rate as Type 1 purchase price. [1/]

Fines IPP agreeing to the type 2 contract will be subject to fines under the following conditions:

1. IPP failing to meet the peak and the partial load supply agreements will be fined 10% of the value of the amount of electricity undersupplied.
2. If the amount of electricity supplied annually from IPP is lower than the amount agreed upon for three consecutive years, the purchase price will automotically revert to the Type 1 purchase price.

1/ NOTE

Peak

Purchase Price = (Energy Cost + Operating Costs + Maintenance Cost + Depreciation of thermal plant) + 25%

Partial Peak

Purchase Price = (Energy Cost + Operating Cost of thermal plant) + 25%

Light Load

Purchase Price = Energy Cost of thermal plant + 25%

Note that the 3 periods are

Peak	18.30-21.30
Partial Peak	08.00-18.30
Light	21.30-08.00

I. Terms of payment

Monthly payments for the purchase of electricity will be made within 45 days upon the receipt of payment notifications.

J. Damages to the main power system

IPP will be held responsible for all damage done to their own power system whether the causes of damage originate from within their own plant or from the public power system.

IPP will also be held responsible for all damage done to the public main power system whether the damage is caused by a failure of their own equipment or by the public power system.

Note IPP wishing to purchase electricity from the electricity authorities must follow the normal procedures established by the authorities for all prospective users. The purchase price from the electricity authorities are the same as other customers.

Form EGAT RF-1

Economic Policy Division

The Electricity Generating Authority of Thailand

Receipt No.....

Date Received.....

Signed.....

(Receiver)

APPLICATION FOR ELECTRICITY SALE

Address .....

Date.....Month.....Year.....

Name ..... Age ..... Nationality .....

Race ..... Home address number ..... Trok/Soi .....

Province ..... Telephone number .....

I am submitting the application in the capacity of .....

Name of the company .....

Headquaters address ..... Telephone number .....

Plant location ..... Telephone number .....

I hereby submit this application form for the sale of electricity to the state electricity authorities. The following additional documents are attached.

1. The Juristic entity registration and the prospectus
2. Maps showing the location of the plant and its layout.
3. A description of the power generating site.
4. Details of thermal utilization in the production process of the plant and the characteristics of the power generation process.
5. Descriptions of details of electricity generators, prime movers and their technical specifications.

6. Single line diagrams and metering and relaying diagrams illustrating how the plant is to be connected to the public power system.
7. The amount of power consumption and the proposed procedure for supplying power into the public power system.
8. The number of power generator operatrs, and the operator's educational records and their engineering licenses.

I herely certify that the above information and the documents attached are true and correct.

Signed.....Applicant

(.....)

Position .....

Descriptions of Details of Electricity Generators and Prime Movers

1. Power generator

- Type of electricity generator
- Capacity (Kilowatt per unit)
- Rated Voltage
- Rate Current
- Rotation (Round per minute)
- System (phase, line number)
- Frequency (Round per minute)
- Power factor (%)
- Engine condition
- Manufacturer
- Serial number

2. Prime mover

- Type (combustion, thermal gas turbine, steam turbine)
- Horse power
- Rotation
- Fuel (Diesel, natural gas, etc.)
- Number of piston or stage
- Engine condition (%)
- Manufacturer
- Serial number

Detail of the Safety System

1. Metering and safety equipment

- Amp. Meter
- Volt meter
- Demand meter
- Frequency and Kilowatt hour meters
- Fuse
- Cut-out
- Circuit Breaker
- Relay

(Sample)

(EGAT Trademark)

ANNOUNCEMENT

THE PURCHASE PRICE OF ELECTRICITY FROM PRIVATE INDEPENDENT POWER PRODUCERS

With reference to the regulation for the purchase of electricity from the independent power producers (for power generated from residue fuel or cogeneration only), the Electricity Generation Authority of Thailand will buy electricity, during the 1989 fiscal year, based on the following rates.

A.	Type 1 purchasing price	00.75 Baht/kwh
B.	Type 2 purchasing price	
	B.1 During the peak load period	00.91 Baht/kwh
	B.2 During the partial peak load period	00.80 Baht/kwh
	B.3 During the light load period	00.75 Baht/kwh

The above prices are effective as of October 1, 1988.

Announcement date : September 30, 1988

.....

(Mr. Paophat Chaovanalikikorn)

General Manager

ANNEX 5

MODEL POWER PURCHASE AGREEMENT

MEMORANDUM

DATE : February 22, 1989

From : John Levett

Peter Borre

TO: Dr. Piyasvasti Amranand

Director, National Energy Policy Office

SUBJECT Draft Model power Purchase Agreement

Attached please find a draft power purchase agreement for use with cogeneration and residue/renewable/waste energy power projects.

AGREEMENT dated as of _____ between _____ ("Seller") and the Electric Generating Authority of Thailand ("EGAT")

ARTICLE I. BASIC UNDERSTANDINGS

Seller intends to own and operate a [cogeneration or residue fueled] electric power generating facility (the "Facility") located in _____. The Facility will have a generating capability of approximately _____ kilowatts.

Subject to the following terms, Seller agrees to sell and EGAT agrees to purchase the entire Net Electric Output of the Facility.

ARTICLE II. DEFINITIONS

Whenever used in this Agreement, the following terms shall be defined as follows:

"Electric System" shall mean the electric system of EGAT and/or the electric system of the Metropolitan Electricity Authority and/or the Provincial Electricity Authority.

"Good Utility Practice(s)" shall mean the practices that, at a particular time, in the exercise of reasonable judgement in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy and expedition. With respect to the Facility, Good Utility Practice includes but is not limited to taking reasonable steps to provide that:

(i) adequate materials, resources and supplies, are available to meet the Facility's needs;

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(2) Sufficient operating personnel are available and are adequately experienced, trained and licensed to operate the Facility properly and are capable of responding to emergency conditions whether caused by events on or off the site of the Facility;

(3) routine and non-routine maintenance and repairs are performed on a basis that promotes reliable long-term and safe operation, and are performed by trained and experienced personnel utilizing proper equipment and tools;

(4) appropriate monitoring and testing is done to ensure equipment is functioning as designed;

(5) equipment is not operated in a reckless manner, or in a manner unsafe to workers, the general public or the environment or without regard to defined limitations such as steam pressure, temperature and moisture content, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, frequency, rotational speed, polarity, synchronization, control system limits, etc.;

(6) equipment will function properly under both normal and emergency conditions.

"Light Load Energy Rate" shall mean 125 percent the average energy cost incurred by EGAT's thermal power plants during the prior fiscal year (October). A calculation of Light Load Energy Rate for 1989 is attached. The Light Load Energy Rate will be recalculated in the same manner annually

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(including any new thermal power plants EGAT adds to its system), and will be adjusted on the first day of each calendar year.

"Light Load Periods" shall mean all hours from 9.30 p.m. to 8.00 a.m.

"Monthly Peak Capacity" shall mean the sum of : (i) .7x [Peak Period Net Electric Output in month/(.8x hours in Peak period in month)] ; and (ii) .3 x [Partial Peak Period Net Electric Output/ (.8 x hours in Partial Peak Period in month)] . If EGAT requests seller to discontinue deliveries in any month [up to 500 hours per year permitted] then such hours shall be subtracted from the quantities hours in Peak period and/or hours in Partial peak period, consistent with the time periods EGAT requested Seller to discontinue deliveries of electricity. No adjustments to the calculation of Monthly Peak Capacity will be made for reduced Net Electric Output during Light Load Periods.

"Monthly Ratio" shall mean EGAt's peak electric demand for the corresponding month in the prior year divided by the sum of EGAT' twelve monthly peak electric demands for the prior year.

"Must Run" shall mean that Seller shall have operating control over the amount of electricity to be generated at the Facility and sold to EGAT. Seller's operating control shall be subject only to such directions as may be issued by EGAT solely for purposes of ensuring safe and reliable Electric System operation. EGAT may include economic considerations in their directions to Seller only to the extent permitted in Article IV of the Agreement.

"Net Electric Output" shall mean the total amount of electricity delivered to EGAT.

"Partial-Peak Periods" shall mean all hours from 8.00 a.m. to 6.30 p.m.

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"Peak Energy Rate" Shall mean 125 percent of the sum of average energy cost and operating and maintenance costs incurred by EGAT's thermal power plants during the prior fiscal year (October). A calculation of Peak Energy Rate for 1988 is attached. The Peak Energy Rate will be recalculated in the same manner annually (including any new thermal power plants EGAT adds to its system) ,and will be adjusted on the first day of each calendar year.

"Peak Periods" shall mean all hours from 6.30 p.m. to 9.30 p.m.

"Project Lender (s)" shall mean any party providing construction or permanent financing of the Facility.

"Monthly Stated Capacity" is shown in Schedule _____ [to be provided by Seller prior to the execution of this Agreement]. Seller may respecify Monthly Stated Capacity at three year intervals following the execution of this Agreement based on the operating experience of the Facility.

ARTICLE III. TERM

The term of this Agreement shall extend for a period of _____ years [5-20 years to be selected by Seller if Seller desires capacity payment plus energy payment. Seller may select a shorter term than 5 years but only energy payments will be made if the term is less than 5 years], beginning on the date Seller first delivers electricity to EGAT.

Notwithstanding the preceding paragraph, EGAT may terminate this Agreement if Seller has not (a) obtained all permits necessary for the construction of the Facility; and (b) begun a continuous program program of construction, both within 18 months after the execution of this Agreement.

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ARTICLE IV. TERMS OF SALE

Design and Construction Requirements

Seller agrees that the Facility shall be designed and constructed fo a planned useful life of not less than the term of this Agreement as the resul of the utilization of construction meterials and equipment and its operatio and maintenance in accordance with the requirements of Good Utility Practice Seller shall ensure that all equipment used in the Facility shall be designed constructed and tested in accordance with the applicable codes and standards t permit operation of the Facility for the term of this Agreement in accordanc with Good Utility Practice.

Purchase and Sale of Electricity

Seller shall sell and EGAT shall purchase the Net Electric Outpu when and if available at the price specified in ARTICLE V, below. EGAT agree to accept delivery of the Net Electric Output. EGAT shall not, however, t liable for any damages arising from its inability to accept delivery of an electricity that the Facility is otherwise capable of generating if EGA operates in accordance with Good Utility Practice and promptly restores su ability.

Operating Requirements

All equipment and facilities connected to the Electric System sha be installed and maintained in a safe manner, and in accordance with Go Utility Practice and applicable regulations. If at any time the operation the Facility endangers the safety of personnel, or interferes with the safe a reliable operation of the Electric System, EGAT may discontinue purchases fr Seller and disconnect from the Facility until such condition has be

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corrected. Unless an emergency exists, EGAT shall give Seller reasonable notice of its intention to disconnect from the Facility and to discontinue purchases from Seller, and, where practical, allow suitable time for Seller to remove the interfering condition. EGAT's judgements with regard to discontinuance of purchases or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice.

Commencing as of the Commencement Date of Operation, Seller shall:

(1) operate and maintain the Facility in accordance with Good Utility Practice. Seller shall provide EGAT with such information as EGAT may request to determine whether the Facility is being so operated and maintained;

(2) use best efforts to maximize delivery of electricity from the Facility during Peak Periods;

(3) provide EGAT, at EGAT's request, an estimate of electricity to be sold on a monthly basis for any period specified by EGAT;

(4) provide EGAT, at EGAT's request, an estimate of the amount of electricity that the Facility is capable of selling to EGAT for the next day;

(5) provide for scheduled maintenance of the Facility during periods designated by EGAT. EGAT shall designate such periods for each calendar year in writing prior to the preceding September. The periods designated by EGAT shall be subject to Seller's approval which shall not be withheld unless maintenance during such periods is inconsistent with Good Utility Practice or Seller's steam requirements or residue fuel constraints.

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(6) provide EGAT such supporting information related to billing as EGAT may reasonably request.

The estimates and schedules provided by Seller under subparagraphs (3) and (4) above shall be prepared based on conditions anticipated at the time such estimates and schedules are made, but shall not be binding on Seller. Seller shall, however, promptly inform EGAT, whenever it appears that actual generation at the Facility will vary more than ten percent (10%) from the most recent estimates or schedules provided under subparagraphs (3) or (4) above.

The parties recognize that emergencies, accidents, and events of force majeure may necessitate a departure from scheduled generation. Seller, however, agrees to use all reasonable efforts to promptly resume scheduled generation.

Power Factor and Voltage Standards

Unless otherwise requested by EGAT Seller will operate the Facility at a unity power factor during Light Load Periods, and in an overexcited condition at ninety percent (90%) power factor during Peak and Partial Peak Periods. If Seller lacks the capacity to operate the Facility at a ninety percent (90%) power factor (or fails to so operate the Facility when required) EGAT may install, at Seller's expense, capacitors or other electric equipment necessary to ensure that electricity can be delivered at such power factor.

Upon EGAT's request, Seller shall operate at such other power factor or excitation level as EGAT specifies. In no case, however, will Seller be required to operate outside of the range of the Facility's capability as determined from the equipment manufacturer's recommendations.

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If EGAT requests, Seller shall operate the Facility in accordance with a voltage schedule provided by EGAT that specifies maximum and minimum voltage levels for high and low system load periods. In no case, however, will Seller be required to operate outside the volt-ampere (VAR) range of the Facility's capability as determined from the equipment manufacturer's recommendations.

Dispatch Requirements

Seller agrees to submit the Facility to dispatch by EGAT. EGAT agrees to dispatch the Facility as a Must Run Facility's; provided, however, that EGAT may request, upon 8 hours prior notice, that the Facility not deliver electricity to EGAT for such time period as EGAT designates. Seller agrees not to deliver electricity to EGAT during such periods. The parties agree that such periods shall not exceed 500 hours per year.

ARTICLE V. PRICE AND BILLING

EGAT shall pay Seller the sum of:

(a) a monthly capacity charge equal to the product of 2640 Baht per kilowatt times the Monthly Ratio times the lesser of : (i) the Stated Monthly Capacity; or
(ii) the Monthly Average Peak Capacity minus [0.1x (Monthly Stated Capacity minus Monthly Peak Capacity)];and

(b) a monthly energy charge equal to the sum of :
(i) Net Electric Output during Peak and Partial Peak Periods multiplied by Peak Energy Rate; and
(ii) Net Electric Output during Light Load Periods multiplied by Light Load Energy Rate.

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Provided, however, that EGAT will estimate the energy costs it expects to avoid on a bahts per kilowatthour basis by purchasing power from cogeneration and residue plants in the next calendar year. EGAT shall submit its estimate and details of its calculation for review and approval to the National Energy Policy Committee prior to the beginning of each calendar year. Seller may, at its option, elect to be paid on the basis of such avoided energy rates (which may differ by time period) for the calendar year.

Both the energy and capacity payments described above shall be increased by a percentage value ("Loss Factor") to reflect reduced losses as a result of the Facility. The Loss Factor for this Agreement is equal to [illegible].30% for delivery above 15000 volts, 10.38% for delivery below 15000 volts. EGAT may, however conduct a loss study if it believes the Facility will reduce system losses by less than this amount. If the loss study (for representative load levels over the year) shows a lower value of loss reduction EGAT may employ such lower loss factor. The Loss Factor will be adjusted annually to equal EGAT, MEA and PEA average transmission, subtransmission and distubution losses for the prior year.

The monthly capacity charge will be paid only if the term of this Agreement equals or exceeds five years.

Bills for all amounts due under this ARTICLE V shall be rendered to EGAT monthly. EGAT shall provide Seller with a description of the format for such bills and Seller agrees to follow such format and to provide copies of such billing information as EGAT may request.

EGAT shall pay Seller within thirty (30) days after receipt of the invoice by EGAT. EGAT may dispute all or any part of any bill by mailing to Seller written notice thereof within thirty (30) days of receipt of such bill and by paying to Seller any amount not in dispute.

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ARTICLE VI. DEFAULT/TERMINATION/SECURITY

A. Events of Default The occurrence of any one of more of the following shall constitute an "Event of Default" hereunder:

(1) If, except to the extent permited under ARTICLE V, above, with regard to amounts in dispute, EGAT shall fail to make any payment required pursuant to ARTICLE V, above, or fails to accept delivery except as permitted in this Agreement and such failure continues for a period of forty-five (45) days after written notice thereof from Seller;

(2) If (i) Seller shall fail in any material respect to comply with any material obligation under this Agreement, except due to causes excused by force majeure or attributable to EGAT's wrongful act or failure to act, and (ii) after written notice thereof from EGAT, such failure shall continue for a period of forty-five (45) days, or, if such failure cannot reasonably be cured within such forty-five (45) day period, such further period as shall reasonably be required to effect such cure, provided that Seller commences within such forty-five (45) day period to effect such cure and at all times thereafter proceeds diligently to complete such cure as quickly as possible;

It is expressly understood that a Project Lender may cure any Event of Default enumerated above on behalf of Seller within any time limit specified in this Paragraph A.

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The enumeration of Events of Default hereunder shall not be construed to limit or exclude the right of the parties to seek remedies at law or damages for the breach of any other obligation hereunder.

B. Termination. If an Event of Default shall occur and be continuing, the non-defaulting party may, by notice in writing, terminate this Agreement as of the date of such notice.

C. Milestones and Completion Security. Seller shall within thirty (30) days of the signing this Agreement provide EGAT with a written development plan that outlines preoperational milestones. Seller shall include, at a minimum, milestone dates for financial closing, permitting, construction start date and expected date of first delivery of electricity. Seller shall provide with a quarterly status report on its progress in meeting each of the milestones in its development plan. In addition, Seller shall provide EGAT with immediate written notice of any occurrences that are likely to substantially delay the construction start date or the date of first delivery of electricity. Seller shall immediately notify EGAT in writing if, and at such time that, it decides to discontinue its efforts to construct the Facility.

ARTICLE VII. DELIVERY AND MEASUREMENT OF ELECTRICITY

All electricity shall be delivered to EGAT at the point of interconnection between the Electric System and Seller's system in the form of three-phase fifty hertz alternating current at a voltage determined by mutual agreement of the parties. Momentary voltage fluctuations shall be permitted, provided that they neither disturb service provided by EGAT to its customers nor hinder EGAT in maintaining proper voltage conditions. The location of the interconnection shall be determined by mutual agreement of the parties.

EGAT shall, at Seller's expense, provide, own, and maintain metering

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and communication equipment at the Facility for measuring electricity delivered to EGAT and the status of switching equipment. Seller shall provide suitable space at the Facility for installation of the metering and communication equipment at no cost to EGAT. The metering equipment shall be capable of recording var flow and of segregating electricity delivered during Peak Period, Partial Peak and Light Load Periods.

EGAT agrees to operate and maintain its interconnection and transmission facilities in accordance with Good Utility Practice so as to permit the delivery to the Electrical System of the Facility's Net Electric Output.

Meters shall be read by Seller on the first day of each month. The amount of electricity delivered to EGAT in Peak Periods, Partial Peak and Light Load Periods during the preceding month shall be determined from such readings. Daily meter readings and log sheets shall be recorded. If EGAT so requests, one copy shall be mailed to EGAT each day.

All metering equipment installed pursuant to this ARTICLE VII associated with the Facility shall be routinely tested, in accordance with Good Utility Practice, at Seller's expense. If, at any time, any metering equipment is found to be inaccurate by more than two percent (2%), EGAT shall cause such metering equipment to be made accurate or replaced at Seller's expense, and meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the preceding month shall be made except by agreement of the parties. The test shall be made in such manner as may be mutually agreed upon by the parties. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the

Facility. If either party believes that there has been a meter failure stoppage, it shall immediately notify the other.

ARTICLE VIII. CONSTRUCTION OF INTERCONNECTION FACILITIES

The interconnection facilities shall be constructed at Seller's expense. EGAT reserves to itself the construction and ownership of the interconnection taps and all necessary modifications to the Electric System attributable to the interconnection of the Facility. Seller agrees to pay EGAT in advance prior to the start of construction for all costs that EGAT reasonably estimates will be incurred in connection with such activities. Upon completion of construction, the parties agree to make a final adjustment to correct for any overpayment or underpayment. EGAT represents that in making the interconnection, it will use standard equipment customarily employed by EGAT for its own system, all in accordance with Good Utility Practice.

Seller shall be responsible for construction of all other interconnection facilities. As soon as reasonably practicable, Seller shall furnish, for review and approval by EGAT, specifications for such facilities. Responsibility for making the final interconnection between the systems is reserved exclusively to EGAT. Prior to making such interconnection, EGAT shall have the right to require Seller to provide documentation reasonably demonstrating that the Facility and the interconnection facilities constructed by Seller have been constructed in accordance with Good Utility Practice and comply with all applicable safety and electrical codes. The interconnection requirements will be consistent with the requirements attached to this Agreement.

ARTICLE IX. ACCESS TO FACILITY

Properly accredited representatives of EGAT shall at all reasonable times and upon reasonable notice have access to the Facility to make

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inspections and obtain information required in connection with this Agreement. While at the Facility, such representatives shall observe such reasonable safety precautions as may be required by Seller and shall conduct themselves in a manner that will not interfere with the operation of the Facility.

ARTICLE X. NOTICES; REPRESENTATIVES OF THE PARTIES

Any notice, demand or request required or authorized by this Agreement to be given by one party to the other party shall be in writing. It shall either be personally delivered or mailed, postage prepaid, to the representative of said other party designated in this ARTICLE.- Any such notice, shall be deemed to be given when so delivered or mailed.

Notices and other communications by Seller to EGAT shall be addressed to:

Electric Generating Authority of Thailand

_____

_____

Notices and other communications by EGAT to Seller shall be addressed to:

_____

_____

_____

Either party may change its representative by written notice to the other.

The parties' representatives designated above shall have full authority to act for their respective principals in all technical matters relating to the performance of this Agreement. However, they shall not have authority to amend, modify, or waive any provision of this Agreement unless they are authorized officers of their organization.

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ARTICLE XI. INSURANCE, LIABILITY, INDEMNIFICATION, AND RELATIONSHIP OF PARTIES

[Note : Insurance specialists in Thailand should provide input as t appropriate levels]

A. Seller shall, at its own expense, acquire and maintain throughout th term of this Agreement the following minimum insurance coverages:

(i) Statutory coverage for Worker's Compensation, and Basic Employers' Liability coverage with a limit no. less than _____

(ii) comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability, written with limits no less than: _____

Bodily Injury - _____ per occurrence

Property Damage - _____ per occurrence

or _____

Combined Single Limit;

(iii) Comprehensive Automobile Liability Coverage, including all owned, non-owned, and hired vehicles, written with limits no less than:

Bodily Injury - _____ per person/

_____ per accident

Property Damage - _____ per occurrence;

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(iv) All Risk Property Coverage and Boiler and Machinery Coverage against damage to the Facility in amount not less than the full replacement cost of the Facility (to restore the Facility to its condition prior to the casually loss). Such policies shall be endorsed to require that:

(1) complete copies of each inspection or other report required by or performed for the insurer shall be provided to EGAT within _____ days of its completion.

(2) The coverage afforded shall not be canceled or reduced without at least _____ days prior written notice to EGAT and

(3) in the event of a loss, the insurance proceeds shall be applied to repair of the Facility unless Seller and EGAT agree otherwise;

(v) Business Interruption Insurance providing funds to cover all of Seller's costs to the extent that they would not be eliminated or reduced by the failure of the Facility to operate (including but not limited to rent or mortgage payments, interest and principal payments on loans or bonds and salaries and wages) for a period of at least twelve (12) months after a reasonable deductible period;

The insurance policies specified in clause (ii) and (iii), above, shall be endorsed naming EGAT, its employees, agents, and affiliates as

additional insured with respect to any and all third party bodily injury and/or property damage claims arising from Seller's performance of this Agreement and shall require days written notice to be given to EGAT of cancellation and/or material change in any of the policies.

Evidence of insurance for the coverages specified herein shall be provided to EGAT prior to the First delivery of electricity to EGAT. Should any changes occur during the term of the Agreement, Seller shall furnish EGAT with revised certificates of insurance evidencing coverage described in this section.

The insurance coverages described in clause (ii) and (iii), above, shall be primary to any other coverage available to EGAT and shall not be deemed to limit Seller's liability under this Agreement.

B. Neither EGAT nor Seller, nor their respective officers, directors, agents, employees, parent or affiliates, or their respective officers, director, agents or employees shall be liable to the other party or its parent, subsidiaries, affiliates, officers, director, agents, employees, successors or assigns, for claims, for incidental, indirect or consequential damages connected with or resulting from performance or non-performance of this Agreement, including, without limitation, claims in the nature of lost revenues (other than payments properly due under this Agreement), income or profits irrespective of whether such claims are based upon warranty, negligence , strict liability, contract, operation of law or otherwise

C. Seller agrees to defend, indemnify and save EGAT, its officers, directors, employees, agents and affiliates and their officers, drectors, employees and agents harmless from and against any and all claims, suits, actions or causes of action for damage by reason of bodily injury, death or damage to property caused by Seller, its officers, directors, employees, agents

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or affiliates or caused by or sustained on its facilities, except to the extent caused by an act of negligence or willful misconduct by an officer, director, agent, employee or affiliate of EGAT, its successors or assigns.

D. EGAT agrees to defend, indemnify and save Seller, its officers, directors, employees, agents and affiliates and their officers, directors, employees and agents harmless from and against any and all claims, suits, actions or causes of action for damage by reason of bodily injury, death or damage to property caused by, its officers, directors, employees, agents or affiliates or caused by, its officers, directors, employees, agents or affiliates or caused by or sustained on its facilities, except to the extent caused by an act of negligence or willful misconduct by an officer, director, agent, employee or affiliate of Seller, its successors or assigns.

E. Nothing in this Agreement shall be construed as creating any relationship between the parties other than that of independent contractors for the sale and purchase of electricity generated by the Facility.

ARTICLE XII <u>ASSIGMENT</u>

Neither party shall assign, pledge or otherwise transfer this Agreement or any right or obligation under this Agreement without first obtaining the other party's written consent, which shall not be unreasonably withheld; except that Seller may assign its interests in this Agreement, in whole or in part, to financing institutions or entities in connection with the construction and/or permanent financing of the Facility or modification thereof without EGAT's consent.

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ARTICLE XIII. FORCE MAJEURE

A. The parties shall be excused from performing their respective obligations hereunder and shall not be liable in damages or otherwise, if and only to the extent that they are unable to so perform or are prevented from performing by an event of force majeure, including, without limitation, change of law, storm, flood, lightning, drought, earthquake, fire, explosion, equipment failure, civil disturbance, labor dispute, act of God or the public enemy, action of a court or public authority, or any other cause beyond their control, including, without limitation, shutdown of, or limited operation of, the Facility due to breakdown or unscheduled repair or maintenance.

B. If either party shall rely on the occurrence of an event or condition described in Paragraph A, above as a basis for being excused from performance of its obligations under this Agreement, then the party relying on the event or condition shall (i) provide prompt notice to the other party of the occurrence of the event or condition giving an estimation of its expected duration and the probable impact on the performance of its obligation hereunder, (ii) exercise all reasonable efforts to continue to perform its obligations hereunder, (iii) expeditiously take action to correct or cure the event or condition excusing performance, (iv) exercise all reasonable efforts to mitigate or limit damages to the other party to the extent such action will not adversely affect its own interests, and (v) provide prompt notice to the other party of the cessation of the event or condition giving rise to its excusal from perfomance.

ARTICLE XIV WAIVERS

The failure of either party to insist in any one or more instance upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights under this Agreement shall not be construed as a general waiver of any such provision or the relinquishment of any such right,

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but the same shall continue and remain in full force and effect, except with respect to the particular instance or instances.

ARTICLE XV. REGULATION

This Agreement and all rights, obligations and performances of the parties hereunder, are subject to all applicable laws, and to all duly promulgated orders and other duly authorized action of governmental authority having jurisdiction.

ARTICLE XVI DISPUTE RESOLUTION

Any dispute under this Agreement shall be resolved by binding arbitration in accordance with the requirements of this subsection.

(1) Either party shall give to the other written notice in sufficient detail of the existence and nature of any dispute proposed to be arbitrated. If within sixty (60) days the dispute is not resolved through negotiations pursued diligently in good faith, the parties shall attempt to agree on a person to serve as arbitrator. If the parties cannot agree on an arbitrator within ten days, each shall then appoint one person to serve as an arbitrator and the two thus appointed shall select a third arbitrator with such expertise to serve as Chairman of the panel of arbitrators; and such three arbitrators shall determine all matters by majority vote; provided, however, if the two arbitrators appointed by the parties are unable to agree upon the appointment of the third arbitrator with five days after their appointment, both

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shall give written notice of such failure to agree to the parties, and, if the parties fail to agree upon the selection of such third arbitrator within five days thereafter, then either of the parties upon written notice to the other may require such appointment from and pursuant to the rules of ____. Prior to appointment, each arbitrator shall agree to conduct such arbitration in accordance with the terms of this subsection. The arbitration panel may choose legal counsel to advise it on the remedies it may grant, procedure and such other legal issues as the panel deems appropriate.

(2) The parties shall have sixty calendar days to perform discovery and present evidence and argument to the arbitrators. During that period, the arbitrators shall be available to receive and consider all such evidence as is relevant and, within reasonable limits due to the restricted time period, to hear as much argument as is feasible, giving a fair allocation of time to each party to the arbitration. The arbitrators shall use all reasonable means to expedite discovery and to sanction noncompliance with reasonable discovery requests or any discovery order. The arbitrators shall not consider any evidence or argument not presented during such period and shall not extend such period except by the written consent of both parties or upon a finding that the party opposing an extension has unreasonably delayed the discovery process. At the conclusion of such period, the

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arbitrators shall have forty-five (45) calendar days to reach a determination.

(3) The arbitrators shall have the right only to interpret and apply the terms and conditions of this Agreement and to order any remedy allowed by this Agreement, but may not change any term or condition of this Agreement, deprive either party of any right or remedy expressly provided hereunder, or provide any right or remedy that has been excluded hereunder.

(4) The arbitrators shall give a written decision to the parties stating their findings of fact, conclusions of law and order, and shall furnish to each party a copy thereof signed by them within five calendar days from the date of their determination.

(5) Any factual determination made by the arbitrators shall be conclusive and binding upon the parties and not subject to judicial review, except on the grounds of fraud or bias and may be presented to any court as a stipulation of the parties.

(6) The parties shall each pay fifty percent of the cost of arbitrator or arbitrators and any legal counsel appointed pursuant to subsection (1).

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ARTICLE XVII. SEVERABILITY

If any provision or provisions of this Agreement shall be held invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

ARTICLE XVIII. MODIFICATIONS

No modification to this Agreement shall be binding on either party unless it shall be in writing and signed by both parties.

ARTICLE XIX. PRIOR AGREEMENT SUPERSEDED

This Agreement constitutes the entire agreement between the parties relating to the subject matter hereof and its execution supersedes all previous agreements, discussions, communications and correspondence with respect to the subject matter hereof.

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ARTICLE XX. COUNTERPARTS

This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first above written.

ELECTRIC GENERATING AUTHORITY OF THAILAND

By _____

Title: _____

By _____

Title: _____

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ANNEX 6

PRO FORMA FINANCIAL MODEL FOR PROJECT ANALYSIS

THAI-AA.WK1 → THAI-AA Final pms

Scenario: Operating Charge $6.00 (1992) Escalation 0 INFLATION
Capacity Charge $11.00 (1991) Escalation 0 5.00%

THAII DATE: 02/06/89 EQUIPMENT DESCRIPTION: GE STAG 207 "THAI I OR" COGEN ELECTRICITY UTILITY: FUEL SUPPLIER:

COST DATA			DATA
Fixed Price System	1990	: $	$137.50
Reserve Contingency @	10.00%		$13.75
Owners Expenses		: M$	$10.00
Cogen Cap. Cost (As Spent)		: M$	$161.25
Constr. Interest @	11.00%	: M$	$15.13
Lease Take Out Cost	1992	: M$	$176.38
Lease Take Out Cost	1992	: M$	$176.38
Operation, Maint. & Consumables	1992	: M$	$6.01
Local Taxes, Admin & Insurance	1992	: M$	$3.84

PERFORMANCE DATA (Std. Annual Avg.)	DESIGN
Heat Rate (HHV) BTu/KWh	8,305
Fuel Flow (HHV) MMBtu/Hr	1,985
Net Power Output MW	239.0
Actual Availability Factor	85%
Load Factor	85%
Power Sales (GWH)	1,780

GENERAL TAX RATE 38.00%
STARTUP DATE 1992

UNIT COSTS			DATA	BASIS YEAR	% ESC YEARLY
Fuel Costs: ($/MMBTU)					
Total Demand	100.00%	L.F.	1.40	1989 Inflation	
Total Commodity			1.40	1989 Fuel Esca	
Total Burnertip			2.80		

Leveraged Project Analysis

RETURN ON EQUITY 36.76%

Project Analysis

Project Unleveraged DCRR		
	20 YR	17.87%
	15 YR	16.08%
	10 YR	10.98%
	5 YR	-9.89%

Debt Coverage Ratio

Average	2.59
Minimum	1.80

PROJECTED ESCALATION

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
INFLATION		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
FUEL ESCALATION		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
TOTAL FUEL COST	($/MMBTU) Load Factor																						
Total Demand	85.00%	1.71	1.78	1.85	1.93	2.00	2.08	2.17	2.25	2.34	2.44	2.54	2.64	2.74	2.85	2.97	3.08	3.21	3.34	3.47	3.61	3.75	3.90
Total Commodity		1.47	1.54	1.62	1.70	1.79	1.88	1.97	2.07	2.17	2.28	2.39	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.71	3.90	4.10
Total Burnertip		3.18	3.32	3.47	3.63	3.79	3.96	4.14	4.32	4.52	4.72	4.93	5.15	5.38	5.62	5.88	6.14	6.42	6.71	7.01	7.32	7.65	8.00
O&M, Consl(fixed)				6.01	6.25	6.50	6.76	7.03	7.31	7.60	7.90	8.22	8.55	8.89	9.25	9.62	10.00	10.40	10.82	11.25	11.70	12.17	12.65
Local Taxes, Admin. & Ins				3.84	3.99	4.15	4.32	4.49	4.67	4.85	5.05	5.25	5.46	5.68	5.91	6.14	6.39	6.64	6.91	7.19	7.47	7.77	8.08

THAI-AA.WK1

equals $375

(page 2)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Fuel Consumption-Actual (BBtu)			14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780	14,780
Power Output-Actual (GWH)			1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780	1,780
escalation @			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
INFLATION Operating Charge per KWHo			$4.00	$4.16	$4.33	$4.50	$4.68	$4.87	$5.06	$5.26	$5.47	$5.69	$5.92	$6.16	$6.40	$6.66	$6.93	$7.20	$7.49	$7.79	$8.10	$8.43
5.00% Capacity Charge per KWHo			$11.00	$11.55	$12.13	$12.73	$13.37	$14.04	$14.74	$15.48	$16.25	$17.06	$17.92	$18.81	$19.75	$20.74	$21.78	$22.87	$24.01	$25.21	$26.47	$27.80
POWER CONTRACT REVENUES: (MILLONS $)																						
Operating Charge @			11.47	11.93	12.41	12.90	13.42	13.96	14.52	15.10	15.70	16.33	16.98	17.66	18.37	19.10	19.87	20.66	21.49	22.35	23.24	24.17
Capacity Charge @			31.55	33.13	34.78	36.52	38.35	40.26	42.28	44.39	46.61	48.94	51.39	53.96	56.66	59.49	62.46	65.59	68.87	72.31	75.92	79.72
Demand Charge @ as billed			27.38	28.48	29.62	30.80	32.03	33.31	34.65	36.03	37.47	38.97	40.53	42.15	43.84	45.59	47.42	49.31	51.29	53.34	55.47	57.69
Energy Charge @ as billed			23.95	25.15	26.41	27.73	29.11	30.57	32.10	33.70	35.39	37.16	39.02	40.97	43.02	45.17	47.42	49.80	52.29	54.90	57.65	60.53
Wheeling Charge @ as billed			1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Total Power Revenues			95.55	99.88	104.41	109.15	114.11	119.30	124.73	130.42	136.37	142.60	149.11	155.93	163.07	170.55	178.37	186.55	195.12	204.09	213.48	223.30
EFFECTIVE PRICE/KWH			$0.054	$0.056	$0.059	$0.061	$0.064	$0.067	$0.070	$0.073	$0.077	$0.080	$0.084	$0.088	$0.092	$0.096	$0.100	$0.105	$0.110	$0.115	$0.120	$0.125
EXPENSES: (MILLIONS $)																						
Total Demand			27.38	28.48	29.62	30.80	32.03	33.31	34.65	36.03	37.47	38.97	40.53	42.15	43.84	45.59	47.42	49.31	51.29	53.34	55.47	57.69
Total Commodity			23.95	25.15	26.41	27.73	29.11	30.57	32.10	33.70	35.39	37.16	39.02	40.97	43.02	45.17	47.42	49.80	52.29	54.90	57.65	60.53
Fuel Costs - TOTAL			51.34	53.63	56.02	58.53	61.15	63.89	66.75	69.74	72.86	76.13	79.55	83.12	86.86	90.76	94.84	99.11	103.57	108.24	113.12	118.22
O&M, Maint, Cons			6.01	6.25	6.50	6.76	7.03	7.31	7.60	7.90	8.22	8.55	8.89	9.25	9.62	10.00	10.40	10.82	11.25	11.70	12.17	12.65
Local Taxes, Admin. & Insurance			3.84	3.99	4.15	4.32	4.49	4.67	4.85	5.05	5.25	5.46	5.68	5.91	6.14	6.39	6.64	6.91	7.19	7.47	7.77	8.08
Wheeling Charge @ $5.00 PER KW			1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
TOTAL EXPENSES:			62.37	65.06	67.87	70.80	73.86	77.05	80.39	83.88	87.53	91.34	95.31	99.47	103.81	108.34	113.08	118.03	123.20	128.60	134.25	140.15
OPERATING INCOME (MILLIONS $)			33.18	34.82	36.54	38.35	40.25	42.25	44.34	46.54	48.84	51.26	53.80	56.47	59.26	62.20	65.29	68.52	71.92	75.48	79.23	83.15
PROJECT DCRR EVALUATION			3.75%	7.22%	6.68%	6.18%	5.71%	5.28%	4.89%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%
Operating Income			33.18	34.82	36.54	38.35	40.25	42.25	44.34	46.54	48.84	51.26	53.80	56.47	59.26	62.20	65.29	68.52	71.92	75.48	79.23	83.15
Capital Investment		(88.19)	(88.19)																			
Depreciation : 150%DDB/SL			6.61	12.73	11.78	10.89	10.08	9.32	8.62	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18
Normal Taxes @ 38.00%			10.09	8.39	9.41	10.43	11.47	12.51	13.57	14.58	15.45	16.37	17.34	18.35	19.41	20.53	21.70	22.93	24.22	25.58	27.00	28.49
NET CASH FLOW AFTER TAX	0	(88.19)	(65.10)	26.43	27.13	27.92	28.79	29.74	30.77	31.96	33.39	34.89	36.46	38.12	39.85	41.67	43.59	45.59	47.70	49.91	52.23	54.66
PROJECT DCRR	17.87%	16.08%	10.98%	-9.89%																		
	20 YR	15 YR	10 YR	5 YR																		

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(page 3)

LEVERAGED PROJECT FINANCING

Interest Rate	11.70%	Term (Years)	15
Overall Debt Ratio	75.00%	Principal Pmt	$8.82
Total Debt Amount	132.28	Annual Pmt	$18.40

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
INCOME TAX CALCULATION:																						
Operating Income			33.18	34.82	36.54	38.35	40.25	42.25	44.34	46.54	48.84	51.26	53.80	56.47	59.26	62.20	65.29	68.52	71.92	75.48	79.23	83.15
Less: Depreciation: 150%DDB/SL			6.61	12.73	11.78	10.89	10.08	9.32	8.62	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18
Less: Interest on Debt			14.55	14.13	13.66	13.14	12.56	11.92	11.20	10.41	9.54	8.56	7.48	6.28	4.94	3.47	1.82	0.00	0.00	0.00	0.00	0.00
Taxable Income			12.01	7.96	11.11	14.32	17.62	21.01	24.51	27.94	31.13	34.52	38.14	42.01	46.14	50.56	55.28	60.34	63.74	67.30	71.05	74.97
Normal Taxes @ 38.00%			4.56	3.02	4.22	5.44	6.69	7.98	9.31	10.62	11.83	13.12	14.49	15.96	17.53	19.21	21.01	22.93	24.22	25.58	27.00	28.49
Income after Tax			7.45	4.94	6.89	8.88	10.92	13.03	15.20	17.32	19.30	21.40	23.65	26.05	28.61	31.35	34.27	37.41	39.52	41.73	44.05	46.48
AFTER TAX CASH FLOW:																						
Capital Investment		(22.05)	(22.05)																			
Income after Tax			7.45	4.94	6.89	8.88	10.92	13.03	15.20	17.32	19.30	21.40	23.65	26.05	28.61	31.35	34.27	37.41	39.52	41.73	44.05	46.48
Add: Depreciation: 150%DDB/SL			6.61	12.73	11.78	10.89	10.08	9.32	8.62	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18	8.18
Less: Principal Payment			3.84	4.27	4.74	5.26	5.84	6.48	7.19	7.98	8.86	9.84	10.92	12.12	13.45	14.93	16.57	0.00	0.00	0.00	0.00	0.00
Net Cash Flow After Tax		(22.05)	(11.83)	13.40	13.93	14.52	15.16	15.87	16.63	17.52	18.62	19.75	20.91	22.11	23.34	24.59	25.88	45.59	47.70	49.91	52.23	54.66
Cash Available for Distributn	0	0	(7.26)	16.42	18.15	19.96	21.86	23.85	25.94	28.14	30.45	32.87	35.41	38.07	40.87	43.81	46.89	68.52	71.92	75.48	79.23	83.15

RETURN ON EQUITY 36.76%

Debt Coverage Ratio			1.80	1.89	1.99	2.08	2.19	2.30	2.41	2.53	2.66	2.79	2.92	3.07	3.22	3.38	3.55	-	-	-	-	-

average 2.59
minimum 1.80

Cumulative Total Principal Repayment, %			2.91%	6.13%	9.71%	13.69%	18.10%	23.00%	28.44%	34.47%	41.17%	48.60%	56.86%	66.02%	76.18%	87.47%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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ANNEX 7

EGAT POWER DEVELOPMENT PLAN: COMMENTS BY TEAM

EGAT Power Development Plan
(1988-2001)

PDP 88-02

PDP 88-02 presents a severe dilemma for the Royal Thai Government (RTG) and the economy going into the 1990s:

> Significant shortages of electric generating capacity against EGAT's projection of needs (negative reserve margin by May, 1990); and

> Unacceptably-large amounts of public sector capital spending to bring reserve margins back to a prudent level in the course of the 1990s.

Of some B100 billion proposed during the VI plan, approximately B53 billion ($2.04 billion equivalent) would be in foreign exchange, representing around 40% of total public sector borrowing during the VI plan cycle. The RTG is confronted by the probability of two highly undesirable future outcomes: extensive buildup of public-sector foreign debt, and protracted shortfalls in electricity in the near term which will constrain economic growth and consumer well-being.

It is therefore a matter of priority and some urgency to find alternatives to these outcomes. A private power program can make a significant contribution, if implemented rapidly, decisively and effectively. Current discussions and debates make it clear that there is strong, built-in opposition, sufficient to delay implementation, and to discourage prospective investors who will be reluctant to enter into longterm contracts with an adversarial purchaser.

The process of reviewing and discussing PDP 88-02 should be used as the forum and opportunity to establish the basis for a private power program in Thailand, by:

1. Setting out authoritatively and clearly the program's objectives;

2. Approving and publishing implementing regulations for the introduction of cogeneration and larger-scale IPPs; and

3. Identifying within a revised version of PDP 88-02 target levels of expected contribution from cogeneration, and selected projects in the plan that should be given prompt and careful consideration for development as larger-scale IPPs by the private sector.

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Each of these points is discussed below.

1. Objectives of Private Power Program

To date the emphasis given to private power has been in the context of energy efficiency and conservation. While these goals are laudable, they are only part of a broader set of appropriate objectives, that could be defined as follows:

a) Financing arrangments that avoid or minimize the future public sector debt burden of the RTG, compared with the alternative of EGAT sponsorship;

b) Implementing regulations and procedures which will support early development and commercial operations, to help meet the needs of the 1990s;

c) Reliable and economically-priced supplies of bulk power, for the benefit of the nation's consumers and industries; and

d) Enhanced conservation and efficiency in the utilization of Thailand's primary energy resources.

2. Implementing Regulations

The program's objectives must be supported by implementing regulations which will give prospective investors a clear view of the economic and regulatory framework governing their activities. In the absence of clarity, they will stay on the sidelines, rather than commit capital. Unlike EGAT, they have no compelling reason to invest unless the returns and risks are acceptable.

The implementing regulations should be accompanied by two key elements:

> A model power purchase agreement, laying out the standard terms and conditions for a longterm purchase of capacity and energy by EGAT; and

> A published methodology for establishing the base level of payments (capacity charge and energy charge), and provisions for the adjustment over time (escalation) of the charges.

These elements, defined explicitly, will enable investors to decide whether to undertake the project feasibility work necessary to determine whether an investment is warranted. Absent this kind of framework, it is not possible to make credible business and investment analyses, and one remains in the realm of hypothetical studies.

3. Target Cogeneration/Candidate IPPs

In the U.S. where private power is now an accepted part of a utility's requirements plan, it is standard practice for the utility to identify and set aside a portion of its future requirements that may be met by cogeneratio or IPPs, provided that acceptable offers are received. In some jurisdictions, the utilities are required by the regulators to make this set-aside.

While there is no hard-and-fast rule as to appropriate percentages for cogeneration, with a future gross requirement as large is EGAT's (the equivalent of over 900 MWe per year from 1989 through 2001) it is not unreasonable to specify a sizeable portion, say 25-30%, and test the cogeneration market's response.

Concerning larger-scale IPPs, the structure of PDP 88-02 lends itself to a review and identification of optimal candidates for development as IPPs. Candidates could be screened against the following criteria:

a) Sufficient leadtime to complete feasibility studies, power purchase contract execution, clearance of all regulatory permits for construction, international and domestic financing, and construction;

b) Access to reliable indigenous fuel supplies; while spot and shortterm imports may be acceptable, the project's fuel needs should not be a longterm burden on the nation's balance of payments;

c) Unit capacity size sufficient to amortize the upfront pioneering costs of contract negotiation, project development and financing;

d) Standalone project, to permit a fair comparison with an equivalent, EGAT-sponsored expansion unit;

e) Potential to serve as the demonstration prototype for subsequent projects of similar characteristics.

Against these criteria, and based upon PDP 88-02's Project Work Schedule (p. 49), it would appear that a lignite fuel project such as Saba Yoi #1 might be considered. Alternatively, one of the Mae Moh expansions could also be envisaged. The selection of a lignite project could also qualify the venture for some support from the U.S. Department of Energy's Clean Coal program.

It is important to keep in mind that EGAT's work proposal as currently presented is very ambitious, with ten of the 19 proosed projects put into preliminary construction during FY-1989. It may be prudent to question whether EGAT

can undertake on its own account such a massive program, and pursue it successfully to completion, on schedule and budget. Serious consideration should be given to unloading the front end of the program, by earmarking a gas-fired combined-cycle unit for IPP development. While ECAT may object that this delays the program, there is possibly a lot of unscheduled delay and overrun now embedded in FDP 88-02 as currently structured.

ANNEX 8

PROPOSAL FOR FOLLOW-UP TECHNICAL CONFERENCE

Technical Conference on
Cogeneration and Residue Fuel Plants

You are invited to attend a Technical Conference on Cogeneration and Residue Fuel Plants, to be hosted by the National Energy Policy Office, in conjunction with EGAT, MEA and PEA. The conference will be held on Wednesday, February 22 at 10:00 AM, at the offices of ....

The purpose of the conference is :

1. To describe the basic provisions of proposed "Regulations on the Purchase of Electricity from Independent Power Producers (cogeneration and residue fuel only)", as they might apply to projects developed by, or in association with, your enterprise ; and

2. To invite your comments on some of the technical issues rising from the proposed regulations; a suggested list of questions is attached.

The agenda for the meeting is as follows :

> Overview : The Introduction of Private Power in Thailand	NESDB
> Private Sector Participation : Objectives	NEPO
> Future Requirements for Generating Capacity Additions	EGAT
> Proposed Regulations for Cogeneration and Residue Fuel	NEPO/ advisors
> Industry Responses to Technical Issues	various

The proposed regulations have been drafted, and are under review by the NEPC. It is anticipated that the regulations will be made final after the results of the technical conference have been assessed, and further deliberations have been held by the NEPC. It is expected that the regulations will be published in final form by the end of March.

The regulations, when made final and published, will establish the policy and administrative framework for the development of electric capacity from cogeneration and residue fuel plants. This capacity will make an important contribution in meeting Thailand's growing needs for reliable and economically-priced electric power, and in stimulating more efficient utilization of the nation's energy resources.

The regulations will also serve as the basis for additional measures, to be introduced in the near future, to encourage greater private sector participation in the development of larger-scale private power generation.

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Regulations on the Purchase of Electricity

from

Independent Power Producers : Suggested Technical Issues

1. Characteristics of Independent Power Producers

Cogeneration is defined as "optimizing the ratio between waste heat and electricity generation" (p.6).

Should this definition be made more specific, i.e. setting a defined minimum level of the cogeneration plant's total energy output that must be utilized for thermal (steam or heat) applications, to qualify the plant as a cogenerator?

2. Criteria for Power Purchase

It is proposed that the IPP "must not exceed 50 MW" (p.7).

Is this size limitation too restrictive in terms of :

a) The quantity of steam available from the generation of electricity to support your operations ;

b) The size of the most cost-effective steam recovery and power generating units available for purchase ; or

c) Other criteria that apply to your operations?

3. Criteria for Determining the Purchase Price

Two types of pricing are proposed, both involving a 25% premium over certain EGAT costs incurred during a particular year (p.9-10). Specific purchase price levels are also proposed (p.15).

From your standpoint as potential sponsors of a cogeneration facility, are the proposed pricing structures and pricing levels sufficient incentive for you to consider seriously the development of a cogeneration facility?