Chapter 6 Transmission Development Planning

6.1 Current Situation of Sulawesi System

6.1.1 Outline of the Sulawesi System

In Sulawesi Island, the power systems in southern three provinces (Sulawesi Selatan, Sulawesi Tenggara and Sulawesi Barat) is handled by PLN Wilayah Sulselrabar, and the system in northern three provinces (Sulawesi Utara, Sulawesi Tengah and Gorontalo) is handled by PLN Wilayah Suluttenggo. The main power systems among them are the Sulsel system in Wilayah Sulselrabar and the Minahasa-Kotamobagu system in Wilayah Suluttenggo. Other than these are many small isolated power systems.

Currently, the voltage of 150 kV and 70 kV is adopted for transmission systems: 150 kV mainly in Sulsel system and 70 kV in Minahasa-Kotamobagu system. Small isolated systems are mostly distribution systems with the voltage of 20 kV, which are mainly consists of diesel generators.

The peak demand and generation capacity for both Wilayah Sulselrabar and Suluttenggo in 2006 is shown in Table 6.1.1.

Table 6.1.1 Peak demand and Generation capacity (in 2006)

	Peak demand (MW)		Installed Capacity (MW)	
Wilayah Sulselrabar	518	65.2%	729	64.9%
(Sulsel power system)	(445)	(56.1%)	(619)	(55.1%)
(Other than Sulsel system)	(72)	(9.1%)	(110)	(9.8%)
Wilayah Suluttenggo	277	34.8%	395	35.1%
(Minahasa-Kotamobagu system)	(132)	(16.6%)	(183)	(16.3%)
(Other than Minahasa-Kotamobagu system)	(145)	(18.2%)	(212)	(18.8%)
Total	794	100.0%	1,124	100.0%

Overview of Sulawesi power system is shown in Figure 6.1.1.

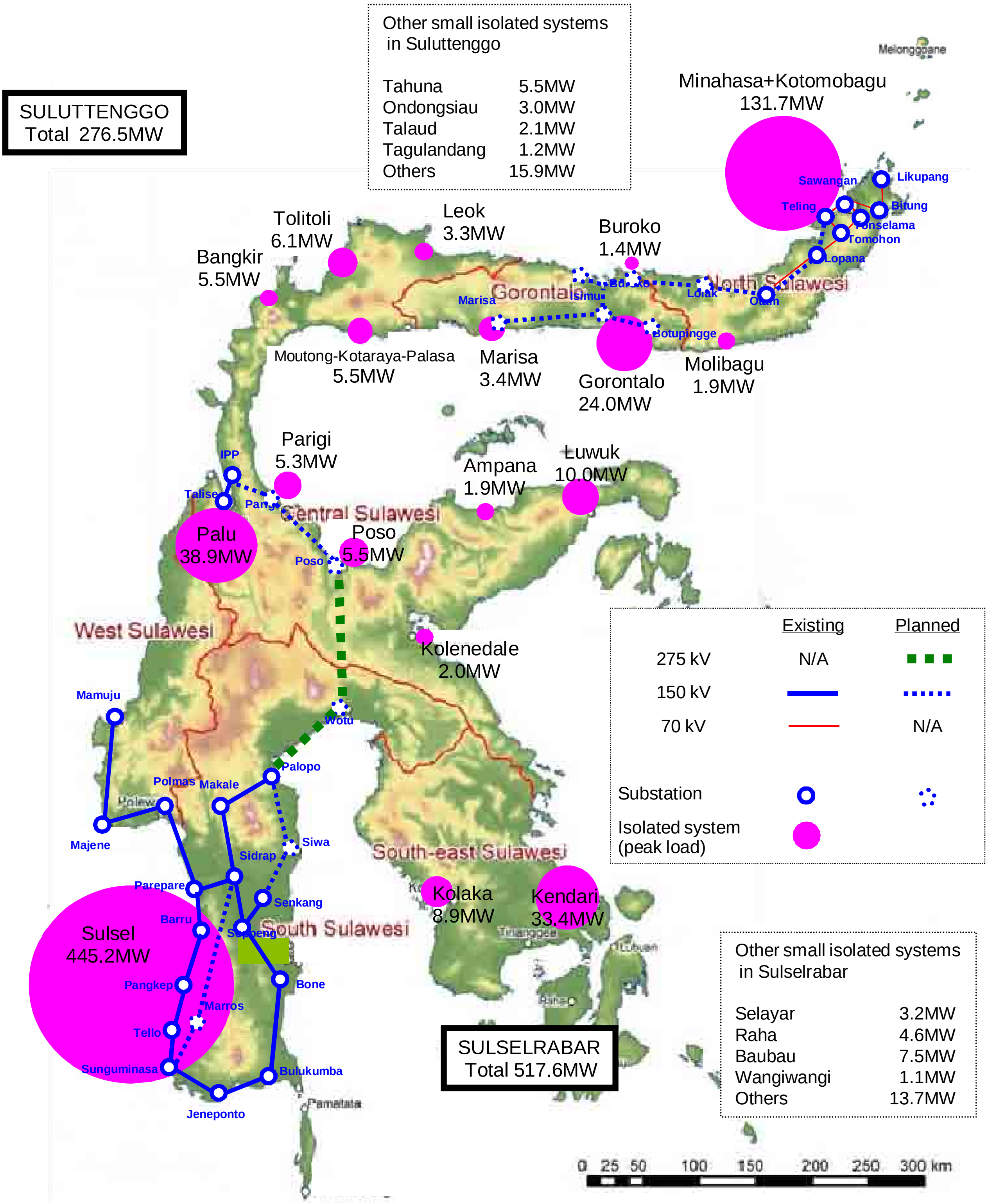


Figure 6.1.1 Overview of Sulawesi power system (in 2006)

In the Sulsel power system in Wilayah Sulselrabar, 150 kV transmission line is mainly used. In this power system, larger power plants like Bakaru hydro power (126 MW) or Sengkang thermal power (135 MW) are concentrated in the northern area, and large power flows from the north to the south, then the voltage of Makassar area in the southern area tends to be lowered. In order to relieve this, in addition to the existing western-side route (Parepare-Pangkep), eastern-southern route (Jeneponto-Bulukumba) was installed and started operation in February 2007.

The Sulsel system has been extended toward north in order to introduce new power sources like hydro power. In September 2006, 150 kV transmission line between Sidrap-Makale-Polopo started operation. In addition, introduction of an IPP's hydro power plant in Poso (145 MW) through 275 kV transmission line (Poso-Wotu-Polopo) is now being planned.

The Sulsel system is planned to be connected not only to power sources in the northern area as above but also to small isolated systems in the Southeast Sulawesi. With such interconnection, transmission distance will be extended more and power flow will be enhanced, which may cause the excess of line heat capacity, more voltage drop around Makassar, and furthermore system stability problem that has never happened so far.

In the Minahasa-Kotamobagu power system in Wilayah Sulttenggo, main power sources include Tangari hydro power (37 MW) and Lahendong geothermal plant (40 MW). The power from such plants is transmitted mainly to Manado city (Telling substation and Ranmomuut substation) via 70 kV transmission lines.

In preparation for the extension of Lahendong geothermal plant and installation of PoigarII hydro power plant, the transmission line between Tomohonn-Lahendong-Kawangoan-Lopana is planned to be upgraded from 70 kV to 150 kV. In the future 150 kV transmission system will be extended more. For example, 150 kV transmission line via Lopana substation to Manado (Telling substation) is planned in order to evacuate the power from Amurang power plant (110 MW) and a coal power plant by the crush program (50 MW).

In Gorontalo, in line with the installation of a coal power plant (by the crash program), the Gorontalo150 kV transmission system will be constructed. There is a plan the Gorontalo 150 kV system will be interconnected with the Minahasa-Kotamobagu system.

The Minahasa-Kotamobagu system, with relatively small capacity of about 130MW, currently doesn't have so much problems regarding transmission system like voltage or stability. However, because of installation of larger power sources like geothermal or coal power, increased power flow may cause problems like overloading or voltage drop. Moreover, unit size of generators is too large against the system capacity. Installation of larger units may cause system instability.

In the area where no transmission line exists like the Central Sulawesi or the Southeast Sulawesi, there are a lot of small isolated grids. These grids mainly use diesel generators. However, they have problems in both reliability and economical efficiency because of degradation of generators, deficit in generation capacities and the rise in fuel cost.

In the future these small grids may be connected by the extension of transmission line. In that case, however, voltage fluctuation may occur at the edge of the system because of connection to the load of low density with very long distance. The issue regarding the connection to these small isolated systems has been discussed in the section 5.7.

6.1.2 Current Situation of Power System Operation

The power system in Sulawesi is operated by two dispatching centers at Makassar and Manado.

N-1 rule is almost satisfied in the Sulawesi system currently. There is not serious problem with regard to voltage and short circuit capacity. Currently, there is no stability problem in Sulawesi, different from the Java Bali system. This is because large power is not transferred over long distance in Sulawesi at present.

Table 6.1.2 shows the allowable voltage range and the allowable loadings adopted by PLN.

Table 6.1.2 Allowable Voltage Range and Allowable Loading

Allowable Voltage Range	-10% - +5%
Allowable loading limit	80% (normal condition) 100% (contingency condition)

The allowable range of the frequency is from 49.5 Hz to 50.5 Hz. The frequency is almost kept at this range although deviation is sometimes observed. In case of contingency, the frequency will be kept constant taking measures shown in Table 6.1.3 and Table 6.1.4.

Table 6.1.3 Measures against Frequency Drop (Minahasa-Kotamobagu system)

Frequency	Measures
50.00 Hz	Normal Operation
49.80 Hz	Voltage Reduction (Brown out)
49.60 Hz	Manual Load Shedding
49.25 Hz	Automatic Load Shedding (14.25 MW)
48.90 Hz	Automatic Load Shedding (5.5 MW)
48.55 Hz	Automatic Load Shedding (4.0 MW)

Table 6.1.4 Measures against Frequency Drop (Sulsel power system)

Frequency	Measures
50.00 Hz	Normal Operation
49.50 Hz	Manual Load Shedding
48.90 Hz	Automatic Load Shedding
48.70 Hz	Automatic Load Shedding
48.50 Hz	Automatic Load Shedding
48.30 Hz	Automatic Load Shedding
48.00 Hz	Automatic Islanding

6.1.3 Facilities in Sulawesi Power System

Currently the voltage of 150kV and 70kV are mainly adopted in the Sulawesi transmission system. 30kV is also adopted in the part of the Sulsel system.

Table 6.1.5, Table 6.1.6 and Table 6.1.7 show the outline of the transmission facilities and substation facilities in 2006.

Table 6.1.5 Transmission Facilities in Sulawesi System (2006)

(Unit : km・cct)

	30 kV	70 kV	150 kV	Total
North Sulawesi	--	259	77	336
South Sulawesi	11	143	1,692	1,846
Total	11	401	1,769	2,182

Table 6.1.6 Capacity of Transformers in Sulawesi System (2006)

(Unit: MVA)

	150/70 kV	150/30 kV	70/30 kV	150/20 kV	70/20 kV	30/20 kV	Total
North Sulawesi	--	--	--	51	184	-	235
South Sulawesi	221	20	20	613	210	30	1,114
Total	221	20	20	664	394	30	1,349

Table 6.1.7 shows the typical transmission lines in Sulawesi. Typically, ACSR 240 is adopted for 150 kV transmission lines and ACSR 120 is adopted for 70 kV transmission lines. With respect to the number of the circuits on the transmission lines, double-circuit is usually adopted, although single-circuit is adopted in some cases.

Table 6.1.7 Typical Transmission Line

Voltage	Conductor	Size	Capacity
150 kV	ACSR	240 mm^2	645 A
70 kV	ACSR	120 mm^2	300 A

Table 6.1.8 shows the typical capacities of the transformers.

Table 6.1.8 Typical Capacities of Transformers

Voltage	Capacity (MVA)
150/70 kV	31.5
150/20 kV	31.5, 30, 20, 10
70/20 kV	20, 10

With respect to protection relays of transmission lines, distance relay is adopted as main protection (with Tele-protection function). Over current relay and ground fault relay are adopted as back-up.

Table 6.1.9 shows the types of the neutral point connecting method.

Table 6.1.9 Neutral Point Connecting Method

Voltage	Neutral point connecting Method
150 kV	Solidly grounding method
70 kV	Resistively grounding method

6.1.4 Power Supply Reliability

Table 6.1.10 shows the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) in Indonesia in 2002.

Table 6.1.10 SAIDI and SAIFI (2006)

	System Average Interruption Duration Index (SAIDI) (hours/customer)	System Average Interruption Frequency Index (SAIFI) (times/customer)
North Sulawesi	367.0	8.08
South Sulawesi	274.6	9.43

6.1.5 Transmission Losses

Table 6.1.11 shows the transmission losses in Indonesia in 2006.

Table 6.1.11 Transmission Losses

	Transmission Losses (GWh)	Loss Ratio
North Sulawesi	15.39	2.51
South Sulawesi	127.37	5.26

6.2 Transmission Planning of PLN

6.2.1 Methodology of Transmission Planning

PLN Wilayah Sulselrabar and Wilayah Suluttenggo in Sulawesi make transmission development plans as RUPTL, and the PLN head office integrates them. Table 6.2.1 shows the methodology for transmission planning described on the *Guideline for the Power Development Planning* (Pedoman Penyusunan Rencana Umum Ketenagalistrikan, Nomor: 865K/30/MEM/2003).

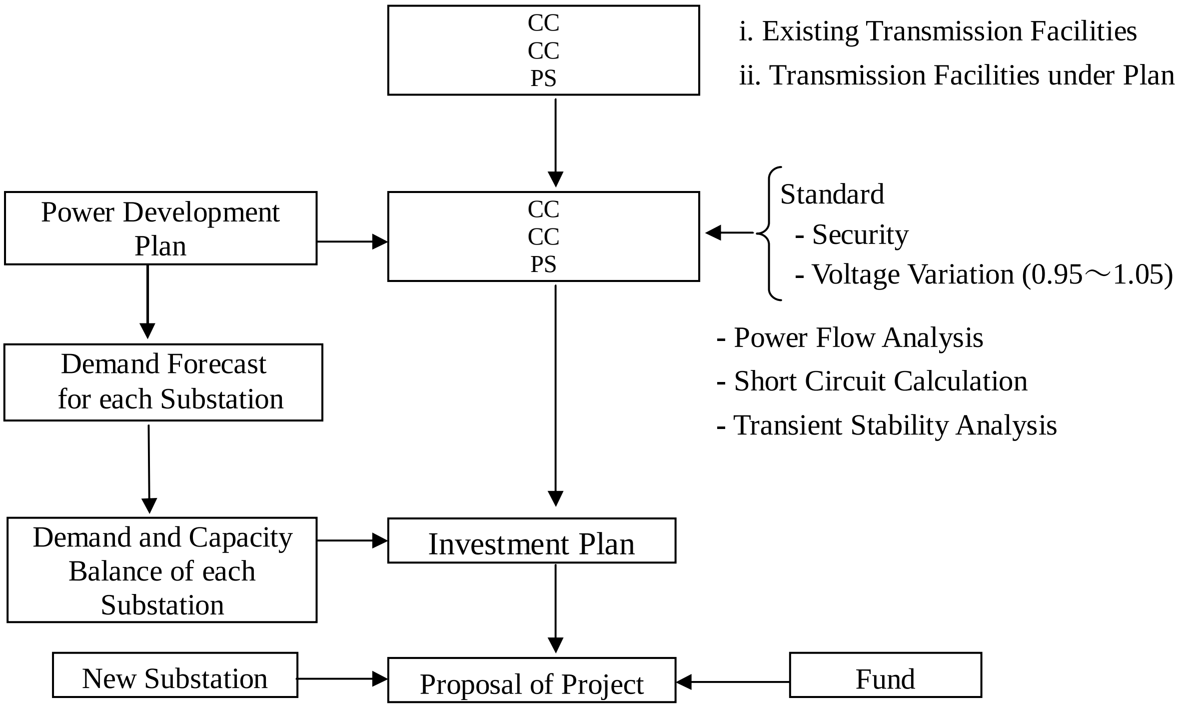


Figure 6.2.1 Methodology for Transmission Planning

Based on the demand forecast for the Sulawesi system, demands for each substation are forecasted and the necessity of installment of additional transformers and/or construction of new substations is studied. On the other hand, based on the demand forecasts for each substation and the power development plan, transmission plan is made with system analyses, such as power flow analysis (voltage analysis), short circuit calculation and transient stability analysis, using the system data of the existing and planned facilities. After the study on investment plan and fund, projects which should be implemented are determined.

6.2.2 Criteria of PLN

PLN adopts the N-1 rule to develop the transmission plan in the Sulawesi system. The N-1 rule is internationally adopted for transmission expansion planning. This rule requires that blackouts (except temporary ones) will not occur even though one of the system components is lost (e.g. a one-circuit fault of a transmission line or a fault of one of the transformers).

In regard to stability, PLN requires that the system should be kept stable with a three-phase to ground fault and clearing by a main protective relay (3LGO).

If the unit capacity of the generators is relatively large compared with the system capacity, the frequency of the system drops sharply in case of a generator drop. Therefore, the unit capacity of the generators is sometimes limited. However, the unit capacity of the generator is not restricted in the Sulawesi system.

Table 6.2.1 shows the system capacities and the largest unit capacities of the generators in each system.

Table 6.2.1 System Capacity and the Largest Unit of the Generator (2006)

	System Capacity (MW) (a)	Largest Unit (MW) (b)	Ratio (b) / (a)	Remarks
Sulsel system	445	63 MW	14.2%	PLTA Bakaru
Minahasa-Kotamobagu system	132	20 MW	15.2%	PLTU Lahendong

6.2.3 Program for System Analysis

PSS/E is adopted at PLN head office for transmission planning. PSS/E has been adopted also in Sulawesi (Wilayah Sulselrabar and Suluttenggo). However, because the system capacity is relatively small, high-level analysis like stability analysis is not conducted currently. In the future stability analysis via PSS/E would be necessary because the system would become more complicated as the system capacity increases.

6.2.4 PLN's Transmission Plan in Sulawesi

PLN Wilayah Sulselrabar and Sulttenggo has transmission development plans as shown in Table 6.2.2 and Table 6.2.3 to accommodate demand increase and power development in the Sulawesi system and to keep reliability level.

Table 6.2.2 Transmission Plan of PLN (Wilayah Sulselrabar)

Project	Description	Commissioning Year
Tnjung bunga - Botntoala	150kV, 2cct, 15km, UGC	2008
PLTU Lakatong (IPP) - Takalar	150kV, 2cct, 1 Hawk, 8km	2009
Sidrap - Maros	150kV, 2cct, 2 x Zebra, 154km	2009
Maros - Sungguminasa	150kV, 2cct, 2 x Zebra, 2km	2009
PLTU Nil Tenasa - Kendari	70kV, 2cct, Ostrich, 2km	2009
PLTU Jeneponto (PLN) - Tip.57	150kV, 2cct, 2 x Zebra, 10km	2009
PLTU Jeneponto (PLN) - Tip.58	150kV, 2cct, 1 Hawk, 10km	2009
PLTU Jeneponto (PLN) - IPP Bosowa	150kV, 2cct, 2 x Zebra, 2km	2009
Sengkang - Siwa	150kV, 2cct, 1 Hawk, 65km	2010
Siwa - Palopo	150kV, 2cct, 1 Hawk, 80km	2010
Kendari - Unahaa	150kV, 2cct, 1 Hawk, 35km	2012
Unahaa - Kolaka	150kV, 2cct, 1 Hawk, 100km	2012
Polopo - Wotu	150kV, 2cct, 1 Hawk, 85km	2012
Wotu - Malili	150kV, 2cct, 1 Hawk, 50km	2012
Malili - Kolaka	150kV, 2cct, 1 Hawk	2012
PLTA Poko - Bakaru	150kV	2013
Bakaru - Sidrap	150kV	2013
PLTA Malea - Enrekang	150kV	2016

Table 6.2.3 Transmission Plan of PLN (Wilayah Suluttenggo)

Project	Description	Commissioning Year
Lopana – Kotamobagu/Otam	150 kV, 2nd cct, 1 Hawk, 77km	2008
Paligi – Talise	70 kV, 2nd cct, 1 Hawk, 52.5km	2008
Lopana – Teling	150 kV, 2cct, 1 Hawk, 45km	2009
Isimu – Botupingge	150 kV, 2cct, 1 Hawk, 30km	2009
Isimu – Marisa	150 kV, 2cct, 1 Hawk, 110km	2009
PLTU Sulut (Perpres) – Lopana	150 kV, 2cct, 1 Hawk, 8km	2009
PLTU PJPP – Talise (Upgrade to 150kV)	150 kV, 2cct, 1 Hawk, 17km	2009
Talise – Lolioge/Donggala	150 kV, 2cct, 1 Hawk, 35km	2010
Kotamobagu/Otam – Lolak	150 kV, 2cct, 1 Hawk, 30km	2010
Teling – Paniki/Ranomut Baru	150 kV, 2cct, 1 Hawk, 8km	2010
Paniki/Ranomut Baru - Kema	150 kV, 2cct, 1 Hawk, 40km	2010
PLTU Gtalo (Perpres) Incomer – Buroko	150 kV, 2cct, 1 Hawk, 12km	2010
Isimu – Buroko	150 kV, 2cct, 1 Hawk, 70km	2010
Poso – PLTU Poso/Tentena	150 kV, 2cct, 1 Hawk, 35km	2010
PLTA Poigar – Mokobang (Tip 145)	150 kV, 2cct, 1 Hawk, 7km	2010
Parigi – Poso	150 kV, 2cct, 1 Hawk, 140km	2011
Buroko – Bintauna	150 kV, 2cct, 1 Hawk, 45km	2011
Bintauna – Lolak	150 kV, 2cct, 1 Hawk, 40km	2012
PLTG Luwuk - Luwuk	150 kV, 2cct, 1 Hawk, 58km	2013
Otam – Molibagu	150 kV, 2cct, 1 Hawk, 50km	2013
Marisa - Moutong	150 kV, 2cct, 1 Hawk, 78km	2015

6.3 Preconditions for transmission expansion planning

In this section, the preconditions for formulating the transmission expansion planning are summarized.

6.3.1 Study Cases

Table 6.3.1 shows the study cases for transmission planning. Then, details of the study case are shown as follows.

Table 6.3.1 Study Cases for Transmission Planning

Item	Study Case
Demand Forecast	Peak and Off Peak (2 cases)
Generation Development	Economic Oriented Development Scenario and Local Energy Premier Development Scenario (2 cases)
Interconnection	Interconnection of a large system with small isolated systems (1 case)
Studied Year	2012,2017,2022 and 2027(4 cases)

(1) Demand Forecast

The demand forecast formulated by the Study Team has been adopted for the transmission planning. The figure of off-peak demand is calculated based on the load curve in 2006 as follows:

- The off-peak demand of the north system : 52% of the peak load
- The off-peak demand of the south system : 60% of the peak load

(see Table 6.3.2 and Table 6.3.3)

The figure of the reactive power is set as 50% of the active power.

Table 6.3.2 Peak Demand Forecast for Each Sulawesi Province

(Unit: MW)

	2007	2012	2017	2022	2027
Sulawesi Utara	147	223	333	493	765
Gorontalo	-	55	823	124	184
Sulawesi Tengah	-	100	177	266	393
Sulawesi Barat	18	37	54	79	116
Sulawesi Sulatan	469	707	1,018	1,459	2,135
Sulawesi Tenggara	-	73	104	149	218
North System	147	285	449	667	1,028
South System	487	908	1,319	1,902	2,783
Total	634	1,193	1,767	2,569	3,810

Table 6.3.3 Off-peak Demand Forecast for Each Sulawesi Province

(Unit: MW)

	2007	2012	2017	2022	2027
Sulawesi Utara	76	118	173	257	398
Gorontalo	-	28	43	64	96
Sulawesi Tengah	-	59	105	157	230
Sulawesi Barat	11	22	32	47	70
Sulawesi Sulatan	315	458	644	908	1,313
Sulawesi Tenggara	-	44	62	89	130
North System	76	150	235	349	534
South System	326	579	825	1,173	1,701
Total	402	729	1,059	1,523	2,235

Note that the demand in Table 6.3.2 and Table 6.3.3 shows the amount connected to the larger systems (Sulsel or Minahasa). Demand allocation for each substation is determined considering actual demand record for each substation and characteristics of each substation area.

(2) Power Source Development Plan

Regarding Power Source Development Plan, ‘Economic Oriented Development Scenario’ and ‘Local Energy Premier Development Scenario’, prepared by the Study Team in Chapter 5, are adopted to formulate the transmission plan. Each power source development point is determined, based on information from PLN, considering the development plans, concepts and also possibilities. Table 6.3.4 and Table 6.3.5 show the amount of power sources to be developed for each type.

Table 6.3.4 Amount of power sources for each type
(Economic Oriented Development Scenario)

(Unit: MW)

	Type	2012	2017	2022	2027
North System	Hydro	88	108	108	108
	Geothermal	60	60	60	60
	Coal	135	210	385	685
	Gas Turbine	75	175	275	400
	Diesel	22	22	14	0
South System	Hydro	339	339	339	339
	Coal	490	1,040	1,540	2,340
	Gas Combined Cycle	135	135	235	335
	Gas Turbine	117	50	50	200
	Diesel	65	178	176	174

Table 6.3.5 Amount of power sources for each type
(Local Energy Premier Development Scenario)

(Unit: MW)

	Type	2012	2017	2022	2027
North System	Hydro	88	108	108	108
	Geothermal	60	100	200	340
	Coal	85	160	210	285
	Gas Turbine	125	175	300	525
	Diesel	22	22	14	0
South System	Hydro	573	573	879	1,153
	Coal	390	590	840	1,190
	Gas Combined Cycle	135	385	635	985
	Gas Turbine	117	50	100	300
	Diesel	65	178	176	174

(3) Operation conditions of power plants

In implementing power system analysis, it is necessary to determine not only the capacity of power plants but also their operation conditions. The conditions are determined as follows, based on which power system analysis is implemented.

- Considering scheduled outages of generators for maintenance, the following amount of generators are stopped:

Type of generator	Amount to be stopped for maintenance
Coal thermal type and gas combined-cycle type	The units which capacity corresponds to 12.3% (45day/year) of the total demand or more.
Gas turbine type	The units which capacity corresponds to 8.2% (30day/year) of the total demand or more.

- The amount of spinning reserve shall basically correspond to (or more than) the maximum-capacity generation unit in a power system.
- Balance stop of generators during off-peak time shall be implemented from the units with high cost. The following order: 1) diesel, 2) gas turbine, 3) gas-combined cycle, 4) Coal
- Coal plants shall not implement DSS operation, and shall not be operated under 60% of nominal output.[29]

(4) Timing of Interconnection

The timing of interconnection (small isolated systems to a large system) is determined considering economy and when power plants are installed as shown in Table 5.7.4 in Chapter 5. The timing of interconnection is shown again in Table 6.3.6, which is adopted in the power system analysis.

Table 6.3.6 Timing of interconnection

Isolated System	Nearest point of Large system	Distance (km)	Interconnection year
Gorontalo	Buroko	94	2010
Marisa	Isimu (Between Golontaro and Buroko)	118	2011
Buroko	Bintauna	40	2010
Palu+Parigi	Poso	102	2010
Poso	Poso Hydro	37	2010
Toli-Toli	Leok	99	2014
Moutong-Kotaraya-Palasa	Marisa	84	2012
Leok	Gorontalo Coal Power Plant	148	2013
Kolondale	Poso Hydro	90	2016
Bangkir	Toli-Toli	98	2023
Luwuk	Ampana	165	2012
Ampana	Poso	123	2011
Molibagu	Otam	70	2014
Bintauna	Lolak	41	2010
Kolaka	Wotu	300	2011
Kolaka	Kendari	135	2011

[29] Some types of steam-turbine generators (including coal power) can decrease their output to around 30%. However in this study, the lower limit of coal power is set as 60% because the operation with much lower limit seriously degrades efficiency and old-type generators require even severer operation.

Interconnection between the two large systems (south and north) will be additionally considered in Section 6.5.

6.3.2 Planning Criteria and Methodology

(1) Criteria of transmission expansion planning

In transmission planning, N-1 criterion is adopted, in which under single fault of facilities (transmission line, transformer or generator) no blackout or outage basically occurs.

(2) Planning Methodology

In planning, the power system shall be composed so that no problem basically happens under implementation of any power system analysis: 1) Load flaw analysis, 2) Stability analysis and 3) Short circuit analysis. Conditions to be satisfied in each analysis are shown in Table 6.3.7 to Table 6.3.9.

Table 6.3.7 Conditions for load flow analysis

	Normal condition	During N-1 fault
Power flow limit	80%	100%
Allowable voltage	-10%～+5%	

During N-1 fault, the above conditions shall be basically satisfied even if transformer tap or phase-modifying equipment is not switched over.

Table 6.3.8 Preconditions for stability analysis

Type of fault	Transmission Line	3-phase Short Circuit
	Generator	Single unit drop
Fault clearance time	150 kV line	150 ms
	275 kV and 500 kV line	100 ms
Voltage characteristic of Load	Active power	Constant Current
	Reactive power	Constant Impedance
Allowable frequency range	Northern system	49.25Hz or more
	Southern System	

Table 6.3.9 Analysis conditions for short circuit analysis

Voltage Class	Allowable Short-circuit Current
70 kV	20 kA or less
150 kV	30 kA or less
275 kV, 500 kV	40 kA or less

6.3.3 Software and Data for Power System Analysis

PSS/E made by SIEMENS is adopted as the software for power system analysis in this study. The data for transmission lines is basically adopted from Table 6.3.10. Regarding the data for generators, PLN data and standard data are adopted.

Table 6.3.10 Data for Transmission Lines (100MVA Base)

Voltage (kV)	Type	Bundle	Cond.	R (p.u/km)	X (p.u/km)	B (p.u/km)	Thermal Capacity (MVA)
150	HAWK	1	240	0.000573	0.001800	0.000637	139
150	HAWK	2	240	0.000288	0.001244	0.000913	275
150	ZEBRA	1	430	0.000353	0.001729	0.000664	196
150	ZEBRA	2	430	0.000176	0.001209	0.000939	393
275	ZEBRA	2	430	0.000051	0.000410	0.002689	620
500	GANNET	4	338	0.000010	0.000110	0.010108	2,210
150	ZEBRA (275kV Design)	2	430	0.000170	0.001378	0.000800	338
70	OWL	1	135	0.004372	0.008676	0.000131	48
70	OSTRICH	1	152	0.003834	0.008584	0.000133	55
70	ORIOLE	1	170	0.003393	0.008477	0.000134	60
70	HAWK (150kV Design)	1	240	0.002633	0.008263	0.000139	65
30	OWL	1	135	0.018471	0.046153	0.000025	20
20	CAT	1	111	0.110000	0.069750	0.000000	12
70	XLPE	1	400	0.000960	0.002840	0.004618	44
150	XLPE	1	400	0.000209	0.000451	0.010598	131

6.4 Transmission Development Plan

Based on the precondition stated before, the transmission development plan has been formulated. In this section, above all, the results when the Economic Oriented Development Scenario is applied are shown as the base case.

Power system diagram for 2007 is shown in Figure 6.4.1. Then the diagrams for 2012, 2017, 2022 and 2027 as the results of the planning are shown in Figure 6.4.2 to Figure 6.4.5 respectively, which are followed by the features of the plan and its technical issues.

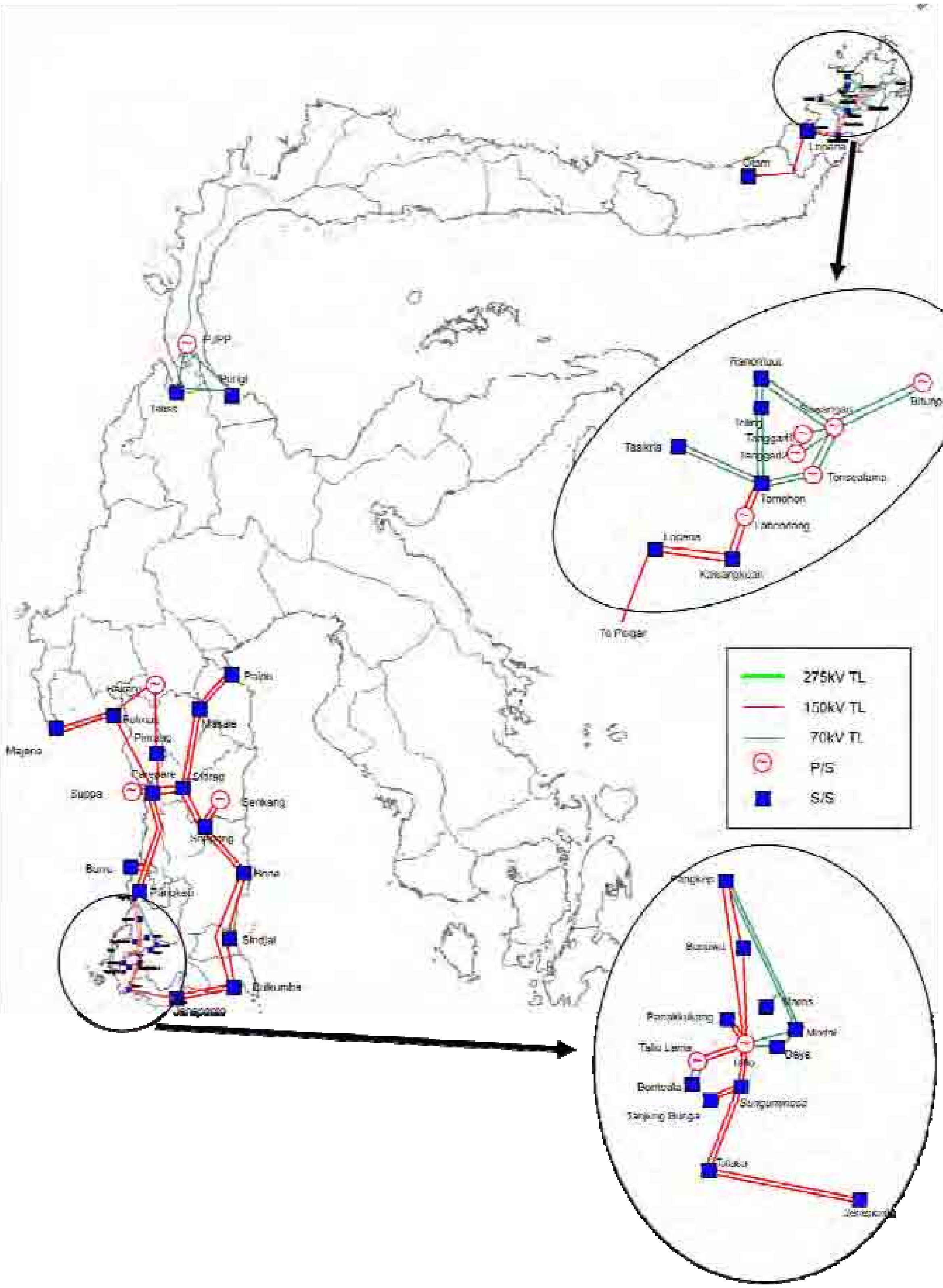


Figure 6.4.1 Sulawesi Power System in 2007

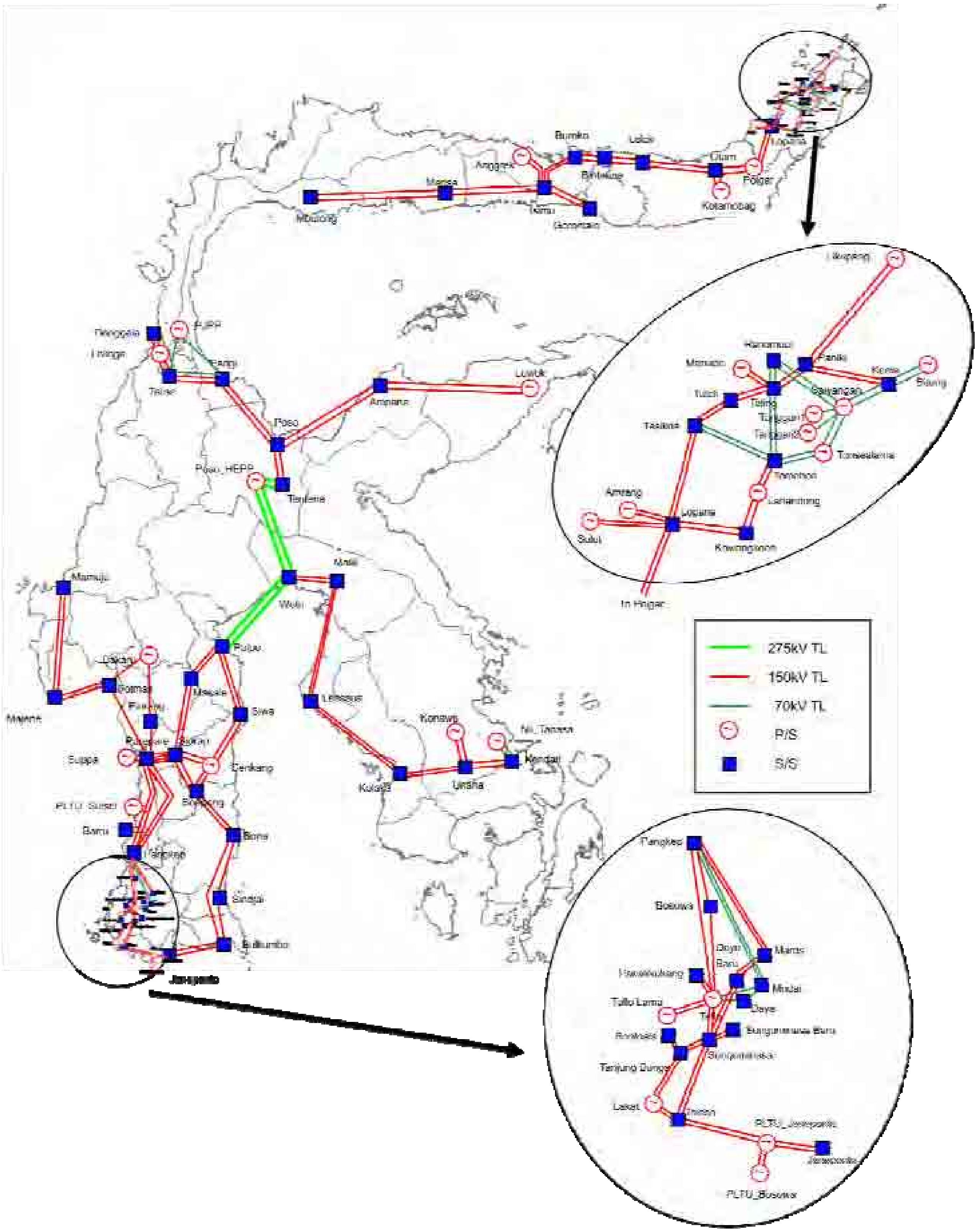


Figure 6.4.2 Sulawesi Power System in 2012 (Economic Oriented Development Scenario)

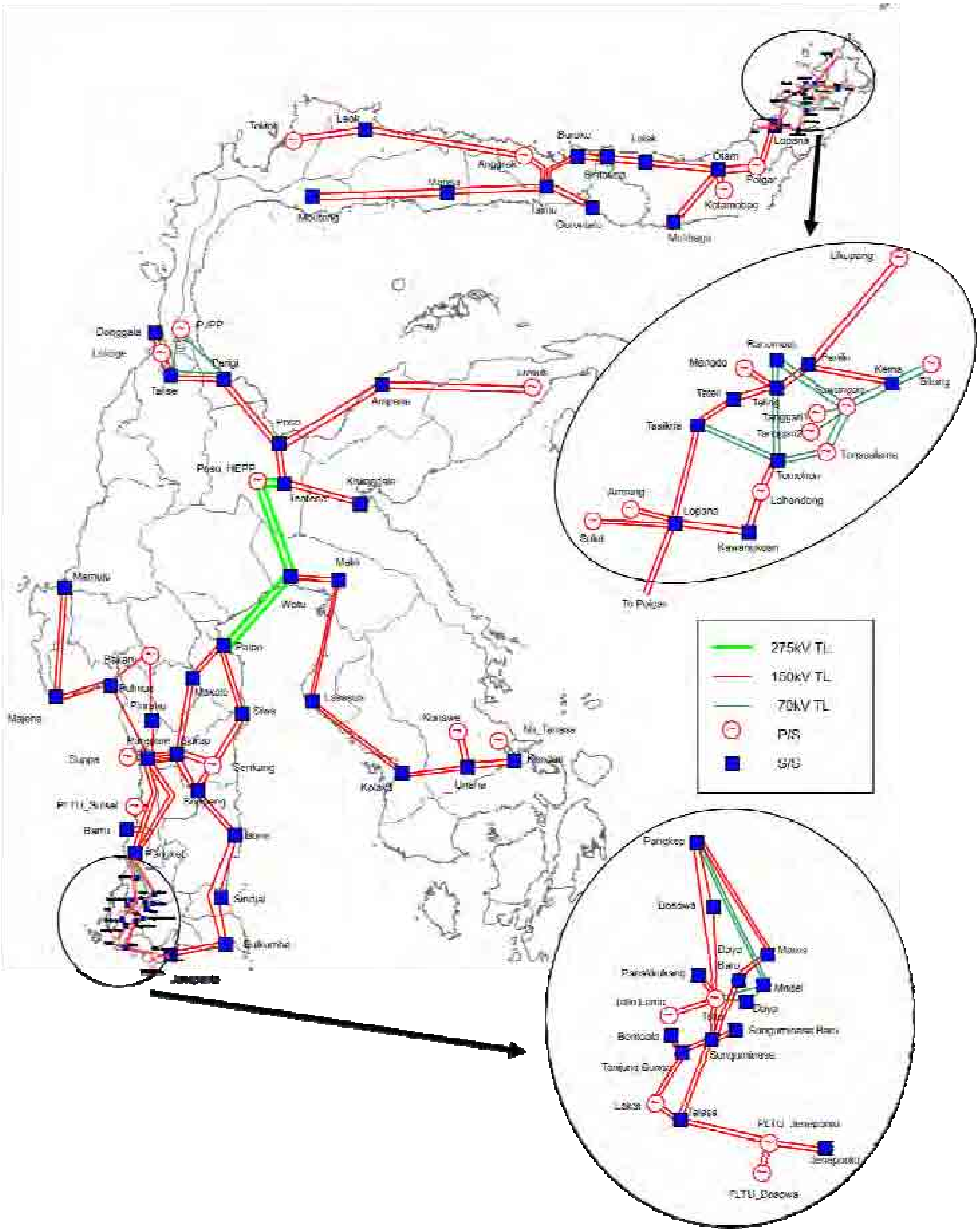


Figure 6.4.3 Sulawesi Power System in 2017 (Economic Oriented Development Scenario)

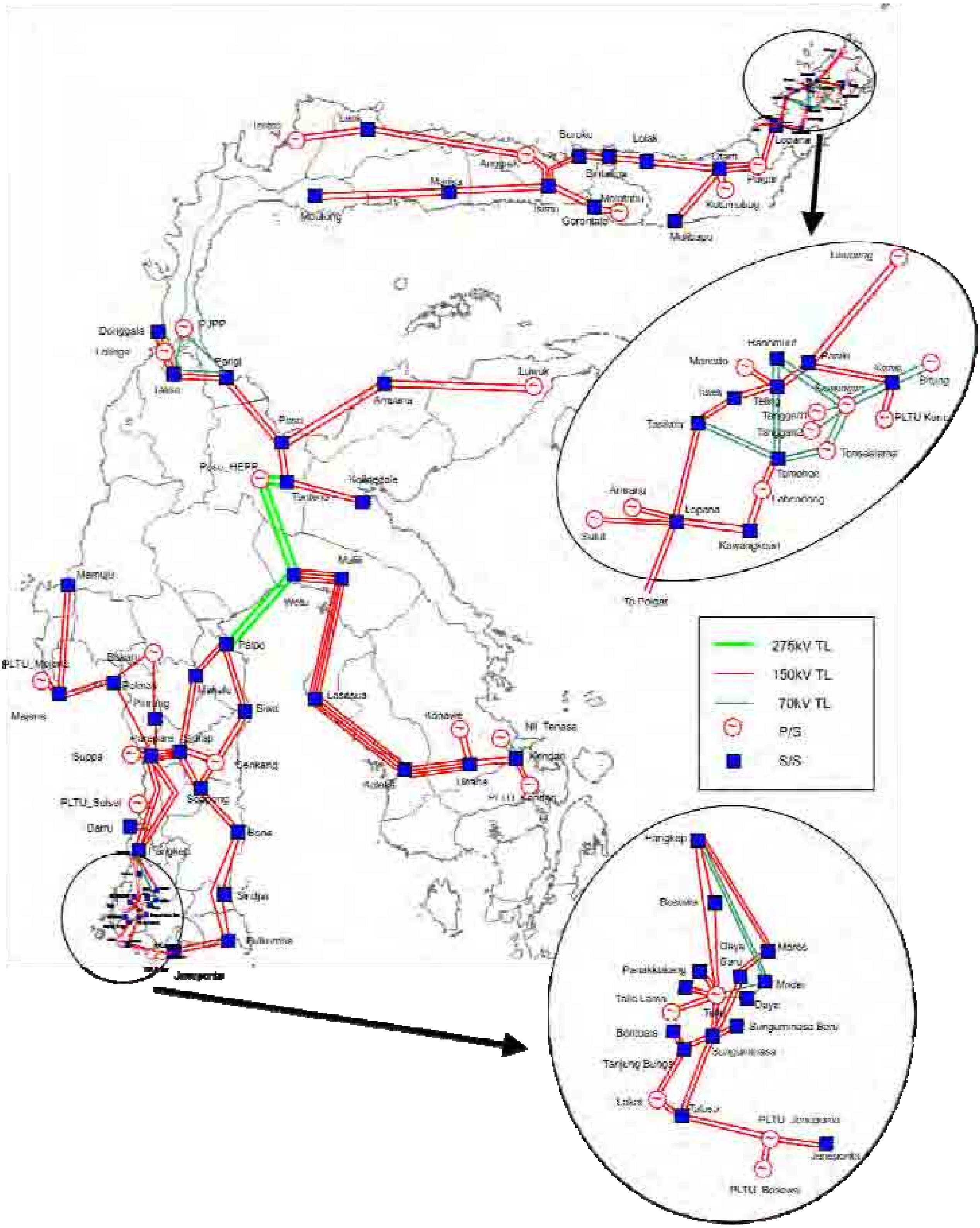


Figure 6.4.4 Sulawesi Power System in 2022 (Economic Oriented Development Scenario)

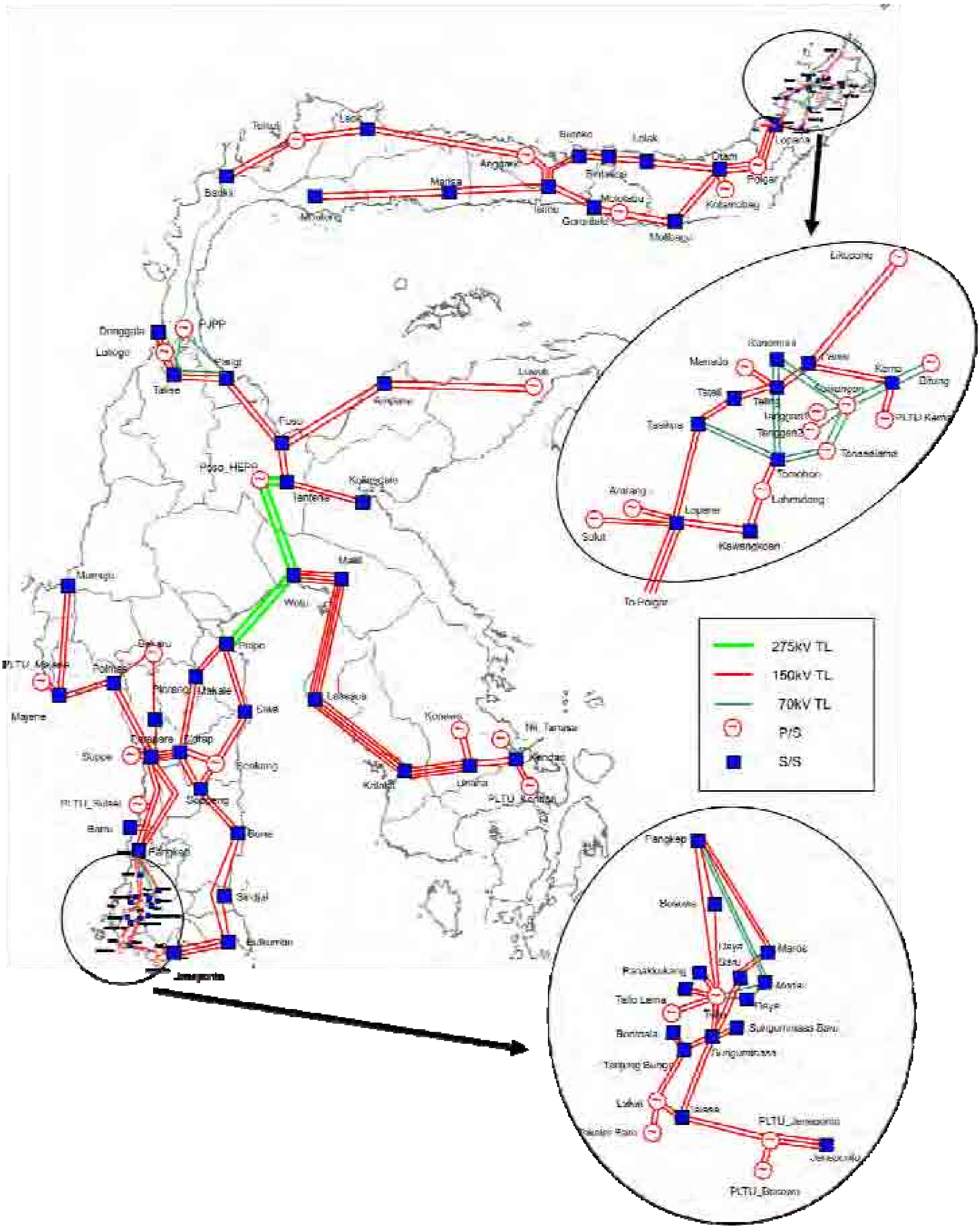


Figure 6.4.5 Sulawesi Power System in 2027 (Economic Oriented Development Scenario)

6.4.1 Transmission Development Plan in Northern Sulawesi Power System

The northern Sulawesi power system comprises of, except for Minahasa-Kotamobagu system, mostly small isolated systems. Because of this, the power system plan for the northern system is almost equal to how the interconnection between Minahasa-Kotamobagu system and small isolated systems can be composed. The issues of the plan in the northern system and the measures for them are described.

(1) Issue of Demand-supply Balance during Off-peak Time

Power sources in the northern Sulawesi system are currently mostly natural-flow hydro plants and diesel-type plants, and in the near future a lot of coal power plants and geothermal plants are planned to be installed. These power sources, except for diesel, are suitable for the operation at a fixed rate: the DSS operation[30] or large output alternation is difficult. In addition, the off-Peak/Peak Ratio in a day in this power system is 52%: difference between the peak and off-peak is relatively large. Because of these factors, power sources are sometimes difficult to turn down enough during off-peak time, which may result in surplus power. Particularly in the off-peak time in 2012, power system operation will face difficulty as described below.

Table 6.4.1 shows the comparison between minimum available output and off-peak demand. Here, 'minimum available output' means the sum total of generator outputs in the power system under the following 'minimum' conditions:

- Generators in planned outage due to maintenance are excluded,
- Generators such as diesel-type and gas-turbine type (capable of DSS operation) are excluded,
- The output of coal power plants are turned down to 60%, and
- The output of pondage-type hydropower plants are turned down to 40%

Table 6.4.1 explains that power system cannot be operated in 2012 due to surplus power because the minimum available output exceeds the off-peak demand by 31 MW. On the other hand, there will be no surplus power in 2017 and after because the minimum available output is less than the off-peak demand.

Table 6.4.1 Minimum Available Output and Off-peak Demand in Northern System

(MW)

Year	2012	2017	2022	2027
Generation Capacity	478	700	963	1,379
Minimum Available Output	181	234	324	459
Off-peak Demand	150	235	349	534

Countermeasures for this issue are described as below:

[30] In DSS (Daily Stop and Start) operation, a generator is stopped during night time start up early in the morning.

I) Planned outage of coal power plants which leads to the decrease of the minimum available output
   - Planned outage of one unit (55 MW) in Amurang power plant. This decreases the minimum available output by 33 MW and enables system operation
II) Change of lower limit of coal power plants
   - Currently the lower limit of coal power output is stipulated as 60% of the nominal value. By changing this to 40%, the minimum available output decreases by 32 MW and the operation becomes possible. However,
   - Planned outage of one unit (55 MW) in Amurang power plant. This decreases the minimum available output by 33 MW and enables system operation. The decrease of the limit may cause disadvantages such as large decrease of generation efficiency and the lifetime of turbine.
III) Power interchange between the northern and southern system via north-south interconnection
IV) Reconstruction of natural-flow type hydro plants to pondage-type plants

Among the above, the measures III) or IV) may not be realistic from economic viewpoints. Possible measures would be I) or II): the planned outage or the operational change of coal power plants. Therefore, installing low limit generator for new coal power plant is recommended. Then, it would be necessary to consider the capacity and timing carefully to install new coal power plant more than present plan.

(2) Effects of Excessive Generator Unit Capacity and Countermeasures

Amurang coal power plant (55 MW x 2 units) is planned to be introduced in 2011. The ratio of the unit capacity (55 MW) of the plant to the capacity northern Sulawesi power system is rather high: 19.3% of the peak load (285.2 MW) of the system in 2012.

When a generator unit with such excessive capacity is introduced, a drop of the unit from the system directly leads to load shedding or power system collapse. Such situation continues until 2027. However, introduction of large coal power plants cannot be avoided because the improvement of serious power deficit would be the first priority for the northern Sulawesi power system.

Some countermeasures for the unit capacity issue may be as follows:

I) Load shedding for against the drop a large generation unit
II) Interconnection between northern and southern system

Both measures may be unrealistic from technical and economical viewpoints: to take fundamental measure would be difficult. Realistic measures would be to facilitate restoration from large scale blackout by upgrading SCADA and communication systems and implementing dispatchers' training.

(3) Avoid new installation of 70kV facilities

Currently Minahasa power system is composed of mainly 70 kV system and partly 150 kV system. Howerver hereafter, as the power system growing larger will not be enough with 70 kV and in the near future dominated by 150 kV.

In this situation, without expanding 70 kV, in the long run, changing to 150 kV is recommendable. So new power plants and substations are required to be installed in 150 kV side and more expansion of 70 kV facilities should be avoided.

(4) Avoid large generation capacity in Bitung

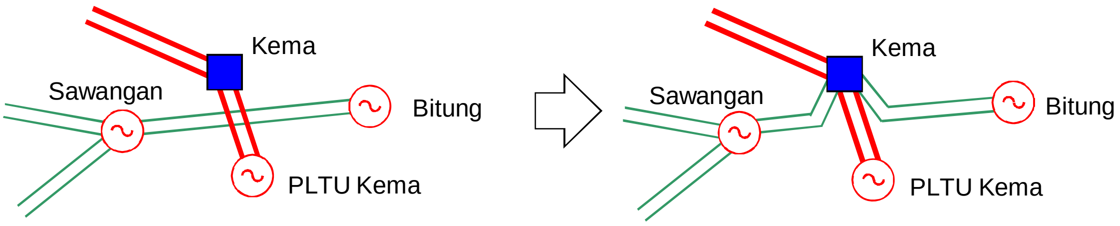
Bitung power plant is connected to 70 kV system. Because of this the transmission capacity from Bitung is limited under 60 MW, which is transmission thermal capacity under N-1 condition. Therefore generation capacity in Bitung plant should not be somuch: in case of 25 MW-size gas turbine, two units or less.

(5) Dynamic stability issue in Tolitoli

Tolitoli can be suffered from dynamic stability problem because it is located far from other demands or power sources. A dynamic stability analysis shows generation capacity in Tolitoli should be 50 MW or less because larger power source than 50 MW here can lead to step-out when a disturbance occurs on the transmission line between Tolitoli-Leok.

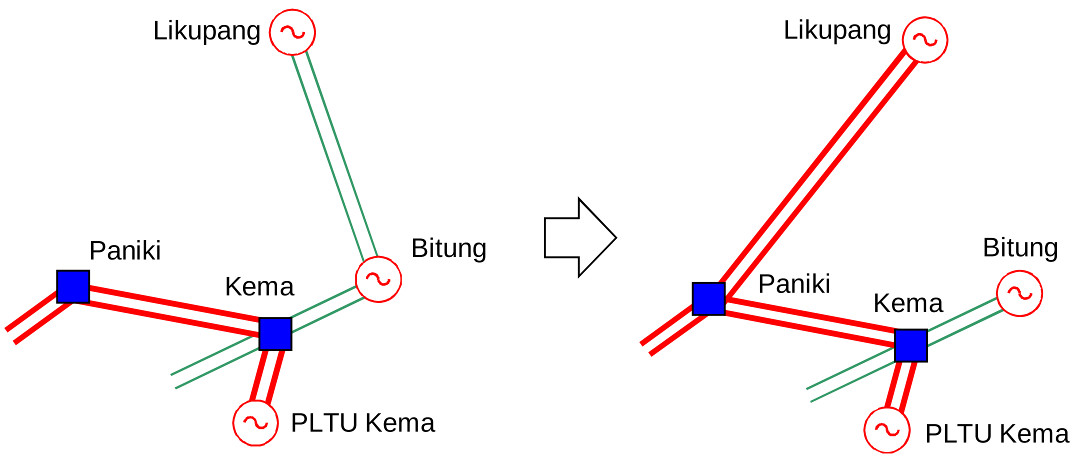
(6) 70kV system connection to Kema

The power generated in Bitung power plant is sent by 70 kV transmission line to Manado. Instead, connecting the 70 kV line in- between to 150 kV system at Kema via 150/70 kV transformer is recommendable. By doing so, the power flow in 70 kV system can be decreased, which means the restriction of 70 kV system expansion. The system loss can be also saved around 0.5 MW.



(7) Change of connection point of Likupang power plant (70 kV→150 kV)

Likupang power plant is currently planned to be connected to Bitung by 70 kV. In this case, however, not so much power can be sent from Likupang unless decreasing the output of Bitung. This is because the transmission capacity between Bitung and Sawangan is 60 MW whereas the output of Likupang is more than 60 MW at the maximum. Therefore Likupang is recommended to be connected to Paniki substation directly by 150 kV.



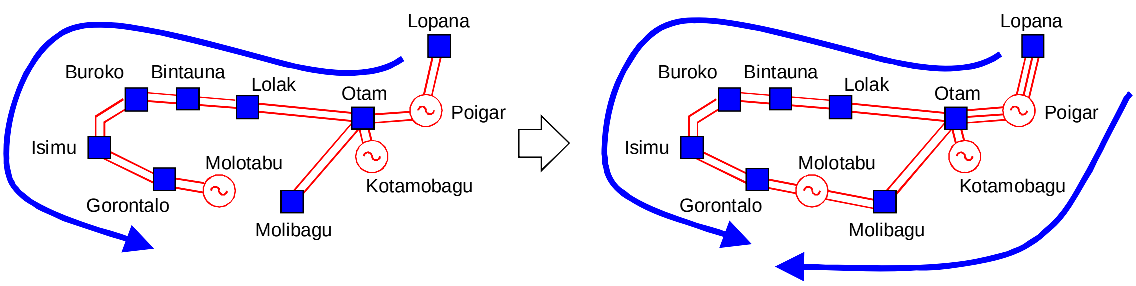
(8) Measures against overloading at Lopana-Otam-Lolak transmission line

The role of this line is to send power from Minahasa-Kotamobagu system to Gorontalo or more western area. So the power flow of the line is greatly affected by how much power sources are developed in Gorontalo Province. The analysis in this study shows that reinforcement of this line is necessary due to overloading during N-1 contingency in 2027, or earlier than 2027 incase power development in Gorontalo delays.

The following measures are recommended against transmission overloading:

I) Add one more circuit between Lopana-Otam (2 cct to 3 cct)
II) Install a new route between Molibagu-Molotabu

The measure I) reinforces transmission capacity without constructing a new route because there is no load between Lopana-Otam. On the other hand, the power flow of Otam-Lolak, through Buroko and Isimu, is supplied to the center of Gorontalo. In this case, not reinforcing along this roundabout route but installing the new route between Molibagu-Molotabu is better, which decreases transmission loss by 3.7 MW and increases stability from Gorontalo and to the west.



(9) Voltage problem in the north of Central Sulawesi Province

The north area of Central Sulawesi Province like Tolitoli or Moutong has less demand and far from power sources. In this place like this, voltage fluctuates so much as load changes. Besides, during off-peak time, voltage increase problem can happen due to Ferranti Effect.

These problems are likely to happen especially when no generator exists in Tolitoli. Not only static capacitors but also shunt reactors are required as a countermeasure.

6.4.2 Transmission Development Plan in Southern Sulawesi Power System

Power source composition in southern Sulawesi system is quite different from that of Northern system: the southern system has large hydro plants like Bakaru and Poso, and gas combined-cycle type like Senkang. Another difference from the northern system is that regarding interconnection, this area has rather large isolated systems with several dozen MW like Kendari or Palu. The issues of the transmission development plan and countermeasures are described below.

(1) Issue of Demand-supply Balance during Off-peak Time (Output alternation of coal power plants)

Power sources in the southern Sulawesi system are currently mostly hydro power plants and diesel power plants, and in the near future a lot of coal power plants and pondage-type hydro plants are planned to be installed. Apparently much more power plants exit which output can be changed easily like pondage-type hydro or gas-fired type compared with the northern system. Still, decreasing outputs for off-peak time is difficult because of a lot of coal power plants to be installed (in Scenario 1 in which economy is prioritized). In addition, the off-Peak/Peak Ratio in a day in this power system is 60%: difference between the peak and off-peak is relatively large. Because of these factors, power sources are sometimes difficult to turn down enough during off-peak time, which may result in surplus power (just like the northern system). In order to solve this, as shown below, coal power plants need output change operation in response to demand, even though the coal plants cannot change output so much and the change of output worsens efficiency.

Table 6.4.2 shows the comparison between the amount of coal power sources to be introduced and off-peak demand in the southern Sulawesi system. In 2017 and after, the amount of coal power exceeds off-peak demand, which means that even coal power requires output decrease. Actually this problem can be solved because the output of a coal plant could be decrease to around 60% of nominal output.

Table 6.4.2 Amount of Coal Power and Off-peak Demand in Southern Sulawesi

Year	2012	2017	2022	2027
Generation Capacity	1,395	1,840	2,390	3,440
Coal Power	520	1,070	1,570	2,370
Off-peak demand	579	826	1,174	1,701

(2) Effects of Excessive Generator Unit Capacity and Countermeasures

Jeneponto (Bosowa) power plant (100 MW × 2) is planned to be introduced in 2011. The ratio of the unit capacity (100 MW) of the plant to the capacity South Sulawesi system is rather high: 11% of the peak load (908.22 MW) of the system in 2012.

When a generator unit with such excessive capacity is introduced, a drop of the unit from the system directly leads to load shedding or power system collapse. A recent case is that a drop of 28.6 MW generator led to total blackout of the southern system. The system may not be able to withstand the drop of a 100 MW generator, and this situation continues until 2023.

A countermeasure would be to introduce a large-amount load shedding scheme upon the drop of a large generator. However, this scheme requires installing communication networks with high reliability, which may take time for realization.

(3) Avoid new installation of 70 kV facilities

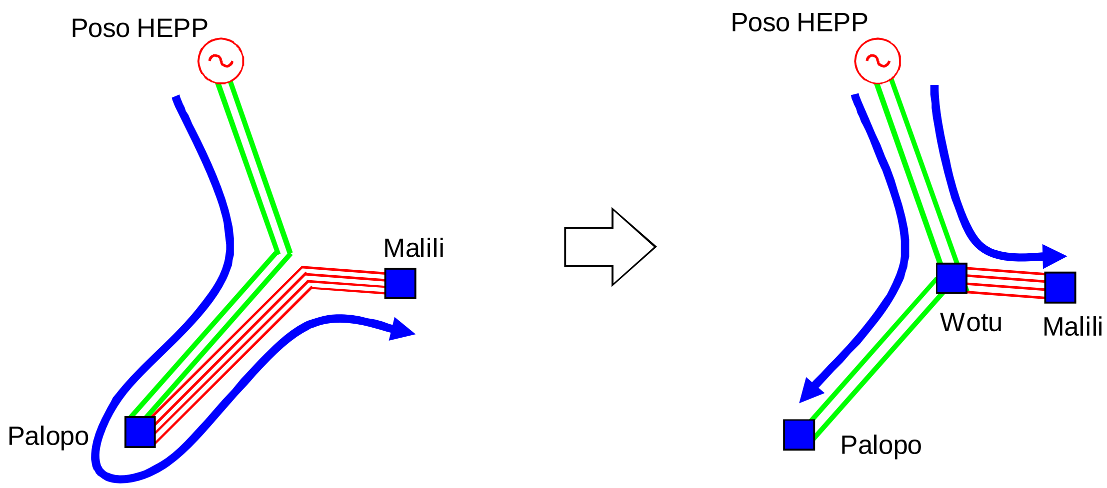
Currently Sulsel power system is composed of mainly 150 kV system, and 70 kV system is limited to around Makassar. As the power system grows larger, the ratio of 150 kV system will be more and more larger, and it would be rational to confine and demolish 70 kV system.

Under this situation, it is not good to expand the 70 kV system: new power plants and substations are required to be installed in 150 kV side and more expansion of 70 kV facilities should be avoided.

(4) Necessity of Wotu Substation

PLN's current plan is to send power from Poso power plant by 275 kV line to Palopo substation, and then send to Makassar area by 150 kV. Furthermore, in order to send power to Kendari area in Southeast Sulawesi Province, it is recommended to install Wotu substation between Poso and Palopo to send eastbound as shown in the right-below figure. Without Wotu substation, 150 kV line has to be additionally installed in parallel with 275 kV line as the left-below figure, which results in the following disadvantages:

- Costs 8 million US$ more[31]
- Longer distance to Kendari results in more transmission loss, degradation of voltage stability and dynamic stability



[31] It is assumed that Wotu substation has 2 units of 250MVA transformers, and the transmission line between Wotu – Palopo is Hawk 4 circuits. Cost difference would be larger as actually smaller transformers may adopted.

(5) Type of transmission line towards Kendari

Kendari area is far away from Sulsel system and the demand and generators will be concentrated in the end of the system. This situation tends to cause dynamic stability problem: in 2022 and later dynamic stability may not be secured with the normal transmission line: Hawk (1 bundle) 2 circuits. Alternative measures would be the followings:

I) Hawk (240 mm^2) 1 bundle, 4 circuits (to increase number of circuit)
II) Zebra (430 mm^2) 2 bundle, 2 circuits (to increase the size of conductor)

In order to realize long-distance transmission, the most important factor would be to improve the inductance of transmission line. The measure I) is effective in improving inductance. On the other hand, the measure II) may enlarge heat capacity but not directly improve inductance: for example, replacing Hawk (1 bundle) to Zebra (2 bundle) would enhance heat capacity by three times, whereas inductance changes just by 50%. As a result, Zebra (2 bundle) 2 circuits is not enough for Kendari line, but the 3red circuit is necessary.

In conclusion, for transmission line towards Kendari, it would be rational to start operation with Hawk 2 circuits, and when necessary (the system is enhanced), to install additional 2 circuits (totally 4 circuits). To use Zebra would not be economical. For the area where land acquisition is difficult, to construct towers for 4 circuits beforehand may be necessary in preparation for the future additional circuits.

Type of Conductor	Required Circuit Number		Construction Cost (NPV at 2008)
	2011-2017	2018-2027	
150 kV Hawk	2	4	78 millionUS$
150 kV Zebra x 2	2	3	107 millionUS$

(6) Luwuk area voltage stability measure

Luwuk area is far from power sources and may easily suffer from voltage stability problem. Voltage increase due to Ferantti Effect will happen just after interconnection, and voltage degradation problem will increasingly become prominent as demand grows. Especially in 2027 voltage will largely drop on a single line fault.

As countermeasures, it is recommended to introduce phase modifying equipment like SC or ShR, and to install power plants to stabilize the voltage in this area.

In case no power plant is introduced, during the peak time in 2027, the busbar voltage in Luwuk will be lowered to 0.88 pu: less than the lower limit 0.9 pu. The measures for this would be as the following two:

- Automatic SC control just after a line fault between Ampana-Luwuk
- Introduction of SVC in Luwuk

(7) Capacity of 275/150 k V transformer in Poso

275/150 kV transformer to be installed in Poso power plant not only sends power generated in the plant to the north area of Central Sulawesi Province but also acts as a connector of Palu system and Sulsel system. For this reason the capacity has to be larger than what is necessary to send northbound. (Especially in case of the north-south interconnection, much larger transformer is necessary by which the power will be interchanged between the north and south) In case of 2027 power system, the transformer requires the capacity that can deal with demand change during a day in Palu and Luwuk area. In addition, the tansformer with much larger capacity is not necessary than the capacity of the line from Poso forward northbound is Hawk type (heat capacity: 139 MW/ circuit). From the above discussion, 2 units of 150 MVA (275/150 kV) transformers are recommended to be installed in Poso hydro station.

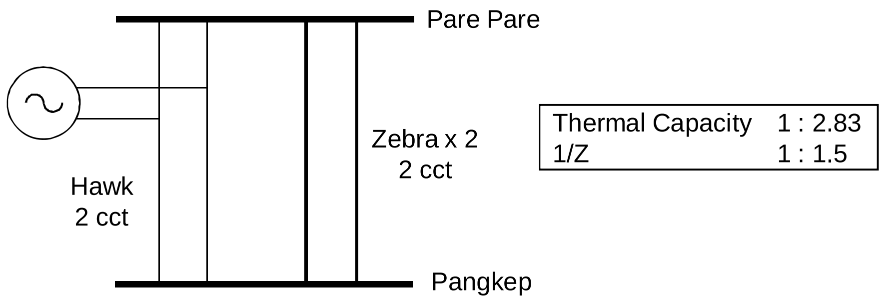
(8) Measure against transmission overloading I (Bakaru area)

Transmissions around Bakaru Bakaru (Bakaru-Polmas, Polmas-Parepare, Bakaru-Pinrang, Pinrang-Parepare) have possibility of ovderloading on a single-line fault in 2027. This can be solved by installing additional one circuit between Polmas and Parepare (totally 2 circuits).

(9) Measure against transmission overloading II (Parepare-Pangkep)

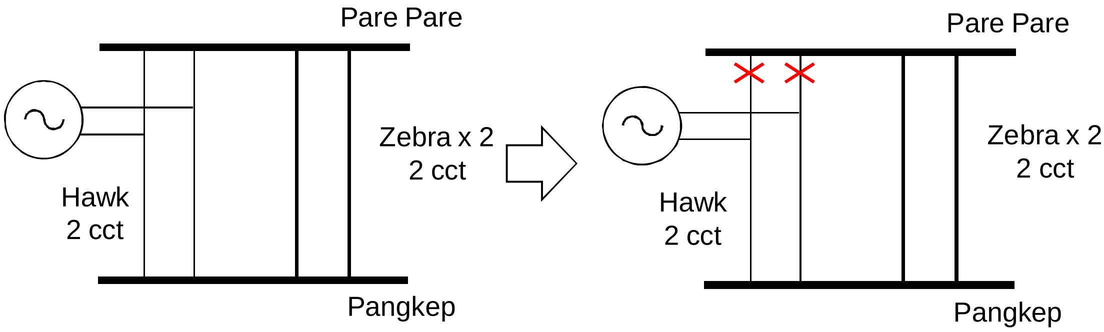
The transmission line between Parepare-Pangkep is composed of Hawk 2 circuits. On the same route, there is a plan to install a line (Zebra 2 bundle 2 circuits) as a part of the transmission line from Sidrap to Makassar area. When this plan is realized, Hawk line and Zebra line will exist in parallel on the same route.

In such a case where different type conductors run in parallel, the power flow is divided into each line in proportion to not heat capacity but basically the inverse of inductance (Z) of the line. Here, the heat capacity of Zebra line (2 bundle) is 2.83 times of Hawk line (1 bundle), whereas the value (1/Z) of Zebra is 1.5 times of Hawks. This means that, despite its heat capacity, the ratio of power flow to the Zebra-line side is not so much.



Because of this, when power flows heavily between Parepare and Pangkep, the Hawk line may be overloaded even though the Zebra line still have margin. The hawk line is even more apt to be overloaded because the power from Barru coal plant is added on this side.

In order to avoid this issue, an operation is recommended: to switch off the Parepare side of the Hawk line. By doing this, the overloading of this route is restricted by separating the flows: the power from Barru plant on the Hawk line and the power from Parepare to Pangkep on the Zebra line.



(10) Measure against transmission overloading III (Jeneponto-Bulukumba)

In 2027, there will be overloading on the two routes: Jeneopond-Bukukumba and Tanjung Bunga-Bontoala. The countermeasure would be adding 1 circuit (totally 3 circuits) for each route. As the route Tanjung Bunga-Bontoala is an undergroud line, the conduit for 3 circuits is recommended to be installed from the start.

6.5 Study on the North-South interconnection

Regarding the interconnection of small isolated systems to a larger system, voltage stability is a main issue: technical difficulty is limited. By contrast, regarding the interconnection between the North system and the South system: the connection is between the two power systems with the capacity of more than 1,000 MW for each in 2027 and with 1,800 km distance. This will cause not only overloading and voltage instability issues but also, more importantly, dynamic stability problem. The possibility and purpose of the north-south interconnection has been studied for 2027 power system.

6.5.1 The north-south interconnection by 150 kV line

The power system diagram when the systems are interconnected by 150 kV line is shown in Figure 6.5.1. Here, the interconnection line is supposed to be 2 routes: 150 kV Hawk line for each route (totally 4 circuits), and part of the northern system is reinforced.

A result of system analysis shows that the power flow on the interconnection line has to be restricted by 20 MW or under in order to secure dynamic stability: larger power flow than this with a line fault around Amurang will degrade dynamic stability which may lead to system collapse.

To restrict the power flow under 20 MW is very difficult just considering the fringe[32]: because the capacity of the north and south systems (peak load) are relatively large: more than 1,000 MW and 2,700 MW, respectively. Therefore the interconnection by 150 kV is in fact impossible.

6.5.2 The north-south interconnection by 275kV line

The system diagram when 275 kV line is applied for the interconnection instead of 150 kV

[32] Alternation of power flow on the interconnection line caused by the change of short-term power demand

line is shown in Figure 6.5.2. This requires new 275 kV line construction which connects Manado and Makassar with 1,800 km distance: the connection of the two large cities is necessary in order to decrease the impedance and improve dynamic stability. The construction cost amounts to 580 million US$, which blows away the cost savings through interconnection by introduction of large-capacity generators and decrease of stand-by generators. Therefore, the north-south interconnection by 275 kV line is, though technically possible but economically not rational and unrealistic.

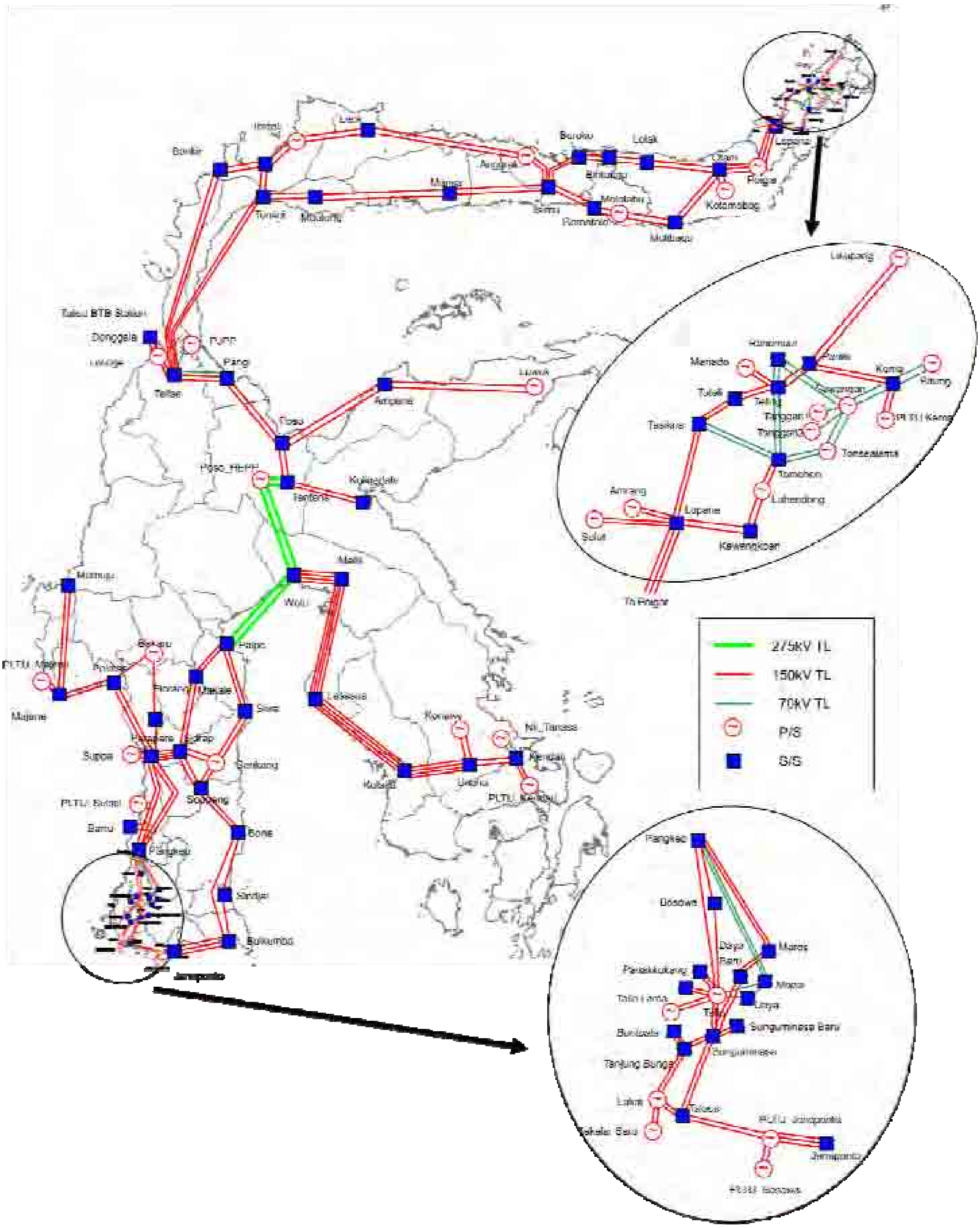


Figure 6.5.1 North-south interconnection by 150 kV line

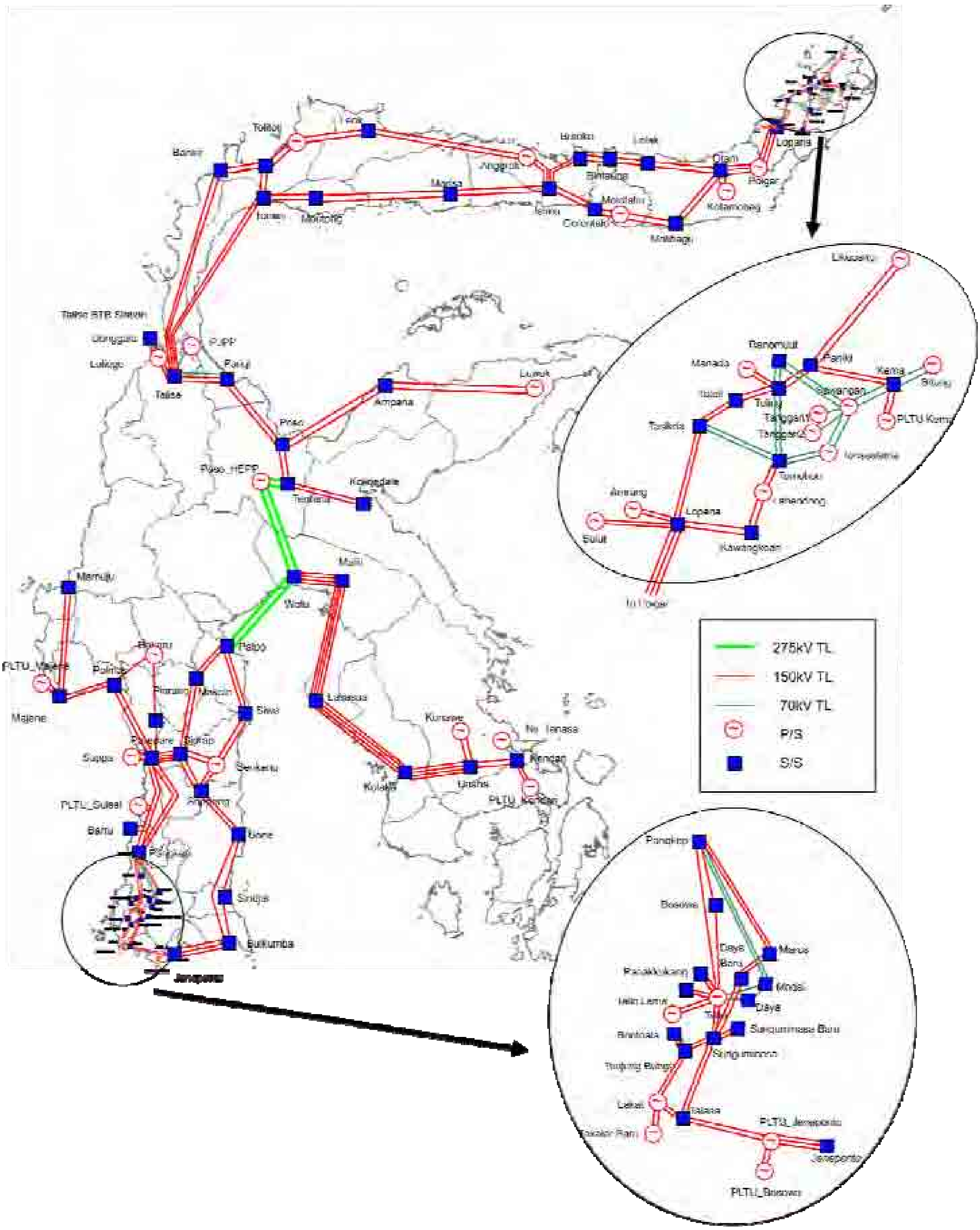


Figure 6.5.2 North-south interconnection by 275 kV line

6.5.3 North-South Interconnection by BTB

The biggest issue in conducting the north-south interconnection is the problem of dynamic stability. This is because the power systems concentration of power source and demand in Manado and Makassar and very long distance of the two cities resulted in expansion of phase difference which may lead to step out. Therefore the introduction of direct-current equipment between the two power systems will solve the problem of phase difference and make the interconnection possible even with 150 kV line.

Here, considering cost effectiveness, the case of introducing a BTB (Back-to-Back) interconnection facility in Palu has been studied. The result shows that, through BTB interconnection, reserve margin can be decreased because 100 MW-unit generators can be installed in the North Sulawesi system, which cost savings amounts to be 101 milion US$ (converted to NPV in 2008): more than the introduction cost of BTB (48 million US$).

However, as BTB facility requires high technology in both maintenance and operation, problems may be caused for operation when introduced in Central Sulawesi Province. Moreover, the power flow in the BTB has to be normally controlled to zero (for converting loss reduction): demand-supply unbalance for each system is not allowed, resulting in limited advantages.

Therefore, it is recommended not to conduct the north-south interconnection and proceed the construction of each power system for the time being. Then, after accumulating experiences of direct-current technology enough in Indonesia, the BTB installation in Sulawesi can be examined.

6.5.4 Conclusion on the North-South interconnection

As far as this study in concerned, it would be better not to conduct the north-south interconnection but to develop the northern system and the southern system separately because any alternatives — by 150 kV line, by 275 kV line or by BTB — proved to be difficult. It would be recommended to construct two separate systems in Sulawesi, and to consider the interconnection in the future after the direct-current technologies like DC transmission or BTB is accumulated in Indonesia.

6.6 Transmission Development Plan for Local Energy Premier Development Scenario

In this section, the transmission development plan for the Local Energy Premier Development Scenario. Power system diagrams as the result of the planning are shown in Figure 6.6.1, Figure 6.6.2, Figure 6.6.3 and Figure 6.6.4 for the year 2007, 2012, 2017 and 2027, respectively. Then technical issues and features in the planning are described.

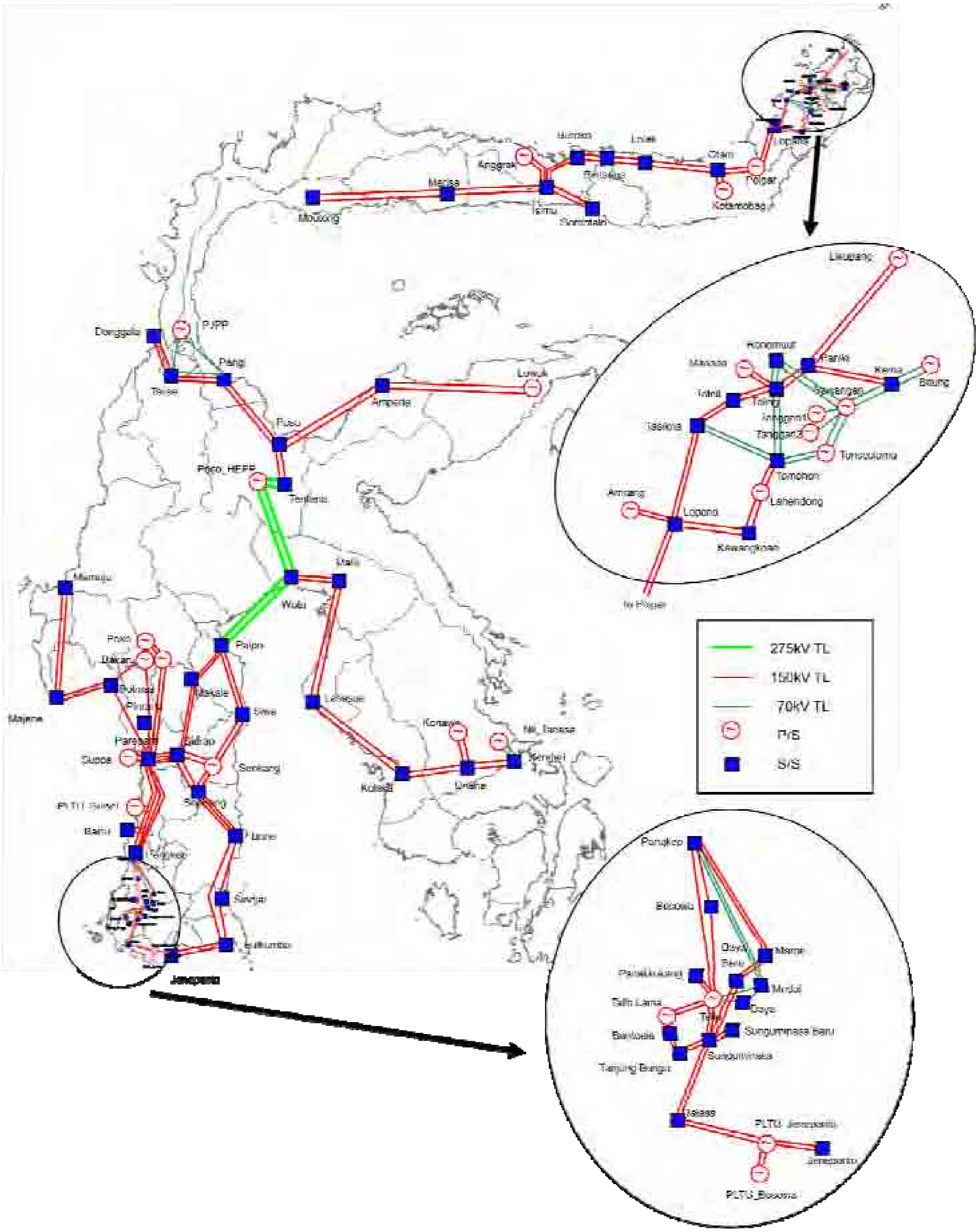


Figure 6.6.1 Sulawesi Power System in 2012 (Local Energy Premier Development Scenario)

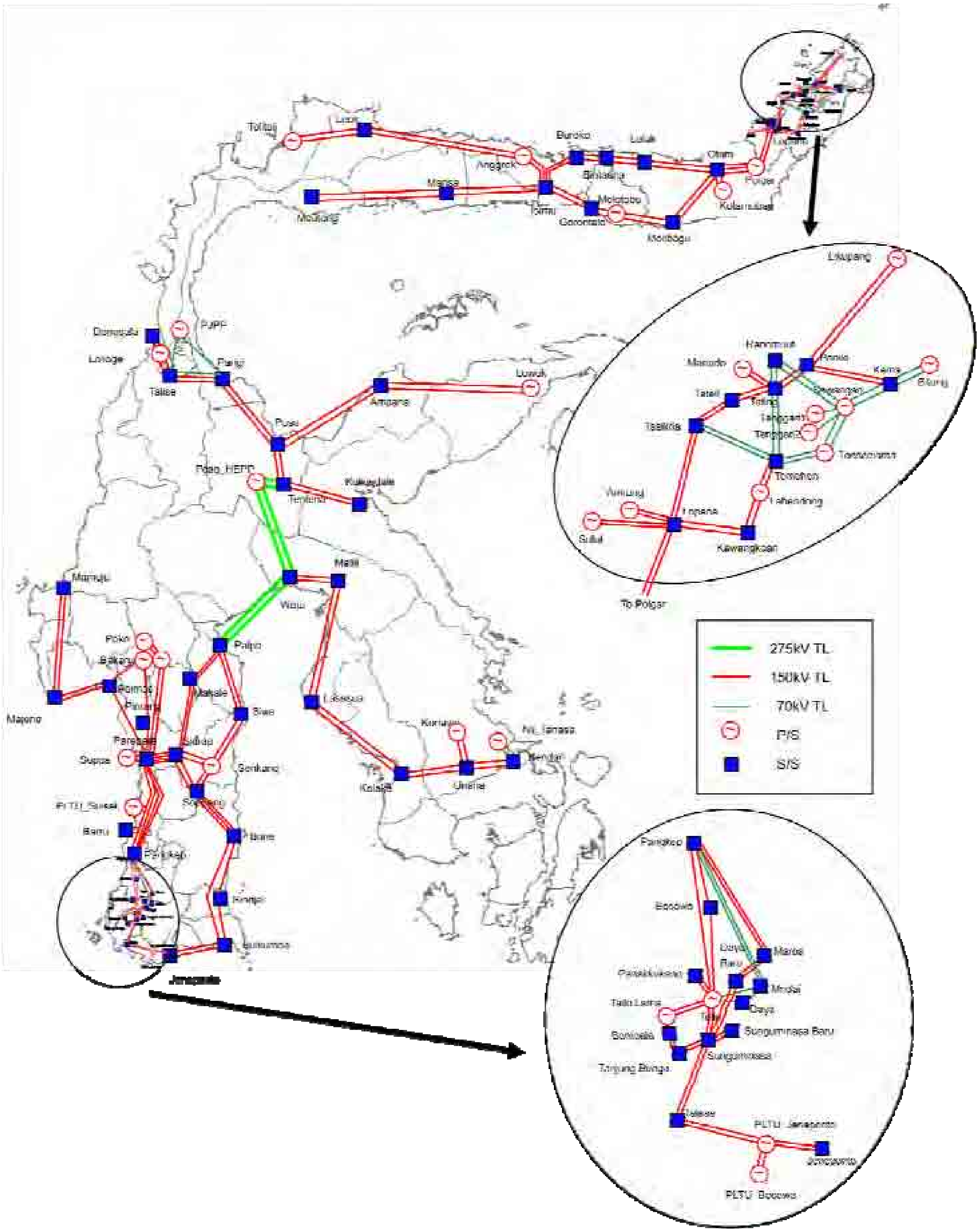


Figure 6.6.2 Sulawesi Power System in 2017 (Local Energy Premier Development Scenario)

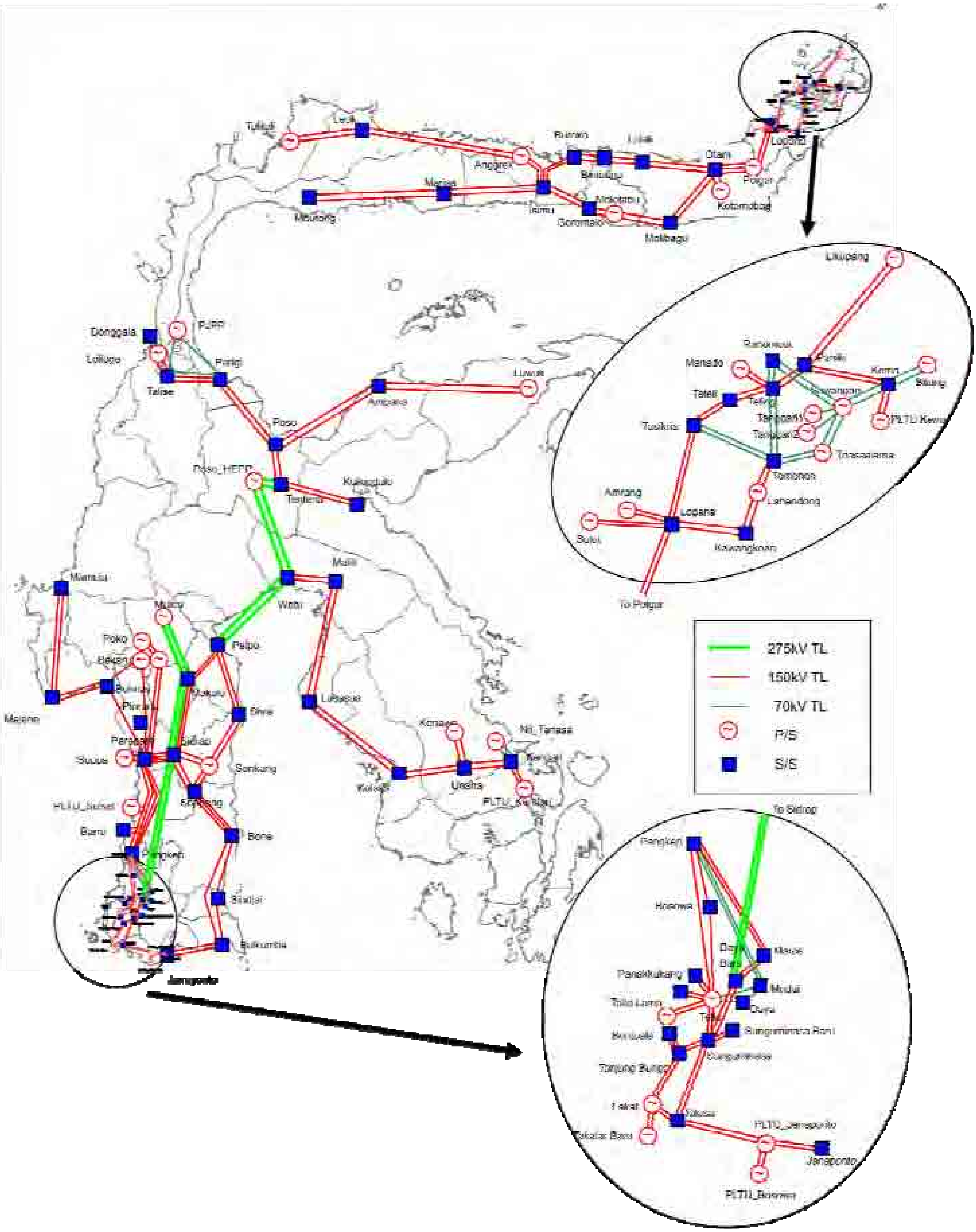


Figure 6.6.3 Sulawesi Power System in 2022 (Local Energy Premier Development Scenario)

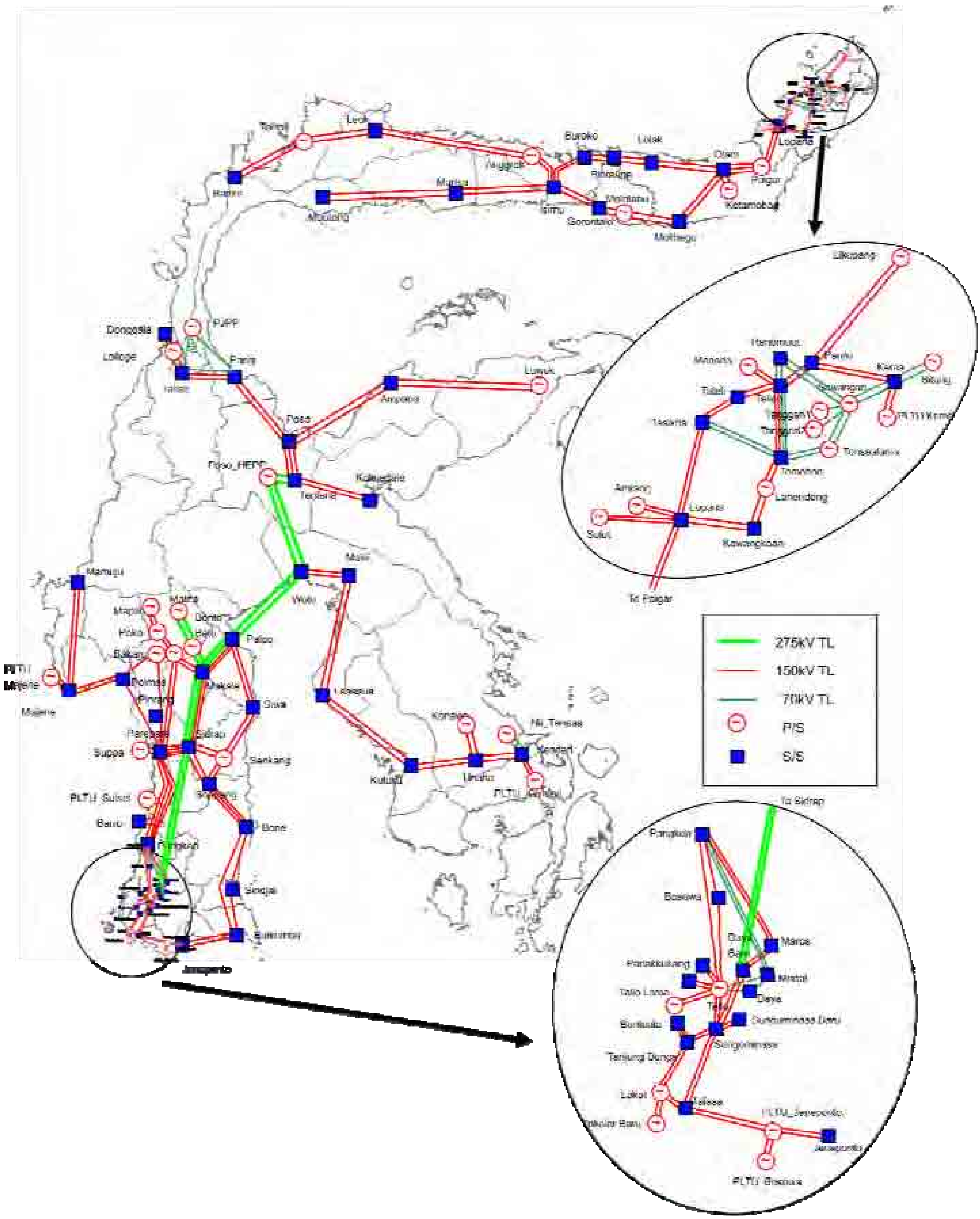


Figure 6.6.4 Sulawesi Power System in 2027 (Local Energy Premier Development Scenario)

6.6.1 Power System Plan in North Sulawesi System

In the Local Energy Premier Development Scenario, compared with the Economic Oriented Development Scenario, the amount of geothermal power plants in Lahendong and Kotamobagu largely increases and introduction of coal power sources decreases. As a result, power sources are concentrated in the middle area of North Sulawesi System, and from here the power flows to Manado area, Gorontalo and Central Sulawesi area. For this reason the plan is somewhat different from the Economic Oriented Development Scenario. The results are described below.

(11) Power System Reinforcement in the Western Area

In the Local Energy Premier Development Scenario, compared with the Economic Oriented Development Scenario, a lot of geothermal plants around Lahendong are installed and coal power development in Gorontalo and Tolitoli area is restricted. This requires the reinforcement of transmission line from Lahendong to westbound. In Table 6.6.1, the difference of the two Scenarios in reinforcement plans of the west area is described.

Table 6.6.1 Development Plan of the West Area

	Timing of Installation	
	Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Poigar-Otam 3rd circuit	2018-2022	2013-2017
Molibagu-Molotabu interconnection	2023-2027	2013-2017
Lopana-Poigar 3rd circuit	2023-2027	2028 and after

Poigar-Otam 3rd circuit and Molibagu-Molotabu interconnection is introduced earlier in the Local Energy Premier Development Scenario. This is because, in this scenario, the power flow from Lahendong and Kotamobagu to the west area increases and the heat capacity problem becomes become conspicuous in the earlier stage.

Regarding Lopana-Poigar 3rd circuit, different from the above, introduction is later in the Local Energy Premier Development Scenario. This is because, in this scenario, a lot of geothermal generators are introduced in Kotamobagu during 2023-2027, which restricts the power flow on Lopana-Otam. This means that when to introduce Lopana-Otam 3rd circuit should be revisioned according to the status of power development in Kotamobagu area.

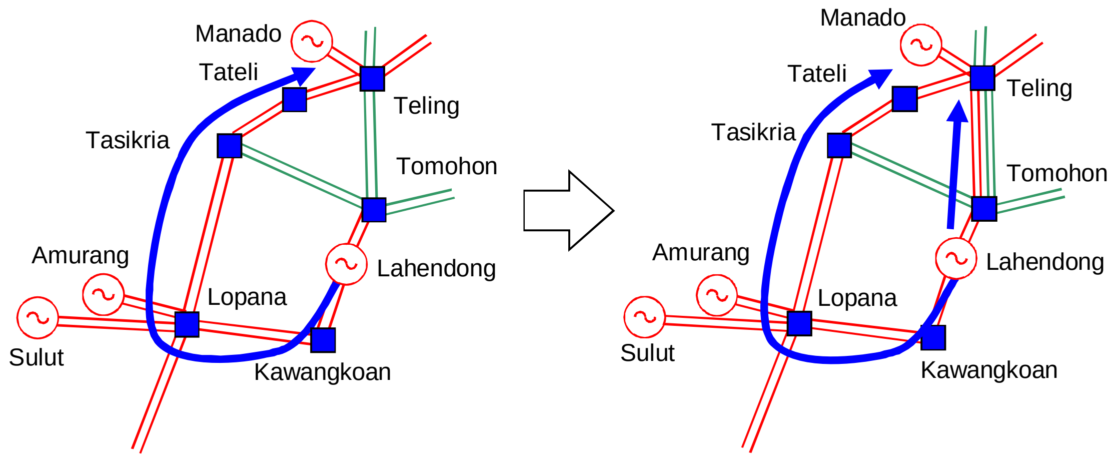
(12) Power System Reinforcement in the Western Area

In the local-energy development prioritized scenario, a lot of geothermal power sources are introduced which causes overloading between Lahendong-Kawangkoan during single line fault in 2007. The countermeasures would be the following two:

I) 3rd circuit introduction between Lahendong-Kawangkoan
II) Introduction of new line between Tomohon-Teling

I) is the simplest method and installation cost is cheaper than II) when compared for the case of 2027. However, sending Lahendong's power via Kawangkoan and Lopana to Manado (largest demand area) means long transmission with much loss and instability. Besides, when Lahendong plant is developed more, the route Kaswangkoan-Lopana-Tasikira requires enhancement, which results in more costly.

Therefore, enhancement in this area is recommended to implement the measure II) : new 150 kV line installation between Tomohon-Teling.



6.6.2 Power System Plan in Southern Sulawesi System

In the South Sulawesi system, under the Economic Oriented Development Scenario, a lot of large-scale hydropower plants in the northern area of South Sulawesi Province like Malea and Poko. As a result, status of the power system is different from the economy prioritized scenario, represented by the transmission line that goes down through South Sulawesi Province. The details are shown below.

(1) The transmission line that goes down through South Sulawesi Province

In the Economic Oriented Development Scenario, the transmission lines that connect the north and south of South Sulawesi Province are planned to be totally three routes: two routes in the west area and one route in the east area. On the other hand, in the local energy development prioritized scenario, the above 3 routes are not enough to send power down to Makassar because large-scale hydro power like Poko and Malea concentrates in the northern part of South Sulawesi Province.

In order to cover the lack of transmission capacity, introduction of a 275 kV line that connects Malea-Makale-Sidrap-Daya Baru is recommended (at the same time of Malea hydro installation), which will send power from the large hydro plants to Makassar.

Regarding the voltage of this line, 150 kV may be applied in case just the power system in 2027 is considered. However, the 150 kV application will not be able to deal with further power development around the northern part in South Sulawesi Province and the reinforcement around Poso in the future, which may require the 5th route of north-south transmission in South

Sulawesi Province: 5 routes (10 circuits) of 150 kV transmission lines toward the same direction may cause land-acquisition problem and would not be realistic. Therefore, it is appropriate to adopt 275 kV line as the 4^{th} route of the transmission line down through South Sulawesi Province.

(2) Reinforcement of Makale-Palopo transmission line

In the Economic Oriented Development Scenario, concentration of large hydro plants in the northern area of South Sulawesi Province enlarges also the power plow towards the eastern area, which causes overloading in Makale-Palopo line when N-1 contingency. The countermeasure is recommended to newly install 275 kV transmission line between Makale－Palopo.

Regarding this measure, the 3^{rd} 150 kV line installation may be enough if just the heavy power flow in 2027 is considered. However, 275 kV line introduction in Makale－Palopo directly connects both 275 kV Poso－Palopo system and 275 kV Malea－Daya Baru system. This largely improves stability around Poso and Kendari area. This can delay the installation of 3^{rd} and 4^{th} lines toward Kendari.

(3) Transmission line toward Kendari area

In this scenario, the development amount of coal power plants in the southern area of South Sulawesi province and Kendari decreases and instead, a lot of hydro plants are developed in the northern part of South Sulawesi Province. This has effects on the stability in Kendari area in the following manner.

I) Distance from Kendari to the center of power sources is shortened because the center shifts from the south to north in South Sulawesi Province.

II) Kendari has less generators which phase oscillates during a line fault in this area because the amount of coal power introduction in Kendari is small.

III) Impedance between Wotu and the power sources in South Sulawesi Province becomes small because 275 kV transmission line is connected from Wotu to Daya Baru.

IV) Power flow between Wotu and Kendari increases because the amount of power development in Kendari is small.

Because of the effects I, II and III, dynamic stability around Kendari largely improves compared with the economy prioritized scenario. As a result, regarding the number of circuits the line toward Kendari, no problem of dynamic stability occurs with just two circuits in this scenario, whereas 4 circuits are required in 2017 and after in the economic prioritized scenario.

On the other hand, the effect IV may cause heat- capacity problem, however, the power flow will be with the capacity of 150 kV x 2 circuits in the year 2027.

From the above discussion, the transmission line toward Kendari in this scenario can be 150 kV Hawk x 2 circuits until 2027.

(4) Tentena 275/150 kVtransformer and Tentena-Poso transmission line

In this Scenario, the amount of power development around Palu is smaller than in the economy prioritized scenario, and therefore the flow between Poso hydro and Palu is larger. Because of this, which is compensated, Wotu-Kendari line is overloaded on N-1 contingency. As a countermeasure, it is recommended to install the 3rd 150 kV line between Tentena-Poso.

At the same time, revision of 275/150 kV transformer in Tentena is necessary: in this scenario 3 units of 150 MVA transformer is recommended, whereas in the economy prioritized scenario 2 units of 150 MVA is appropriate.

6.7 Amount of Facilities and Investment for Transmission Development

From the study so far, the amount of facilities and investment necessary for the transmission development in Sulawesi. Amount of transmission facility development necessary by 2027 for each scenario is shown in Table 6.7.1, Table 6.7.2, Table 6.7.3and Table 6.7.4.

Table 6.7.1 Amount of Development Facilities in the Economic Oriented Development Scenario (Transmission Line)

(kms)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70 kV	24	0	0	0
	150 kV	3,240	180	870	174
	275 kV	400	0	0	0
North	150 kV	1,304	604	64	460
Total	70 kV	24	0	0	0
	150 kV	4,544	784	934	634
	275 kV	400	0	0	0

Table 6.7.2 Amount of Development Facilities in the Economic Oriented Development Scenario (Transformer)

(MVA)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70/20 kV	0	0	30	0
	150/20 kV	840	370	800	880
	150/70 kV	246	32	0	0
	275/150 kV	1,100	0	0	0
North	70/20 kV	40	10	40	20
	150/20 kV	380	190	370	200
	150/70 kV	246	0	0	0
Total	70/20 kV	40	10	70	20
	150/20 kV	1,220	560	1170	1,080
	150/70 kV	492	32	0	0
	275/150 kV	1,100	0	0	0

Table 6.7.3 Amount of Development Facilities in the Local Energy Premier Development Scenario (Transmission Line)

(kms)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70 kV	24	0	0	0
	150 kV	3,364	180	191	162
	275 kV	400	0	675	75
North	150 kV	1,256	910	20	230
Total	70 kV	24	0	0	0
	150 kV	4,620	1,090	211	392
	275 kV	400	0	675	75

Table 6.7.4 Amount of Development Facilities in the Local Energy Premier Development Scenario (Transformer)

(MVA)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70/20 kV	0	0	30	0
	150/20 kV	840	370	800	880
	150/70 kV	246	32	0	0
	275/150 kV	1,100	0	1,500	150
North	70/20 kV	40	10	40	20
	150/20 kV	380	190	370	200
	150/70 kV	246	0	0	0
Total	70/20 kV	40	10	70	20
	150/20 kV	1,220	560	1,170	1,080
	150/70 kV	492	32	0	0
	275/150 kV	1,100	0	1,500	150

The amount of investment necessary for the above facility expansion is shown in Table 6.7.5 and Table 6.7.6. As shown here, the investment is larger in the earlier stage (2008-2012). This is because connecting small isolated systems to the large system as soon as possible will restrict high-cost diesel generation resulting in totally cost effective.

Table 6.7.5 Amount of Transmission Investment in the Economic Oriented Development Scenario

(million US$)

		2008-2012		2013-2017		2018-2022		2023-2027	
		FC	LC	FC	LC	FC	LC	FC	LC
South	Transmission	235	89	8	5	66	34	13	11
	Substation	119	30	8	2	32	10	21	7
North	Transmission	54	26	27	15	4	3	26	20
	Substation	54	15	10	3	13	4	14	5
Total	Transmission	288	115	35	20	69	36	40	31
	Substation	174	44	18	5	44	13	35	12

Table 6.7.6 Amount of Transmission Investment in the Local Energy Premier Development Scenario

(million US$)

		2008-2012		2013-2017		2018-2022		2023-2027	
		FC	LC	FC	LC	FC	LC	FC	LC
South	Transmission	245	102	8	5	134	63	24	15
	Substation	113	26	8	2	83	24	41	14
North	Transmission	52	25	41	24	1	1	13	9
	Substation	48	11	18	5	11	3	12	4
Total	Transmission	296	128	49	28	135	63	36	24
	Substation	161	38	26	7	94	27	53	18

6.8 Comparison of transmission plans for each scenario

So far the transmission development plans are formulated for the economy prioritized scenario and the local energy prioritized scenario. Here, the two scenarios are compared.

The two scenarios are different not in technical or operational aspect but the cost aspects. Total investment amount is shown below:

Table 6.8.1 Comparison of total investment amount for the two scenarios

Scenario	Total Investment Amount (million US$)
Economic Oriented Development Scenario	979
Local Energy Premier Development Scenario	1,184

As shown in the above table, the cost for the local energy prioritized scenario is larger than that for the economy prioritized scenario by around 20%. This is because, in the local energy prioritized scenario, the locations of power plants are fixed which results in long distance from the plants to load and more costly in transmission development.

6.9 Issues on the transmission development planning

Among the findings acquired through power system analysis and the transmission development planning, what is especially important are described as below.

(1) Power plant's unit capacity issue

Some power plants currently planned in Sulawesi have generators with rather large-size unit capacity like Amurang in the North system and Jeneponto in the South system. It may be reasonable to recommend smaller-sized generator units to be installed because in case such a large-sized unit falls down, the power system may suffer from load shedding or system collapse. However, the introduction of such large units would be actually necessary considering the current situation of serious power deficit in Sulawesi. The countermeasures of this large unit capacity issue would be I) introduction of automatic load shedding scheme on the fault of a large unit, II) full preparation of SCADA system and III) training for dispatchers in order to facilitate restoration after a large scale blackout.

(2) Demand-supply issue during off-peak time

Power plants planned to be installed in Sulawesi, like natural hydro, geothermal and coal power, are mostly the types which output is difficult to change. Because of this, the problem is that when power plans are operated so that the total output matches the peak demand in the evening, power supply may exceed the demand during off-peak time which will cause operational difficulty. To avoid this situation, it would be important to introduce gas turbine plants which is easier to start and stop (though fuel is not cheap), or to develop pondage-type hydro plants by which output can be changed easily.

(3) North-south interconnection

Interconnection of small isolated systems to a large large power system at earlier stage will be economically superior and does not cause any technical problems. On the other hand, the north-south interconnection will cause dynamic instability problem and cost too much. Because of this, it is rational to compose the two large power systems in the north and south, and avoid the north-south interconnection for the time being.

(4) Transmission line toward Kendari

Kendari system is rather large among isolated systems and far away from the large system (Sulsel system). Because of this, dynamic stability problem may happen just with 150 kV x 2 circuits. Therefore, this transmission line needs to be introduced with a view to 4 circuit installation in the future.

Chapter 7 Environmental and Social Considerations

7.1 Legal Framework of Environmental and Social Considerations

7.1.1 Guideline Adopted for Impact Assessment

The study team has adopted the JICA Guidelines for Environmental and Social Considerations of 2004. Indonesia has an EIA regulation entitled Government Regulation of the Republic of Indonesia concerning EIA (G.R. No.27, 1999), which defines the projects that need EIA (called AMDAL in Indonesia; see Table 7.1.1). However, the regulation does not define strategic environmental assessment for master plan studies. Thus the study team followed the JICA Guidelines and conducted a strategic environmental assessment. The AMDAL procedure will be started during the feasibility study stage.

Table 7.1.1 Projects That Need AMDAL (Energy Sector Only)

Type of Project	Size	Scientific Reasons
Construction of transmission line	**150 kV**	- Local residents' concerns over health impact of transmission line - Impact on society, economy and culture, and local residents' concerns on land acquisition
Construction of diesel, gas turbine, steam turbine, combined cycle	≥**100 MW**	Possible impacts: - Physical impact: air (emission substance, noise), water (discharge of grease, thermal effluents, etc.), underground water - Impact on society, economy and culture, and local residents' concerns on land acquisition
Development and utilization of geothermal steam; development of geothermal energy	≥**55 MW**	Possible impacts: - Physical impact: air (foul odor, noise), water quality - Biological impact - Impact on society, economy and culture, and local residents' concerns on land acquisition
Construction of hydro power plant	Dam height≥**15 m** Dam area≥**200 ha** Power generation≥ **50 MW**	Possible impacts: - Physical impact: air (foul odor, noise), water quality - Biological impact - Social, economical and cultural impact, especially on land acquisition - Categorized as "large dam" - Burst dam might cause flood which would damage downstream environment - Scale could necessitate special specifications for material and design - Large quarry and excavation site which might affect environment - Impact on hydrology
Other types of power plants (solar, wind, biomass)	≥**10 MW**	- Vast amount of land needed - Impact on landscape - Noise - Impact on grassland ecosystem (if grassland is utilized)
Construction and operation of nuclear power plant	All	- Requires highly secure buildings - High risk - Effect of radiation after closing plant - Unrefined raw materials and residual radioactive substance

7.1.2 Land-Use Regulations

Land use in Indonesia has been restricted by the Forest Law (No. 41, 1999), and the Ministerial Ordinance on Energy and Mining Resources (No. 1456, 2000).

(1) Conservation Forest based on Forest Law

The forest in Indonesia is classified as national forest and private forest. National forest is sub-divided into conservation forest, protected forest and productive forest. The definitions and regulations are shown in the next table.

Table 7.1.2 Definition of National Forest in Indonesia

Name	Definition	Prohibited Matters	Laws or Ordinances
Protection Forest/ Hutan Lindung	A forest area having the function of protecting life-supporting systems for hydrology, preventing floods, controlling erosion, preventing sea water intrusion and maintaining soil fertility	- Open-cast mining - Encroach a forest area - Cut trees within a radius or distance of: a. 500 meters from the edge of a lake b. 200 meters from the edge of water sources and along rivers in swamp area c. 100 meters along riverside d. 50 meters along sides of streams e. twice the depth of ravine from the edge of ravine f. 130 times the difference between the highest and the lowest tides, measured from the coastline	Law No. 41/ 1999 on Forestry
Strict Nature Reserve/ Cagar Alam	A nature reserve forest area with specific plants, animals, and ecosystem that need protection	- Remove, carry, transport plants and wildlife species which are protected by the law, from forest area without any legal authorization - Take or cut trees, damage, destroy, keep, carry, and sell plants which are protected, regardless of they are dead or alive - Take plants and animals which are protected or part of them out of the Indonesian Region - Catch, hurt, kill, keep, carry, and sell live animals which are protected - Keep, carry, and sell dead animals which are protected	Law No. 5/ 1990 on Conservation of Natural Resources and Ecosystem
Strict Sea Nature Reserve/ Cagar Alam Laut	A nature sea reserve forest area with specific plants, animals, and ecosystem that need protection		
Wildlife Sanctuary/ Suaka Margasatwa	A nature reserve forest area with specific and unique animals and their habitat		
Sea Wildlife Sanctuary/ Suaka Margasatwa Laut	A nature sea reserve forest area with specific and unique animals and their habitat		
Hunting Park/ Taman Buru	A forest area designated as a park area for hunting		
National Park/ Taman Nasional	A nature preservation forest area that has a natural ecosystem, is managed in a zone system, and is used for research, education, traditional farming, tourism, and nature recreation	- Any activity that can change the core zone, damage its functions, and bring in and increase foreign plant or animal species - Any activity which is unsuitable to the zone functions and National Parks, Grand Forest Parks, and Nature Recreation Parks	
Sea National Park/ Taman Nasional Laut	A nature preservation forest area that has a natural sea ecosystem, is managed in a zone system, and is used for research, education, traditional farming, tourism, and recreation		

Name	Definition	Prohibited Matters	Laws or Ordinances
Nature Recreation Park/ Taman Wisata Alam	A nature preservation forest area whose principal purpose is tourism and nature recreation	- Any activity which can damage the main functions of a forest area	Law No. 5/ 1990 on Conservation of Natural Resources and Ecosystem
Nature Recreation Sea Park/ Taman Wisata Alam Laut	A nature preservation forest area whose principal purpose is tourism and nature recreation		
Grand Forest Park/ Taman Hutan Raya	A nature preservation forest area for native or foreign plant or animal species that are used for research, education, traditional farming, tourism, and recreation	- Any activity which can damage the main functions of a forest area	
Normal Productive Forest/ Hutan Produksi Tetap	A forest area that is neither a wildlife sanctuary nor a nature preservation forest, and whose sum of slope angle, soil type, and rainfall is under 124	- Cut trees, or harvest or collect any forest product in the forest area without any permission or license by authorities - Carry, possess or keep forest products without carrying any legally authorized documentation	Law No. 41/ 1999 on Forestry Law No. 44/ 2004 on Planning of Forestry
Limited Productive Forest/ Hutan Produksi Terbatas	A forest area that is not a wildlife sanctuary, a nature reserve forest, a nature preservation forest, or a hunting park, and whose sum of slope angle, soil type, and rainfall is over 125 and under 174		
Conversion Productive Forest/ Hutan Produksi Konversi	A forest area whose sum of slope angle, soil type, and rainfall is under 124 except wildlife sanctuaries and nature preservation forests. Used for a trans-immigration area, settlement, or farmland.		
State Forest/ Hutan Negara Bebas	A forest located in lands bearing no ownership rights	- Cut trees, or harvest or collect any forest product in the forest area without any permission or license by authorities - Carry, possess or keep forest products without carrying any legally authorized documentation	Law No. 41/ 1999 on Forestry
Another Purpose Area/ Areal Penggunaan Lain	A forest area used for purposes other than forestry	- Any activity which can worsen the environmental quality	Law No. 41/ 1999 on Forestry
Protection Forest Area/ Kawasan Lindung	A forest area with the main function of protecting life-supporting systems for hydrology, such as preventing floods, controlling erosion, preventing sea water intrusion, and maintaining soil fertility		Law No. 41/ 1999 on Forestry
Specific Purpose Forest/ Hutan Fungsi Khusus	A specific forest area used for purposes such as research, education, training, religion, and culture, without damaging forest functions	- Any activity which can damage the main function a forest area	Law No. 41/ 1999 on Forestry
Tideland/ Beting Karang	Sediment land which is exposed to water but always visible from the water surface		

(2) Karst area designated by the decree of the Minister of MEMR

The karst area designated by the decree of the Minister of Mining, Energy, and Mineral Resources (MEMR)[33] is classified into the first class karst area, the second class karst area and the third class karst area. The definition of each class is shown in the table below. The karst area in Sulawesi has not been designated yet.

Table 7.1.3 Definitions of and Regulations on Karst Areas

Class	Definition	Regulations
First class karst	A karst area that meets one or more of the following conditions: - Permanent groundwater source which has hydrological functions such as aquifer, underground river and underground lake - Underground caves and rivers which stretch in many directions and have hydrological and scientific functions - Caves which can be resources for tourism such as ancient structure or growing stalactite - Caves which are socially, economically or culturally important or scientifically valuable	All activities except mining are allowed as long as karst is not damaged.
Second class karst	A karst area that meets one or more of the following conditions: - Karst that stores rain water, supplies water to underground water, controls the level of underground water, and supports hydrological functions - Karst that consists of a network of tunnels of waterless rivers or caves, consists of inactive or damaged stalactite, and is the habitat of economically useful fauna	Upon AMDAL and RKL/ RPL, activities including mining are allowed.
Third class karst	Any karst area which does not meet the conditions above	Activities including mining are allowed.

7.1.3 Water Emission Standards

Water emission standards are defined by the Environment Minister’s Decision No. 51 (1995). Water emission standards for the geothermal industry (Minister of Environment Decree No. Kep-09/ MENLH/ 4/ 1997) are shown in the appendix table.

7.1.4 Exhaust Standards

Exhaust standards from stationary sources are defined by the Minister of Environment Decree No. Kep-13/MENLH/3/1995. Exhaust standards for electricity facilities are shown in the appendix table.

7.1.5 Hazardous and Toxic Waste Standards

The Government Regulation No. 85 (1999) on the Management of Hazardous and Toxic Waste regulates companies’ responsibility for management, procedures for collection, storing, and transporting harmful and toxic waste and penalties for transgressors. The appendix to the regulation provides details on the specific substances categorized as hazardous and toxic waste. Types of toxic waste generated by electricity facilities are shown in the appendix table.

[33] Keputusan Menteri Energi Dan Sumber Daya Mineral Nomor 1456 K/20/Mem/2000

7.2 Scoping

Based on the results of the field survey and interviews, the study team conducted scoping for each impact item. In the scoping, the study team considered which items should be selected for the baseline survey, the pollution load survey, and prediction. Three items including land use are selected for the baseline survey. Eight items including global warming gases are selected for the pollution load survey. Five items including waste are selected for prediction. Due to lack of information in the master plan stage, items such as water pollution and water use and are not selected as prediction items although they are considered big impact items. The items will be figured out again from the feasibility study stage.

Table 7.2.1 Draft Scoping Table

Item	Possible Social and Environmental Impact						Extent of impact /probability[34]	Baseline survey	Pollution load survey[35]	Prediction[35]
	Coal	Natural Gas	MFO	HSD	Hydro	Geo-thermal				
Air pollution	Yes: Exhaust gas	Yes: Exhaust gas	Yes: Exhaust gas	Yes: Exhaust gas	No	Unclear	***	― Lack of information	○ Pollution load by energy source	○ Pollution load estimation
Water pollution	Yes: Water discharge	Yes: Water discharge	Yes: Water discharge	Yes: Water discharge	Yes: Water discharge (SS)	Yes: Water discharge	***	― Lack of information	―	― Review since F/S
Soil pollution	Yes: Improper management of waste and waste water	Yes: Improper management of waste water	Yes: Improper management of waste and waste water	Yes: Improper management of waste and waste water	No	Yes: Improper management of waste and waste water	*	― Lack of information	― Lack of information	―
Waste	Yes: Coal ash	Small: Filter dust	Yes: Waste oil	Yes: Waste oil	Small: Screen dust	Yes: Heavy metal	***	― Lack of information	○ Pollution load by energy source	○ Pollution load estimation
Noise and vibration	Yes: Construction and operation	Yes: Construction and operation	Yes: Construction and operation	Yes: Construction and operation	Yes: Construction	Yes: Construction and operation	*	―	―	― Review since F/S
Ground subsidence	No	No	No	No	No	Unclear		―	―	―
Offensive odors	No	No	No	No	No	Yes: Sulfur smell	*	―	―	― Review since F/S
Geographical features	Small	Small	Small	Small	Yes: Earthwork	Small	*	―	―	― Review since F/S
Bottom sediment	Yes: Sediment contaminated by waste water	Yes: Sediment contaminated by waste water	Yes: Sediment contaminated by waste water	Yes: Sediment contaminated by waste water	Small: Water reservoir and low water section	Yes: Sediment contaminated by waste water	*	―	―	― Review since F/S

34 ***: Big impact and high probability, **: Middle impact and high probability, *: Small impact or low probability

35 ○: Implementation, ―: No implementation

Item	Possible Social and Environmental Impact						Extent of impact /probability[34]	Baseline survey	Pollution load survey [35]	Prediction[35]
	Coal	Natural Gas	MFO	HSD	Hydro	Geo-thermal				
Biota and ecosystem	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	***	○	—	○ Overlay method
Water usage	No	No	No	No	Yes: Low water section	No	**	— Lack of information	—	— Review since F/S
Accidents	Yes: Spill of poisonous substance	Yes: Spill of poisonous substance	Yes: Spill of poisonous substance	Yes: Spill of poisonous substance	Yes: Drowning by discharge water	Yes: Spill of poisonous substance	*	—	—	— Review since F/S
Global warming	Yes: Generation of greenhouse gases	Yes: Generation of greenhouse gases	Yes: Generation of greenhouse gases	Yes: Generation of greenhouse gases	No	No	***	—	○ Pollution load by energy source	○ Pollution load estimation
Involuntary resettlement	Small	Small	Small	Small	Unclear: Depends on the site	Small	***	○	—	○ Overlay method
Local economy such as employment and livelihood	Yes: Increase in employment	Yes: Increase in employment	Yes: Increase in employment	Yes: Increase in employment	Yes: Increase in employment	Yes: Increase in employment	**	—	○ Employment by energy source	○ Pollution load estimation
Land use and utilization of local resources	Small	Small	Small	Small	Unclear: Depends on the site	Small	**	○ Land use map	—	○ Overlay method
Social institutions such as social infrastructure and local decision-making institutions	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site		—	—	—
Existing social infrastructures and services	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site		—	—	—
Poor indigenous population	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	**	○ Poverty map, ethnic map	—	— Review since F/S

Item	Possible Social and Environmental Impact						Extent of impact /probability[34]	Baseline survey	Pollution load survey [35]	Prediction[35]
	Coal	Natural Gas	MFO	HSD	Hydro	Geo-thermal				
Misallocation of benefit and damage	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	*	—	—	— Review since F/S
Local conflict of interests	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	*	—	—	— Review since F/S
Gender	No	No	No	No	No	No		—	—	—
Children's rights	Unclear: Child labor	Unclear: Child labor	Unclear: Child labor	Unclear: Child labor	Unclear: Child labor	Unclear: Child labor	*	—	—	— Review since F/S
Cultural heritage	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	Unclear: Depends on the site	**	○ Cultural heritage map	—	— Review since F/S
Infectious diseases such as HIV/AIDS	Yes: Infectious disease brought by construction workers	Yes: Infectious disease brought by construction workers	Yes: Infectious disease brought by construction workers	Yes: Infectious disease brought by construction workers	Yes: Infectious disease brought by construction workers	Yes: Infectious disease brought by construction workers	*	—	—	— Review since F/S

7.3 Methodology and Process

In the survey stage, the study team conducted a baseline survey and a pollution load survey. In the prediction stage, the study team conducted an impact assessment by item and comparison scenarios. Figure 7.3.1 shows the process of survey and prediction.

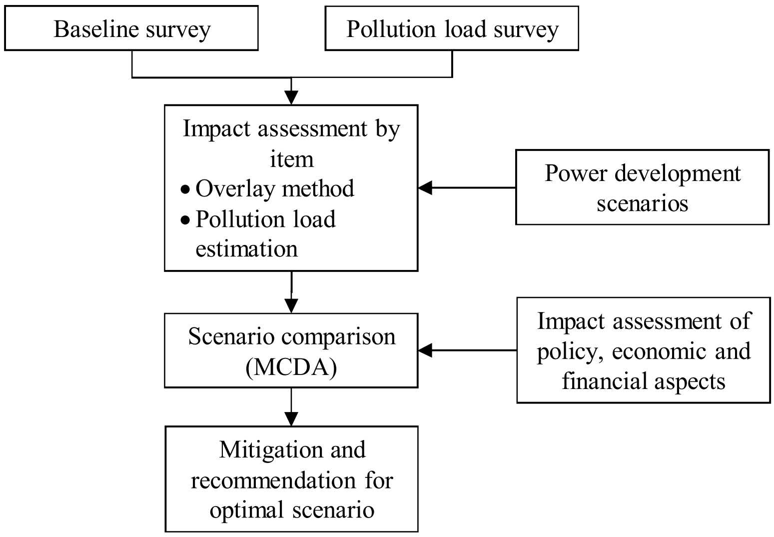


Figure 7.3.1 Process of Survey and Prediction

7.3.1 Baseline Survey

The baseline survey means environmental data collection in Sulawesi Island excluding small islands. After scoping, the following five items are selected as the survey items: (1) biota and ecosystem, (2) involuntary resettlement, (3) land use and utilization of local resources, (4) poor indigenous population, and (5) cultural assets. For each item, the extent of environmental impact depends on the condition of the site. The results of surveys were arranged in maps.

7.3.2 Pollution Load Survey

The pollution load survey involves the estimation of pollution load for each scenario. After scoping, the following four items are selected as survey items: (1) air pollution, (2) water pollution, (3) waste, and (4) global warming. For each item, the extent of the environmental impact does not depend on the condition of the site.

7.3.3 Impact Assessment by Item

The impact assessment by item means absolute environmental impact evaluation for each scenario by item or comparative environmental impact evaluation for two scenarios. After scoping, 14 evaluation items are selected. Economic and financial items include (1) consistency with the national electricity policy, (2) utilization of local energy, (3) economic efficiency, (4) total investment cost, (5) uncertainty of operation cost, (6) operability, and (7) uncertainty of energy production. Social items are the following three: (8) involuntary resettlement, (9) local economy such as employment and livelihood, and (10) land use and utilization of local resources. Environmental items are the following four: (11) air pollution, (12) waste, (13) biota and ecosystem, and (14) global warming.

(1) Overlay method

The overlay method is a prediction method that overlays a baseline map and a scenario map and predicts the impact area. The items to be predicted are as follows: (13) biota and ecosystem, (8) involuntary resettlement, and (10) land use and utilization of local resources.

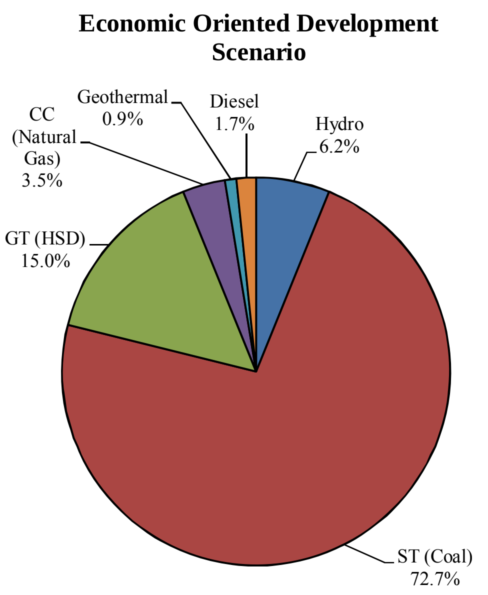
(2) Pollution load estimation

Pollution load estimation is a method for predicting the total pollution load in each scenario. In order to calculate the value of the impact, the unit table and energy production of each energy source are used. The estimation items are (9) local economy such as employment and livelihood, (11) air pollution, (12) waste, and (14) global warming,

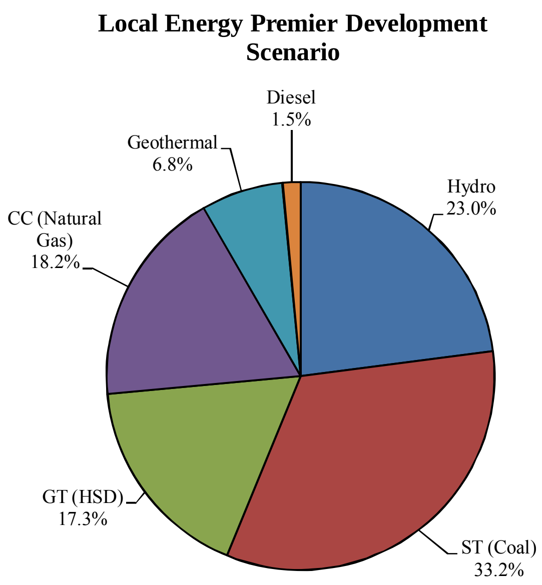
7.3.4 Scenario comparison

(1) Compared scenarios

The compared scenarios are the Economic Oriented Development Scenario and the Local Energy Premier Development Scenario. More than 70% of energy generated in the Economic Oriented Development Scenario consists of power from coal thermal power plants. On the other hand, the percentages of geothermal and hydropower are relatively high in the Local Energy Premier Development Scenario.

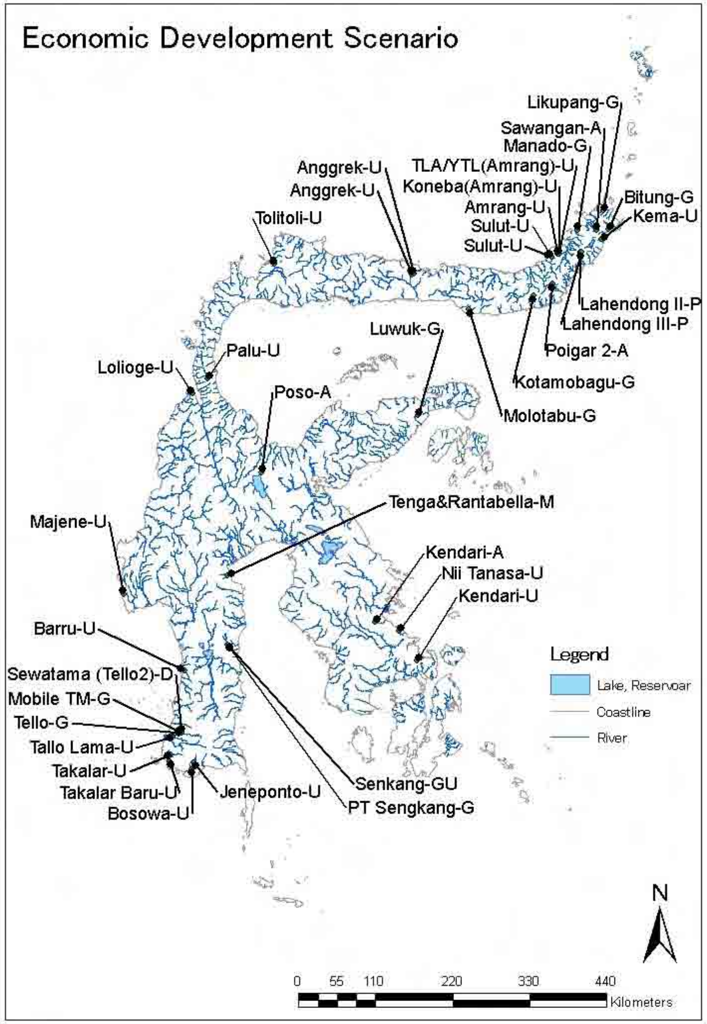


(a) Economic Oriented Development Scenario

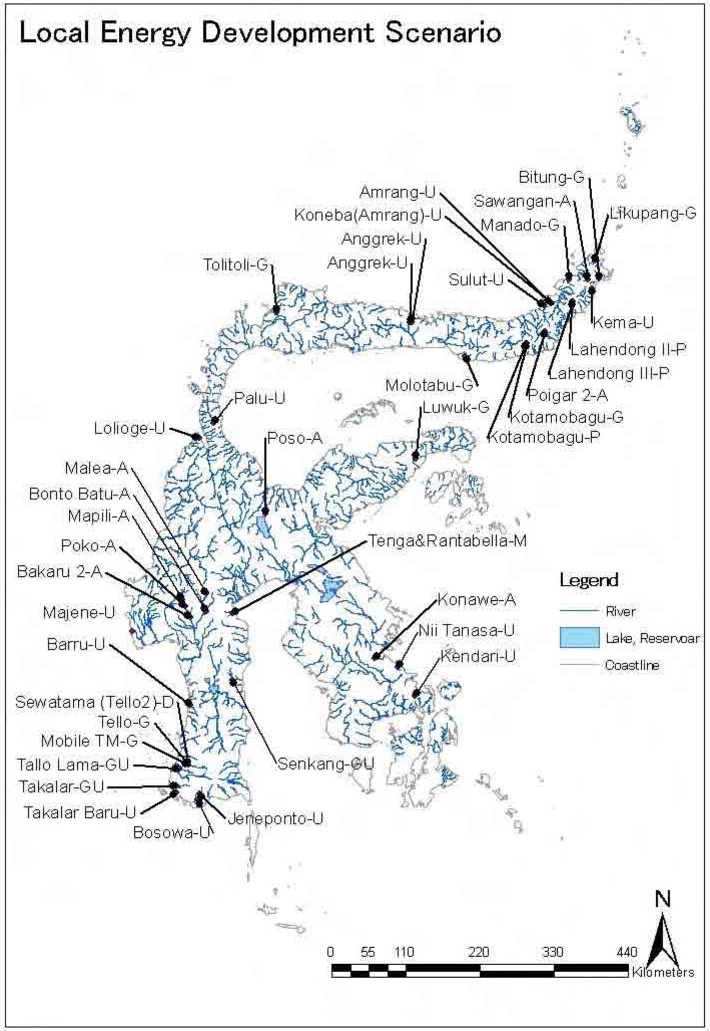


(b) Local Energy Premier Development Scenario

Figure 7.3.2 Share of Energy Source



(a) Economic Oriented Development Scenario



(b) Local Energy Premier Development Scenario

Figure 7.3.3 Location of Power Plants

(2) Comparative Method

Scenario comparison is a way of comparing two scenarios from multiple directions by using the following table. The items for the criteria are the same as the 14 items in the impact assessment. The criteria are classified as economic and financial items, social items, and environmental items.

Table 7.3.1 Form of the Comparative Table

Criteria		**Economic Oriented Development Scenario**	**Local Energy Premier Development Scenario**
Economic and financial items	(1) Consistency with the national electricity policy		
	(2) Utilization of local energy		
	(3) Economic efficiency		
	(4) Total investment cost		
	(5) Uncertainty of operation cost		
Social items	(6) Involuntary resettlement		
	(7) Local economy such as employment and livelihood, etc.		
	(8) Land use and utilization of local resources		
Environmental items	(9) Air pollution		
	(10) Waste		
	(11) Biota and ecosystem		
	(12) Global warming		
Overall Rating			

7.3.5 Mitigation and Recommendations for Optimal Scenario

The study team considered mitigation and recommendations during the feasibility study stage for the selected optimal scenario.

7.4 Description of the Project Site

7.4.1 Geography

The area of Sulawesi Island is 174,000 km^2, which is about 80 percent of the size of Honshu Island of Japan. The island has a mountainous topography with an area 1,500 meters above sea level in the midland. The highest point of the island is Mt. Rantemario, located southeast of Tana Toraja. Most of the active volcanoes are in north Surawesi peninsula. Sulawesi islands are famous for its deep lakes because it is on the boundary between Himarayan organic zone and the circum-Pacific volcanic zone. Lake Poso is the twentieth deepest lake in the world[36]. A topology map of Sulawesi Islands is in the appendix.

7.4.2 Climate

Sulawesi Island is located between latitudes six degrees south and two degrees north, with

[36] John F. McCoy, “GEO-DATA: THE WORLD GEOGRAPHICAL ENCYCLOPEDIA” (2002)

tropical rainforest climate. The island has two seasons: dry and wet. The durations of each season depends on the region. The wet season lasts more than nine months in the area from Mamuju (West Sulawesi) to Kolondale (Central Sulawesi) and around Manado. On the other hand, the wet season lasts less than three months in the area surrounding Tomini Gulf from Central Sulawesi to Gorontalo. The pattern map of wet and dry seasons in Sulawesi is shown in the appendix.

7.4.3 Administrative Boundaries

Sulawesi Island consists of six provinces including North Sulawesi (*Sulawesi Utara*), Gorontalo, Central Sulawesi (*Sulawesi Tengah*), West Sulawesi (*Sulawesi Barat*), South Sulawesi (*Sulawesi Selatan*), and South-East Sulawesi (*Sulawesi Tenggara*). West Sulawesi is a newly province created from part of South Sulawesi on 16th October 2004. All provinces are divided into districts (called *Kabupaten*). Sulawesi Island has 62 districts. The government boundary map is shown in the appendix.

7.4.4 Population

According to the national statistics of 2005, the population of Sulawesi is 15,700,000. 48% of the population is concentrated on South Sulawesi province. The urban population ratio is 28%. Population densities of the southern part of South Sulawesi, the southern part of South East Sulawesi, the northern part of North Sulawesi and around Palu are higher than in other parts. Figure 7.4.1 shows the population of urban and rural areas and population densities.

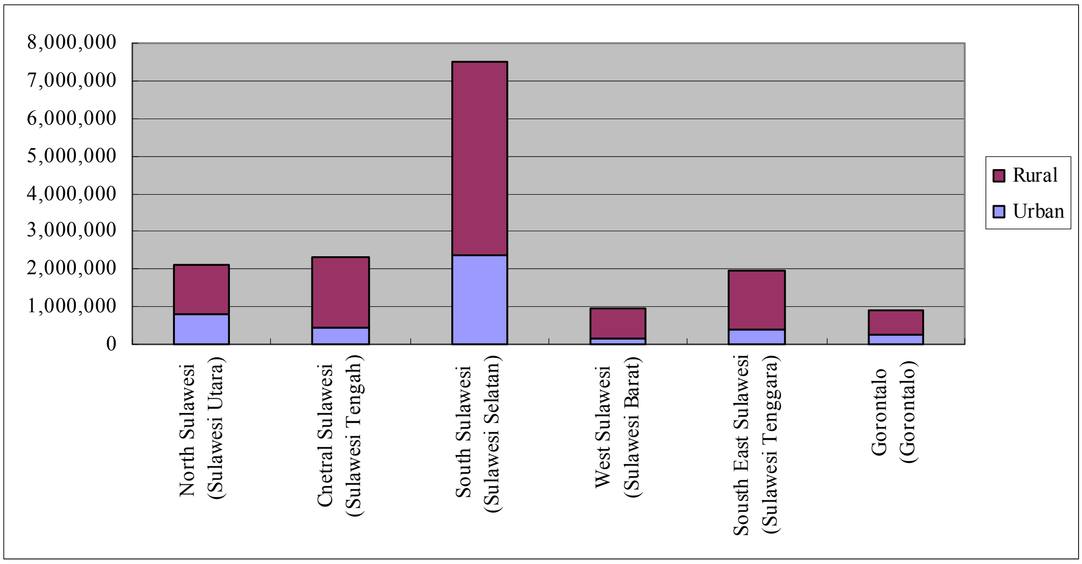


Figure 7.4.1 Population of Sulawesi Islands by Province

7.4.5 Poverty

The Indonesian Human Development Report 2004 by UNDP shows the following poverty rates in the provinces of Sulawesi: 11.2% in North Sulawesi; 24.9% in Central Sulawesi; 15.9%

in former South Sulawesi (including west Sulawesi); 24.2% in South East Sulawesi; and 32.1% in Gorontalo. The poverty rate map is shown in the appendix.

7.4.6 Poor Indigenous Population

Indonesia is famous for its variety of tribes and languages. There are 122 languages in Sulawesi. The Bugis and the Buton who are Muslims live along the coast. The Toraja and the Wana live in the mountainous area. The Toraja maintains its own culture and customs and its village is a famous tourist spot. The language map of Sulawesi is in the appendix.

7.4.7 Gender

With regard to Sulawesi, the Gender Empowerment Measures of the Indonesian Human Development Report 2004 by UNDP are as follows: 58.1 for Central Sulawesi, which is the first of all 30 provinces in Indonesia; 55.1 for North Sulawesi (sixth); 54.1 for Golontaro (10th); 48.0 for South East Sulawesi (18^{th}), 45.6 for former South Sulawesi, including West Sulawesi (23^{rd}).

7.4.8 Cultural Assets

Sulawesi has many cultural assets such as buildings, caves, and old castles. 841 cultural assets are recorded in South Sulawesi, West Sulawesi and South East Sulawesi provinces. North Sulawesi, Gorontalo, and Central Sulawesi province have more than 70 cultural assets, most of which are located near Manado, Poso and Palu.

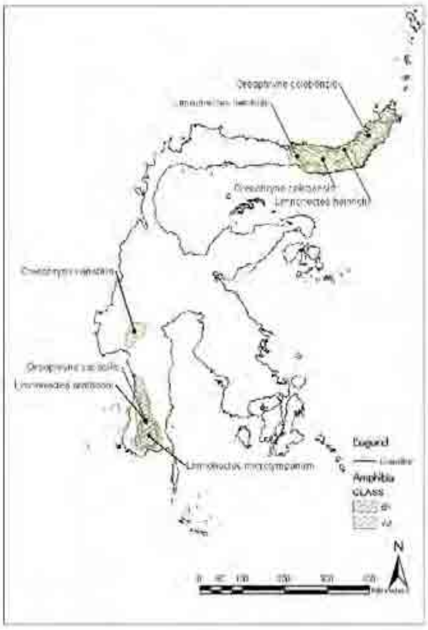
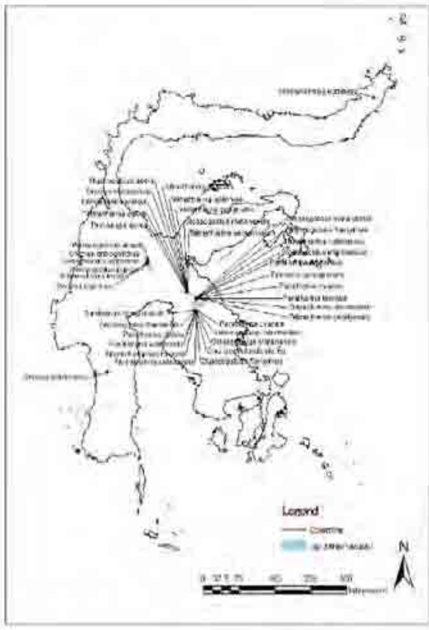
7.4.9 Vegetation

Sulawesi has many types of vegetation such as mangrove, wetland forest, and farmland. Inland forest is mainly seen in mountainous areas with the altitude of more than 500m. Farmland and plantation are seen in sub-mountainous areas. Rice fields are in South Sulawesi province. The forest area in Sulawesi shrank from 11.27 ha to 9.00 million ha from 1985 to 1997. The main causes of the deforestation are forest fire, illegal logging, illegal incursions, and forest land diversion. The appendix shows a vegetation map and the distribution of the forest remaining as of 1997.

7.4.10 Flora, Fauna, and Rare Species

The biota of Sulawesi is very unique. It has both Asian and Australian biota because the island was formed from two islands originating from the Asian continent and the Australian continent. The island also has many indigenous species that exist only in Sulawesi as the island did not connect with the continents after the combination. These indigenous species are being lost due to increasing population and deforestation. The World Conservation Union (IUCN) identifies 170 of these species as critically endangered, 189 as endangered, and 498 as vulnerable. Habitats of the rare species are not yet clear. Table 7.4.1 shows the latest information on the habitats.

Table 7.4.1 Distribution of Rare Species

 Mammalia	 Reptilia
 Amphibia	 Fish

Note: Endangered (EN): A taxon is classified as endangered when the best available evidence indicates that it meets any of the criteria A to E for endangered (see Section V), and it is therefore considered to be facing a very high risk of extinction in the wild.

Vulnerable (VU): A taxon is classified as vulnerable when the best available evidence indicates that it meets any of the criteria A to E for vulnerable (see Section V), and it is therefore considered to be facing a high risk of extinction in the wild.

7.5 Pollution Load Survey

7.5.1 Air Pollution

(1) Contribution ratio of electricity sector to air pollution

Air pollution is a major problem in Indonesia's major cities such as Jakarta for which the electricity sector bears a large responsibility. This is because thermal electric power plants fueled by coal, heavy oil, diesel oil, and natural gas emit large amounts of gas. The electricity sector accounted for 32% of NO_2 emissions from energy utilization in Indonesia in 2003. Emissions in the transportation sector grew 203% from 1990 to 2003 while the growth rate of emissions was more than 270% in the electricity and industrial sectors. Thus emissions from the electricity sector contribute a great deal to the air pollution of Indonesia, and the weight of its contribution is increasing every year.

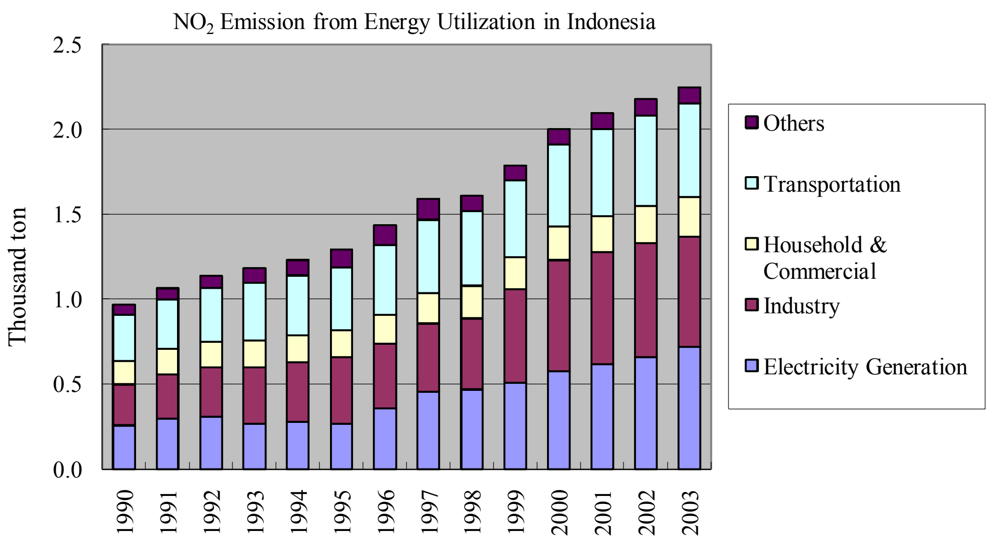
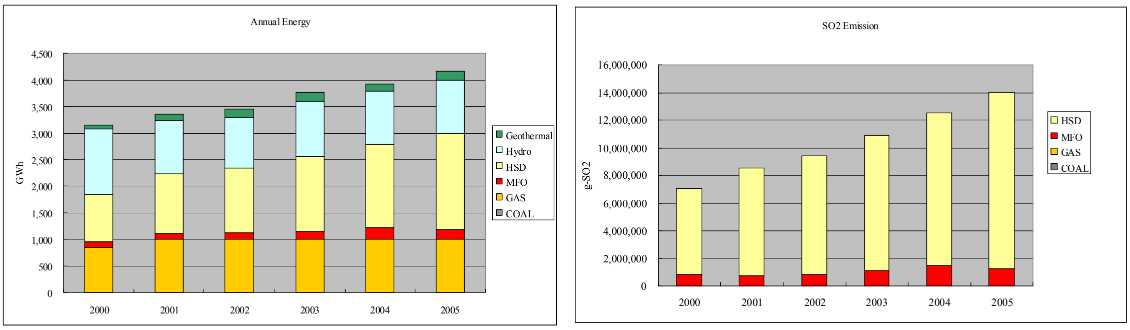


Figure 7.5.1 NO_2 Emission from Energy Utilization in Indonesia

(2) Contribution rate of diesel thermal plants to air pollution

The majority of emissions from electrical power plants in Sulawesi come from diesel electrical power plants. Energy produced by diesel electrical power plants accounts for 30-45% of the total energy in Sulawesi. However, SO_2 emissions from diesel electric plants account for 90% of the total SO_2 emissions from electrical power plants. Although the total electricity generation in Sulawesi increased 132% from 2000 to 2005, the SO_2 emission growth rate from the diesel plants was 198%.

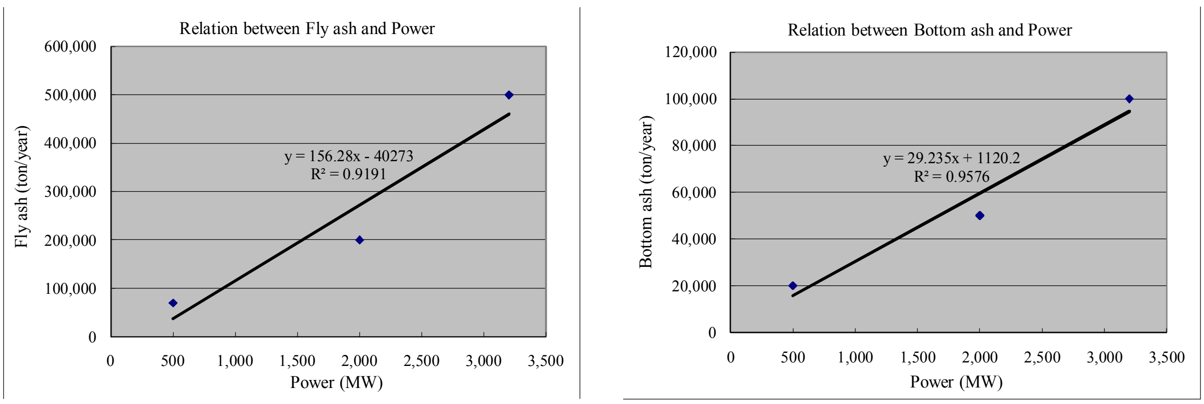


(a) Annual energy produced (b) SO_2 emission

Figure 7.5.2 Power Generation and SO_2 Emission in Sulawesi

7.5.2 Waste

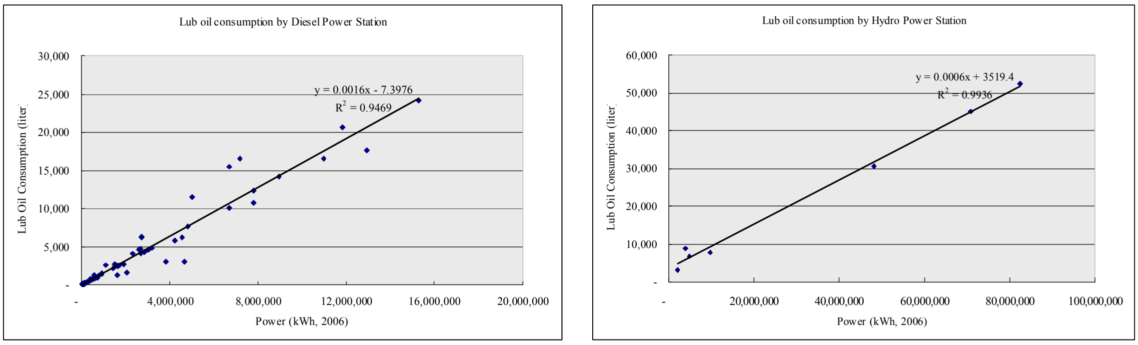
Based on the report of the Indonesia State Ministry of Environment, hazardous waste in rural areas is mainly generated by electrical power plants[37], although hazardous waste in Jakarta is mainly generated by mining or the chemical industry. The main types of waste from electrical power plants are fly ash from coal thermal plants and waste oil. Figure 7.5.3 shows the relationship between the volume of bottom ash and fly ash from coal power plants and the power generation capacity of existing Indonesian power plants. According to the statistics of 2006, the lubricating oil used in Sulawesi is 833,292 liters for diesel power plants, 154,478 liters for hydropower plants, and 105,424 liters for geothermal power plants. Figure 7.5.4 shows the relationship between the volume of lubricating oil and the power generation capacity of the power plants in Sulawesi in 2006. Many industries do not dispose of hazardous waste appropriately due to financial reasons. In the electricity sector, 68% of fly ash and bottom ash and 16% of waste grease are not disposed of properly (see Table 7.5.1).



(a) Fly ash (b) Bottom ash

Figure 7.5.3 Bottom Ash/ Fly Ash from Coal Power Plant and Power Generation Capacity in Indonesia

[37] The State Ministry of Environment: The State of Environment Report in Indonesia 2005



(a) Diesel Power Plants (b) Hydropower Plants

Figure 7.5.4 Lubricants and Power Generation Capacity in Sulawesi

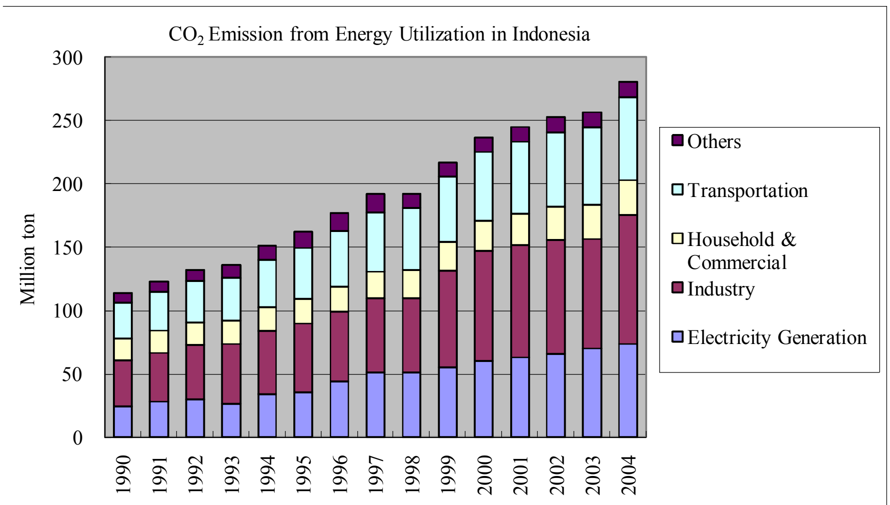
Table 7.5.1 Amount of Fly Ash and Waste Grease Treated

Type of waste	Unit	Amount generated	Amount treated	Amount untreated
Fly ash and bottom ash	Ton	427,466	138,696	288,769
Waste grease	Liter	76,800	64,400	12,400

7.5.3 Global Warming

According to Wetland International (2006)[38], if peatland emissions are included, Indonesia is ranked third among countries based on their total CO_2 emissions after the US and China. When we look at CO_2 emissions from energy utilization by sector, we see that the electricity sector accounted for 26.2% in 2004. Emissions increased 229% in the transportation sector from 1990 to 2004, 278% in the industrial sector, and 304% in the electricity sector.

In terms of CO_2 emissions in Sulawesi, emissions from diesel thermal plants have grown significantly, accounting for over 70% of the total emissions in 2005.



[38] Peatland degradation fuels climate change, 06.11.2 (http://www.wetlands.org/publication.aspx?ID=d67b5c30-2b07-435c-9366-c20aa597839b)

Figure 7.5.5 CO$_2$ Emissions from Energy Utilization in Indonesia

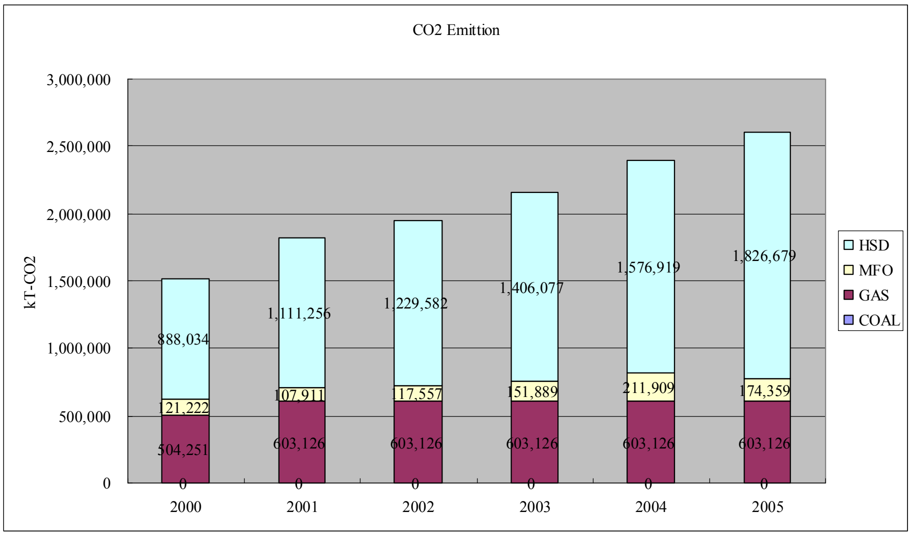
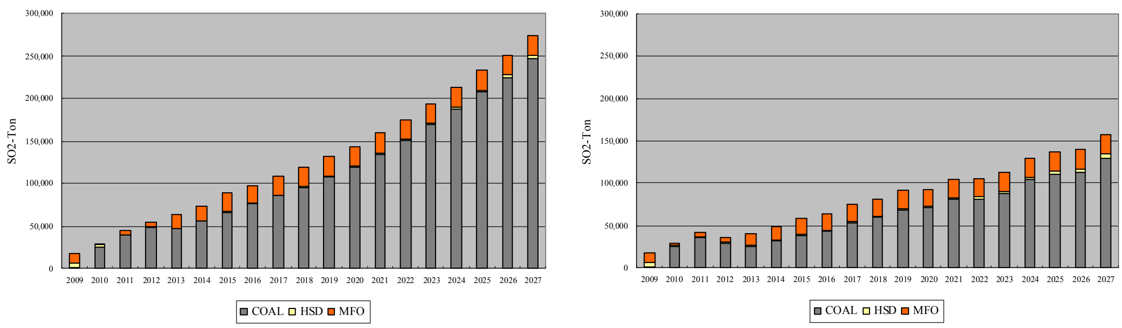


Figure 7.5.6 CO$_2$ Emission in Sulawesi Island

7.6 Impact Assessment by Item

7.6.1 Air Pollution

The emission volume of SO_2 is estimated for impact assessment of air pollution. The total estimated volume of SO_2 from 2006 to 2027 is 2,508,406 tons for the Economic Oriented Development Scenario and 1,603,930 tons for the Local Energy Premier Development Scenario. The estimated volume of the Economic Oriented Development Scenario is about 1.5 times the Local Energy Premier Development Scenario. The changes of the estimated volume over the years are shown in Figure 7.6.1.



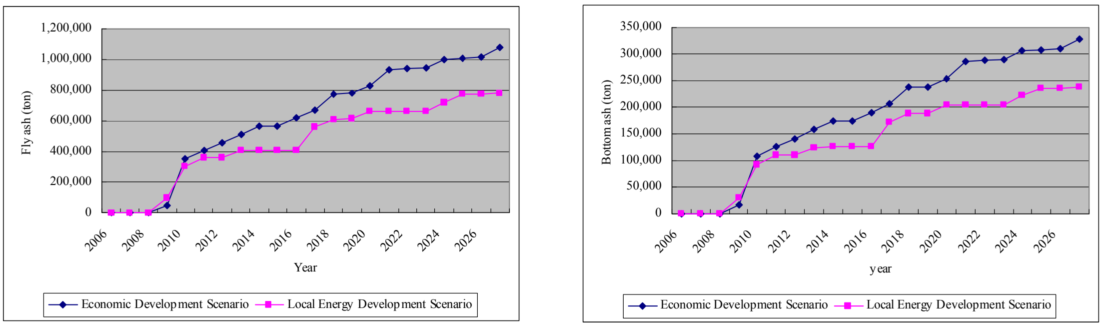
(a) Economic Oriented Development Scenario (b) Local Energy Premier Development Scene

Figure 7.6.1 Power Generation and SO$_2$ Emission in Sulawesi

7.6.2 Waste

Volumes of fly ash and bottom ash are estimated for impact assessment of waste. A volume is calculated using the relationship formula between volumes and generating power. The estimated volume of fly ash is 13,476,376 tons for the Economic Oriented Development

Scenario and 10,201,776 tons for the Local Energy Premier Development Scenario. The estimated volume of bottom ash is 4,140,399 tons for the Economic Oriented Development Scenario and 3,143,714 tons for the Local Energy Premier Development Scenario.



(a) Fly ash (b) Bottom ash

Figure 7.6.2 Estimated Fly Ash and Bottom Ash from Planned Coal Power Plants

7.6.3 Biota and Ecosystem

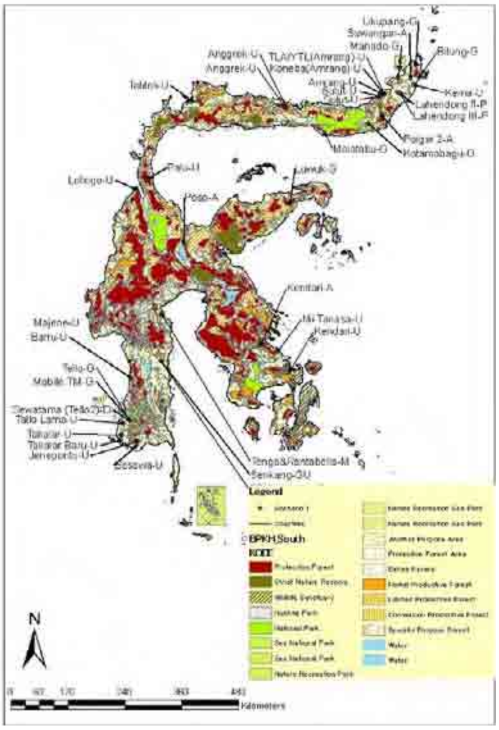
Impacts on protected areas and rare species are estimated for biota and ecosystem.

(1) Impact on protected area

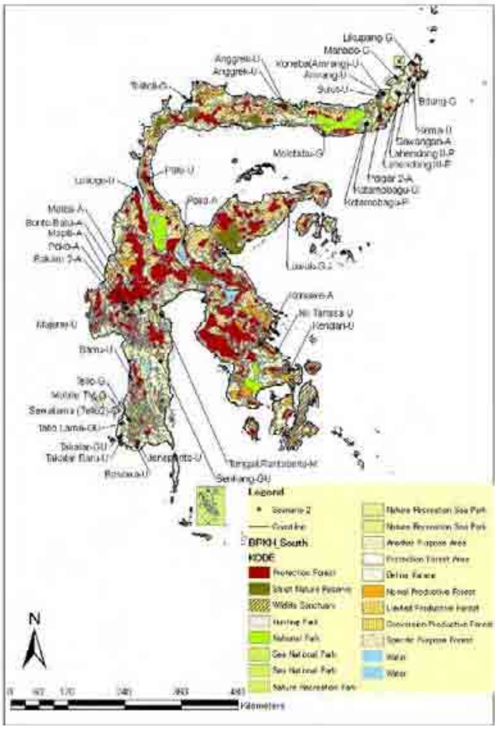
Impacts on protected areas are estimated by number of overlapping projects in the areas. However, except hydropower plants, locations of most power plants have not been clearly identified. The maps did not help in estimating impacts on the projected areas were not accurate enough in locations (Figure 7.3.3), because the margins of error are plus or minus 10 km. Thus impact assessment was done only for the hydropower projects whose locations are relatively clear. The existing EIA reports are referred to. The numbers of possibly affected protected areas are one for the Economic Oriented Development Scenario and four for the Local Energy Premier Development Scenario.

Table 7.6.1 Protected Area and Project Site

Name of power plant	Existence or nonexistence of protected area in the project site	Risk of illegal logging	Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Poigar 2	None (source: PLN)	Low	○	○
Sawangan	None (source: National forest map)	(Unknown)	○	○
Poso 3	None (source: PLN)	(Unknown)	○	○
Bonto Batu	None (source: National forest map)	(Unknown)	－	○
Poko	Exists: a part of protected forest[39]	(Unknown)	－	○
Bakaru 2	Exists: (source: National forest map)	(Unknown)	－	○
Mapili	Exists: (source: National forest map)	(Unknown)	－	○
Malea	None (source: PLN)	(Unknown)	－	○
Konaweha 3	Exists: 1,153 ha of Protected forest[40]	High	○	○



(a) <u>Economic Oriented Development Scenario</u>



(b) <u>Local Energy Premier Development Scene</u>

Figure 7.6.3 Planned Project Sites and Protected Area

[39] Draft Laporan Rencana Pemantauan Lingkungan (RPL) PLTA Poko Sulawesi Selatan, 1996. Departemen Pertambangan dan Energi PT. PLN (Persero).

[40] Laporan Akhir Pekerjaan Pra Studi Kelayakan PLTA Konaweha Sulawesi Tenggara, 1995. PT. PLN (Persero) Direktorat Perencanaan Divisi Perencanaan Sistem.

(2) Impact on rare species

Impacts on rare species are estimated by overlaying a distribution map and a planned project map. The existing EIA reports are also consulted. The numbers of possibly affected rare species are 30 for the Economic Oriented Development Scenario and 31 for the Local Energy Premier Development Scenario.

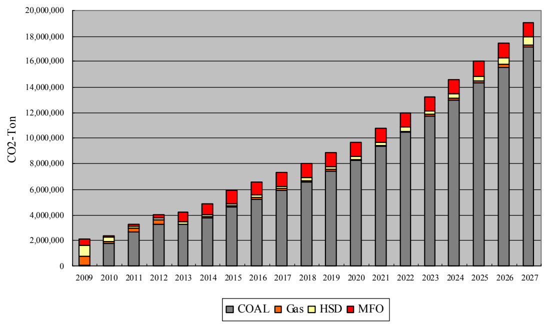
Table 7.6.2 Planned Hydropower Plants and Affected Rare Species

Name of Power Plant	Name of Rare Species	Source	Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Poigar 2	*Anguilla sp* (Ikan Sidat) *Bubulus clepressicornis* *Muntiacus muntjak* *Cervus unicolor* *Macaca nigeescens* *Phyton reticulatus*	EIA Report[41]	○	○
	Macaca nigra	IUCN		
Sawangan	*Macaca nigra* *Bubalus quarlesi*	IUCN	○	○
Poso 3	*Macaca sp* *Presbytisaugulla* *Phalanger sp* *Cervus timorensis* *Tarsus spectrum* *Tarsius sp* *Vrocodillus sp.*	EIA Report[42]	○	○
	Adrianichthys kruyti *Weberogobius amadi* *Xenopoecilus poptae* *Xenopoecilus oophorus* *Oryzias orthognathus* *Oryzias nigrimas*	LIPI	○	○
Konaweha 3	*Babyrousa babyrousa* *Macaa ochreata* *Bubalus depresicornis* *Cervus timorensis* *Hydrosaurus amboniensis* *Varanus salvator* *Phyton reticulates* *Crosocilus porosus* *Anhinga melanogaster* *Halycon chloris*	PLN[40]	○	○
Malea	*Bubalus quarlesi*	IUCN		○
Mapili	*Oreophryne variabilis*	LIPI		○
Poko	*Oreophryne variabilis*	LIPI		○
Bakaru 2	*Oreophryne variabilis*	LIPI		○

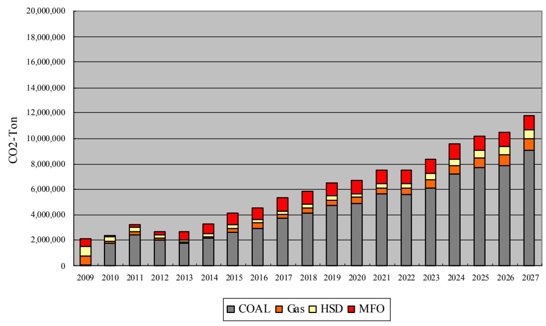
41 Review Main Report Enviromental Impact Assessment (Andal) PLTA Poigar 2 (2 x 16 MW) North Sulawesi Province, 2005. PT. Perusahaan Listrik Negara (Persero) Proyek Induk Pembangkit dan Jaringan Sulawesi.
42 Final Report Environmental Impact Assessment Poso -3 Hepp Central, 1999. Departemen Pertambagan dan Energi PT. PLN (Persero).

7.6.4 Global Warming

The volume of CO_2 emissions is calculated for assessment of global warming. The estimated amount of emissions from 2006 to 2027 is 175,947,616 tons for the Economic Oriented Development Scenario and 120,105,839 tons for the Local Energy Premier Development Scenario. The amount for the Economic Oriented Development Scenario is 1.5 times of the Local Energy Premier Development Scenario. The figure below shows the yearly changes of CO_2 emissions.



(a) Economic Oriented Development Scenario



(b) Local Energy Premier Development Scene

Figure 7.6.4 Estimated CO_2 Emission

7.6.5 Involuntary Resettlement

Numbers of involuntary resettlement cases by hydropower projects are based on the existing Environmental Impact Assessment Reports (ANDAL). The resettlement cases by thermal power plants are not counted because the plant sites are unclear. Possible numbers of households to be resettled are at least 1,652 in the Economic Oriented Development Scenario and 1,845 in the Local Energy Premier Development Scenario. The number in the Local Energy Premier Development Scenario would be larger than in the Economic Oriented Development Scenario, even if the numbers of households to be resettled in projects such as Bonto Batu, Malipi, and Sawangan are unclear.

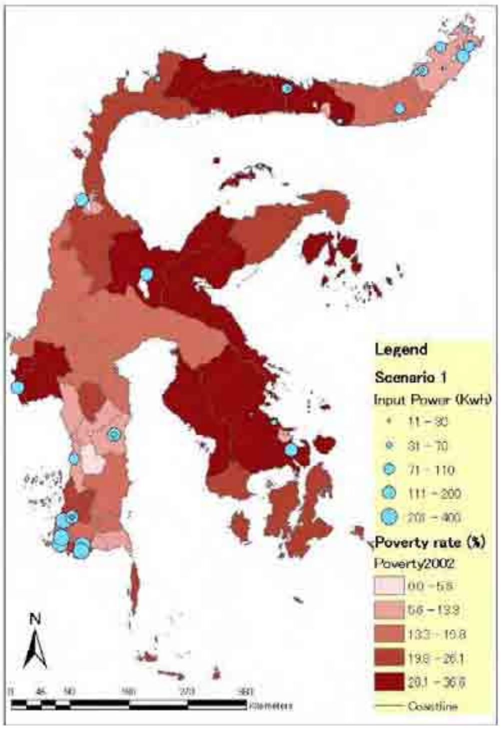
Table 7.6.3 Estimated Number of Resettlement Cases

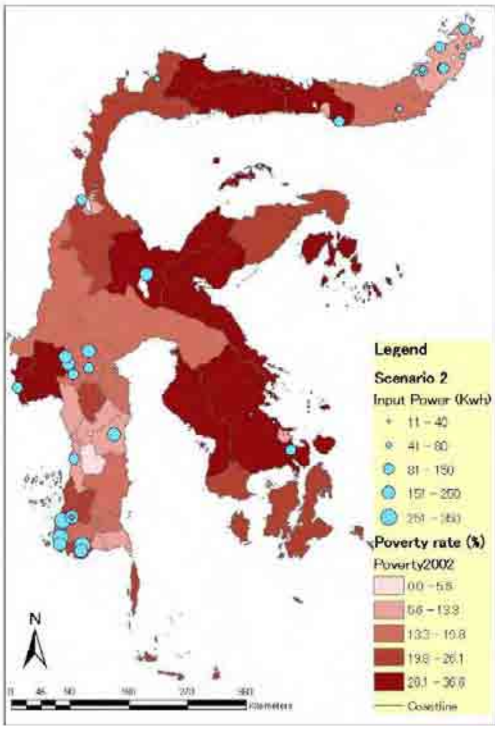
Name of hydropower plant	Estimated number of households that needed resettlement	Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Poigar 2	0[41]	○	○
Poso 3	75	○	○
Poko	168		○
Bakaru 2	0		○
Bonto Batu	unknown		○
Malea	25[43]		○
Mapili	unknown		○
Konaweha 3	1,577[40]	○	○
Sawangan	unknown	○	○
Total		1,652	1,845

7.6.6 Local Economy such as Employment and Livelihood

Impacts on the local economy are estimated by overlaying a generation planning map and a poverty map. Development of power plants creates a fair amount of employment during construction and operation, and thus contributes to the local economy around the power plants. The extent of contribution is higher in the poverty areas than in the urban areas. Thus the job creation impact in the Local Energy Premier Development Scenario is bigger than that in the Economic Oriented Development Scenario because many project sites are located in high poverty rate areas.

[43] Social Acceptance Study and Resettlement and Rehabilitation Plan Study PLTA Malea Tana Toraja Regency South Sulawesi Province, 1998. PT. PLN. (Persero) Kantor Pusat.





(a) <u>Economic Oriented Development Scenario</u>　　(b) <u>Local Energy Premier Development Scene</u>

Figure 7.6.5　　Input Power and Poverty Rate

7.6.7 Land Use and Utilization of Local Resources

Affected areas are quoted from references such as feasibility study reports. Estimated affected areas are 3,128 ha of farmland and 2,267 ha of forests in the Economic Oriented Development Scenario, and 3,239 ha of farmland and 3,007 ha of forests in the Local Energy Premier Development Scenario. The affected area in the Local Energy Premier Development Scenario is larger than the Economic Oriented Development Scenario. Affected areas in some planned projects are unclear. But there is no possibility that the affected area in the Economic Oriented Development Scenario will be larger than in the Local Energy Premier Development Scenario, even if the affected areas in such projects are identified.

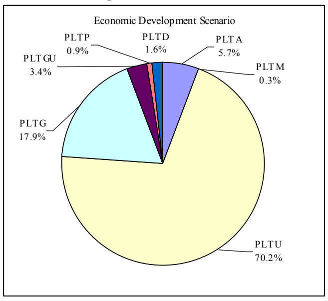
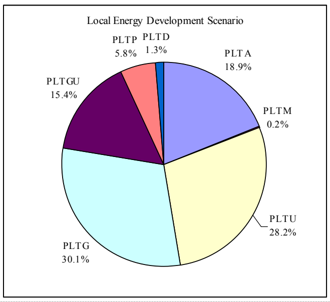
Table 7.6.4 Impacted Area of Agricultural Land and Forest

Name	Reservoir Area (ha)	Affected Farmland (ha)		Affected Forest Area (ha)	
		Economic Oriented Development Scenario	Local Energy Premier Development Scenario	Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Bakaru 2	200	-	(unknown)	-	(unknown)
Bonto Batu	0	-	(unknown)	-	(unknown)
Konaweha 3[40]	4,906	3,003	3,003	1,903	1,903
Malea		-	60	-	0
Mapili		-	(unknown)	-	(unknown)
Poigar 2[39]		3	3	54	54
Poko	860	-	50.0	-	740
Poso 3	35,900	123	123	310	310
Sawangan		(unknown)	(unknown)	(unknown)	(unknown)
Total		3,129	3,239	2,267	3,007

7.7 Comparison of the Scenarios

Table 7.7.1 summarizes the comparison of the two scenarios in economic, social, and environmental aspects. The results in “Total investment cost”, “Involuntary resettlement”, “Land use and utilization of local resources”, and “Biota and ecosystem” suggest that the Economic Oriented Development Scenario is preferable. On the other hand, the results in “Consistency with the national electricity policy”, “Utilization of local energy”, “Economic efficiency”, “Uncertainty of operation cost”, “Local economy such as employment and livelihood”, “Air pollution”, “Waste”, and “Global warming” suggest that Local Energy Premier Development Scenario is preferable.

Table 7.7.1 Comparative Table

Criteria		Economic Oriented Development Scenario	Local Energy Premier Development Scenario
Economic and Financial Items	(1) Consistency with the national electricity policy	△ Energy diversity is low. Most of generation depends on coal thermal generation.  	○ Energy diversity is high. Power generation is divided into hydro, coal, gas, and geothermal. 
	(2) Utilization of local energy	△ The percentage of renewable energy is low because of high dependence on coal power plants.	○ The percentage of renewable energy sources such as hydropower and geothermal is relatively high.
	(3) Economic efficiency	△ Economic efficiency is relatively low because of low local procurement.	○ Economic efficiency is relatively high because of high local procurement.
	(4) Total investment cost	○ Investment cost: 5.1 (billion US$)	△ Investment cost: 5.8 (billion US$)
	(5) Uncertainty of operation cost	△ Easily influenced by change in fuel price due to high dependence on thermal power plants	○ Relatively unaffected by change in fuel price due to high percentage of hydropower plants
Social Items	(6) Involuntary resettlement	○ More than 1,652 households	△ More than 1,845 households
	(7) Local economy such as employment and livelihood	△ Contribution to creating jobs in urban area	○ Contribution to creating jobs in poverty areas
	(8) Land use and utilization of local resources	○ Affected farmland: more than 3,129 ha ○ Affected forest area: more than 2,267 ha	△ Affected farmland: more than 3,239 ha △ Affected forest area: more than 3,007 ha
Environmental Items	(9) Air pollution	△ 2,508,406 tons	○ 1,603,930 tons
	(10) Waste	△ Fly ash: 13.5 MT △ Bottom ash: 4.1 MT	○ Fly ash: 10.2 MT ○ Bottom ash: 3.1 MT
	(11) Biota and ecosystem	○ Number of affected protected areas: 1 ○ Number of affected rare species: 30	△ Number of affected protected areas: 4 △ Number of affected rare species: 31
	(12) Global warming	△ CO_2 emission: 176 MT	○ CO_2 emission: 120 MT
Overall Rating		△	○

7.8 Mitigation and Recommendations for Optimal Scenario

Mitigation and recommendations are considered for the Local Energy Premier Development Scenario. Items considered are sedimentation, resettlement, and biota and ecosystem.

7.8.1 Mitigation for Sedimentation

Sedimentation might be problematic for some hydropower plants. Effective mitigation measures depend on the plants' location. Suitable mitigation measures should be selected during the feasibility study stage for each project. Mitigation measures in Japan include spilling out facilities, excavation, flood bypass tunnel, and sedimentation dam. The following are characteristics of the measures.

(1) Spilling out facilities

A spilling out facility flushes out sedimentation in the dam using natural water power. The spilling out gate is usually closed. The gate is open during flood and sedimentation is flushed out. This facility is used at Unazuki dam and Dashidaira dam, both of which are in Toyama prefecture, Japan.

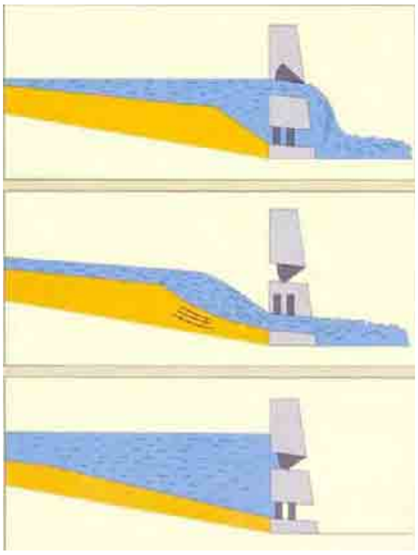


Figure 7.8.1 Example of Spilling Out Facility (Unazuki Dam, Japan)[44]

(3) Keeping reservoir capacity by excavation

Excavation is a way of removing sedimentation by using means such as a dredge boat. Excavated sedimentation is usually used for construction material. In Japan, excavations are done at Sakuma dam in Shizuoka prefecture and Miwa dam in Nagano prefecture.

Figure 7.8.2 Image of Excavation[45]

(4) Flood bypass tunnel

A flood bypass tunnel takes sand and muddy water from the river upstream of the dam and flows them downstream of the dam during flooding. The tunnel prevents sedimentation and turbid water in a reservoir and recovers the natural movement of sand and soil. In Japan, flood bypass tunnels are used Asahi dam in Nara prefecture, Koshibu dam in Nagano prefecture, and Miwa dam in Nagano prefecture.

[44] *Dam Binran 2008* (http://wwwsoc.nii.ac.jp/jdf/Dambinran/binran/TPage/TPTaisya.html)
[45] *Dam Binran* 2008（http://wwwsoc.nii.ac.jp/jdf/Dambinran/binran/TPage/TPTaisya.html）

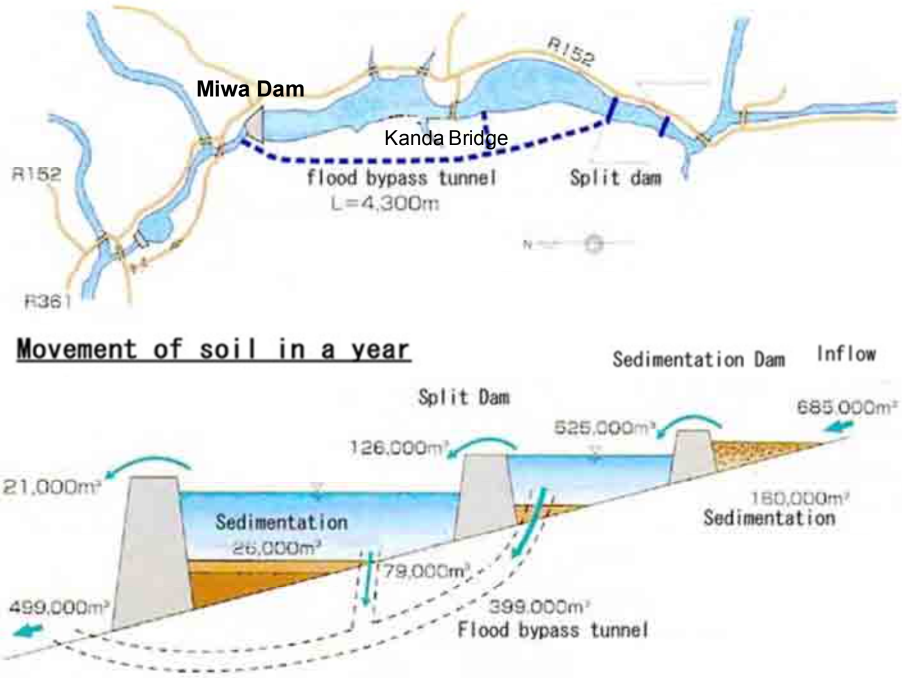


Figure 7.8.3 Example of Flood Bypass Tunnel (Miwa Dam, Japan)[46]

(5) Sedimentation dam

A sedimentation dam is a dam constructed in the river upstream of the main dam in order to prevent inflow of soil and sand into the main dam. Sedimentation in the dam is excavated before the dam loses its function. In Japan, sedimentation dams are used in Shimokubo dam in Gunma prefecture, Nagashima dam in Shizuoka prefecture, Misogawa dam in Nagano prefecture, Miwa dam in Nagano prefecture, and Yuta dam in Iwate prefecture.

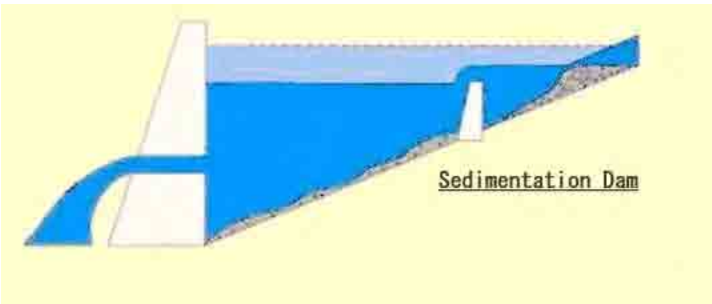


Figure 7.8.4 Example of Sedimentation Dam (Nagashima Dam, Japan)[47]

7.8.2 Resettlement

Resettlement is predicted for Poso 3, Poko, Malea, and Konaweha. Before starting these projects, local land use, livelihoods, customs and culture must be surveyed. A resettlement

[46] Source: brochure of Miwa Dam

[47] *Dam Binran* 2008 (http://wwwsoc.nii.ac.jp/jdf/Dambinran/binran/TPage/TP1178Tyosa1.html)

plan must be prepared by a participatory approach. Not only compensation for land and houses but also vocational training should be considered if the residents must change switch jobs.

7.8.3 Biota and Ecosystem

An impact on some rare species is predicted in the Local Energy Premier Development Scenario. To minimize the impact, a biological study should be done in the following steps. EIA studies also have to be conducted for all the projects because all the EIA reports are expired.

(1) Biological survey before feasibility study

A biological survey should be done before a feasibility study for the projects anticipated for impact on rare species. The biological survey can be a part of an EIA study or wide area survey for some projects before EIA. Target species should include not only species that are likely to be affected but also endangered species whose habitats are unknown. Survey area, duration, and methods must be identified for calculating risks of species' extinction. Population and extinction risks should be calculated. Core area, buffer area and corridor of the home range should be identified. The survey should be done by highly qualified specialists in cooperation with LIPI. The result of this biological survey must be reflected in the feasibility study.

(6) Avoidance of impact in feasibility stage

Based on the result of the biological survey, the environmental specialist is to suggest to the planners a way of avoiding an environmental impact. For example, a facility arrangement plan or a construction road which do not enter habitats of important species might be suggested.

(7) Minimizing impact in feasibility stage

After taking measures to avoid an impact, the environmental specialist is to suggest to the planners a way of minimizing the impact. For example, a facility arrangement plan or construction road which minimizes damage to important habitats of species may be suggested.

(8) Mitigating impact in feasibility study

After taking measures to avoid and minimize the impact, impact mitigation can be considered. For example, a special bridge or tunnel for surface moving animals, a new sanctuary, or an extra fish way might be mitigation measures. However, mitigation measures are the last resort because they are more expensive and ineffective than avoidance or minimizing measures. Thus they should be considered only when avoidance and minimizing measures are fully explored and exhausted.

Appendix 2 Emission Standards in Indonesia

Appendix Table 1 Water Emission Standards of Geothermal Power Plant[48]

Items	Unit	Maximum density
BOD_5	mg/l	100
COD	mg/l	200
Oil content	mg/l	25
Sulfur as H_2S	mg/l	1.0
Ammonia as NH_3-H	mg/l	10
Total phenol	mg/l	0.1
Temperature	ºC	45
pH		6.0-9.0
Max. effluent volume		1,200m^3/1,000m^3 production

Appendix Table 2 Exhaust Fume Standards of Coal Thermal Power Plant[49]

Items	Emission cap (mg/m^3)
1. Total Particulates	150
2. Sulfur Dioxide (SO_2)	750
3. Nitrogen Oxide (NO_2)	850
4. Opacity	20%

Notes:
- Nitrogen Dioxide is specified as NO_2.
- Particle concentration is corrected around 3% O_2.
- Gas volume in standard condition (25˚C and pressure of 1 atm)
- Opacity is used as practical indicator for monitoring and developed to obtain correlation with total particle observation.
- Enforcement of Emission Quality Standard for 95% normal operation time for three months.

Appendix Table 3 Exhaust Fume Standards of Power Boiler[50]

Items	Emission cap (mg/m^3)
1. Total Particulates	230
2. Sulfur Dioxide (SO_2)	800
3. Nitrogen Oxide (NO_2)	1,000
4. Opacity	20%

Notes:
- Nitrogen Dioxide is specified as NO2.
- 7 % oxygen correction for boilers
- Gas volume on dry basis in standard condition (25˚C and pressure of 1 atm)
- Opacity is used as a practical indicator for monitoring and developed to obtain

[48] Kepmen LH Nomor 09/MENLH/4/1997 tentang Perubahan Kepmen LH Nomor 42/MENLH/10/1996 tentang Baku Mutu Limbah Cair Bagi Kegiatan Minyak dan Serta Panas Bumi.

[49] Appendix III B, Decree of the State Minister for Environment, KEP-13/MENLH/3/1995 concerning Emission Standards for Stationary Sources

[50] Appendix I B, II B, IV B, Decree of the State Minister for Environment, KEP-13/MENLH/3/1995 concerning Emission Standards for Stationary Sources

correlation with total particle observation.
- Enforcement of Emission Quality Standard for 95% normal operation time for three months.

Appendix Table 4 Exhaust Fume Standards of Other Industries[51]

Parameters	Emission cap (mg/m^3)
Non-Metals	
1. Ammonia (NH3)	0.5
2. Chlorine Gas (Cl2)	10
3. Hydrogen Chloride (HCl)	5
4. Hydrogen Fluoride (HF)	10
5. Nitrogen Oxide (NO2)	1,000
6. Opacity	35%
7. Total Particulates	350
8. Sulfur Dioxide (SO2)	800
9. Total Reduced Sulfur (TRS)	35
Metals	
10. Mercury (Hg)	5
11. Arsenic (As)	8
12. Antimony (Sb)	8
13. Zinc (Zn)	50
14. Lead (Pb)	12

Notes: Gas volume on dry basis in standard condition (25˚C and pressure of 1 atm)

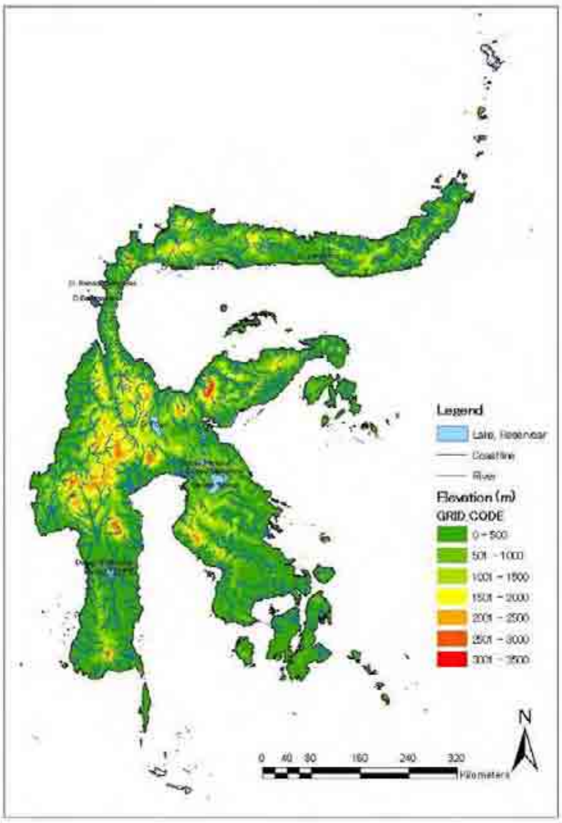
Appendix Table 5 Hazardous Waste from Generation Sources[52]

Waste Code	Type of Industry/ Activity	Explanation of Waste
D220	Oil and natural gas exploration - Exploration and production - Maintenance of production facilities	- Residues of oil emulsions - Drilling mud - Sludge
D222	Mining	- Heavy metal sludge - Solvents
D223	Steam electric power generation, fly ash, bottom ash	

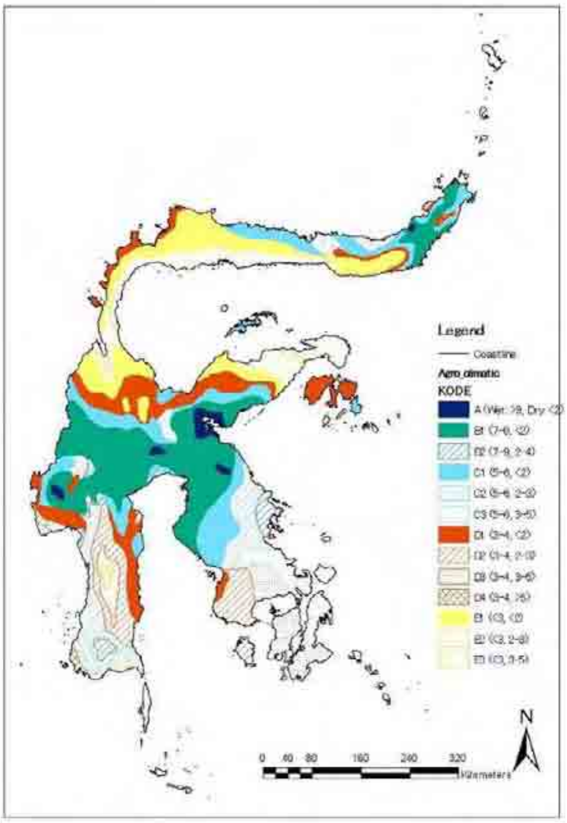
[51] Appendix V B, Decree of the State Minister for Environment, KEP-13/MENLH/3/1995 concerning Emission Standards for Stationary Sources

[52] Peraturan Pemerintah Nomor 85 Tahun 1999 tentang Perubahan Atas Peraturan Pemerintah Nomor 18 Tahun 1999 tentang Pengelolaan Limbah Bahan Berbahaya dan Beracun.

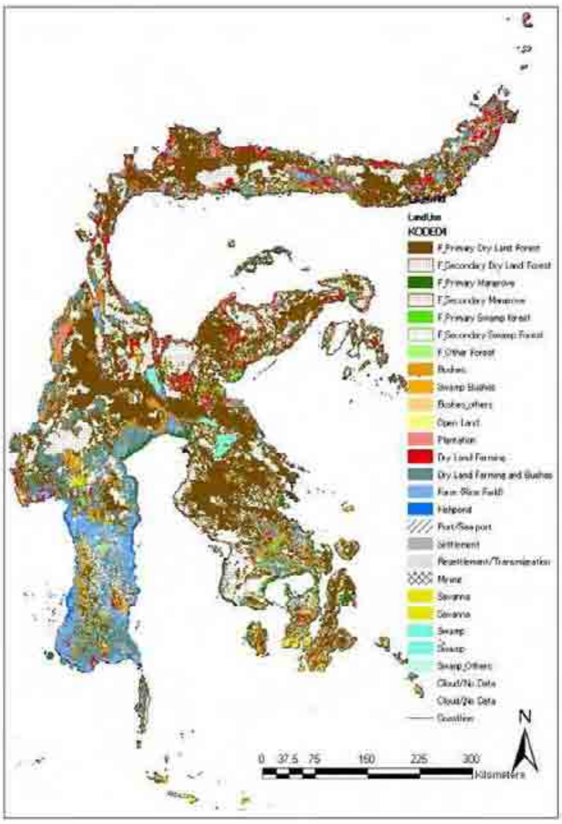
Appendix 3 Environmental Information Map



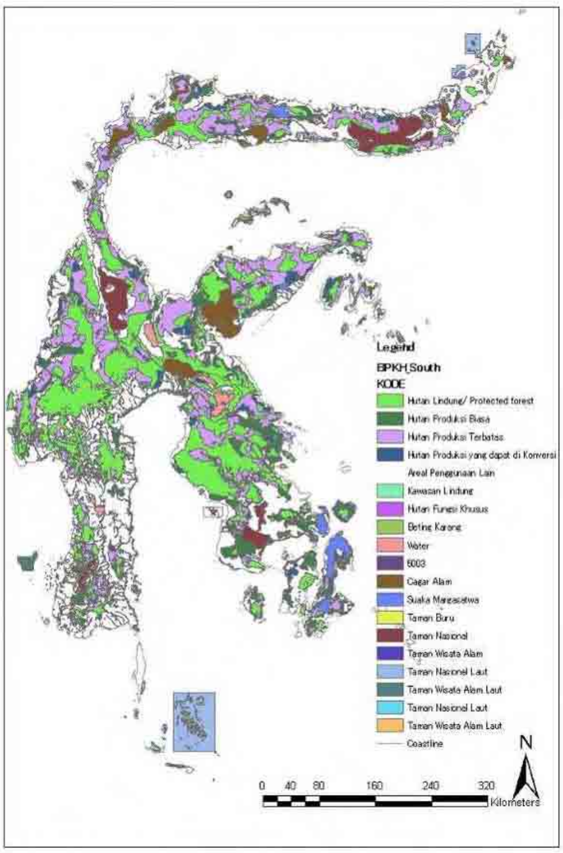
Topography



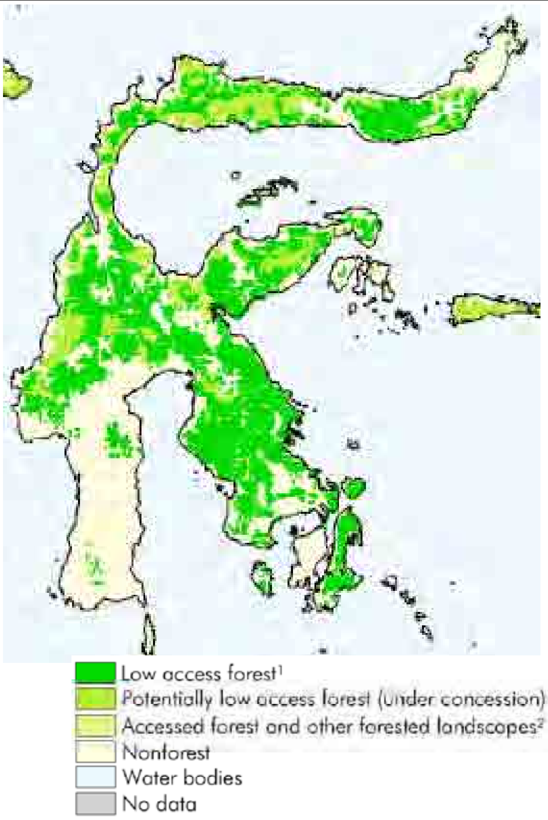
Pattern of Rainy and Dry Seasons



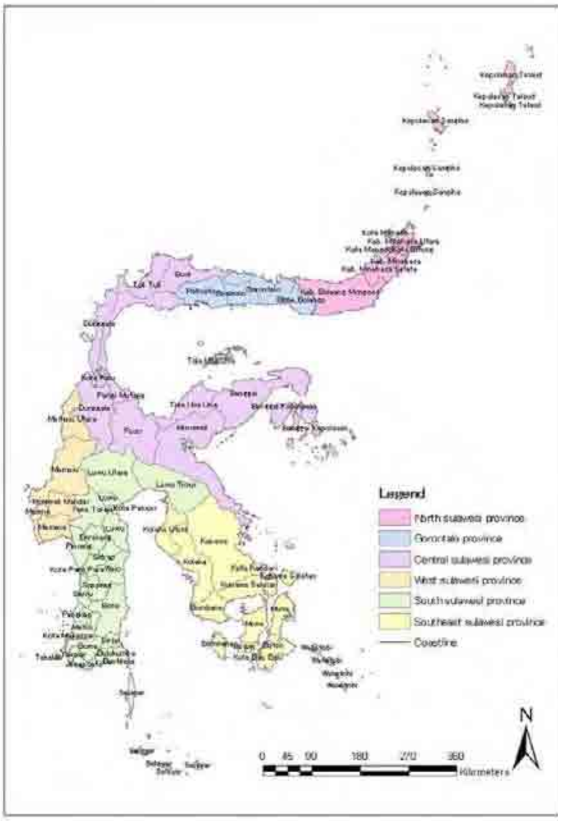
Land Use



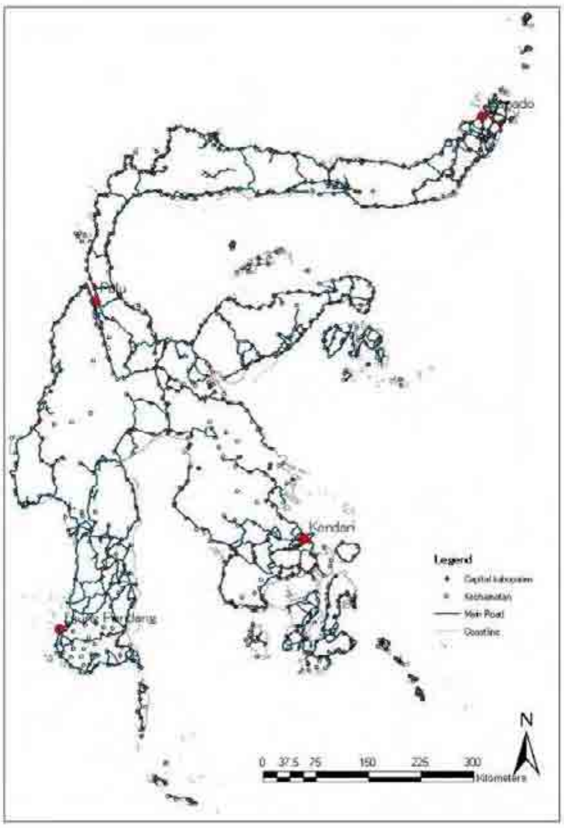
National Forest



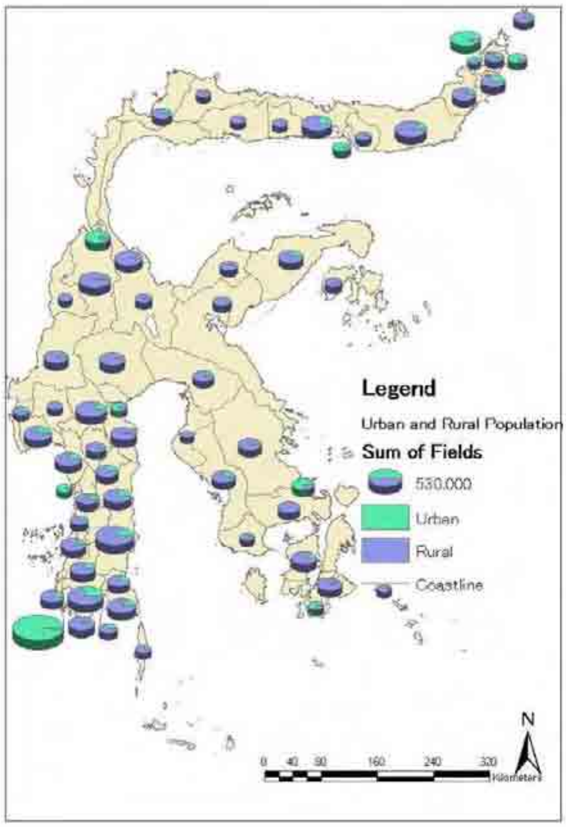
Remaining Forest[53]



Government Boundaries

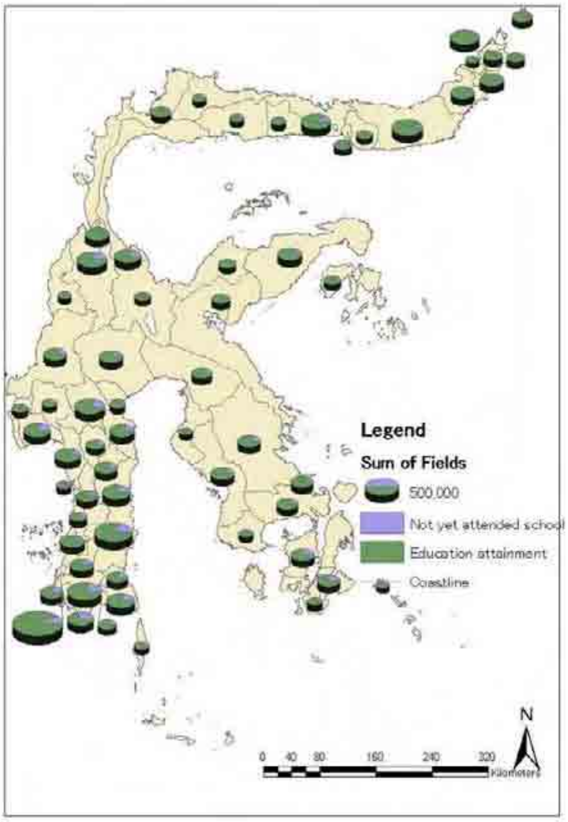


Urban and Rural Population

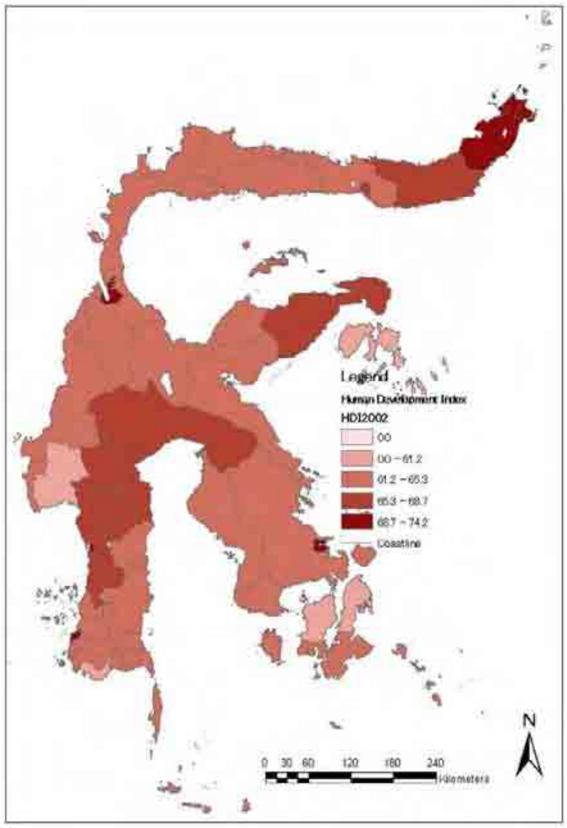


Urban and Rural Population

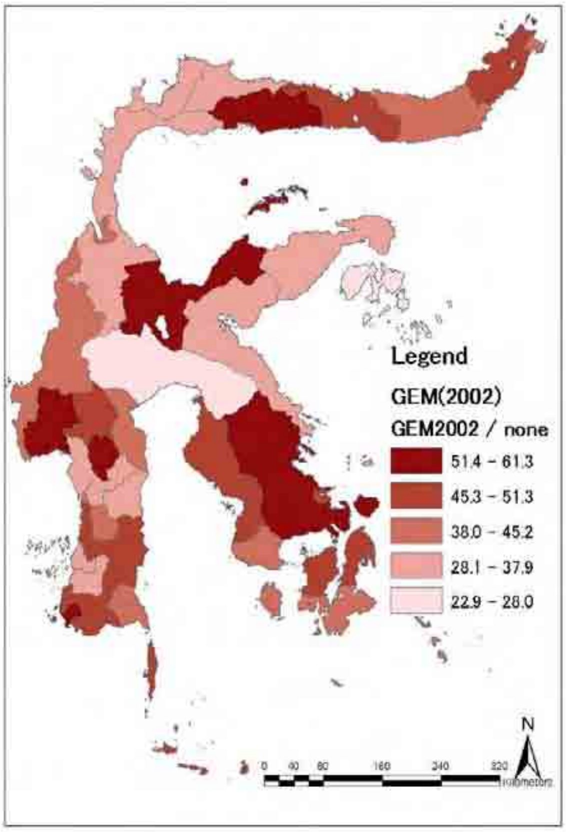
[53] Forest Watch Indonesia/ Global Forest Watch (2002) "The State of the Forest Indonesia"



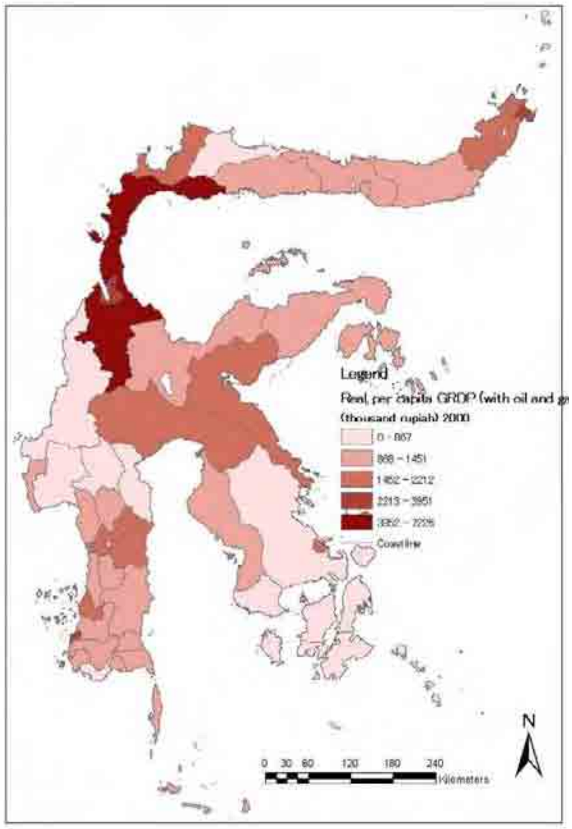
Enrollment Ratio



HDI (Human Development Index)[54]



GEM Index[54]



GRDP per Capita[54]

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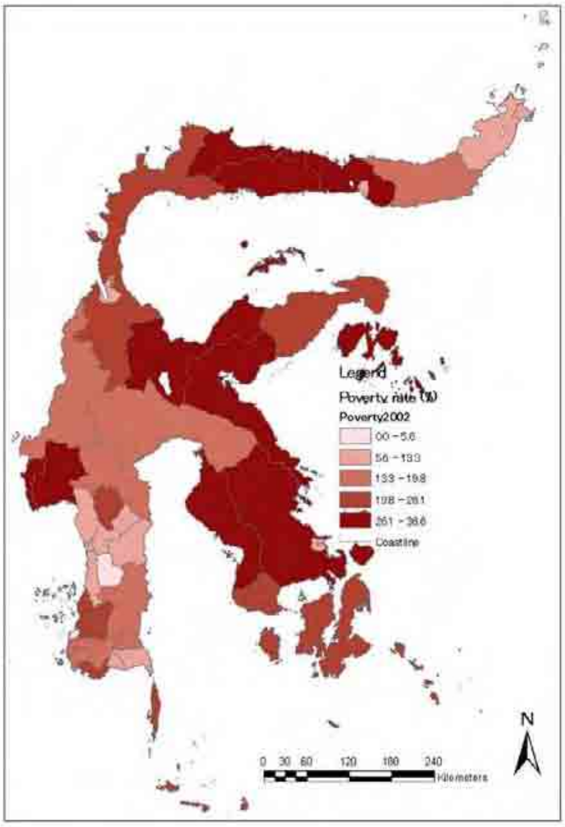
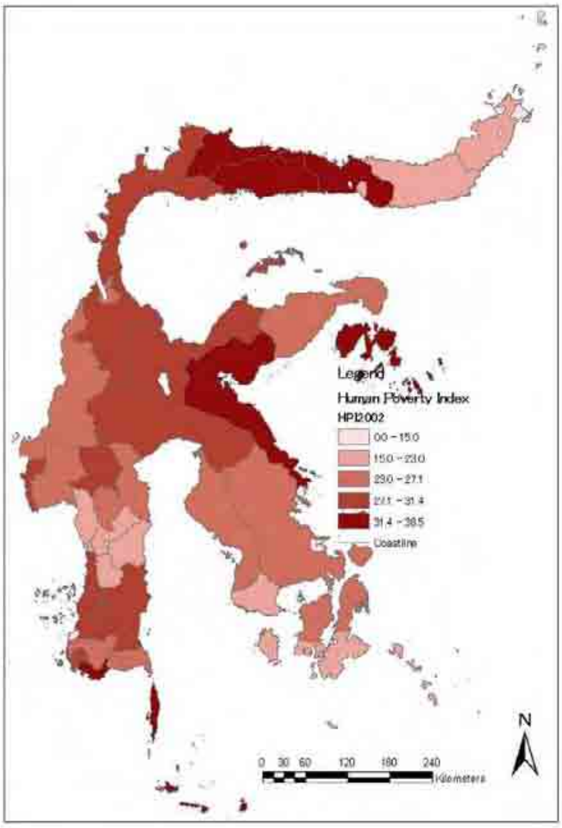
54 BPS - Statistics Indonesia, BAPPENAS, UNDP "Indonesia Human Development Report 2004".

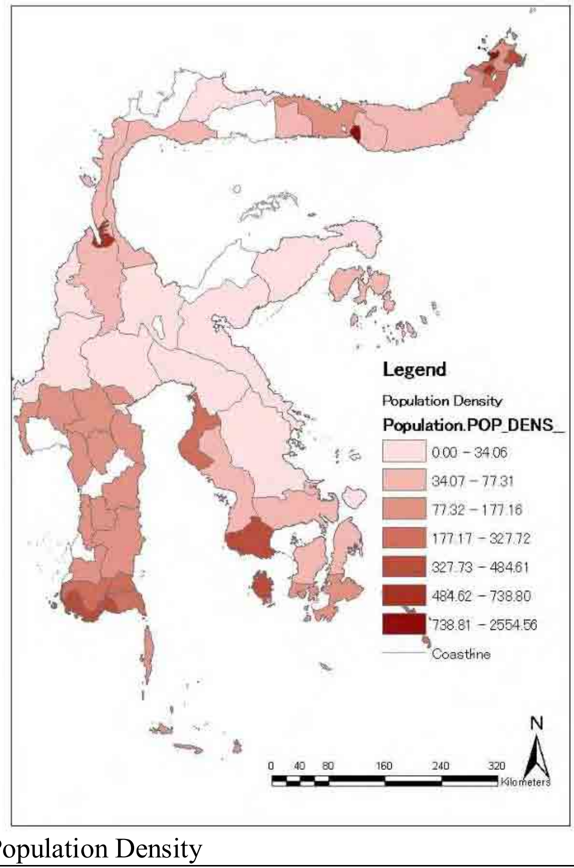


Poverty Rate[54]



Hunan Poverty Index[54]

Ethnic Languages



Population Density

Chapter 8　Optimal Power Development Plan

8.1　Best Scenarion fot the Optimal Power Development Plan

The two scenarios are compared from the viewpoint of Generation Development Plan (Chapter 5), Transmission Development Plan (Chapter 6) and Environmental and Social Consideration (Chapter 7). Local Energy Premier Development Scenario is much preferable to Economic Oriented Development Scenario from the various viewpoints. Therefore, Local Energy Premier Development Scenario will be the best scenario for the optimal power development plan.

8.2　Optimal Generation Development Plan

8.2.1　Generation Development Plan

It points out that interconnection between main grid and isolated small grid nearby may save the operation cost (fuel cost) and be economically feasible. Optimal Generation Development Plan of North Sulawesi system and South Sulawesi system is shown in Table 8.2.1

Table 8.2.1　Optimal Generation Development Plan
(Local Energy Premier Development Scenario)

Year	Peak (MW)	North Sulawesi System					
		ST			GT	CCG	Hydro
		10	25	50	50	50	
2006	132	--	--	--	--	--	--
2007	147	--	--	--	--	--	--
2008	161	--	--	--	--	--	--
2009	175	--	--	--	--	--	--
2010	223	--	25	--	75	--	--
2011	256	10	50	--	25	--	--
2012	285	--	--	--	25	--	--
2013	314	--	25	--	--	--	20
2014	355	--	--	--	25	20	--
2015	384	--	25	--	--	--	--
2016	415	--	--	--	25	20	--
2017	449	--	25	--	--	--	--
2018	485	--	--	--	50	20	--
2019	525	--	--	--	25	20	--
2020	567	--	25	--	--	20	--
2021	615	--	--	--	25	20	--
2022	667	--	25	--	25	20	--
2023	731	--	--	--	75	20	--
2024	796	--	25	--	25	20	--
2025	867	--	25	--	50	20	--
2026	944	--	--	--	50	40	--
2027	1,028	--	25	--	25	40	--
No. of Units		1	11	--	21	14	1
		48					
Capacity (MW)		10	275	--	525	280	20
		1,110					

Year	Peak (MW)	South Sulawesi System					
		ST			GT	CCG	Hydro
		10	25	50	50	50	
2006	445	--	--	--	--	--	--
2007	488	--	--	--	--	--	--
2008	525	--	--	--	--	--	--
2009	576	10	--	--	--	--	--
2010	687	30	--	350	--	--	180
2011	810	--	--	--	--	--	--
2012	889	--	--	--	--	--	243
2013	962	--	--	--	--	--	--
2014	1,040	--	--	50	--	--	--
2015	1,117	--	--	--	--	200	--
2016	1,199	--	--	50	--	50	--
2017	1,291	--	--	100	--	--	--
2018	1,386	--	--	50	--	50	--
2019	1,488	--	--	100	--	50	--
2020	1,597	--	--	--	--	50	126
2021	1,724	--	--	100	50	50	--
2022	1,862	--	--	--	--	50	180
2023	2,009	--	--	--	--	150	--
2024	2,168	--	--	150	--	50	--
2025	2,340	--	--	50	100	--	100
2026	2,525	--	--	--	50	100	174
2027	2,725	--	--	150	50	50	--
No. of Units		4	--	23	5	17	6
		55					
Capacity (MW)		40	--	1,150	250	850	1,003
		3,293					

Hydropower and geothermal power plants are given preference because they are local and renewable energies.

8.2.2 Transmission Development Planning

Regarding the transmission development plan for the local development scenario, power system diagrams for 2012, 2017, 2022 and 2027 have been already shown in Figures 6.6.1 - 6.6.4 in Chapter 6. The amount of facilities to be developed (transmission lines and transformers) are shown in Table 8.2.2 and Table 8.2.3.

Table 8.2.2 Amount of Facilities to be developed Local Energy Premier Development Scenario

(Transmission Line, kms)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70kV	24	0	0	0
	150kV	3,364	180	191	162
	275kV	400	0	675	75
North	150kV	1,256	910	20	230
Total	70kV	24	0	0	0
	150kV	4,620	1,090	211	392
	275kV	400	0	675	75

Table 8.2.3 Amount of Facilities to be developed Local Energy Premier Development Scenario

(Transformer, MVA)

		2008-2012	2013-2017	2018-2022	2023-2027
South	70/20 kV	0	0	30	0
	150/20 kV	840	370	800	880
	150/70 kV	246	32	0	0
	275/150 kV	1,100	0	1,500	150
North	70/20 kV	40	10	40	20
	150/20 kV	380	190	370	200
	150/70 kV	246	0	0	0
Total	70/20 kV	40	10	70	20
	150/20 kV	1,220	560	1,170	1,080
	150/70 kV	492	32	0	0
	275/150 kV	1,100	0	1,500	150

8.2.3 Amount of Power Facilities to be developed

		Amount to be developed				Total
		2008-2012	2013-2017	2018-2022	2023-2027	
North Sulawesi system						
(Generation)	Gas fired (MW)	125	50	125	225	525
	Coal fired (MW)	85	75	50	75	285
	Geothermal (MW)	0	40	100	140	280
	Hydro (MW)	0	20	0	0	20
(Transmission)	Line (kms)	1,256	910	20	230	2,416
	Substation (MVA)	666	200	410	220	1,496
South Sulawesi system						
(Generation)	Gas fired (MW)	0	0	50	200	250
	Gas CC (MW)	0	250	250	350	850
	Coal fired (MW)	390	200	250	350	1,190
	Hydro (MW)	423	0	306	274	1,003
(Transmission)	Line (kms)	3,788	180	866	237	5,071
	Substation (MVA)	2,186	402	2,330	1,030	5,948
All Sulawesi						
(Generation)	Gas fired (MW)	125	50	175	425	775
	Gas CC (MW)	0	250	250	350	850
	Coal fired (MW)	475	275	300	425	1,475
	Geothermal (MW)	0	40	100	140	280
	Hydro (MW)	423	20	306	274	1,023
(Transmission)	Line (kms)	5,044	1,090	886	467	7,487
	Substation (MVA)	2,852	602	2,740	1,250	7,444

8.2.4 Investment for Power Development

(unit: MUS$)

		Amount of investment for Power Development				Total
		2008-2012	2013-2017	2018-2022	2023-2027	
North Sulawesi system						
(Gen)	Gas Thermal	55	43	64	98	260
	Coal Thermal	152	69	79	127	426
	Geothermal	18	86	139	215	458
	Hydro	36	0	0	23	60
(Trans)	Tranmission Line	77	65	2	22	166
	Substation	59	23	15	17	113
South Sulawesi system						
(Gen)	Gas Thermal	0	0	21	129	150
	Gas CC	5	235	256	282	779
	Coal Thermal	514	335	272	442	1,563
	Hydro	708	138	677	577	2,100
(Trans)	Tranmission Line	347	13	197	39	595
	Substation	140	10	106	55	311
All Sulawesi						
(Gen)	Gas Thermal	55	43	86	227	410
	Gas CC	5	235	256	282	779
	Coal Thermal	666	404	351	569	1,989
	Geothermal	18	86	139	215	458
	Hydro	745	139	676	600	2,159
(Trans)	Tranmission Line	424	78	198	61	761
	Substation	199	33	121	72	424

8.3 Electricity tariff and economic & financial analyses

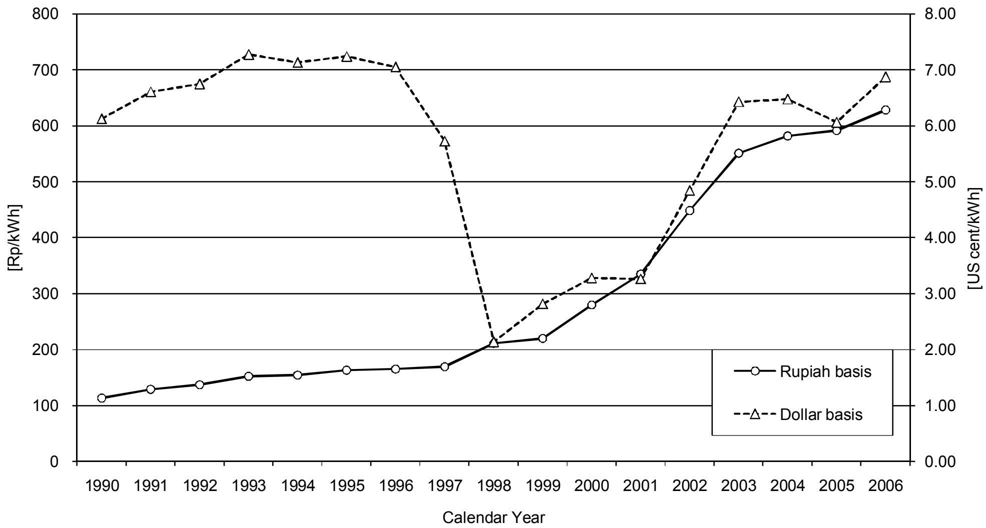
Examining the financing for power development, the financial situation of PLN is important in terms of not only self-funding and its credit for bollowing of PLN, but its ability to fulfil obligation as the off-taker of electricity generated by IPPs.

The financial situation of electric power utilitities mostly depends on their electricity tariff rate. Thus, policy and system regarding electricity tariff in Indonesia is firstly reviewed and then the financial situation of PLN is studied in this section.

8.3.1 Pricing policies

The Indonesian electricity tariff obeys basically nationwide uniform rate structure except some areas[55]. About the tariff of PLN which is the monopolistic electricity utility, it is applied to the Ministry of Energy and Mineral Resources which are competent authorities and passes through discussion/ adjustment with the authorities concerned, and it is finally approved and decided under the authorization of the President.

Before the Asian currency crisis in 1997, the electricity tariff level of securing 8 % of ROA was demanded as a conditionality by the World Bank, Asian Development Bank (ADB) etc. and the Electricity Tariff Adjustment Mechanism (ETAM)[56] was introduced based on Presidential Decree (Keppres No. 68/ 1994) in September to reflect the fluctuation of supply cost to the retail electricity prices. Under such policies, average electricity selling price (= sales income / electric energy sold) had been adjusted incrementally shown in Figure 8.3.1 (○ mark with solid line) against the backdrop of stable economy.



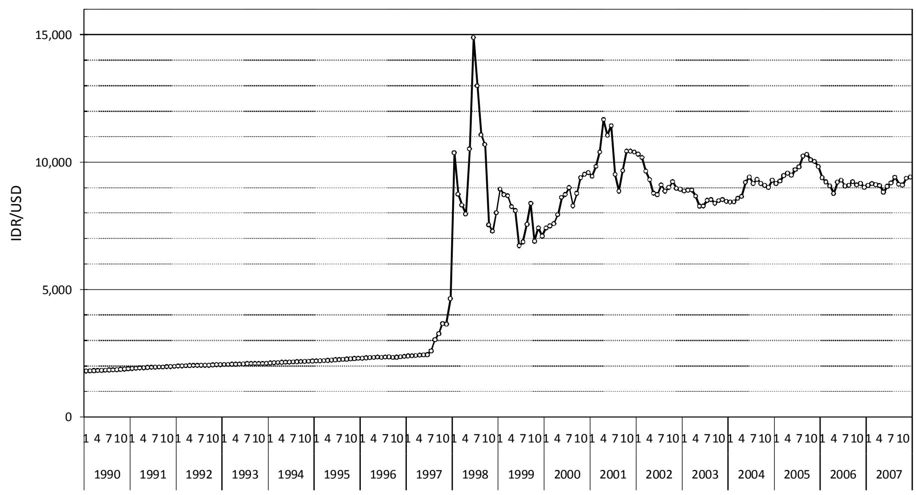
Source: "PLN Statistics, PLN" 1990-2006.
Note: Monthly average rates of the Bank Indonesian are used as the exchange rates.

Figure 8.3.1 PLN average selling price (1990 to 2006)

[55] Some PLN Branch jurisdictions introducing SBU (Strategic Business Unit) system accounting system, or remote areas where local governments / cooperatives carries on power supply business

[56] Adjusting the rate based on the change of consumer price index, fuel price, purchase price from IPP, inflation rate and exchange rate to U.S. dollars every quarter.

In addition, because the Government maintained the dollar-peg system as the exchange policy shown in Figure 8.3.2, the dollar based average price also changed in the form of stable and gradual climb and finally reached 7 cent/kWh in 1993. This level was kept till the Asian currency crisis in 1997 (in Figure 8.3.1, △ mark with dashed line).



Source: Bank Indonesia (http://www.bi.go.id/)

Figure 8.3.2 Exchange rate to U.S. dollars (1990 to 2007)

However, as the result of abandoning dollar peg system and having shifted to the floating rate system on the occasion of the Asian currency crisis in 1997, Rupiah was suddenly devaluated shown in Figure 8.3.2, and the average electricity rate fell to 2 cent/kWh in dollar in 1998. At the same time ETAM was stopped after July of year 1997. Sudden fall of dollar-based electricity rate let the PLN involve in difficulties with fulfillment of its obligation.

Handling this situation, the Government of Indonesia agreed to the cancellation of the debt with cashflow support to PLN, and decided to raise the average rate to 7 cent/kWh as a part of the sector revival strategy by 2005.

After the currency crisis, the tariff was raised 25 % in total in September & December 1997 and March 1998. During the confusion such as riots which tariff hike was supposed to be one of the causes, and change of the government etc., tariff hike was suspended for a short period. Again tariff hike was conducted every year by 27 % in 2000, 20 % in 2001, 34 % in 2002 and 19 %. In 2003, quarterly hike was conducted by 6% and average unit sales price (= sales revenue/ energy sold) reached 6.87 cent/kWh in dollar basis almost recovering the level of 7 cent/kWh maintained before the currency crisis..

The Government of Indonesia had immediate goal of early recovery to "the economic level" getting an average of 7 cent/kWh before the currency crisis, and this goal was almost reached. But the recent international fuel price hike as mentioned in Chapter 2 deteriorated the financial situation of PLN further despite such continuous efforts. The government declared to postpone tariff hike until the next presidential election scheduled in 2009 and compensate by the government subsidy. In this way, outlook of future pricing policy is opaque along with the deliberation on new "new Electricity Law".

8.3.2 Tariff structure

The electricity tariff of PLN is designed based on two major principles of "nationwide uniform rate" and "the progressive (large lot is higher than small lot)". The current tariff table is classified mainly in six categories; Rumah (Residential), Bisnis (Business), Industri (Industrial), Sosial (Social), Pemerintah (Government Office and Public Street Lighting), and in each category the tariff consists of fixed charge (capacity charge) and metered charge (demand charge) according to contract capacity (VA). In addition, time-of-day rate with peak hours (WBP; 18 to 20 o'clock) and off-peak hours (LWBP) is introduced for large scale users of Business, Industrial, Social and the Government Office categories.

The cross subsidy mechanism which the electricity rate for small (residential) consumers is set lower than for the big consumers (business, industrial) contrary to the supply cost, is built into the consumer-wise tariff design. Under such mechanism, disincentive for rural electrification would be natural[57].

From the viewpoint of securing rationality, fairness and transparency in the power sector, the international organizations such as the World Bank, ADB, the JBIC demand the countermeasures such as review of nation-wide uniform rate, introduction of accounts separation by functions (generation/ transmission/ distribution), abolition of cross subsidy, introduction of the automatic rate adjustment mechanism etc.

[57] There is no reason why PLN demanded the pursuit of the profit as a company, promote positively grid extension (electrification) in remote areas with high residential demand and low profitability.

Table 8.3.1 Electricity Tariff Table of PLN (2003 revision)

i) Sosial (Social)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
S-1 / TR	220VA	--	--	--	--	Monthly fixed charge (Rp):	14,200	14,500	14,800	15,100
S-2 / TR	450VA	8,000	9,000	10,000	11,000	0 to 30 kWh :	121	122	123	124
						30to 60 kWh :	200	235	265	300
						60 kWh above :	280	310	360	420
S-2 / TR	900VA	11,000	13,000	15,000	17,000	0 to 20 kWh :	150	175	200	230
						20 to 60 kWh :	225	255	295	340
						60 kWh above:	280	310	360	420
S-2 / TR	1.300VA	22,000	24,000	25,000	27,000	0 to 20 kWh :	215	230	250	270
						20 to 60 kWh :	290	310	335	360
						60 kWh above:	350	375	405	435
S-2 / TR	2.200VA	24,000	25,000	27,000	29,000	0 to 20 kWh :	220	235	250	270
						20 to 60 kWh :	315	340	370	395
						60 kWh above:	365	390	420	455
S-2 / TR	2,200VA to 200kVA	27,000	29,000	30,500	32,000	0 to 60 hrs	325	350	380	410
						60 hrs above	380	400	430	460
S-3 / TM	200kVA above	26,000	28,000	29,500	30,500	Block WBP	K x P x 295	K x P x 310	K x P x 325	K x P x 345
						Block LWBP	P x 295	P x 310	P x 325	P x 345

WBP: Waktu Beban Puncak (Peak Load Tariff)
LWBP: Luar Waktu Beban Puncak (Off-Peak Load Tariff)
TR: Tegangan Rendah (Low Voltage)
TM: Tegangan Menengah (Medium Voltage)

ii) Rumah (Residential)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
R-1 / TR	upto 450VA	8,500	9,500	11,000	12,000	0 to 30 kWh :	163	166	169	172
						30 to 60 kWh :	350	355	360	380
						60 kWh above:	415	460	495	530
R-1 / TR	900VA	16,200	18,100	20,000	23,000	0 to 20 kWh :	225	240	275	310
						20 to 60 kWh :	360	395	445	490
						60 kWh above:	415	460	495	530
R-1 / TR	1,300VA	28,000	28,800	30,100	30,500	0 to 20 kWh :	350	370	385	395
						20 to 60 kWh :	370	395	445	490
						60 kWh above:	430	465	495	530
R-1 / TR	2,200VA	28,000	29,000	30,200	30,500	0 to 20 kWh :	355	375	390	400
						20 to 60 kWh :	375	395	445	490
						60 kWh above:	440	465	495	530
R-2 / TR	2,200VA to 6,600VA	28,100	29,100	30,400	31,500	--	535	550	560	575
R-3 / TR	6,600VA above	34,260	34,260	34,260	34,260	--	621	621	621	621

iii) Bisnis (Business)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
B-1 / TR	upto 450VA	21,000	22,000	23,500	24,500	0 to 30 kWh : 30 kWh above:	248 385	251 405	254 420	257 445
B-1 / TR	900VA	23,500	25,000	26,500	28,300	0 to 108 kWh : 108 kWh above:	370 415	400 442	420 465	440 490
B-1 / TR	1,300VA	26,200	27,200	28,200	29,500	0 to 146 kWh : 146 kWh above:	430 435	450 454	470 473	490 493
B-1 / TR	2,200VA	27,200	28,200	29,200	30,500	0 to 264 kWh : 264 kWh above:	440 475	460 497	480 518	500 540
B-2 / TR	2,200VA to 200kVA	28,500	29,500	30,000	31,000	0 to 100 hrs : 100 hrs above	480 510	500 527	520 545	535 550
B-3 / TM	200kVA above	26,500	27,400	28,400	29,500	Block WBP Block LWBP	K x 410 410	K x 430 430	K x 452 452	K x 475 475

iv) Industri (Industrial)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
I-1 / TR	upto 450VA	24,000	25,000	26,000	27,000	0 to 30 kWh : 30 kWh above:	158 325	159 360	160 395	161 435
I-1 / TR	900VA	27,000	29,500	31,500	33,500	0 to 72 kWh : 72 kWh above:	250 330	280 365	315 405	350 465
I-1 / TR	1,300VA	28,000	30,000	31,800	33,800	0 to 104 kWh : 104 kWh above:	390 400	420 430	450 460	475 495
I-1 / TR	2,200VA	28,500	30,200	32,000	33,800	0 to 196 kWh : 196 kWh above:	395 405	425 435	455 460	480 495
I-1 / TR	2,200VA to 14kVA	28,700	30,400	32,200	34,000	0 to 80 hrs : 80 hrs above	400 410	425 435	455 460	480 495
I-2 / TR	14kVA to 200kVA	29,000	31,000	32,500	35,000	Block WBP Block LWBP	K x 395 395	K x 410 410	K x 440 440	K x 466 466
I-3 / TM	200kVA above	26,100	27,800	29,500	31,300	Block WBP: - 0 to 350 hrs: - 350 hrs above: Block LWBP:	 K x 387 387 387	 K x 412 412 412	 K x 439 439 439	 K x 468 468 468
I-4 / TT	30,000 kVA above	24,000	25,500	27,000	28,700	--	387	410	434	460

TT: Tegangan Tinggi (High Voltage)

v) Pemerintah (Government Office)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
P-1 / TR	upto 450VA	19,000	19,500	20,000	20,500	--	550	560	575	595
P-1 / TR	900VA	24,000	24,200	24,600	25,000	--	590	595	600	605
P-1 / TR	1,300VA	24,000	24,200	24,600	25,000	--	590	595	600	605
P-1 / TR	2,200VA	24,000	24,200	24,600	25,000	--	590	595	600	605
P-1 / TR	2,200VA to 200kVA	24,000	24,200	24,600	25,000	--	590	595	600	605
P-2 / TM	200kVA above	23,300	23,600	23,800	24,000	Block WBP Block LWBP	K x 371 371	K x 376 376	K x 379 379	K x 382 382
P-3 / TR	--	--	--	--	--	--	575	605	635	665

vi) Traksi (Railway)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
T / TM	200kVA above	19,600 *)	21,000 *)	23,000 *)	25,000 *)	Block WBP Block LWBP	K x 320 320	K x 340 340	K x 360 360	K x 385 385

vii) Curah (Bulk for PIUKU)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
C / TM	200kVA above	23,600	25,000	22.500 *)	22.500 *)	Block WBP Block LWBP	K x 360 360	K x 375 375	K x 350 350	K x 350 350

※ Hatching parts are supposed to be wrong data.

viii) Multiguna (Multipurpose)

Tariff Class	Contract Capacity	Capacity Charge (Rp/kVA/month)				Demand Charge (Rp/kWh)				
		1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03	Slab	1-Jan to 31-Mar-03	1-Apr to 30-Jun-03	1-Jul to 30-Sep-03	1-Oct to 31-Dec-03
M / TR / TM / TT	--	--	--	--	--	--	1.300 *)	1.340 *)	1.380 *)	1.415 *)

8.3.3 Financial situation of PLN

As the result of having continued raising the rate step by step as shown in Table 8.3.2, the average unit selling price of PLN reached Rp. 628/kWh in 2006, and recovered to the level of 6.87¢/kWh in dollar basis close to the level before the Asian currency crisis. However, the unit supply cost increased to Rp. 934/kWh in 2006 and the big negative spread occurred.

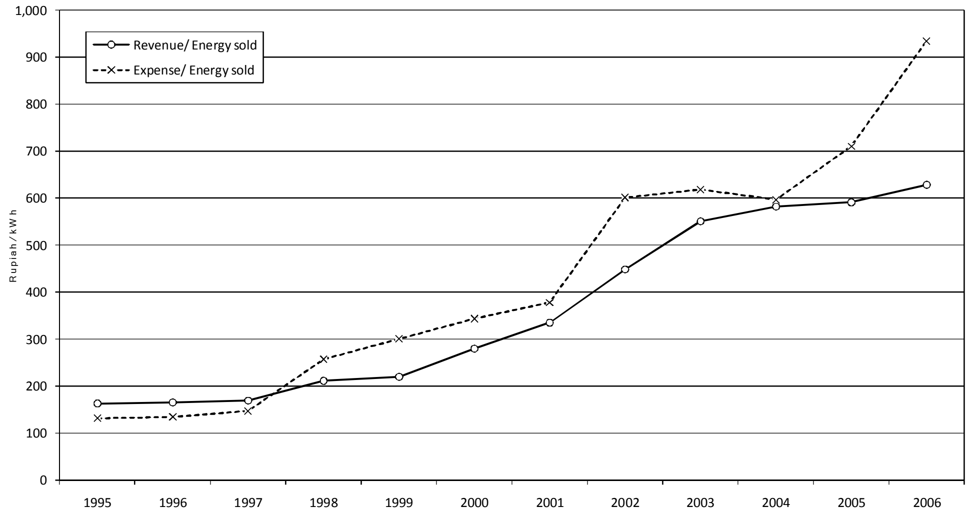
Table 8.3.2 Category-wise average unit selling price of PLN

(Rp/kWh)

Year	Residential	Industrial	Business	Social	Government Office	Public Street Lighting	Total
1990	123.34	91.17	203.66	83.10	137.15	101.30	113.17
1991	125.81	112.51	228.60	98.90	160.64	118.82	129.05
1992	128.85	122.83	237.81	106.88	180.93	131.42	137.12
1993	144.53	135.35	253.56	119.21	208.36	153.52	151.99
1994	146.57	137.75	255.49	122.78	214.25	154.25	154.28
1995	156.83	144.79	264.00	128.16	224.73	167.70	163.01
1996	158.91	146.16	266.04	130.60	225.63	169.05	165.43
1997	161.65	149.70	270.35	130.34	232.07	172.82	169.13
1998	184.40	201.01	305.83	193.32	294.02	238.97	210.94
1999	193.80	208.56	313.47	215.29	316.61	266.07	219.68
2000	207.34	302.52	380.51	231.51	491.93	439.08	279.67
2001	253.65	361.67	451.91	272.47	596.68	484.17	334.55
2002	392.79	442.94	592.77	421.28	692.23	515.37	448.03
2003	522.48	530.32	661.41	538.09	725.90	594.98	550.74
2004	557.76	559.15	682.32	568.65	712.47	638.99	581.75
2005	563.05	569.87	694.71	569.90	730.32	628.72	590.91

Source: "PLN Statistics, PLN" 1990-2005.

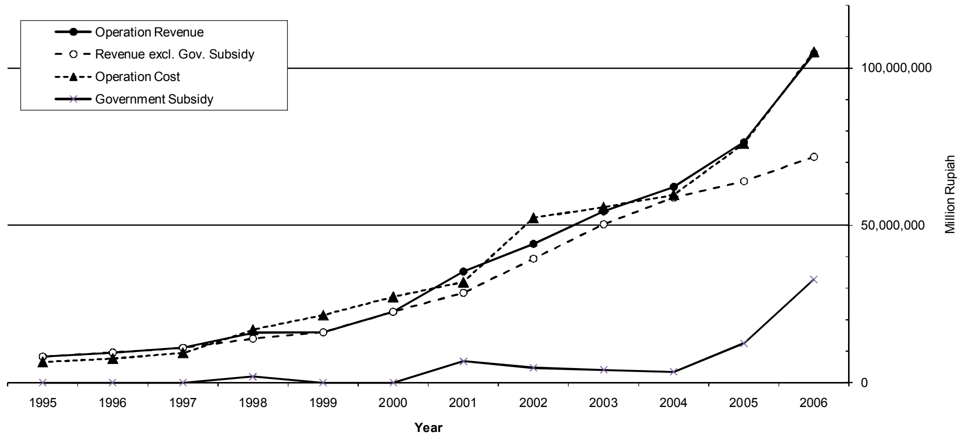
Figure 8.3.3 compares average supply cost (operating expense per electric energy sold) with average sale unit price (electricity sales income per electric energy sold) from 1995 to 2006 and shows the fact that PLN has continuously failed to retrieve the supply cost since 1998. As mentioned in the previous two clauses, successive rate hike improved the income and expenditure balance and the balance reaced close to equilibrium in 2004. After that, international energy price hike adding pause of electricity tariff hike, has made matter worse. In 2006, the expenditure was 50% higher than the income. Taking the movement of fossil fuel price mentioned in Chapter 2, the recent situation is easily guessed to turn even worse.



Source: "PLN Statistics, PLN" 1990-2005

Figure 8.3.3 Unit income and expense per energy sold

The deficit such income and expense gap per energy sold caused has been compensated by the government subsidies as shown in Figure 8.3.4. The operation cost has been exceeding the operaton revenue since 1998, and the amount of government subsidies has surged since 2004 and reached 12 trillion Rupiah in 2005, 33 trillion Rupiah in 2006[58].



Source: "PLN Statistics, PLN" 1990-2005

Figure 8.3.4 Operating income of PLN and operating expense

The financial statements of PLN from 2001 to 2006 are shown in Table 8.3.3 - Table 8.3.5.

PLN's chronic deficits after the Asian currency crisis as mentioned above, are supposed to be mainly caused by the surge of dollar basis cost by the sudden fall of Rupiah, that is to say,

[58] According to a press, 55 trillion Rupiah of 84% increase of the initial budget seem to have been appropriated in the revised budget in 2007 while the total annual expenditure in the 2007 in the initial budget is about 750 trillion Rupiah.

increase of fuel costs, electricity purchase costs from IPPs and interest payment. The Government of Indonesia took the countermeasures as follows to tackle this situation.

i) Renegotiation of power purchase agreements (PPAs) between IPPs
ii) Debt equity swap
iii) Raise of electricity rate
iv) Reevaluation of assets

Among these items, the first one is mentioned in clause 8.4.2 and the other three items are mentioned in the following.

Though at first, the third item (raise of electricity rate) is mentioned just as the previous two clauses, surge of recent fuel costs (Fuel and Lubricants) attracts attention in income statements of Table 8.3.3. Especially, while the energy sales growth of PLN's own production is 5.4 % in 2005 and 3.6 % in 2006, the growth of fuel cost is 52.5 % and 69.7 % in respective year. The amount of fuel and lubricants cost corresponds to 60 % of total operation cost and 90 % of energy sales revenue, and exceeds the net energy sales revenue of IPP generated energy. In 2007 and 2008, the situation is supposed to worsen reviewing the energy price movement. In Chapter 2, future energy price is expected to keep the level in 2006 and if so, introduction of the mechanism which fluctuation of fuel price can pass through the selling price automatically like the suspended ETAM, and more essentially, efforts to reduce the dependence on fossil fuel are required.

The second item is so-called debt-equity swap, which converted overdue interests and penalty on the two step loans to the government equity in 2000. Though the effect does not appear the financial statements after 2001, as the result of debt-equity swap, the amount of interest payment diminished from 13.7 trillion Rupiah in 2000 to 2.6 trillion Rupiah in 2001.

The fourth item, revaluation of assets was carried out in 2002. Accordingly the amount of fixed assets increased more than three times from 53 trillion Rupiah to 186 trillion Rupiah as shown in the balance sheet (Table 8.3.4) and the amount of depreciation also increased close to five times from 3.4 trillion Rupiah to 15.6 trillion Rupiah as shown in the income statement (Table 8.3.3). The fixed assets of PLN were accounted by the amount of acquisition cost net of depreciation and originally most of the fixed assets were procured with foreign currency based loans. According to the accounting rule of PLN, the amount of foreign currency based loan is accounted using the exchange rate (TTM) that Bank Indonesia delivers, and the balance is accounted as "gain (loss) on foreign exchange". Therefore, there exists the difference between the acquisition cost of imported fixed assets and foreign currency based loan which is reevaluated by devaluated Rupiah after the currency crisis. In other words, Rupiah was devaluated less than one-fourth from Rp. 2,347/US$ in 1996 to Rp. 10,263/US$ in 2001 as shown in Figure 8.3.2, so that foreign currency based loan is revaluated more than four times in Rupiah while acquisition cost of fixed assets is unchanged. This difference is accounted as "gain (loss) on foreign exchange".

This revaluation of assets brought about the increase of depreciation negating other positive effect of other countermeasures such as raise of electricity rate. As a result, the situation to record a loss continues, but the realistic evaluation of assets is important as basic information to calculate the appropriate tariff level or to examine plowback for replacement of assets.

Table 8.3.3 Income Statement of PT PLN (Persero)

(2001 to 2006)

(Unit: million Rupiah)

DESCRIPTION		2006	2005	2004	2003	2002	2001
REVENUES							
Sale of electricity		70,735,151	63,246,221	58,232,002	49,809,637	39,018,462	28,275,983
	(annual growth ratio)	11.8%	8.6%	16.9%	27.7%	38.0%	27.7%
Customer connection fees		479,991	439,917	387,083	342,257	302,308	265,858
Government subsidy		32,909,148	12,510,960	3,469,920	4,096,633	4,739,074	6,735,210
Others		602,246	346,226	184,057	182,251	123,510	82,907
Total Revenues		**104,726,536**	**76,543,324**	**62,273,062**	**54,430,778**	**44,183,353**	**35,359,958**
OPERATING EXPENSES							
Fuel and lubricants		63,401,080	37,355,450	24,491,052	21,477,867	17,957,262	14,007,296
	(annual growth ratio)	69.7%	52.5%	14.0%	19.6%	28.2%	35.0%
Purchased electricity		14,845,421	13,598,167	11,970,811	10,837,796	11,168,843	8,717,141
Maintenance		6,629,065	6,511,004	5,202,146	4,827,606	3,588,828	2,630,360
Personnel		6,719,746	5,508,067	5,619,384	6,533,182	2,583,290	2,086,330
Depreciation		10,150,985	9,722,315	9,547,555	12,745,047	15,626,763	3,404,114
Others		3,481,853	3,328,598	2,879,819	2,165,000	1,420,607	1,094,147
Total Operating Expenses		**105,228,150**	**76,023,601**	**59,710,767**	**58,586,498**	**52,345,592**	**31,939,387**
INCOME (LOSS) FROM OPERATIONS		**▲ 501,614**	**519,723**	**2,562,295**	**▲ 4,155,720**	**▲ 8,162,239**	**3,420,570**
OTHER INCOME (CHARGES)							
Interest income		591,712	212,198	231,789	307,928	665,414	363,856
Interest expense and financial charges		▲ 4,350,579	▲ 4,455,456	▲ 4,485,928	▲ 3,581,495	▲ 2,152,232	▲ 2,619,507
Interest on taxes payable on revaluation increment of property, plant and equipment assumed by the Government		1,863,754	2,795,630	4,659,384	--	--	--
Gain (loss) on foreign exchange - net		1,762,948	▲ 698,637	▲ 1,675,830	1,010,385	2,725,596	▲ 458,948
Others - net		▲ 451,556	▲ 548,017	152,977	222,297	345,646	▲ 139,827
Other Charges - Net		**▲ 583,721**	**▲ 2,694,282**	**▲ 1,117,607**	**▲ 2,040,885**	**1,584,424**	**▲ 2,854,425**
INCOME (LOSS) BEFORE TAX		**▲ 1,085,335**	**▲ 2,174,559**	**1,444,688**	**▲ 6,196,605**	**▲ 6,577,814**	**566,145**
TAX EXPENSE		▲ 2,972,508	▲ 2,746,036	▲ 3,184,503	▲ 1,388,881	▲ 1,814,785	▲ 569,420
LOSS FROM ORDINARY ACTIVITIES		**▲ 4,057,843**	**▲ 4,920,594**	**▲ 1,739,815**	**▲ 7,585,486**	**▲ 8,392,599**	**▲ 3,275**
EXTRAORDINARY ITEM - net of tax		2,129,987	--	▲ 281,551	1,685,404	2,333,041	183,394
NET INCOME (LOSS)		**▲ 1,927,856**	**▲ 4,920,594**	**▲ 2,021,367**	**▲ 5,900,082**	**▲ 6,059,558**	**180,119**
Operation Data:							
Energy Sales (GWh)		112,609	107,032	100,097	90,441	87,089	79,165
	(annual growth ratio)	5.2%	6.9%	10.7%	3.8%	3.0%	6.8%
Energy Production (GWh):		133,108	127,370	120,244	113,030	108,360	101,654
- Own Production		101,664	98,177	93,113	90,046	88,068	87,634
	(annual growth ratio)	3.6%	5.4%	3.4%	2.2%	0.5%	*N.D*
- Diesel rent		2,804	3,105	3,154	2,435	1,225	720
	(annual growth ratio)	-9.7%	-1.6%	29.5%	98.8%	70.1%	*N.D*
- Purchase		28,639	26,088	23,978	20,549	19,067	13,299
	(annual growth ratio)	9.8%	8.8%	16.7%	7.8%	43.4%	*N.D*
Network (T&D) Losses (%)		11.45	11.54	11.29	16.88	16.54	13.52
Number of Customers (thousand)		35,751	34,559	33,366	32,151	30,953	29,827

Source: PLN Financial Statement 2002-2006

Table 8.3.4 Consolidated Balance Sheet of PT PLN (Persero)

(2001 to 2006)

(Unit: million Rupiah)

As of December 31	2006	2005	2004	2003	2002	2001
ASSETS						
NONCURRENT ASSETS						
Property, plant and equipment						
- carrying value	257,695,815	224,680,444	217,604,612	207,491,683	201,318,267	71,199,099
- accumulated depreciation	▲ 57,312,559	▲ 47,289,093	▲ 37,820,831	▲ 28,421,314	▲ 15,700,329	▲ 18,150,769
- net of accumulated depreciation	200,383,256	177,391,351	179,783,781	179,070,368	185,617,938	53,048,330
Construction in progress	11,286,322	19,674,782	13,603,539	12,028,719	9,587,301	12,340,035
Long-term investments	591,457	362,212	521,148	312,561	289,886	32,775
Deferred tax assets	64,946	8,363	15,535	1,165,728	--	20,811
Assets not used in operations	1,335,055	2,333,952	2,677,172	2,978,307	4,360,878	2,338,754
Accounts receivable from related parties	1,012,848	1,083,834	879,260	351,116	--	--
Restricted cash in banks and time deposits	3,105,254	345,730	--	--	--	--
Other noncurrent assets	1,317,407	2,148,151	1,633,754	687,776	1,139,103	762,651
Total Noncurrent Assets	**219,096,545**	**203,348,375**	**199,114,190**	**196,594,576**	**200,995,105**	**68,543,355**
CURRENT ASSETS						
Cash and cash equivalents	12,968,420	5,361,749	6,073,057	6,759,657	7,218,517	6,142,461
Short-term investments	981,855	1,415,187	523,961	472,565	641,463	684,669
Trade receivable						
- doubtful accounts	314,973	341,032	228,467	53,391	70,611	79,914
- net of allowance	2,362,125	1,873,836	1,824,695	1,848,813	2,053,296	2,893,600
Other accounts receivable					456,113	89,741
- Related parties			217,008	185,961	--	--
- Third parties			1,197,660	436,596	--	--
Receivables on electricity subsidy	7,261,209	3,660,314	--	--	--	--
Other receivables	196,021	529,770	--	--	--	--
Inventories	4,188,361	3,765,979	2,187,131	2,253,061	2,104,459	1,394,162
Prepaid taxes	191,074	284,766	92,639	61,799	2,012	802
Prepaid expenses and advances	672,208	602,759	563,255	511,893	417,447	157,728
Total Current Assets	**28,821,273**	**17,494,360**	**12,679,406**	**12,530,345**	**12,893,307**	**11,363,162**
TOTAL ASSETS	**247,917,818**	**220,842,735**	**211,793,597**	**209,124,921**	**213,888,413**	**79,906,517**

As of December 31	2006	2005	2004	2003	2002	2001
EQUITY AND LIABILITIES						
EQUITY						
Capital stock - par value of Rp 1,000,000 per share Authorized - 63,000,000 shares Subscribed and fully paid - 46,107,154 shares	46,107,154	46,107,154	46,107,154	46,107,154	46,107,154	46,107,154
Additional paid-in capital	25,868,016	23,855,892	21,530,462	19,863,834	18,917,340	17,571,443
Revaluation increment in property, plant and equipment	77,640,558	77,640,558	77,640,558	77,640,558	137,599,980	--
Difference due to change in equity of subsidiaries	59,915,695	59,915,695	59,915,695	59,915,695	--	--
Retained earnings (deficit)						
Appropriated	1,894,149	1,894,149	1,894,149	1,894,149	1,894,149	1,894,149
Unappropriated	▲ 71,587,626	▲ 69,659,770	▲ 64,739,175	▲ 62,717,808	▲ 52,434,303	▲ 46,374,745
Total Equity	**139,837,946**	**139,753,678**	**142,348,843**	**142,703,581**	**152,084,320**	**19,198,001**
MINORITY INTEREST IN NET ASSETS OF CONSOLIDATED SUBSIDIARIES	--	--	--	--	**3,910**	**--**
NONCURRENT LIABILITIES						
Deferred revenue	6,252,377	5,858,062	5,144,568	4,521,360	3,998,868	3,502,134
Customers security deposits	4,128,328	3,795,907	3,350,142	2,972,290	2,633,025	2,363,026
Deferred tax liabilities	7,426,583	5,369,976	3,173,986	1,193,477	766,550	3,020,650
Long-term liabilities - net of current maturities						
Others payable	417,959	673,663	--	--	9,023,016	104,202
Two-step loans	12,418,581	14,236,914	14,024,968	15,017,505	16,763,996	20,146,895
Government loans	3,830,804	4,147,597	4,464,390	4,781,182	5,326,456	5,742,525
Lease liability	13,230,361	--	--	--	--	--
Bank loans and notes payable	20,504	--	--	69,879	140,320	210,309
Bonds payable	12,775,257	2,091,055	2,090,087	600,000	600,000	600,000
Electricity purchase payable	6,677,417	7,460,450	7,182,769	6,789,080	7,149,588	--
Taxes payable on revaluation increment of property, plant and equipment	--	--	1,941,410	3,917,713	--	--
Employee benefit obligations	11,590,277	10,651,721	10,647,833	9,400,127	--	--
Payable to related parties	132,560	59,156	--	--	--	--
Project cost payables	1,480,459	847,517	232,977	417,487	551,572	748,611
Total Noncurrent Liabilities	**80,381,467**	**55,192,018**	**52,253,131**	**49,680,100**	**46,953,392**	**36,438,353**
CURRENT LIABILITIES						
Trade accounts payable					9,554,282	19,930,392
Related parties	229,064	37,507	38,543	69,231	--	--
Third parties	18,056,485	16,264,383	9,431,824	7,354,957	--	--
Other accounts payable					403,200	306,505
Related parties	--	--	82,930	5,182	--	--
Third parties	--	--	934,041	750,991	--	--
Taxes payable	1,031,529	3,337,836	2,127,205	2,088,359	1,038,689	108,987
Accrued expenses	1,293,259	544,958	515,628	2,523,325	854,298	951,620
Current maturities of long-term liabilities						
Two-step loans	2,007,533	2,603,332	2,786,434	2,567,798	2,509,633	2,463,202
Government loans	316,793	316,793	316,793	443,789	416,651	439,766
Lease liability	757,283	--	--	--	--	--
Bank loans and notes payable	15,874	188,895	239,664	199,368	70,038	69,691
Bonds payable	600,000	--	--	--	--	--
Electricity purchase payable	731,612	151,449	278,190	253,716	--	--
Employee benefit obligations	1,278,434	1,165,993	440,372	484,524	--	--
Other payables	1,380,539	1,285,893	--	--	--	--
Total Current Liabilities	**27,698,405**	**25,897,039**	**17,191,623**	**16,741,240**	**14,846,791**	**24,270,163**
TOTAL EQUITY AND LIABILITIES	**247,917,818**	**220,842,735**	**211,793,597**	**209,124,921**	**213,888,413**	**79,906,517**

Table 8.3.5 Cashflow Statement of PT PLN (Persero) (2001 to 2006)

(Unit: million Rupiah)

	2006	2005	2004	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES						
Cash receipts from customers	72,603,726	65,587,554	60,159,702	51,938,809	41,155,376	28,996,958
Cash receipts for interest income and current accounts	--	--	--	--	664,090	374,133
Cash paid to suppliers and employees	▲ 60,228,035	▲ 53,966,843	▲ 46,284,621	▲ 39,683,441	▲ 34,868,772	▲ 24,792,031
Cash paid for other operations	▲ 1,020,398	▲ 1,867,757	▲ 1,774,681	▲ 1,948,022	▲ 1,297,089	▲ 1,471,103
Cash generated from operations	11,355,293	9,752,953	12,100,399	10,307,347	5,653,606	3,107,957
Electricity subsidy received	--	3,150,442	2,837,815	4,070,065	4,404,897	6,735,210
Interest and financial charges paid	▲ 1,821,173	▲ 1,723,028	▲ 1,830,656	▲ 2,128,829	▲ 2,134,653	▲ 2,603,289
Interest received	538,229	210,021	230,764	308,714	--	--
Income tax restitution received	1,466	--	--	398	--	--
Payment of taxes on revaluation increment of property, plant and equipment	▲ 2,607,354	▲ 688,959	▲ 1,941,410	▲ 3,641,395	▲ 1,332,237	▲ 15,655
Income tax paid	▲ 627,579	▲ 65,840	▲ 72,462	▲ 42,719	--	3,640
Net Cash Provided by Operating Activities	**6,838,882**	**10,635,590**	**11,324,450**	**8,873,580**	**6,591,613**	**7,227,863**
CASH FLOWS FROM INVESTING ACTIVITIES						
Proceeds from sale of property, plant and equipment	11,370	22,282	22,670	5,577	30,955	15,686
Acquisitions of property, plant and equipment, construction in progress and assets not used in operations	▲ 4,643,063	▲ 6,852,193	▲ 9,422,418	▲ 5,543,946	▲ 2,517,780	▲ 1,404,205
Increase in receivables from related parties	▲ 34,012	52,974	▲ 593,886	▲ 125,000	--	--
Increase in long-term investments	▲ 48,786	▲ 5,849	▲ 276,980	▲ 56,310	--	--
Payment of payable on investment in shares of stock	▲ 17,250	--	--	--	▲ 257,111	▲ 6,618
Dividends received	473	--	--	--	--	--
Proceeds from sale of long-term investments	2,000	231	--	--	--	--
Increase in short-term investments	▲ 556,172	▲ 891,226	▲ 42,831	▲ 39,336	--	--
Net Cash Used in Investing Activities	**▲ 5,285,440**	**▲ 7,673,780**	**▲ 10,313,446**	**▲ 5,759,015**	**▲ 2,743,936**	**▲ 1,395,137**
CASH FLOWS FROM FINANCING ACTIVITIES						
Proceeds from issuance of bonds	11,560,100	--	1,500,000	--	--	--
Bond issuance costs	▲ 141,206	--	▲ 10,048	--	--	--
Payments of two-step loans	▲ 2,668,297	▲ 2,685,610	▲ 2,469,847	▲ 2,370,037	▲ 2,262,793	▲ 2,578,619
Payments for bonds payable	--	--	--	--	--	▲ 1,000,000
Payments of Government loans	▲ 316,793	▲ 316,793	▲ 443,789	▲ 518,136	▲ 236,800	▲ 691,839
Proceeds of bank loans	34,347	--	160,000	128,912	--	
Payments of bank loans	--	▲ 237,633	▲ 189,582	▲ 70,023	▲ 69,642	▲ 65,250
Payments for dividends	--	--	--	--	▲ 202,384	--
Proceeds from (settlement of) notes payable	▲ 190,000	180,095	--	--	--	--
Payments of electricity purchase payable	▲ 128,692	▲ 267,447	▲ 244,340	▲ 744,140	--	--
Payment of payable arising from acquisition of property, plant and equipment	▲ 150,520	--	--	--	--	--
Net Cash Provided by Financing Activities	**7,998,939**	**▲ 3,327,389**	**▲ 1,697,605**	**▲ 3,573,424**	**▲ 2,771,621**	**▲ 4,335,707**
NET DECREASE IN CASH AND CASH EQUIVALENTS	**9,552,381**	**▲ 365,579**	**▲ 686,600**	**▲ 458,860**	**1,076,056**	**1,497,019**
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**5,361,749**	**6,073,057**	**6,759,657**	**7,218,517**	**6,142,461**	**4,645,442**
Restricted cash in bank	▲ 1,945,710	▲ 345,730	--	--	--	**--**
CASH AND CASH EQUIVALENTS AT END OF YEAR	**12,968,420**	**5,361,749**	**6,073,057**	**6,759,657**	**7,218,517**	**6,142,461**

8.3.4 Financial situation of PLN in Sulawesi island

The business scale of PLN in Sulawesi measured by sold energy or electricity sales, falls into approximately 3 % (South Sulawesi 2%, North Sulawesi 1%) of that in the whole Indonesia. Table 8.3.6 shows that the industrial ratio is low while the residential ratio is high in comparison with the nationwide average. This tendency is similar to other external region of Java.

In addition, the consumer average selling price is low, and this shows that there are many small consumers. The demand structure in Sulawesi is characterized as mentioned above, but the total average unit selling price is almost the same as that of nationwide average or in Java Island.

Table 8.3.6 Customer-wise sold energy and sales revenue (2005)

REGION	ITEM		Residential	Industrial	Business	Social	Government	St. Light	Total	Percent
All PLN	Energy Sold	GWh	41,184	42,448	17,023	2,430	1,726	2,221	107,032	100.00
		(%)	38.5%	39.7%	15.9%	2.3%	1.6%	2.1%	100.0%	--
	Revenue	Mil. Rp.	23,188,785	24,189,890	11,825,952	1,384,770	1,260,284	1,396,542	63,246,221	100.00
		(%)	36.7%	38.2%	18.7%	2.2%	2.0%	2.2%	100.0%	--
	Ave. Price	Rp/kWh	563	570	695	570	730	629	591	--
Jawa	Energy Sold	GWh	28,982	37,734	12,253	1,813	1,168	1,345	83,295	77.82
		(%)	34.8%	45.3%	14.7%	2.2%	1.4%	1.6%	100.0%	--
	Revenue	Mil. Rp.	16,382,490	21,372,326	8,445,399	1,020,079	828,421	851,655	48,900,370	77.32
		(%)	33.5%	43.7%	17.3%	2.1%	1.7%	1.7%	100.0%	--
	Ave. Price	Rp/kWh	565	566	689	563	709	633	587	--
Outside Jawa	Energy Sold	GWh	12,203	4,714	4,770	617	557	876	23,737	22.18
		(%)	51.4%	19.9%	20.1%	2.6%	2.3%	3.7%	100.0%	--
	Revenue	Mil. Rp.	6,805,362	2,817,563	3,381,475	364,690	431,863	544,887	14,345,841	22.68
		(%)	47.4%	19.6%	23.6%	2.5%	3.0%	3.8%	100.0%	--
	Ave. Price	Rp/kWh	558	598	709	591	775	622	604	--
All Sulawesi	Energy Sold	GWh	1,756	677	547	104	95	134	3,314	3.10
		(%)	53.0%	20.4%	16.5%	3.1%	2.9%	4.0%	100.0%	--
	Revenue	Mil. Rp.	948,948	392,933	383,766	61,332	72,078	85,526	1,944,583	3.07
		(%)	48.8%	20.2%	19.7%	3.2%	3.7%	4.4%	100.0%	--
	Ave. Price	Rp/kWh	540	580	702	589	758	638	587	--
- South Sulawesi (Wil. Sulselrabar)	Energy Sold	GWh	1,124	587	368	64	63	88	2,294	2.14
		(%)	49.0%	25.6%	16.0%	2.8%	2.7%	3.9%	100.0%	--
	Revenue	Mil. Rp.	606,169	329,527	253,839	36,622	46,764	56,123	1,329,046	2.10
		(%)	45.6%	24.8%	19.1%	2.8%	3.5%	4.2%	100.0%	--
	Ave. Price	Rp/kWh	540	562	690	572	742	635	579	--
- North Sulawesi (Wil. Suluttengo)	Energy Sold	GWh	633	90	179	40	32	46	1,020	0.95
		(%)	62.0%	8.9%	17.6%	3.9%	3.2%	4.5%	100.0%	--
	Revenue	Mil. Rp.	342,779	63,406	129,926	24,710	25,315	29,402	615,538	0.97
		(%)	55.7%	10.3%	21.1%	4.0%	4.1%	4.8%	100.0%	--
	Ave. Price	Rp/kWh	542	701	725	617	788	645	604	--

Source: excerpts from "PLN Statistic, 2005"

On the other hand, viewing from the supply side, the values of supply cost per sold energy in 2006 are Rp. 1,109/kWh in the South Sulawesi Branch and Rp. 1,801/kWh in the North Sulawesi Branch as shown in Table 8.3.7 and Table 8.3.8, which exceed Rp. 934/kWh of the national average value remarkably in the North Sulawesi branch.

Table 8.3.7 Power supply cost of PLN Wil. Sulselrabar

(2002 to 2006)

(Unit: Rupiah)

Statement	2006	2005	2004	2003	2002
Purchase of electric power	**844,687,839,900**	**708,937,894,021**	**613,308,805,202**	**563,007,672,152**	**560,014,541,939**
Rental of diesel generation set	**46,627,365,913**	**23,546,748,322**	**19,343,838,086**	**15,931,908,697**	**18,622,985,746**
Transmission using charge	**--**	**--**	**--**	**--**	**--**
Generation function:					
Hydropower generation	48,073,458,667	50,451,778,700	47,373,739,885	44,433,653,704	179,788,200,698
Steam power generation	29,737,479,553	9,208,869,729	23,616,373,357	46,283,806,120	22,550,038,165
Diesel generation	870,563,121,613	429,120,338,908	286,229,183,624	290,086,462,748	351,953,491,163
Gas turbine generation	367,015,471,693	211,685,539,784	121,713,624,690	79,898,642,462	122,302,598,646
Geothermal generation	--	--	--	--	--
Combined cycle generation	--	--	--	--	--
Subtotal	**1,315,389,531,526**	**700,466,527,121**	**478,932,921,556**	**460,702,565,034**	**676,594,328,672**
Transmission function:					
Transmission system	60,978,437,504	59,898,420,935	56,103,576,757	51,323,939,452	47,609,162,224
Tele information and data system	15,063,657,756	14,527,984,035	14,732,096,433	6,889,609,602	3,462,526,608
Subtotal	**76,042,095,260**	**74,426,404,970**	**70,835,673,190**	**58,213,549,054**	**51,071,688,832**
Distribution function:					
Distribution system	224,472,921,066	215,325,942,124	206,234,616,833	308,383,119,127	295,550,479,366
Distribution dispatcher unit	3,457,812,324	2,460,911,122	2,807,693,436	2,092,668,851	670,369,682
Subtotal	**227,930,733,390**	**217,786,853,246**	**209,042,310,269**	**310,475,787,978**	**296,220,849,048**
Customer administration	**70,603,281,682**	**60,052,203,830**	**58,436,072,689**	**48,969,370,987**	**37,329,731,643**
Supporting function:					
Administration expense	145,309,345,164	117,380,733,977	110,387,974,907	89,922,818,125	66,897,146,140
Logistic	4,752,490,517	3,660,861,398	4,222,665,886	2,969,117,002	3,111,930,293
Workshop	12,375,852	26,398,625	547,367,226	423,890,145	648,148,706
Laboratory	193,339,200	368,743,995	841,252,001	558,972,382	890,811,416
Technical services	--	--	--	--	8,200,000
Official buildings	1,468,287,504	1,977,166,899	1,381,742,123	921,376,619	1,013,056,090
Communication	3,445,243,336	3,644,823,538	4,365,595,920	4,742,243,042	7,202,285,101
Other services	--	--	--	--	--
Trainings and educations	--	--	--	--	--
Subtotal	**155,181,081,573**	**127,058,728,432**	**121,746,598,063**	**99,538,417,315**	**79,771,577,746**
Total	**2,736,461,929,244**	**1,912,275,359,941**	**1,571,646,219,055**	**1,556,839,271,217**	**1,719,625,703,626**
Energy sold in kWh	**2,468,100,659**	**2,293,697,614**	**2,154,221,384**	**1,996,936,148**	**1,882,272,277**
Operation cost per Energy sold (Rp/kWh)	**1,109**	**834**	**730**	**780**	**914**

Table 8.3.8 Power supply cost of PLN Wil. Suluttenggo
(2002 to 2006)

(Unit: Rupiah)

DESCRIPTION	2006	2005	2004	2003	2002
Electricity Purchase	**10,305,298,000**	**4,403,348,500**	--	--	--
Rented Diesel	**457,839,597,696**	**243,961,126,748**	**152,909,985,909**	**142,591,552,407**	**47,581,429,087**
Generation:	**1,190,181,076,700**	**678,509,436,685**	**481,283,960,468**	**492,089,967,441**	**768,638,810,020**
Hydro	30,368,793,311	31,912,614,367	28,528,846,842	24,424,715,596	28,024,748,779
Steam	--	--	--	--	--
Diesel	1,114,641,248,338	592,139,770,915	400,387,389,519	428,911,254,206	704,996,101,528
Gas Turbine	--	--	--	--	--
Geothermal	45,171,035,051	54,457,051,403	52,367,724,107	38,753,997,639	35,617,959,713
Combined Cycle	--	--	--	--	--
Transmission:	**22,477,241,363**	**20,490,364,691**	**22,478,281,994**	**16,440,741,777**	**13,584,802,684**
Transmission System	21,081,947,961	19,709,993,960	22,176,257,951	16,440,741,777	13,584,802,684
Tele Information and Data System	1,395,293,402	780,370,731	302,024,043	--	--
Distribution	**147,234,015,029**	**134,213,810,221**	**122,495,501,112**	**206,103,439,109**	**192,265,164,973**
Distribution System	147,234,015,029	134,213,810,221	122,495,134,446	206,103,439,109	192,265,164,973
Distribution Dispatcher Unit	--	--	366,666	--	--
Customer Administration	**50,021,028,948**	**39,251,025,014**	**33,411,841,614**	**31,405,296,958**	**23,584,964,411**
Supporting Function:	**100,381,450,225**	**89,504,299,124**	**75,160,920,755**	**68,645,076,679**	**57,223,276,443**
- Administration	90,232,969,431	79,625,282,321	64,420,092,957	57,938,220,509	47,563,163,662
- Logistic	5,981,718,545	5,075,736,385	4,845,355,018	4,390,710,064	2,978,159,568
- Workshop	23,870,619	28,481,864	25,780,379	37,602,049	56,573,674
- Laboratory	--	--	--	--	--
- Technical Services	73,597,148	75,497,148	78,418,428	54,638,396	169,080,720
- Official Buildings	1,223,182,863	600,277,104	457,695,892	439,138,402	24,081,548
- Communication	2,846,111,619	4,099,024,302	5,333,578,081	5,784,767,259	4,324,641,252
- Other Services	--	--	--	--	2,107,576,019
- Trainings and Educations	--	--	--	--	--
Total Operational Cost	**1,978,439,707,961**	**1,210,333,410,983**	**887,740,491,852**	**957,276,074,371**	**1,102,878,447,618**
Energy Sold (MWh)	**1,098,552**	**1,019,897**	**952,297**	**847,973**	**828,318**
Operation cost / Energy sold (Rp/kWh)	**1,801**	**1,187**	**932**	**1,129**	**1,331**

Although accounts separation system is not introduced in PLN, the South Sulawesi Branch (Wilayah Sulselrabar) and the North Sulawesi Branch (Wilayah Suluttenggo) have prepared their own financial statements as well as other branch offices. The income statement and the balance sheet of Wilayah Sulselrabar are shown in Table 8.3.9 and Table 8.3.10 respectively, and those of Wilayah Suluttenggo in Table 8.3.11 and Table 8.3.12.

As mentioned in the preceding clause, fuel costs exceeded electricity sales except for IPP generation as the whole PLN in 2006 when the rise of fuel prices was remarkable, and this situation is even worse in Sulawesi (particularly in North Sulawesi) where large scale power supply is less, as shown in Table 8.3.9 and Table 8.3.11.

Table 8.3.9 Income Statement of PLN Wil. Sulselrabar

(2002 to 2006)

(Unit: Rupiah)

STATEMENT	2006	2005	2004	2003	2002
Operating Revenues	**2,162,539,670,114**	**1,532,430,486,262**	**1,368,143,122,113**	**1,115,183,166,923**	**857,068,970,472**
Sales of electric power	1,463,055,278,407	1,329,045,604,386	1,260,006,937,934	1,103,387,387,082	844,667,642,747
- Sales of electric power (gross)	1,463,887,333,512	1,329,879,099,666	1,261,356,753,459	1,115,349,942,280	844,667,642,747
- Discount	▲832,055,105	▲833,495,280	▲1,349,815,525	▲11,962,555,198	--
Government subsidy	684,556,582,367	189,494,288,414	91,204,869,000	--	--
Connection fees	12,972,430,397	11,841,314,633	10,727,280,234	9,965,967,086	9,035,144,115
Other revenue	1,955,378,943	2,049,278,829	6,204,034,945	1,829,812,755	3,366,183,610
Operating Expenses	**2,736,461,929,244**	**1,912,275,359,941**	**1,571,646,219,055**	**1,556,839,271,217**	**1,719,625,703,626**
Electricity purchase	844,687,839,900	708,937,894,021	613,308,805,202	563,007,672,152	560,014,541,939
Rental diesel generation set	46,627,365,913	23,546,748,322	19,343,838,086	15,931,908,697	18,622,985,746
Fuel and lubricant oil	1,131,388,033,782	526,110,759,588	289,634,022,749	254,227,775,142	184,482,603,201
- High speed diesel oil	1,033,154,484,797	472,034,904,235	244,006,671,911	184,527,583,132	150,021,597,920
- Medium fuel oil/ Residual oil	81,358,243,927	37,456,564,020	33,112,921,015	56,992,796,383	24,745,535,873
- Water	3,224,844,620	3,605,056,812	3,771,833,068	4,128,291,340	--
- Lubricant oil	13,650,460,438	13,014,234,521	8,742,596,755	8,579,104,287	9,715,469,408
Maintenance	176,096,046,356	148,838,039,800	120,648,873,216	126,310,325,023	132,735,555,329
- Materials	110,022,882,219	100,067,891,006	80,901,285,574	83,206,091,960	70,554,199,933
- Services	66,073,164,137	48,770,148,794	39,747,587,642	43,104,233,063	62,181,355,396
Personnel Cost	200,973,916,487	170,734,469,872	173,208,059,669	144,912,254,730	102,088,989,274
- Salary and Wages	134,413,308,717	123,626,540,370	136,557,044,463	113,670,957,595	80,800,659,278
- Other Personnel Cost	66,560,607,770	47,107,929,502	36,651,015,206	31,241,297,135	21,288,329,996
Depreciation	244,915,079,682	244,206,981,716	275,143,734,765	388,496,867,565	669,835,315,685
Other cost	91,773,647,124	89,900,466,622	80,358,885,368	63,952,467,908	51,845,712,452
Operating Income	**▲573,922,259,130**	**▲379,844,873,679**	**▲203,503,096,942**	**▲441,656,104,294**	**▲862,556,733,154**
Other Income (Expense)	**13,623,702,927**	**▲21,892,333,148**	**▲70,077,057,263**	**18,262,160,715**	**251,234,986,149**
Interest income	1,606,950,188	1,225,991,205	4,616,647,143	38,227,447,066	199,799,918,989
Other income	11,216,628,892	9,215,491,965			
Loan charge	▲7,493,628,564	▲7,130,884,182	▲9,439,359,166	▲12,432,260,342	▲16,706,564,457
Pension charge	▲7,206,471,934	▲5,906,308,245	▲4,575,137,051	▲3,678,532,948	▲1,924,959,840
Other charge	▲7,332,630,930	▲13,505,194,648	▲23,808,996,905	▲25,497,699,476	▲19,979,154,925
Foreign exchange adjustment	22,832,855,275	▲5,791,429,243	▲36,870,211,284	▲21,643,206,415	90,045,746,382
Net Income	**▲560,298,556,203**	**▲401,737,206,827**	**▲273,580,154,205**	**▲423,393,943,579**	**▲611,321,747,005**

Table 8.3.10 Balance Sheet of PLN Wil. Sulselrabar

(2002 to 2006)

(Unit: Rupiah)

As of December 31	2006	2005	2004	2003	2002
ASSETS					
FIXED ASSETS (NET)	**4,401,738,478,614**	**4,512,075,465,793**	**4,689,457,211,181**	**4,936,280,225,953**	**5,122,173,398,637**
Fixed assets (Gross)	6,164,322,011,086	6,022,259,703,415	5,982,750,852,071	5,982,396,989,019	5,793,834,399,800
Accumulated depreciation	▲1,762,583,532,472	▲1,510,184,237,622	▲1,293,293,640,890	▲1,046,116,763,066	▲671,661,001,163
CONSTRUCTION IN PROGRESS	**82,969,583,187**	**45,565,620,271**	**75,474,487,792**	**39,369,782,158**	**38,070,505,948**
INVESTMENT (PARTICIPATION)	--	--	--	--	--
OTHER ASSETS	**185,933,436,411**	**197,209,467,923**	**108,790,057,047**	**30,187,589,987**	**31,821,422,134**
Non operating assets	**172,990,993,250**	**184,484,061,253**	**99,291,511,838**	**22,400,374,202**	**26,098,838,593**
Other accounts receivable (long-term)	**12,552,555,955**	**12,332,186,118**	**9,439,378,534**	**7,673,049,114**	**5,583,416,874**
Deferred cost	**389,887,206**	**389,887,206**	--	--	--
Pre payment (long-term)	--	**3,333,346**	**59,166,675**	**114,166,671**	**139,166,667**
BOND REDEMPTION FUND	--	--	--	--	--
DEFERRED TAX ASSETS	--	--	--	--	--
CURRENT ASSETS	**162,847,280,220**	**141,798,091,964**	**117,701,069,497**	**108,060,565,009**	**125,246,048,906**
Cash and cash equivalent	**21,635,937,400**	**14,410,829,486**	**18,184,342,648**	**13,505,166,608**	**25,780,180,254**
Short-term investment	-	-	-	-	-
Accounts receivable (Net)	**21,629,274,925**	**22,638,637,830**	**35,461,748,241**	**34,133,879,406**	**29,149,726,034**
- Parties with special relationship (Gross)	240,133,000	4,642,018,785	6,432,870,730	4,135,664,341	7,136,457,975
- Elimination (Special relationship)	▲7,203,990	▲139,260,564	▲158,528,026	▲169,081,835	▲233,509,387
	232,929,010	**4,502,758,221**	**6,274,342,704**	**3,966,582,506**	**6,902,948,588**
- Third party (Gross)	23,918,738,661	20,215,625,168	31,704,175,041	30,932,466,883	23,294,939,896
- Elimination (third party)	▲2,522,392,746	▲2,079,745,559	▲2,516,769,504	▲765,169,983	▲1,048,162,450
	21,396,345,915	**18,135,879,609**	**29,187,405,537**	**30,167,296,900**	**22,246,777,446**
Inventories (Net)	**101,454,495,549**	**92,623,923,605**	**49,905,879,902**	**50,137,343,285**	**58,252,396,247**
Money for taxes	--	--	--	--	**135,118**
Other accounts receivable (short-term)	**2,437,388,886**	**3,114,213,738**	**6,671,805,150**	**2,044,667,968**	**1,867,623,163**
	15,690,183,460	**9,010,487,305**	**7,477,293,556**	**8,239,507,742**	**10,195,988,090**
- Parties with special relationship	15,665,558,459	8,895,945,639	7,477,293,556	8,239,507,742	5,182,747,764
- Third party	24,625,001	114,541,666	--	--	5,013,240,326
TOTAL ASSETS	**4,833,488,778,432**	**4,896,648,645,951**	**4,991,422,825,517**	**5,113,898,163,107**	**5,317,311,375,625**
EQUITY AND LIABILITIES					
EQUITY	**▲560,298,556,203**	**▲401,737,206,827**	**▲273,580,154,205**	**▲423,393,943,579**	**▲611,321,747,005**
Retained earnings	▲560,298,556,203	▲401,737,206,827	▲273,580,154,205	▲423,393,943,579	▲611,321,747,005
MINORITY INTEREST	--	--	--	--	--
INTER UNITS ACCOUNTS	**4,968,269,486,803**	**4,780,392,614,341**	**4,804,938,824,361**	**5,051,960,024,542**	**5,417,749,914,106**
DEFERRED EARNINGS	**164,430,900,110**	**152,163,885,677**	**138,935,873,755**	**130,973,027,574**	**120,279,566,928**
LONG-TERM LIABILITIES	**160,691,185,146**	**166,491,249,676**	**159,046,023,317**	**153,291,001,984**	**148,927,726,562**
Other liabilities (long term)	53,824,156,739	66,226,603,873	69,629,051,420	69,746,968,927	80,767,235,429
Customer guarantee money	105,720,091,506	99,025,729,894	88,126,047,434	81,497,286,909	62,009,196,799
Project cost obligation	1,146,936,901	1,238,915,909	1,290,924,463	2,046,746,148	6,151,294,334
CURRENT LIABILITIES	**100,395,762,576**	**199,338,103,084**	**162,082,258,289**	**201,068,052,586**	**241,675,915,034**
Trade obligation	83,944,590,678	142,034,104,881	117,220,854,681	158,998,560,055	212,848,506,388
Pension fund liabilities	2,090,048	28,518,129	32,708,393	86,873,363	199,219,601
Tax liabilities	517,224,958	242,978,511	628,526,502	2,332,922,769	2,016,943,328
Other liabilities	13,103,127,631	54,555,290,490	41,337,893,951	37,112,099,211	24,626,715,043
Unpaid expense	2,828,729,261	2,477,211,073	2,862,274,762	2,537,597,188	1,984,530,674
TOTAL EQUITY AND LIABILITIES	**4,833,488,778,432**	**4,896,648,645,951**	**4,991,422,825,517**	**5,113,898,163,107**	**5,317,311,375,625**

Table 8.3.11 Income Statement of PLN Wil. Suluttenggo

(2002 to 2006)

(Unit: Rupiah)

DESCRIPTION	2006	2005	2004	2003	2002
OPERATION INCOME	**1,021,723,890,542**	**708,238,478,775**	**636,061,618,282**	**481,013,382,385**	**353,463,938,995**
Energy Sales	671,921,838,218	615,537,600,502	568,860,233,782	475,038,220,257	347,980,706,020
Government Subsidy	341,958,976,800	84,687,967,116	54,039,791,000	--	--
Connection Fees	6,720,115,072	6,425,744,710	5,611,082,195	4,840,581,497	4,233,048,153
Others	1,122,960,452	1,587,166,447	7,550,511,305	1,134,580,631	1,250,184,822
OPERATION COST	**1,978,439,707,961**	**1,210,333,410,983**	**887,740,491,852**	**957,276,074,371**	**1,102,878,447,618**
Electricity Purchase	10,305,298,000	4,403,348,500	152,909,985,909	142,591,552,407	47,581,429,087
Rented Diesel Genset	457,839,597,696	243,961,126,748	--	--	--
Fuel and Lubricant Oil	948,170,265,610	436,798,961,334	257,049,563,301	257,765,260,325	265,617,988,581
- HSD	906,423,151,038	397,924,139,216	219,311,681,604	222,428,340,362	226,194,029,905
- Geothermal	23,865,884,185	22,798,050,720	24,610,678,841	20,632,991,550	25,341,394,046
- Water	1,074,218,695	1,110,397,700	1,174,129,530	785,599,550	417,947,590
- Lubricant Oil	16,807,011,692	14,966,373,698	11,953,073,326	13,918,328,863	13,664,617,040
Maintenance	193,632,339,844	178,894,527,981	128,740,356,378	156,453,346,482	118,724,659,442
- Materials	117,732,262,657	123,178,279,346	93,858,153,846	117,623,269,163	84,740,565,092
- Services	75,900,077,187	55,716,248,635	34,882,202,532	38,830,077,319	33,984,094,350
Personnel Cost	120,729,659,060	104,447,472,002	101,783,904,178	88,030,243,111	59,768,365,931
- Salary and Wages	82,010,457,108	73,450,286,921	80,534,661,593	72,394,426,596	48,824,459,043
- Other Personnel Cost	38,719,201,952	30,997,185,081	21,249,242,585	15,635,816,515	10,943,906,888
Depreciation	179,179,983,386	170,744,918,043	189,305,517,190	270,868,218,896	579,629,237,092
Other Cost	68,582,564,365	71,083,056,375	57,951,164,896	41,567,453,150	31,556,767,485
PROFIT (LOSS) IN OPERATION	**▲956,715,817,419**	**▲502,094,932,208**	**▲251,678,873,570**	**▲476,262,691,986**	**▲749,414,508,623**
OTHER INCOME (EXPENSE)	**▲7,694,239,977**	**7,608,583,786**	**▲40,940,562,350**	**▲34,437,890,963**	**17,092,980,815**
- Interest Income	15,773,624,180	29,078,607,832	13,148,249,171	12,423,455,956	7,437,187,998
- Debt Cost	▲9,160,709,571	▲9,469,313,639	▲7,928,782,760	▲22,840,418,696	▲2,507,879,481
- Pension Cost	▲3,142,065,905	▲2,440,982,174	▲2,643,239,263	▲1,890,552,175	▲1,161,361,069
- Other Cost	▲14,143,003,188	▲9,084,620,226	▲14,472,456,892	▲7,238,351,733	▲2,737,725,167
- Exchange Rate Cost	2,977,914,507	▲475,108,007	▲29,044,332,606	▲14,892,024,315	16,062,758,534
PROFIT (LOSS) BEFORE TAXES	**▲964,410,057,396**	**▲494,486,348,422**	**▲292,619,435,920**	**▲510,700,582,949**	**▲732,321,527,808**

Table 8.3.12 Balance Sheet of PLN Wil. Suluttenggo

(2002 to 2006)

(Unit: Rupiah)

DESCRIPTION	31-Dec-2006	31-Dec-2005	31-Dec-2004	31-Dec-2003	31-Dec-2002
ASSETS					
FIXED ASSETS					
Fixed Assets (Gross)	3,954,013,723,209	3,870,762,216,076	3,767,639,810,244	3,546,935,771,123	3,470,749,141,679
Depreciation	▲1,366,845,315,895	▲1,187,637,329,524	▲1,025,486,532,214	▲850,689,211,603	▲579,629,237,092
Fixed Assets (Net)	**2,587,168,407,314**	**2,683,124,886,552**	**2,742,153,278,030**	**2,696,246,559,520**	**2,891,119,904,587**
Construction in Progress	**72,067,478,932**	**67,832,946,281**	**41,357,614,933**	**62,655,414,705**	**23,745,271,127**
Shares	--	--	--	--	--
Other Assets	**34,440,493,561**	**32,493,424,791**	**18,092,797,318**	**40,386,798,762**	**7,886,646,956**
Obligation/ Sinking Funds	--	--	--	--	--
CURRENT ASSETS	**110,968,626,972**	**108,160,186,423**	**84,970,932,868**	**63,782,705,756**	**65,978,920,801**
Cash and Bank	23,148,431,490	17,948,015,098	27,755,789,250	8,781,144,079	7,919,064,164
Temporary Investment	--	--	--	--	--
Accounts Receivables	26,477,876,457	28,279,147,090	25,621,591,379	22,966,935,095	21,974,986,334
Inventories/Materials (net)	52,959,269,803	54,173,345,038	22,905,343,178	25,106,725,088	30,607,413,960
Tax Pre-payment	--	--	--	--	--
Other Receivable (short-term)	3,020,026,704	3,036,294,034	4,071,992,113	3,056,429,874	3,293,271,330
Other Pre-payment	5,363,022,518	4,723,385,163	4,616,216,948	3,871,471,620	2,184,185,013
TOTAL ASSETS	**2,804,645,006,779**	**2,891,611,444,047**	**2,886,574,623,149**	**2,863,071,478,743**	**2,988,730,743,471**
EQUITY ANDLIABILITIES					
EQUITY	**▲964,410,057,396**	**▲493,793,406,736**	**▲290,658,404,894**	**▲504,940,910,072**	**▲726,561,854,931**
Pain in Capital					
Additional Paid in Capital	--	692,941,686	1,961,031,026	5,759,672,877	5,759,672,877
Capital Gain	**▲964,410,057,396**	**▲494,486,348,422**	**▲292,619,435,920**	**▲510,700,582,949**	**▲732,321,527,808**
INTER UNIT ACCOUNTS	**3,204,032,201,888**	**3,069,571,864,082**	**3,021,765,125,102**	**3,206,020,162,511**	**3,560,804,719,772**
RETAINED EARNINGS	**85,800,382,698**	**85,186,098,611**	**74,026,287,236**	**63,326,482,125**	**54,647,186,057**
LONG TERM LIABILITIES	**57,431,864,991**	**53,326,310,486**	**45,283,822,389**	**41,130,249,421**	**39,379,588,925**
Long Term Loan	--	--	--	--	--
Other Long Term Loan	2,681,931,268	775,642,536	--	--	--
Customer Deposits	52,143,572,412	50,609,416,224	43,722,300,679	38,861,869,858	35,415,327,938
Project Cost Liabilities	2,606,361,311	1,941,251,726	1,561,521,710	2,268,379,563	3,964,260,987
Promissory Liabilities	--	--	--	--	--
CURRENT LIABILITIES	**421,790,614,598**	**177,320,577,604**	**36,157,793,316**	**57,535,494,758**	**60,461,103,648**
Accounts Payable	410,320,364,739	164,495,485,541	26,472,087,364	44,017,084,835	50,419,671,817
Retired Fund for Employee	▲8,006,282	550,758	7,979,844	2,319,445	388,754
Taxes Liabilities	1,636,867,958	2,073,806,561	935,929,243	4,434,391,956	2,177,733,814
Other Liabilities	7,776,350,931	5,571,122,874	7,011,074,784	4,982,334,837	4,178,947,191
Other Expenses Liabilities	2,065,037,252	5,179,611,870	1,730,722,081	4,099,363,685	3,684,362,072
Other Current Liabilities	--	--	--	--	--
TOTAL EQUITY AND LIABILITIES	**2,804,645,006,779**	**2,891,611,444,047**	**2,886,574,623,149**	**2,863,071,478,743**	**2,988,730,743,471**

8.4 Financing and private investment promotion

8.4.1 Necessary investment for power development

The investment capital necessary for the power development in Sulawesi for the coming 20 years (2008 to 2027) is summarized as Table 8.4.1 from the study made in Chapter 5 and Chapter 6.

Table 8.4.1 Necessary investment for power development in Sulawesi
(2008 to 2027)

(unit: million US$)

		2008-2012	2013-2017	2018-2022	2023-2027	Total
i) Economic Oriented Development Scenario						
South Sulawesi system	Generation	1,125	507	874	1,263	3,769
	Transmission	472	23	140	53	689
	Total	**1,597**	**530**	**1,014**	**1,316**	**4,458**
North Sulawesi system	Generation	267	199	342	511	1,320
	Transmission	149	55	23	64	291
	Total	**416**	**254**	**365**	**576**	**1,610**
Total Sulawesi	Generation	1,392	706	1,216	1,774	5,089
	Transmission	621	78	163	118	979
	Total	**2,014**	**783**	**1,379**	**1,892**	**6,068**
ii) Local Energy Premier Development Scenario						
South Sulawesi system	Generation	1,227	709	1,226	1,430	4,592
	Transmission	487	23	303	94	906
	Total	**1,714**	**732**	**1,529**	**1,524**	**5,498**
North Sulawesi system	Generation	260	197	282	464	1,203
	Transmission	136	88	16	38	278
	Total	**396**	**285**	**299**	**501**	**1,481**
Total Sulawesi	Generation	1,487	906	1,508	1,894	5,795
	Transmission	623	110	319	132	1,184
	Total	**2,110**	**1,017**	**1,827**	**2,026**	**6,980**

Note: Price escalations are considered.

Since PLN, the state owned power company, has the policy to develop its power systems to support balanced development of the nation's land under the nationwide uniform rate, there is no scope of financing measures such as profit center system or zone pricing to arrange the Sulawesi's own power development. Therefore, PLN headquarters has the right and responsibility to procure and distribute the necessary fund for power development all over Indonesia.

As stated in clause 8.3.1, the electricity rate should be adjusted to archive 8% of ROA in the long term. The amount of fixed assets is around 4.4 trillion Rupiah in North Sulawesi and 2.6 trilion Rupiah in South Sulawesi according to Table 8.3.10 and Table 8.3.12. Then, expected return (profit) of 8% of fixed assets is no more than 350 billion Rupiah (38 million dollar) in South Sulawesi and 210 billion Rupiah (23 million dollar) in North Sulawesi respectively. In contrast, the necessary investment for next 5 years (2008-2013) is bigger amount of 340 million dollar in South Sulawesi and 80 million dollar in North Sulawesi by annualized average. Though it is obvious that security of profit is difficult under the current tariff level, even if succeeded in making surplus making with raising of tariff more than 50 %, the amount of necessary investment is still huge compared with the business scale in Sulawesi.

Therefore, PLN should give priority to connect scattered small scale system with the existing large system (Sulsel system and Minahasa-Kotamobagu system) to get away from the dependence on diesel generations and to save supply costs. At the same time, realistic option is to arrange the investment environment with raising tariff level for IPPs (and PLN) to secure profits so that private entrepreneurs (IPPs) can easily participate in the generation business.

Under such basic recognition, after assembling the situation on the private investment, challenging issues and proposals for private investment promotion in Indonesia in the following part, some specific projects expected from Japan are proposed in the next section

8.4.2 Indonesian environment over IPP business

Late 1980's, private entrepreneurs (including cooperatives) was entitled to enter the power supply business that has long been monopolized by the public corporation (PERUM) PLN, as EEP (Electricity Enterprise Permit) based on the Electricity Law (No. 15/ 1985) in order to respond the rapid increase of power demand originated by economic growth in Indonesia.

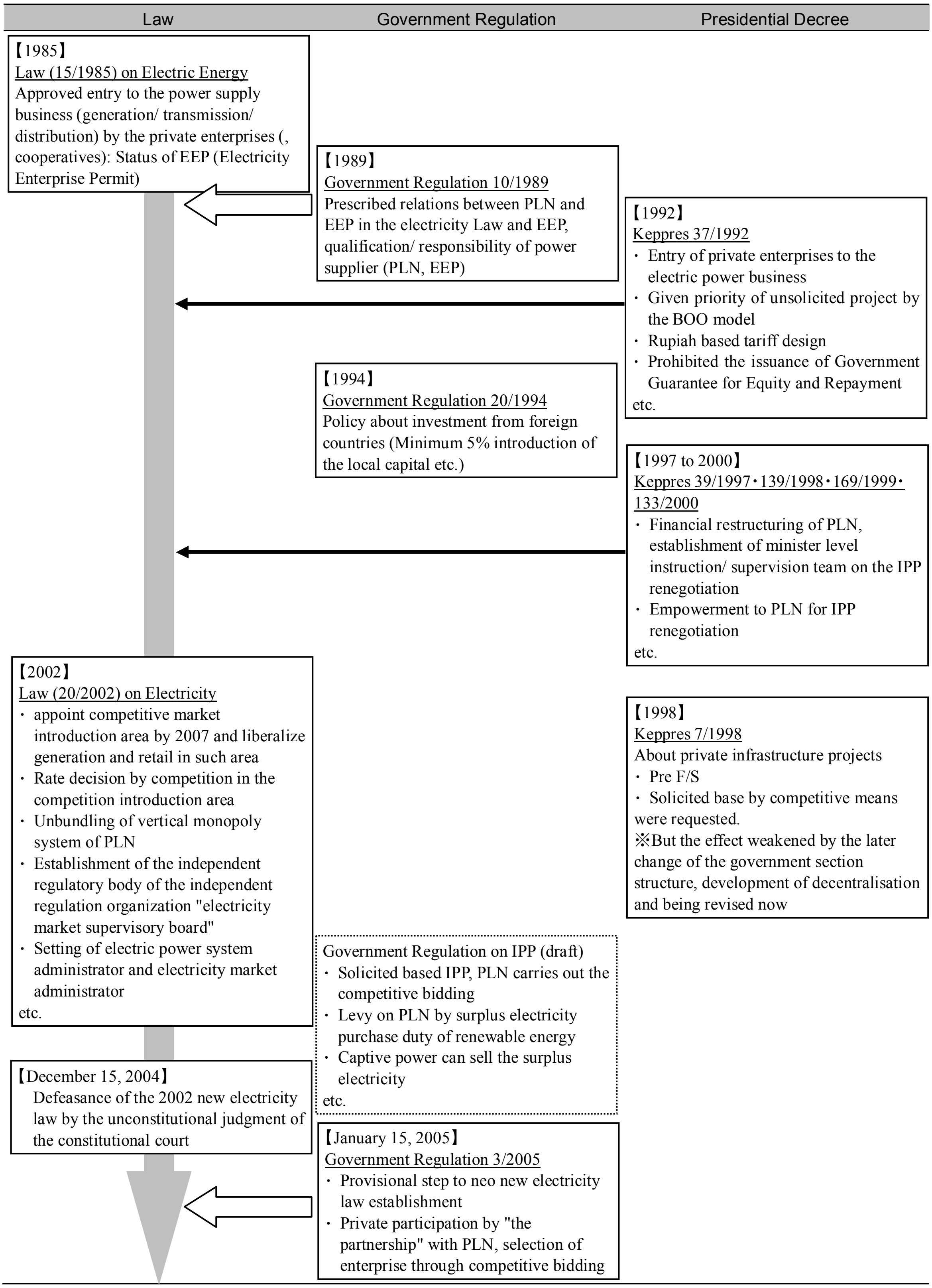
The first IPP invitation in Indonesia (Paiton I & II) was carried out in 1990. The PPA of Paiton I project was concluded in February 1994 and financial close was got about 14 months later. Many IPP projects stood up based on the Presidential Decree (Keppres No. 37/ 1992), and before the economic crisis in 1997, PPA and ESC (Energy Sales Contract) of 26 IPP projects (10,800 MW in total capacity and 13 to 14 billion dollars of total investment) were concluded.

However, large review on the most part of such contracts was pressed by the Asian currency crisis in 1997. PLN made the power purchase agreements with IPPs on the dollar basis, but the sales income of PLN was paid in local currency, so that PLN was forced to bear the large negative spread, and the financial situation of PLN largely turned worse. On this account the Government of Indonesia declared interruption or review of much IPP projects in the Presidential Decree (Keppres No. 39/1997) and started financial restructuring plan such as raise of electricity rate, debt equity swap, reevaluation of assets etc.

About interrupted or reviewed IPP projects, renegotiation of PPA was started based on the Presidential Decree (Keppres No. 15/ 2003) in 2003 and considered to be a review, a renegotiation of PPA is reopened by presidential decree (Keppres No. 15/2,003), and at present, 14 projects are concluded (business continuation), 7 projects are abandoned, 5 projects are bought and one project is under dispute. As the result of renegotiation, PPA with 6.4-8.5 cent/kWh of purchase price at first was reduced to 4.2-5.7 cent/kWh.

The detailed rules on IPP projects were supposed to be prescribed in the supporting Government Regulation in the new Electricity Law (No. 20/ 2002) that determined restructuring of the power sector, but new Electricity Law itself was defeased by the unconstitutionality judgment of the constitutional court in December, 2004 after all.

History of laws and regulations concerning IPP is shown in Figure 8.4.1.



Source: METI "Asian Power Sector Development Support"

Figure 8.4.1 History of IPP-related laws and regulations

8.4.3 Comparison of investment environment among Southeast Asian neighboring countries

The trend of deregulation/ liberalization of the electric utilities spreads to the Southeast Asian countries under the guidance, indication and support from the international organizations such as IMF, the World Bank, the ADB, and power sector reform including privatization of the public electric power utilities and introduction of the competitive market in each country is promoted, and a shift to the infrastructure developement by private sector is being planned.

Under such circumstances, in case of investigating power sector investment in Indonesia from the viewpoint of overseas investor, Southeast Asian neighboring countries such as Thailand, Vietnam, the Philippines can be object of comparison. For example, Goldman Sachs, US Invesetment Bank picked up Indonesia, Viet Nam and the Philippines from the Southeast Asia among the 11 countries (Next 11[59]) where economic development following BRICs countries can be expected. Japanese BRICs Economic Research Institute proposed VISTA[60] as the most possible group of post-BRICs and focused Viet Nam and Indonesia. In such meaning, while ASEAN countries are expected coexistence and co-prosperity in the one economic area, at the same time it may be said that there are rival relations in terms of invitation of (limited) overseas investment.

On the other hand, from the situation of our country, combined with slowdown of the growth of domestic electric demand and development of deregulation/ liberalization of electricity industry, Japanese companies puts big interest in the electricity investment in foreign countries, led by Southeast Asian coutries. Ministry of Economy, Trade and Industry (METI) installed "Asian electricity taskforce" in 2003, and the taskforce studied trend of power sector reform, rearranging the issues on investment/ business environment, examination of business model under such circumstances targeting four countries of Indonesia, the Philippines, Vietnam and Thailand, and gathered the results as a report in 2004.

The followings are according to the argument in the report, updating data based on the recent situation if necessary.

General conditions of focused four countries of Indonesia, Vietnam, Philippines and Thailand are shown in Table 8.4.2.

According to Table 8.4.2, Thailand achieves a little advanced economic development compared with other three countries in terms of per capita GDP and sales of electricity. Regarding Vietnam, compared with Indonesia and the Philippines, per capita GDP is around a half, but a growth rate is high and per capita electric energy sales are almost the same as other two countries. In this way, it may be said that the economic development situation of these Southeast Asian four countries is approximately at the same level although Thailand goes ahead a little.

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[59] Mexico, Nigeria, Egypt, Turkey, Iran, Pakistan, Bangladesh, Korea, Philippine, Vietnam, Indonesia
[60] Vietnam, Indonesia, South Africa, Turkey, Argentina

Table 8.4.2 General condition of Southeast Asian 4 countries

Item	Indonesia	Viet Nam	Philippines	Thailand	Japan (Ref.)
Population (millions)	222.8	83.1	84.2	64.8	127.8
Land area (thousand km^2)	1,860.0	329.3	300.0	513.1	377.9
GDP (billion US$)	281.3	45.2	97.6	176.2	4,565
Per Capita GDP (US$)	1,262	550	1,159	2,721	35,734
GDP growth (%)	5.6	8.4	5.1	4.5	2.8
Regime	Republican	Socialism	Constitutional Republican	Constitutional Monarchy	Constitutional Monarchy
Currency	Rupiah (Rp)	Dong (D)	Peso (P)	Baht (B)	Yen (¥)
Exchange rate (per US¢)[※1]	98.40	159.1	0.53	0.39	1.18
Electrification ratio (%)[※2]	54.1	90.0	71.0	84.7	100
Installed Capacity (MW)[※3]	27,954	11,340	15,619	26,269	234,963
Per Capita Installed Capacity (kW)	0.13	0.14	0.19	0.41	1.84
Energy Generated (GWh)[※4]	127,370	52,050	56,568	132,197	969,135
Energy Sold (GWh)	107,032	44,921	45,158	120,032	882,559
Per Capita Energy Sold (kWh)	480	540	536	1,853	6,908
Maximum Demand (MW)[※5]	19,263	9,255	8,629	20,538	170,244
Maximum Demand growth (%)	1.9	11.7	1.2	6.3	▲0.9
Average Selling Price[※6] (in local currency)	591	787	6.89	2.88/ 2.64	15.8
Average Selling Price (in US cent)	6.00	4.94	12.98	7.41/ 6.79	13.38

※1 As of December 2005
※2 (No. of customers)/ (No. of households)
※3 Public &, Wholesale power supplier and IPP (excluding captive power)
※4 Public & Wholesale power supplier and IPP (at the end of generation)
※5 Oneday maximum output per annum
※6 (Energy sales revenue)/ (Energy sold)
Source: "Statistics of Electric Power Industries in Asian Countries, 2005" (JEPIC, Sep. 2007)

(1) Situation of electricity supply and demand

The current situation and prospect on electricity supply and demand of the four countries are shown in Table 8.4.3. In each country, large-scale investment is continuously supposed for evasion or improvement of power shortage as high growth of electricity demand is expected reflecting steady economic growth.

Table 8.4.3 Electricity supply and demand situation/ prospect

<table>
<tr><th colspan="3"></th><th>Indonesia</th><th>Viet Nam</th><th>Philippines</th><th>Thailand(1)</th></tr>
<tr><td rowspan="3">2003</td><td colspan="2">Installed capacity (MW)</td><td>21,433(2)</td><td>9,895</td><td>15,123</td><td>24,805</td></tr>
<tr><td colspan="2">Maximum demand (MW)</td><td>17,949</td><td>7,366</td><td>8,204</td><td>18,788</td></tr>
<tr><td colspan="2">Utilization factor(3)</td><td>19.4 %</td><td>34.3 %</td><td>84.3 %</td><td>32.0 %</td></tr>
<tr><td rowspan="5">2010
(assumption)</td><td colspan="2">Installed capacity (MW)</td><td>45,853</td><td>21,684</td><td>17,379</td><td>37,945</td></tr>
<tr><td colspan="2">Maximum demand (MW)</td><td>36,493</td><td>16,910</td><td>15,508</td><td>30,587</td></tr>
<tr><td colspan="2">Utilization factor</td><td>26%</td><td>22%</td><td>12%</td><td>24%</td></tr>
<tr><td rowspan="2">Generation to be added after 2003</td><td>Planning(4)
/MW</td><td>approx.
9,300</td><td>approx.
6,000</td><td>825</td><td>8,600</td></tr>
<tr><td>(5)
/MW</td><td>approx.
14,000</td><td>approx.
7,000</td><td>4,150</td><td>approx.
6,000</td></tr>
</table>

Note)

(1) Thai assumption is planned value as of 2011

(2) Excluding captive power generation

(3) Utilization factor ＝ (Installed capacity - Maximum Demand)/ Maximum Demand x 100
Since the actual generation ability considering shutdown or derating of plants is unknown, this value is different from the reserve margin.
In addition, supply shortage has already happened in some areas in Indonesia and the Philippines.

(4) Plants with commitment, Plants under negotiations with invester and plants which location and rated output are fixed in the national long term plan.

(5) Capacity that specific plan is not decided among the capacity that is needed to satisfy the long term plan of the country.

Source: made based on various documents

(2) Structure of power sector

Power supply structure (generation/ transmission/ distribution) of the four countries are shown in Table 8.4.4. IPP is already introduced in the generation section and the transmission business is monopolized by the single state enterprise in each country. About the Philippines, unbundling of generation/ transmission is performed as consistency of electricity sector reform, and sale of generation assets NPC owns is pushed forward. In addition, sale of the business right (concession) of transmission section to private enterprise is prescribed and the procedure is pushed forward as of 2008.

Table 8.4.4 Power supply structure

	Generation	Transmission	Distribution (Retail)
Indonesia	PLN (87%) IPP (13%)	PLN	PLN (monopoly: 17,911 MW)
Viet Nam	EVN (93%) IPP (7%)	EVN	Seven (7) Discos under EVN (Regional monopoly: 6,430 MW)
Philippines	NPC (29%) IPP (71%)	TRANSCO	Private Disco: 19 Nos. Electrification Cooperatives (EC): 119 Nos. (Regional monopoly: 8,248 MW)
Thailand	EGAT (58%) IPP etc. (42%)	EGAT	MEA (6,418 MW) PEA (9,962 MW)

Note) Value in supply scale are as of 2002

Source: made based on various documents

(3) Electricity tariff and pricing policy

Changes of the average retail rate in the four countries are shown in Table 8.4.5. In Indonesia and Vietnam, an increase to 7 cent/kWh is aimed for as the rate level that can retrieve supply cost under the guidance of the World Bank etc. In all countries, compensation by cross subsidies between different consumer categories, or government subsidies is made at present from the policy intention to control the people's strong objection against rate rise, although realization of the "pass through" of the supply cost to the electricity rate is aimed.

Table 8.4.5 Change of the average electricity rate

Year		1996	1997	1998	1999	2000	2001	2002	2003	2004
US dollar basis (nominal; ¢/kWh)										
Indonesia		6.94	3.64	2.62	3.09	2.89	3.22	5.01	5.98	approx. 6.5
Viet Nam				5.06			4.94	5.47		
Philippines (Luzon)		12.13	11.95	9.75	10.49	10.95	11.07	10.32	10.52	
Thailand		5.40	4.88	4.19	4.20	4.42	4.36	4.70	5.01	approx. 6.5
Local currency basis										
Indonesia	(Rp/kWh)	165.43	169.13	210.94	219.68	279.67	334.55	448.03	532.39	585
Viet Nam	(D/kWh)			703.0			743.6	840.0		(The government suggests rate reduction)
Philippines (Luzon)	(P/kWh)	3.18	3.48	3.98	4.10	4.82	5.64	5.32	5.70	(Increase with an average of P. 3.4236 /kWh of NPC generation rates)
Thailand	(B/kWh)	1.37	1.46	1.71	1.59	1.77	1.94	2.02	2.08	2.69 (Increase of fuel adjustment tax (FT) by fuel price hike)

Source: made based on various documents

(4) Power sector reform

In the Philippines, Viet Nam and Thailand except Indonesia, power sector reform is pushed forward including privatization of the state power companies and liberalization. Regarding Indonesia, the outlook is unclear about privatization and unbundling of the state owned power company PLN as the new Electricity Law (No. 20/ 2002) which prescribed power sector reform was defeased by the judgment of the Constitutional Court in December, 2004.

In each country, some form of competition is planned in the generation section. In the Philippines, even the liberalization of retail sales section is prescribed in the Electric Power Industry Reform Act (EPIRA), but the progress of the reform is being considerably late in total.

A summary of the electricity sector reform of four countries is shown in Table 8.4.6. About Indonesia, contents planned under the defeased new Electricity Law are added.

Table 8.4.6 Summary of the power sector reform

	Indonesia		Viet Nam	Philippines	Thailand
	Current	Before defeasance of Law No.20/2002			
Per Capita GDP (in 2005; nominal US$)	1,262		550	1,159	2,721
Per Capita Capacity (in 2005; kW)	0.13		0.14	0.19	0.41
Power Sector Reform Act	Law No.15/1985	Law No.20/2002	No electricity law, but drafting and discussing in Working Group	June, 2001: EPIRA (Electric Power Industry Reform Act) *Feb. 2002: IRR	"A privatization master plan" (April, 98) (cabinet approval), "Energy Industry Act" under drafting
Unbundling	・Among PLN generation sections, separated into PJB and Indonesia Power in Jamari region ・further unbundling is impossible	Unbundling of generation/ transmission/ distribution (retail is finally separated from distribution) ※Only in Jamali system or Batam island	Scheduled (introduction of Single Buyer system)	In progress (distribution already separated)	In progress (distribution already separated)
Energy Policy Maker	MEMR		MOI	DOE	MOE
Independent Regulatory Body	Not yet decided	EMSA	Examining establishment in MOI	ERC	EPPO
Power Utilities	PLN		EVN	NPC/PSALM	EGAT/MEA/PEA
Progress of reform	Disrupted by the defeasance of Law No.20/2002	Step by step	Step by step	legislation to retail competition at a time	Step by step
Introduction of Competition	Generation (Competitive Bidding of IPP projects)	Wholesale→Wholesale & Retail	Wholesale→Wholesale & Retail	Wholesale→Wholesale, Retail & Metering	Wholesale only
Pool (spot market)	—	Not decided	introduction after 2010 according to the ADB road map	During WESM setup preparations ※ Possibly postponed until March, 2005	Initially planning to set up, but abandoned (September, 2003)

	Indonesia		Viet Nam	Philippines	Thailand
	Current	Before defeasance of Law No.20/2002			
Grid Access	Single Buyer	Single Buyer→Third Party Access (TPA)	Single Buyer→TPA	TPA	Single Buyer
Preparation of Codes	Unarranged	Unarranged (draft stage)	Unarranged (in preparation)	Arranged	Scheduled after establishmentof power sector reform act
Country/ Region modeled after	N/A	N/A	China (maintain the government authority) Thailand (Commission by the government decision)	US- PJM	N/A
Electricity Tariff	・Although approached in 7 UScent/kWh level by step-by-step raise, break profit due to fuel price hike ・World Bank, ADB, IMF demand raising of the electricity rate, but the objection of the nation is strong, and the President declares freeze of rate revision to the next presidential election in 2009		・The World Bank requests step-by-step increase to 7US ¢ /kWh ・Raising of the price in the district is difficult	・Apply to ERC for unbundled rate by each distribution company company ・Stranded cost and rural electrification cost are collected by universal charge	・Electricity rate is slowly increasing for a long term ・Cross subsidy between MEA and PEA
Influence of the existing utitlities after reform	Maintain the monopoly of PLN in Transmission & Distribution	PLN continues as a holding company	・EVN governs through capital ・EVN is a holding company	Completely separated	・Policy of accounts separation for generation and transmission section of EGAT
Generation	・IPP already introduced ・New IPP is enforced by "partnership" with PLN	IPP already introduced.	IPP already introduced through BOT contract	IPP already introduced Carrying out the sale process of NPC assets at present	IPP, SPP already introduced
Share of IPP (Capacity base)	13 % (in 2003) ＊ excluding captive power generation		7%（end of 2002）	71% (end of 2002) *Off-take contract with NPC: 52% *No Off-take contract with NPC: 19%	32%（in 2003） including separated IPP from EGAT
Transmission	PLN continues.	Transmission division is separated and privatized.	・Policy of separation in the ADB road map by 2010 ・No specific plan	Sale of concession of TRANSCO (in progress)	Possession and administration of EGAT continues for the time being

	Indonesia		Viet Nam	Philippines	Thailand
	Current	Before defeasance of Law No.20/2002			
System Operation	PLN continues.	Not yet decided (decided by EMSA)	Not yet decided (Three options: continuous enforcement by EVN, setting of the independent system operator,setting of independent market / system operator)	TRANSCO	Install independent system operator in the third stage
Distribution	PLN continues.	Separation of PLN	Carried out by EVN continuously	Private distribution company (DU) mainly MERALCO	MEA/PEA privatization (stock offload) plan after EGAT privatization
Stock offload/ Asset sale	No Plan	Privatization of Generation , Distribution & Retail section of PLN	Government suggests securitization of EVN in 2004 Securitization of a part of power plants and half of them sell off by bidding	Sale of Generation assets of NPC (in progress)	No prospect of the EGAT privatization in 2004 (EGCO of the generation subsidiary, and some part of power station finish stock market flotation)
Government Guarantee for IPP/ BOT	Government Guarantee is prohibited by Presidential Decree 1992 (Support Letter was issued in actual)		Government guarantee till now, but it will be diminished in future	Government Guarantee was given PPA with NPC till now, but is not issued in future	PPA with EGAT No Government Guarantee

Source: made based on various documents

(5) Situation of IPP investment

(a) Introduction of IPPs

Table 8.4.7 shows the share of IPP generation in capacity at present and in 2010. In the Philippines, IPPs by PPA (Power Purchase Agreement) with state owned electric power company NPC and IPPs by bilateral contract with distribution companies consist of more than 70 % of shares in capacity. Moreover, after completion of assets sales and privatization of NPC, almost all the generation facilities will be operated by private capitals.

Table 8.4.7 Current situation and prospect of IPP introduction

Share of Capacity	Current	Plan in 2010
Indonesia	13% (2003)	Approx. 18%
Viet Nam	7% (2002)	Approx. 20%
Philippines	71% (2002)	Approximately 100 % if PSALM asset sell-off is completed. Investment opportunities of new IPP construction.
Thailand	32% (2003)	Approx. 50%

Source: made based on various documents

(b) Rules and regulations on introduction and future procurement of IPP

Table 8.4.8 summarizes the laws and regulations concerning IPP business opportunity or procurement of IPP in the Southeast Asian four countries.

Table 8.4.8 Laws & Regulations on investment opportunity/ procurement of IPPs

	IPP business opportunity	Procurement of new generation
Indonesia	・Law No. 15/1985, Presidential Decree No. 37/1992 etc. ⇒Approved private capital entry to generation/ transmission/ distribution business ・Presidential Decree (Keppres 39/1997) etc. ⇒Renegotiation with IPP due to currency crises ・Government Regulation 3/2005 ⇒Future private sector electricity business is carried out by partnership with PLN	Competitive Bid * excluding the following projects: 1) Renewable Energy 2) Generation business by gas developer (Marginal Gas) 3) Generation business by coal developer (Mine Mouth) 4) Surplus energy sale by captive power generation 5) In case of supply crisis of electric power system
Viet Nam	・100 % private project * Upper limit for 100% private investment projects (20% of total generation capacity) ・EVN JV with the state enterprise like EVN is possible	・EVN specifies a project for the time being ・But the ADB suggests the introduction of competitive bidding after single buyer shift
Philippines	・Prescribed sale of NPC generation assets etc. to private enterprises by EPIRA (2001) ⇒PSALM is carrying out a bid ・When private enterprise participates in a new power project, the private enterprise shall make a business plan after discussion with DOE/ERC and take EIA and the examination of local government. In addition, examination/ approval of SEC/DTI/BOI is also required.	・Sequentially bidding for the sale of old NPC assets ・Proposal for new power supply
Thailand	・Prospect to the present necessary generation capacity by invitation of IPP phase I/ II by the government in 90's, and development of (four) power development projects by EGAT ・Intention of bidding for projects made ahead of schedule in PDP 2004	・EGAT builds 50% of the new power supply ・Competitive bidding for remaining 50% by Regulator that are established in the future (PPA concluded with EGAT)

Source: made based on various documents

(6) Business environment about IPP investment

Examining IPP investment, surrounding environment such as primary energy policy in the host country, fuel supply structure and procedures/ system on investment is important.

Primary energy policy, fuel supply structure and IPP investment scheme including preferential treatment in the Southeast Asian four countries are shown in Table 8.4.9, Table 8.4.10 and Table 8.4.11 respectively.

Table 8.4.9 Outline of primary energy policy

	Oil	Gas	Coal
Indonesia	For reduction of oil dependence of domestic demand and environmental measures (Blue Sky Policy), switch from oil to natural gas is promoted. * Oil importing country: cannot serve with domestic resources * Abolishment of subsidies to oil products * With subsidy abolition, the ratio of the oil for generation is reduced to half by 2010.	・ For reduction of oil dependence of domestic demand and environmental measures (Blue Sky Policy), switch from oil to natural gas is promoted. * sufficient domestic resources ・ Wholesale price is determined by the negotiations between producers and Pertamina, so that the price is different at each gas field and does not always link international price. ・ Selling price of Pertamina is determined by cost +α, and no government control on the pricing	・ Domestic price links international price ・ Possibility to extend share with gas by the decrease of oil ratio in the field of generation * sufficient domestic resources
Viet Nam	Plans further use of domestic product crude oil * With no domestic oil refinery, all the domestic product crude oil is exported and oil products are imported * Domestic oil refinery construction plan (Dung Quat refinery; operation after 2006 etc.) * MoF announced import duties reduction of oil products in 2003	・ Plans production expansion and utilization of own domestic gas ・ Weight on utilization of domestic gas in generation for the time being ・ Activation of the marine gas field development, examination of the marine pipeline laying	・ Volume of production increased dramatically from the mid of 1990's ・ More than 1/3 of the volume of production is for export; the main export counterparts are China, Japan etc. ・ Vietnamese government promotes construction of coal thermal (Vinacoal plans seven power station construction for the next 10 years) ・ In March, 2003, the new coal layer is discovered in the north Red River Delta area
Philippines	・ Most of oil are imported ・ Promotion of fuel switch (oil ⇒ gas) about the deteriorated power station ・ Promotion of use of gas than oil from environmental viewpoint	Plans gas use expansion by the utilization of the Palawan offshore gas field (the most important problem of the Philippine energy policy) * Keep natural gas selling price lower than import price and competent with coal * Land gas pipeline (Bat-Man I) construction * Gas switch such as Limay thermal * Examining introduction of natural gas cars as an anti-environment measure of the transport sector	・ For domestic coal protection, coal importers are imposed to buy up domestic coal fixed quantity of domestic coal. WTO requests abolition of such system ・ Most are imported (domesitic coal is low-calorie, includes abundant alkali and is hard to use)

	Oil	Gas	Coal
Thailand	・Most of oil is imported ・Oil to gas switch of deteriorated power stations ・Promotion of gas use than oil from environmental aspect side ・For self-support rate improvement, encouraging domestic crude oil development by the joint venture with foreign countries	・Directionality of natural gas use promotion clarified by Prime Minister Thaksin's speech in 2001 ・Breakaway from gas import dependence ⇒Gas field development with Malaysia is in progress	・Growth rate is highest in long-range outlook of EPPO ・Disadvantageous on environmental aspect * changed of site and fuel from coal to gas in the Ratchaburi project by the repulsion of inhabitants

Source: made based on various documents

Table 8.4.10 Fuel supply structure

		Oil	Gas	Coal
Indonesia	Supplier	PT. Pertamina (Persero)		・PTBA ・Contractor (Mainly Local Enterprises) ・KP (mining right) holder ・KUD
	Public/ Private	Public		Public/ Private
	Plan of Privatization etc.	As for the Pertamina, the regulation authority was transferred to BP Migas and the monopoly of the down stream section is removed by the new oil and gas law (2001) ※But Pertamina bears fueling delivery responsibility of fueling and delivery to domestic market for four years after effect Change of the Pertamina to limited liability company (Persero) is decided by Government Regulation (PP 31/2003) with signature in June, 2003		Mining needs authorization of local government
Viet Nam	Supplier	Petro Vietnam		VINACOAL
	Public/ Private	Public		Public
	Plan of Privatization etc.	In the domestic oil retail market, monopoly of four government corporation of Petrolimex, Saigon Petro, PVTC, and PETEC. Foreign capital has duty in league with domestic companies. Price was under government control, but got possible to set freely within government guidance since 2004. Private entry to sales market is under discussion.		Supply had been performed under government control, but came to cut it by VINACOAL came to sale since 2004 (possible to negotiate price with consumers)
Philippines	Supplier	PNOC		PNOC
	Public/ Private	Privatization planned		Privatization planned
	Plan of Privatization etc.	・Refinement/ sales division subsidiary Petron of PNOC privatized in 1993 ・Foreign/ private capital entered down stream section in 1998 ・74 companies registered as oil retail as of 2002.		Most of coal are generation and cement industry use
Thailand	Supplier	PTT etc.	PTT etc	Banpu etc.
	Public/ Private	Partially Privatized	Partially Privatized	Private
	Plan of Privatization etc.	・Part of stocks listed in December, 2001 ・70 % of share in retail with PTT, Shell, Exxon and Caltex together	・Unocal is the largest domestic gas production company ・Sold gross quantity to PTT through pipelines, and PTT is the seller to consumers	・Banpu is the largest local coal mining/ supply company. ・Banpu finances projects such as BLCP by oneself.

Source: made based on various documents

Table 8.4.11 Investment scheme/ preferential treatment for IPP investment

		Indonesia	Viet Nam	Philippines	Thailand
Preferential Treatment	VAT	No courtesy (10% for import goods, domestic products and services)	Exemption about imported facilities and machines to be fixed assets of foreign companies or fixed assets for the implementation of the business cooperation contract	・Tax exemption for imported parts, raw material and refill (Generally 10%)	No courtesy (10%)
	Custom duty, Import tax	・Import tax 5% of capital goods ・Import tax 5% of raw materials for two years productive capacity * applied to approved projects in foreign direct investment (PMA) by BKPM, BKPMD or overseas establishment	Import tax exemption on imported facilities and machines forming fixed assets	Duty exemption for imported parts	・Reduction of import duties for imported machines ・Reduction of import duties for imported raw materials / parts * Usually 0-30% according to primary materials/ product classification; and 5% for instruments
	Corporate Income Tax	No courtesy (30 %)	・reduced to 10%, 15%, 20% depending on projects for a certain period of time * Usually 28% ・Subtraction of loss carried forward for five years	・Additional subtraction from taxable income, personnel expenses ・Additional subtraction for the large-scale infrastructure construction * Usually 32%	・Exemption for three to eight years, and Subtraction of loss carried forward for longest five years * Usually 30%
	Others	ITH (Income Tax Holiday) was abandoned under agreement with IMF in Jan. 2000.		・Simplification of customs ・ITH * 6 years for pioneer field * 4 years for non-pioneer field	
Conditions such as local capital participation etc.		・Minimum 5% of local capital ・For foreign capital companies, 100% foreign capital is possible. However, a part of face value stocks should be sold to the Indonesian nation or business entities within 15 years after a business start		Minimum 40% be local capital for utilities * IPPs are not utilities	

Source: JETRO ASEAN center

(7) Wrap-up

Based on the situation of power sector reform, introduction of IPPs, laws and regulations on IPP investment and surrounding business environment for IPPs mentioned above, classifying the IPP investment risk added issuance of government guarantee and preferential treatment, can be classified into four categories (off-take risk, fuel supply risk, policy and legislation change risk and foreign exchange & overseas remittance risk) as shown in Table 8.4.12. In addition, according to this result, the degree of the risk cover of each country is ranked as high, medium and low, as shown in Table 8.4.13.

As a result, the Indonesian IPP investment environment cannot but say there is no advantage compared among the Southeast Asian four countries. Especially, the new electricity law that focused on the introduction of competitive market was disposed of as mentioned in Chapter 2, so that power supply business is permitted for only the state owned power company (PLN) and status of private business including became unstable and unclear[61]. Moreover, PLN the off-taker of generated electricity by IPPs has worsening financial difficulties adding no government guarantees for PLN's liabilities. These are pointed out as the main causes why the degree of risk cover in Indonesia is judged low.

In the following clause, challenging issues on the IPP investment environment in Indonesia are arranged.

[61] Private enterprises are granted to participate in the project only when the state-owned enterprise solicit them in the form of partnership, investment etc.

Table 8.4.12 Current conditions of the IPP risk management of Southeast Asian four countries

		Indonesia	Viet Nam	Philippines	Thailand
Laws and regulations concerning IPP		・IPP invitation by Presidential Decree No. 37/1992, postponement and review by Presidential Decree No. 39/1997, renegotiation by Presidential Decree No. 15/2002 ・Unconstitutional judgment for new Electricity Law 20/2002 while ordinances to treat IPP was drafted	・In 1992, BOT was placed as type of investment in foreign investment act (revised in 2000) ・In 1998, an investment rule (Decree No. 62, the following "BOT rules") about the BOT/ BTO/BT contract including the foreign investment	・Establishment of BOT act in 1990. ・Revision of BOT act in 1994 ・Establishment of EPIRA (Electric Power Industry Reform Act) in 2001, unbundling and privatization of NPC	・Law of private sector utilization for public works in 1992, privatization promotion of national enterprises, entry promotion of private sector in public works ・Announcement of IPP Program in 1994 (to IPP introduction)
Off-take risk	Principal off-taker and its status	PLN (State owned company)	EVN (Public corporation)	PSALM (Power Sector Assets Liabilities Management Corporation)→ electricity pool market introduction	EGAT (Public corporation)
	Description on PPA	・Dollar- based "Take or Pay" clause ・Fuel price adjustment term in purchase price formula	・Dollar- based "Take or Pay" clause ・Fuel price adjustment term in purchase price formula	・Dollar- based "Take or Pay" clause ・Fuel price adjustment term in purchase price formula	・Dollar- based "Take or Pay" clause ・Fuel price adjustment term in purchase price formula
	Status of PPAliabilities	No description	・Prescription in BOT rules that the state organization entrusted by the government guarantees the commitment on off- take of the Vietnamese enterprise in the BOT/BTO/ BT contract	NPC debt as a part of the sovereign debts in Ministry of Finance statistics	・Government has obligation to perform appropriate fund supply by EGAT act when EGAT fell into finance difficulty ・Historic support posture by the government (guarantee for all external liabilities)
	Government Guarantee or Support Letter	Support Letter (Effectiveness ?)	Government Guarantee	Government Guarantee	None
Fuel supply risk	Principal Fuel Supplier	Pertamina, PTBA etc.	Petro Vietnam etc.	PSALM (in case of geothermal, PNC supplies steam for nothing)	PTT etc.

		Indonesia	Viet Nam	Philippines	Thailand
	Contract form	Independent FSA (Parties concerned of FSA is different from PPA)	Independent FSA (Parties concerned of FSA is different from PPA)	ECA (Energy Commerce Agreement)	Independent FSA
	Institutional support	None	Prescription in BOT rules that the state organization entrusted by the government guarantees commitment about the fueling of the Vietnamese enterprise in the BOT/BTO/BT contract	None	None
	Government Guarantee or Support Letter	Support Letter	Government Guarantee	Government Guarantee	None
Policy / Legislation change risk	Description on PPA	Buy out clause by PLN	Buy out clause by the government	Buy out clause by PSALM	Buy out clause by EGAT
	Government guarantee or institutional support	Support Letter	Government Guarantee (In PPA, the Government iteself is buyout subject of buyout)	Government Guarantee (BOT act prescribes a step by the government at the time of the early end of the contract)	None
Foreign exchange/ Overseas remittance risk	Prescription on PPA	Offshore escrow account	Offshore escrow account	Offshore escrow account	Offshore escrow account
	Government guarantee on freedom of foreign exchange/ overseas remittance	Support Letter	・Government guarantee (stated support of the government clearly in BOT Law) ・Central bank secures foreign exchange and overseas remittance by BOT rules	Government Guarantee	None
Government policy on Government Guarantee or Support Letter		No future issuance of Support Letter	No future issuance of Government Guarantee	No future issuance of Government Guarantee	—
IPP business environment	Preferential Treatment for IPP (Tax etc)	None	Courtesies following for BOT/BTO/BT business (including generation business) ・Import tax exemption for	Courtesies following for IPP business ・Exemption of corporate income tax for a certain period	・Generation business is appointed as special importance type of industry by the Board of Investment (BOI) proclamation,

		Indonesia	Viet Nam	Philippines	Thailand
			imported raw materials and articlse for project implementation ・Exemption of land tax, land use fee	assuming registration to the Investment Committee ・Additional subtraction for workers etc.	the following courtesies: ・Machine import tax exemption ・Eight years exemption of corporate income tax
	Remarks	・Example that a local court of law does not accept arbitration on the occasion of dispute solution ・Generation businesses regulation/ Generation business JV regulation (Local corporate participation duty of 5%)	Complexity of administrative procedures peculiar to socialism countries	・Outlook of review of purchase price by the government (all IPP contracts review specified in EPIRA = electric power industry reform act) ・Example of judicial intervention on rate setting	・Two examples that IPP projects changed fuel and geographical convenience, and restarted by the opposition movement of inhabitants for fear of environmental problem ・Cover order to EGAT and PTT from the government in the recent example that increase width of fuel adjustment (FT) was kept lower than the actual (The government considers right protection of enterprise side)

Source: Study Team based on "Japan Institute for Overseas Investment, Nov. 2004"

Table 8.4.13　　Risk-cover and government guarantee for IPP investment

				Indonesia	Viet Nam	Philippines	Thailand
Institutional support and investment environment	Governing Law of IPPs			×	○	○	○
	Individual risk cover	Off-take risk (incl. foreign currency risk)	Single Buyer system	○	○	○→△	○
			Sovereign characteristics of off-taker liabilities	×	○	○→△	○
		Fuel supply risk	Fuel supply obligation by off-taker	×	×	○→△	×
		Policy/ Legislation risk	Buy-out by off-taker	△	△	○→△	○
		Foreign exchange risk	Free foreign exchange and overseasremittance	○	○	○	○
	Reliability of macroeconomy			×	×	×	○
	Overall evaluation			△	△	△	○
Issuance of government guarantee				△→×	○→×	○→×	×

Note: ○, △ and × indicates the degree of risk cover; as ○: high, △: medium, ×: low (or none)

Source: Study Team based on "Japan Institute for Overseas Investment, Nov. 2004"

8.4.4 Challenges in private investment promotion in Indonesia

On the basis of comparison results of the electricity private investment environment in the Southeast Asian four countries mentioned above, challenging issues in the private investment to the Indonesian power sector are compiled as follows:

(1) Legislation

After unconstitutional judgment for the new Electricity Law (No. 20/ 2002), only the government regulation No. 3/ 2005 which was established for the purpose of evading a legal blank, cannot secure the status of future IPP business.

It is decided that the private enterprise can participate in the power business when it is solicited by PLN. But specific form of partnership (JV, O&M contract etc.) in the IPP business, allotment of responsibility between both parties and the method to decide them remain unclear.

In addition, it is not specified how to coordinate the competitive bidding for generation projects as the establishment of the government ordinance regarding the procedure for the selection of private sector participation" which was declared establishment in January 2005 in the Indonesian Infrastructure Summit 2005.

(2) Power development plan and competitive bidding procedure

It is decided that future private sector participation projects are procured through competitive bidding. As for the investment in generation section, not only the IPP but also the project by PLN itself is pushed forward in parallel. In Indonesia, full generation capacity cannot be utilized due to unarrangement of transmission facilities. Under such circumstances, there is concern that the profitability of new IPP projects depends on the future transmission development and other generation projects including PLN's own funding ones.

(3) Status of captive power generation and special supply

Utilization of surplus energy from captive power generation and special supply such as Cikarang Listrindo which exists a lot in Indonesia should be examined from the viewpoint of efficient use of electric power. However, qualification on the operation of specific supply and backup supply by PLN, conditions on surplus electricity purchase are illegible

(4) Concerned legal system

As for the investment in the power sector, there are other regulations regarding general private participation and foreign investment, regulations with questionable effectiveness and variety of rules and regulations, adding the umbiguity of the status of IPPs, so that it is not easy to understand the correspondency of such laws and rules.

(5) PLN's ability to fulfil PPA

Financial situation of PLN, the off-taker of the generation electricity by IPPs, is bad, and default risk of the liabilities (payment to IPPs) is big under the current situation.

(6) Site requisition

In the example of past IPP projects, investors needed to perform all of requisition of construction site and transmission facilities site by their own efforts.

In some cases, negotiations with local people ran into difficulties and delay by various kinds of obstacles. The problem of land expropriation can be a big risk for investors, and in addition, rise of generation cost is concerned about.

(7) Fuel supply

Uncertainty about development/ supply of natural gas is big as detailed rules of Oil & Gas Law (No. 22/ 2001) and pricing regime of supply price is unarranged. In past IPP projects, when an enterprise procure gas, individual negotiations with the gas field that held gas rights and interests or rights and interests maintainer of transportation business were needed.

Investors bear a big risk on the both sides of price and period.

In addition, the coal thermal development by the private capital is expected as well as the development of coal thermal power supply of 10,000 MW (so-called crash program) by PLN (cf. Chapter 2), but fuel transportation problems occurred to the Suralaya coal-fired station in the past, and investers are concerned about certain supply of coal.

8.4.5 Measures for private investment promotion in Sulawesi

(1) Obligation to buy up renewable energy

In Indonesia, PLN's obligation to buy up renewable energy is prescribed to promote use of renewable energy. In MEMR Ministerial Decree (No. 1122/2002) established in June, 2002, purchase obligation is imposed on PLN about a private (company/ group) dispersed power supply by renewable energy less than 1 MW. In addition, the object of purchase obligation was extended to the output of 1-10 MW in the ministerial decree (No. 2/2,006) in January, 2006. Table 8.4.14 shows the summary of the buying up obligation of renewable energy.

Table 8.4.14 Renewable energy buy-up obligation scheme

	MEMR Decree No. 1122/2002	MEMR Decree No. 2/2006
Output	less than 1 MW	1～10 MW
Contract term	One (1) year	Ten (10) years
Purchase price	・LV connection: 60 % of PLN's Production Cost ・MV connection: 80 % of PLN's Production Cost	

However, the following issues can be pointed out for promoting future renewable energy development.

- The existing scheme basically focuses on the small and medium scale generation by domestic capital, and has no scope for large scale development utilizing foreign capital.
- Although basic conditions are prescribed as shown in Table 8.4.14, actually purchase price and contract term in PPA are decided by contract negotiation with PLN, different

from the conditions in Table 8.4.14.

- Grounds of purchase price are not clear without production cost of PLN being announced.
- There is no courtesy on purchase price for the electricity generating system that it is clear that production cost called small renewable energy is expensive.

For large-scale renewable energy development by the private capital, it is necessary to deal with the above-mentioned issues.

(2) PPP: Public Private Partnership

In general, renewable energy development represented by hydropower and geothermal requires large initial investment. PPP model is nominated as one of the measures on the basis of commerce which can reduce financial burden of the public sector compared with pure public projects and, investment risk of private investers. Three types of PPP, namely, i) hybrid type ,ii) OBA and iii) BTO for Value are nominated as PPP models suitable for generation business. The followings are summery of these models.

Additionally PPP on hydropower development in detail is stated in Clause 8.5.1 referring to Malea Hydropower Development for an example.

i) Hybrid type PPP

Hybrid type PPP is a method to share the construction of a power station with public sector and private sector. The private sector also performs all the operation and maintenance work in many cases. Since private sector bears a part of construction costs, public investment can be most surely reduced. Illustratively, there is Philippine San Roque Hydropower Project.

ii) OBA (Output Based Aid)

An IPP business entity (private sector) performs construction of the project in OBA scheme same as in ordinary BOT, but after commissioning, the IPP business entity is supported by public sector in the form of receiving public funds for output, namely, power supply. All the project construction cost is borne by private sector, so that public expenditure can be saved. However, OBA cannot unbundle construction risks and hydrological risks perculiar to hydropower development from private sector compared with Hybrid type PPP.

In addition, OBA may be considered to be a sort of subsidy system for the operation by the private. A negative opinion against Ministry of Finance (MOF) performing borrowed money may be reflected related to the generation business in the case of Indonesia in the privatization way. OBA may be denied by the principle of the self-supporting accounting system even if return can be expected from financial funds of the private sector business concerned.

iii) BTO for value

BTO for Value support is the form to wipe out the side of subsidy of OBA scheme. While in OBA scheme, public service actually provided by private sector is financed, in BTO for value scheme, public fund is utilized to buy some part of assets realized by private investment. But the T = transfer of the ordinary BTO tends to be free, but cannot but think about payment here.

BTO for value scheme as well as OBA scheme cannot unbundle the risks peculiar to hydropower development from private sector.

8.5 Proposed Projects from Japan

8.5.1 Execution of Hydro Master Plan

PLN is working out, every year basically, the General Electricity Supply Plan (RUPTL), which stipulates the middle term power develop planning for the country. The planning possibly has included issues of the potential hydropower project listing[62] for recent years. The Indonesian power sector therefore is suffering from the clear picture of the ultimate power development. In Indonesia two large scale hydropower potential studies[63] were conducted. The first one was in 1980s and the other was in 1990s. Such hydropower potential studies can be evaluated significant in the realization of the hydropower development. Bakaru No. 1 (126 MW, South Sulawesi) and Besai (90 MW, South Sumatra) are both examples of the successful outcomes of the studies.

However, the past hydropower potential studies might not stand on the up-to-date concept of the hydropower development, in view of the development type (reservoir or run-of-river). Accordingly, one is not very sure these days about development scales and the development priorities concluded in the studies. In the past studies, it seems that the development efficiency might have been maximized and enough attentions might not be paid to the negative impacts on society nature. Giving the considerations to the fuel price hike these years, the decisions of the project feasibilities should also need up to date. The Asahan No. 3 Hydroelectric Project, which was turned into its development stage with Japanese ODA loan last year, was originally planned as a reservoir type hydro and is going to be a run-of-river hydro. In fact, an efficient-most development with a huge reservoir does not fit the present requirement, but a run-of-river based smaller scale development does.

In 2008, the Government of Indonesia is in a great hurry to finalize the so-called "Second Phase of the Crush Program", which urges development of renewable energy based power plants with hydropower and geothermal potential in the country. Primarily speaking, the same program should be based on the updated/latest hydropower potential study.

It is highly demanded for the Indonesian electricity sector to have "the Hydro Master Plan" that can be the fundamentals of the middle to long term power development planning, followed by the up-to-date hydropower potential investigations and studies. The Hydro Master Plan is expected to include:

1) Identification of the hydropower development candidates by using the existing data,

[62] Ordinary thermal plants have larger freedom for planning and do not highly demand development listing when a power development plan is established. For geothermal plants, there already exists the Geothermal Master Plan, JICA, 2007.

[63] The Hydro Potential Study, the World Bank Group, 1978-1982; the Hydro Inventory Study, the World Bank Group, 1997-2000.

2) Preliminary development planning of individual candidates (type, rough electricity generation, rough investment costs including related facilities such as power transmissions),
3) Decision of the development priority, and
4) Execution of the feasibility studies for the high priority candidates.

8.5.2 Sawangan Hydropower Project

The Sawangan Hydropower Project (run-of-river, 16 MW) can be pointed out as one of the high priority hydropowers in the North Sulawesi region. The Sawangan is located downstream of the Tonsealama Hydro Plant mentioned later in this report. It is the last and downstream most hydro cascade in the Tondano river system. The Hydro Inventory Study conducted its Pre Feasibility Study. To overcome the fuel price hike these years and to reduce the average power generation costs in North Sulawesi, it is strongly desired to conduct the full feasibility study for its realization.

8.5.3 Bakaru 2 Hydropower Project

The Bakaru No. 2 Hydropower Project (run-of-river, 63 MW, South Sulawesi) is extention of the existing Bakaru No. 1 Hydro. PLN’s latest power development plan schedules its commissioning in 2015. As the detailed design (with Japanese ODA loan) exists, its promotion stage has reached final. Despite its high profitability computed in the detailed design, there are the sedimentation issues within the existing units of Bakaru No. 1. The sedimentation issues are closely related to other hydropower development in the same river system, such as Poko (reservoir, 234 MW, South Sulawesi). To provide reliable renewable energy to the South Sulawesi System, it is highly desired to promote the Bakaru No. 2, followed by the enhanced studies against the sediment issues including a management program of the upstream land use and operations.

8.5.4 Malea Hybrid Hydro PPP

(1) Issues of Private Hydropower Development

The run-of-river hydropower, of which technology has been matured, is high quality renewable energy. Its aggressive development is desired, if the environmental impacts can be mitigated. There are many stagnated hydropower projects due to the higher natural risks and greater investment costs than typical thermal plants. Particularly in IPPs, these high risk and high cost issues discourage private investors and make the financing more difficult.

(a) Higher Natural Risks

Natural condition risks in hydropower development are often too high to overcome for the private investors. This is because i) the geological conditions such as beneath dams are unforeseeable, ii) hydrology, which is virtually the plant's fuel, cannot be figured out in advance, and iii) the construction period is generally much longer.

These issues are all recognized by the private investors as increase of risks and therefore would discourage them from being aggressive in hydropower development. As seen in Table 8.5.1, there is no hydropower project at all among the in-operation IPPs. One can count just one hydropower project, Asahan No. 1 (180 MW), among the 13 PPA-signed IPPs[64].

In Indonesia, where hydro potential is rich but no specific incentive is legislated, private hydropower development can hardly be expected. When private investors attempt to develop it, they would be forced to demand expensive governmental guarantee to relieve the hydropower specific risks.

Box 1 Natural Condition Risks in Hydropower Development

A hydropower project highly depends on the natural conditions. Its dependency is far different from that of a typical thermal project. The natural conditions a thermal project requires are often limited to the powerhouse vicinities, while a hydropower project totally relies on the given natural conditions, even its energy output.

In order for the private sector to make a hydropower project developable, returns to the private investor needs over the project risks. Examples of such developable projects are Asahan No. 2 (an aluminum project) , Nam Theun 2 Hydro in Lao PDR, and not so many others.

Probability to happen to meet such developable hydro projects are not high. It must be difficult to expect development of a number of hydropower projects without special incentives are provided to private investors.

Table 8.5.1 In-Operation IPPs

	Name of Plant	Fuel	Area	Capacity	Commissioning
1.	Salak 4, 5 & 6	Geothermal	Java－Bali	165 MW	Oct. 1997
2.	Pare – Pare	Heavy Oil	Sulawesi	62 MW	May 1998
3.	Cikarang	CC	Java－Bali	150 MW	Dec. 1998
4.	Sengkang	CC	Sulawesi	135 MW	Mar. 1999
5.	Darajat	Geothermal	Java－Bali	180 MW	Feb. 2000
6.	Wayang Windu	Geothermal	Java－Bali	110 MW	Jun. 2000
7.	Paiton I	Coal	Java－Bali	1,230 MW	Jul. 2000
8.	Dieng	Geothermal	Java－Bali	60 MW	Oct. 2000
9.	Paiton Ii	Coal	Java－Bali	1,220 MW	Nov. 2000
10.	Palembang Timur	CC	Sumatra	150 MW	Sep. 2004
11.	Tanjung Jati B	Coal	Java－Bali	1,320 MW	Oct. 2006
12.	Cilacap	Coal	Java－Bali	562 MW	Feb. 2007

Installed capacity over 50 MW. As of May 2007. CC stands for combined cycle.
Source: PT. PLN

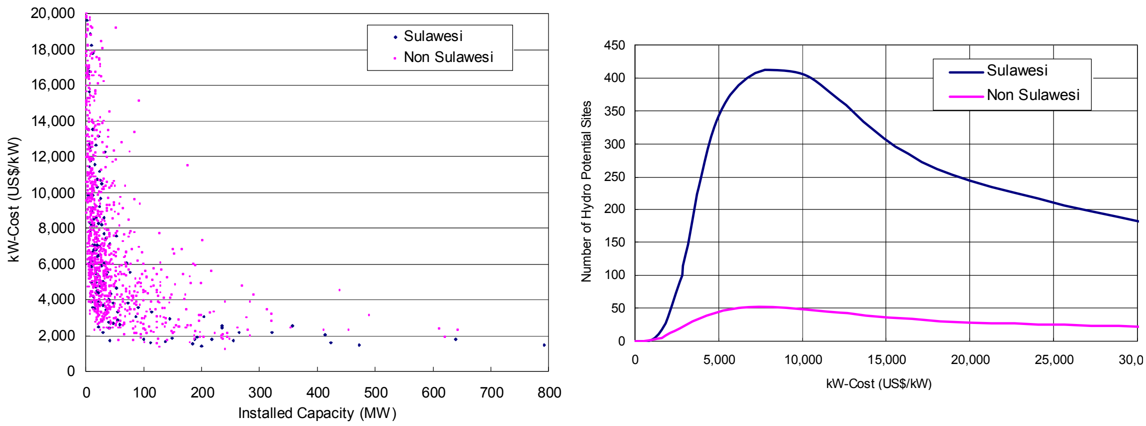
(b) Large Investment Cost

According to the Study Team's survey in 2007, on one hand PLN reportedly estimates US$1,100/kW of the unit construction cost for typical thermal plants. On the other hand, most

[64] Installed capacity over 50 MW. Excluding extention of the existing IPPs.

of hydropower candidates have US$2,000/kW of the construction cost or greater, as shown in Figure 8.5.1. The hydropower candidates with US$2,000 of the construction cost or less are only 9.4% in Sulawesi (15 candidates out of 160), and 2.2% in all over Indonesia (28 out of 1,251).

Hydropower, which does not require fuels, should be developable even with higher initial investment than typical thermal plants. As compared in Table 8.5.2, however, a test calculation warns that a hydropower can yield a good return to the investor only when the initial investment is 160% to that of the typical thermal plant or less. The virtual upper limit of the hydro's unit construction cost can therefore be regarded to be US$1,800/kW. The test calculation assumes 30 years of the evaluation years. Because private investors often take much shorter evaluation years, US$1,800/kW of the virtual limit might be underestimated.



(a) Distribution (b) Cumulation

Source: Study Team based on Hydro Inventory (PLN-World Bank, 2000)

Figure 8.5.1 Planned Installed Capacity and Construction Unit Cost of Hydropower Candidates in Indonesia

Table 8.5.2 Comparison of Hydro and Thermal

(Unit: US$ million)

Year	Hydro				Thermal			
	Cost	Income	Net	IRR	Cost	Income	Net	IRR
0	-180	0	-180	-	-110	0	-110	-
1-30	-5	42	37	-	-20	42	22	-
Total	-342	1,261	919	-	-704	1,261	557	-
PV (10%)	-231	396	165	20%	-297	396	100	20%

Capacity:	100 MW
Annual Energy:	700,800 MWh/yr
Initial Cost:	US$110 million for coal-fired, US$180 million for hydro
Yearly O&M Cost:	3% of the Initial Cost plus fuel cost
Generation Cost:	2.86¢/kWh for hydro, 2.23¢/kWh for coal-fired
Annual Fuel:	287,000 ton/yr x US$60/ton, 6,000 kcal/kg, heat rate 35% (for coal-fired)
Tariff:	0.06 US$/kWh
Annual Income:	US$42 million

Source: Study Team

(c) Difficulty of Financing

Because of aforementioned (a) and (b), financing of hydropower becomes more difficult. Eventually, many hydro candidates would be given up by the experienced investors with good sense. Here, inexperienced investors might easily get opportunities to step into the hydropower development. That is, hydropower projects even with high risks might look as if attractive enough in comparison with typical thermal projects.

In fact, a couple of hydropower projects, of which business concession has been obtained by local inexperienced investors, are observed freezing. Although the Malea Hydro, discussed later in this report, is estimated to be US$1,631/kW of the unit construction cost (which is less than US$1,800/kW of the virtual hydro limitation), a local investor, who reportedly once acquired the business concession has not been successful in its financing.

(2) Hydropower Development by Public Sector

Under the situation that can hardly expect active private promotion, the hydropower development is forced to mostly rely on the Public Sector. The conventional public projects demand less financing charges and accordingly the total project cost could be maintained inexpensive. As the public projects bring an enormous amount of the national debt to the country, however, all of the hydropower cannot be developed by the Public Sector.

(3) Rationale and Effect of Public-Private Partnership

The Public-Private Partnership (PPP) in hydropower development has the great significance in i) reduction of the private sector's risks. Eventually, one can expect ii) reduction of the project implementation cost in comparison with the pure private projects, iii) optimal input of the public money for the hydropower projects, and iv) acceleration of the private investment in the hydropower projects.

There exist a lot of forms of PPP realization, such as from O&M Contract[65] until BOO. Taking all of i) to iv) above into consideration, it is believed that a form of BOT plus the public sector's involvement should be the best and practical choice in the hydropower development. More specifically, (1) Hybrid, (2) Output-based Aid (OBA), and (3) BTO for Value, plus (4) Public-Private Joint Venture scheme, which seems the main formation assumed in the new PPP Law[66] could be the candidates to choose. Despite less public money input expected, as compared in Table 8.5.3, the Hybrid seems the only scheme that can relieve the private sector from the hydro specific natural condition risk. The Hybrid forces the public sector to take over such natural condition risk. However, this should not be a serious issue, because the same risk needs to be fully bore by the public sector anyway under the conventional public projects.

Box 2 Definition of PPP

UK: To provide efficient public services by means of "outsourcing", "PFI", "Public Agency", or "Privatization" depending on attributes of the services through introduction of the market mechanism.

USA: Part or whole of the activities executed by the private sector in stead of the conventional public sector, including any relationships between the public sector and the private sector.

Japan: Any public services, which improve the service efficiency, create new jobs and new industry through "markets" and "competition" opened to the private sector.

Sources for the above: IEEJ-METI, Japan

Asian PPP Study Committee: Implementation of the infrastructure development, administrative services, etc. through work demarcation by the public and private sectors.

Table 8.5.3 Comparison of 4 PPP Schemes

Effect	Hybrid	OBA	BTO for Value	Joint Venture
i) Reduction of Implementation Cost	A certain amount of the cost reduction can be expected from the financing charges and insurance cost.			Depends on depth of thepublic sector's involvement
ii) Relief of Private Sector's Risks	The hydro specific natural condition risk could be unbundled.	The hydro specific natural condition risk remains, because the completion risk needs to be borne 100% by the private sector.		Not sufficient for the private sector.
iii) Optimal Input of Public Money	Because of remarkable private investment, all of 4 schemes must be effective for reducing the public money input, once a project is realized. It is quite possible to optimize the public money input to the hydropower projects.			

Source: Study Team

If the Hybrid PPP scheme, which is detailed later in this report, is introduced, the private sector's focus is shifted onto the powerhouse plus its auxiliaries from the overall hydropower facilities. This focus shifting could vanish US$1,800/kW of the virtual hydro limit. The Hybrid Scheme can be appreciated from the public sector's point of view such that hydropower projects economically feasible but financially not viable can be developed with private investment.

[65] O&M Contract: Public sector builds facilities. Private sector manages the facilities for the contract period.

BOO: Build-Own-Operate、Private sector is responsible for financing, design, construction, ownership, and operation.

[66] Replacement of Presidential Decree No. 67/2005 for Government Cooperation With Business Entities In Providing Infrastructure.

(4) Proposal of Malea Hybrid Hydro PPP

The public sector's concerns are i) huge debt in the public projects and ii) enormous governmental guarantee requested in the private (IPP) projects. Either choice would bring about large amount of the national liability. The private sector's concern is the difficulty of gaining reasonable profits from the hydropower projects.

Box 3 Features of Malea Hydro

Scheme:	Ron-of-river (no resettlements)
Location:	Tanatoraja, South Sulawesi
Installed Capacity:	191 MW (tentative)
Catchment Area:	1,493 km^2
Annual Rainfall:	3,000 mm
Average River Runoff:	95 m^3/s
Max. Turbine Discharge:	51.2 m^3/s (tentative)
Effective Head:	440 m (tentative)
Headrace Tunnel:	Φ4.7 m×8.4 km (tentative)
Annual Energy:	1,465 GWh (tentative)
Construction cost:	US$230 million

The Malea Hybrid Hydro PPP is proposed as discussed below. It can overcome both sectors' issues.

(a) Basic Concept

A Hybrid PPP is applicable and effective to infrastructure development projects. The concept of the Hybrid PPP is straightforward; the public and private sectors jointly take respective responsibilities to and profits from a single project. The private sector behaves as a usual private power producer. For example, the public sector develops the non-power station part, and the private sector develops the power station part. Then, the public sector enjoys low tariff electricity purchased from the private sector and the private sector gains reasonable return from less investment.

A case study of the Hybrid PPP for Malea Hydropower Project is compared with the conventional public and conventional BOT schemes in the following table. In the table, values attributed to the conventional BOT scheme are not recommended figures but based on the likely proposal requested by the typical reputable investors. For example, the estimation of the governmental guarantee in the conventional BOT scheme is as much as the total debt of the BOT company, say 70% to the total implementation cost.

Public Sector: Responsible for planning, design, construction, and financing for the upstream facilities from the water intake to the just-upstream of the powerhouse. The relatively high cost overrun risk and/or completion risk such as in the headrace tunnel can be unbundled from the private work. After completion, these facilities are to be leased to the private sector (the project company) and the public sector can enjoy the reasonable return.

Private Sector: Responsible for construction and financing for the powerhouse and its auxiliaries. After completion, the private sector is to borrow the upstream facilities from the public sector, operate the entire facilities and sell economical electricity to PLN.

(b) Assumptions in Hybrid PPP

The responsibility demarcations are assumed as seen in Table 8.5.4. Financing is assumed to be made by the respective sectors.

The demarcations in the table are sort of the study outputs, coming from the physical boundaries of the respective facilities taking the construction time scheduling into consideration. The demarcations should not be decided regardless of such nature of the project.

Apart from the construction cost, the project implementation demands around US$15 million of the design related cost, and US$ 6 million of the environmental mitigation cost. Both costs are assumed to be bore by the public sector in this case study. However, these costs are not necessarily allocated to the public sector.

It is assumed that all of the post construction activities, such as operation, maintenance, and management of the entire project facilities, are the private sector's roles.

Table 8.5.4 Likely Demarcations of Public and Private Sectors in Malea Hydro Hybrid PPP

(A) Construction (unit: US$ million)

Descriptions	Public	Private	Total
Preparatory Work	25.3	--	25.3
Headworks and Headrace	99.3	--	99.3
Penstock and Gates	--	20.3	20.3
Powerhouse	--	12.8	12.8
Generating Equipment	--	42.9	42.9
Transmission and Substation	--	5.9	5.9
Contingency	18.7	5.4	24.1
Total	143.3	87.3	230.6
Public-Private Proportion	62%	38%	100%

(B) Non-construction Cost (unit: US$ million)

Descriptions	Public	Private	Total
EIA and Lands Acquisition	5.7	--	5.7
Design and Management	15.1	--	15.1
Total	20.8	0.0	20.8
Public-Private Proportion	100%	0%	100%

Source: JICA Study Team

(c) Evaluation of Financial Indicators

Comparisons of the conventional business schemes and the hybrid PPP are summarized in Table 8.5.5, where the comparison subjects are the following three business schemes.

A) Conventional Public Scheme: Denoted as usual PLN projects, normally with soft loans for large scale projects. The public sector including PLN is fully responsible for the project and makes a monopoly of its profit.

B) Hybrid PPP Scheme: The proposed scheme jointly worked by the public and private sectors.

C) Conventional BOT Scheme: Denoted as usual IPPs. The private sector is fully responsible for the project and makes a monopoly of its profit. All values for Conventional BOT Scheme are assumptions for the case of a successful BOT achieved.

Table 8.5.5 Comparison of Financial Indicators in Hybrid and Conventional Business Schemes

Descriptions		A) Conventional Public Scheme	B) Hybrid PPP Scheme			C) Conventional BOT Scheme
			Public	Private	Hybrid Total	
1. Construction Cost		231	143	87	231	231
2. Design & EIA		21	21	0	21	20
3. Financial Charges		8	5	35	40	60
4. Total Implementation Cost (Unit Implementation Cost)		259 (US$1,356/kW)	169 (US$886/kW)	122 (US$639/kW)	291 (US$1,525/kW)	312 (US$1,631/kW)
5. Public Investment		65	42	0	42	0
6. Public LIabilities	National Debt	194	127	0	127	0
	Governmental Guarantee	0	0	0	0	222
	Total Liabilities	194	127	0	127	222
7. Power Purchase Tariff for PLN		N/A	US¢3.0/kWh			US¢6.5/kWh
8. Unit Power Cost for PLN		US¢3.4/kWh	US¢4.9/kWh			US¢6.5/kWh
9. Net PLN Benefit		227	138	0	138	0
10. Net Private Benefit		0	0	50	50	109
11. Project IRR		16.1%	15.4%	14.1%	13.5%	12.9%
12. Investor's IRR		31.5%	30.3%	18.7%	N/A	17.2%

A) Conventional Public Scheme: Denoted as usual PLN projects, normally with soft loans for large scale projects. The public sector including PLN is fully responsible for the project and makes a monopoly of its profit.

B) Hybrid PPP Scheme: The proposed scheme jointly worked by the public and private sectors.

C) Conventional BOT Scheme: Denoted as usual IPPs. The private sector is fully responsible for the project and makes a monopoly of its profit. All values for Conventional BOT Scheme are assumptions for the case of a successful BOT achieved.

1. Construction Cost: The cost required for procuring the project assets or hardware. This cost is assumed identical among the three schemes; A) Conventional Public Scheme, B) Hybrid PPP Scheme, and C) Conventional BOT Scheme.
2. Design & EIA: The cost required for engineering design, project management, and environmental and social mitigations. This cost is also assumed identical among the three schemes.
3. Financial Charges: The costs related to financial arrangements, security packages, and other costs required for project promotion other than its construction.
4. Total Implementation Cost: The sum of 1. to 3.
5. Public Investment: The required investment by the public sector. A) Conventional Public Scheme needs to invest 25% of the total implementation cost, if it is financed with JBIC soft loan. If it is C) Conventional BOT Scheme, the public sector does not need any investment at all.
6. Public Liabilities: Total liabilities of Indonesia, consisting of national debt and amounts equivalent to the governmental guarantee.
7. Power Purchase Tariff for PLN: The unit price to be paid by PLN to purchase 1 kWh of electricity.
8. Unit Power Cost for PLN: The unit cost to be incurred by PLN to obtain 1 kWh of electricity.
9. Net PLN Benefit: Sum of 25 years of benefits or return subtracted by total cost or investment paid by PLN. Values are present worth, discounted at 10% p.a.
10. Net Private Benefit: Sum of 25 years of benefits or return subtracted by total cost or investment paid by the private sector. Values are present worth, discounted at 10% p.a.
11. Project IRR: The internal rate of return for respective schemes. The Project IRR does not count any financial charges or transfer payments. 25 years of the commercial operation is assumed. All of three schemes show enough project IRR for investment.
12. Investor's IRR: The internal rate of return for respective investors. The Investor's IRR counts all of monetary inflow and outflow including financial charges. 25 years of the commercial operation is assumed.

Sources: JICA Study Team

(d) Evaluation of Malea Hydro Hybrid PPP

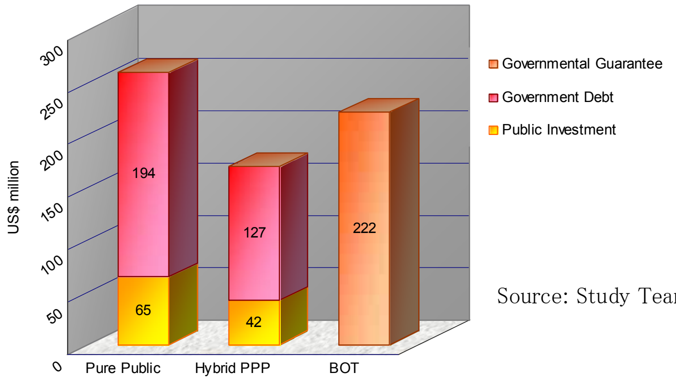
The merits of the Malea Hybrid Hydropower are summarized as below:

i) Risks that can hardly be taken can be unbundled from the private sector. Investment opportunities for the private investors can be increased.

ii) The hydro hybrid can bring profits to both of the public and private sectors.

iii) The public sector can procure the electricity with reasonable cost.

iv) Public money to be put in a hydropower project can be reduced.



Source: Study Team

Figure 8.5.2 Public Sector's Liability in Malea Hydropower

Figure 8.5.2 compares the public sector's liabilities.

(e) Issues of Malea Hydro Hybrid PPP

The issues of the hybrid PPP can be briefed as follows:

i) As the hybrid PPP is literally a mix and composite, an integrated control or managing system is mandate in order to make two components united. To do this, assignment of the specialists should play an important role.

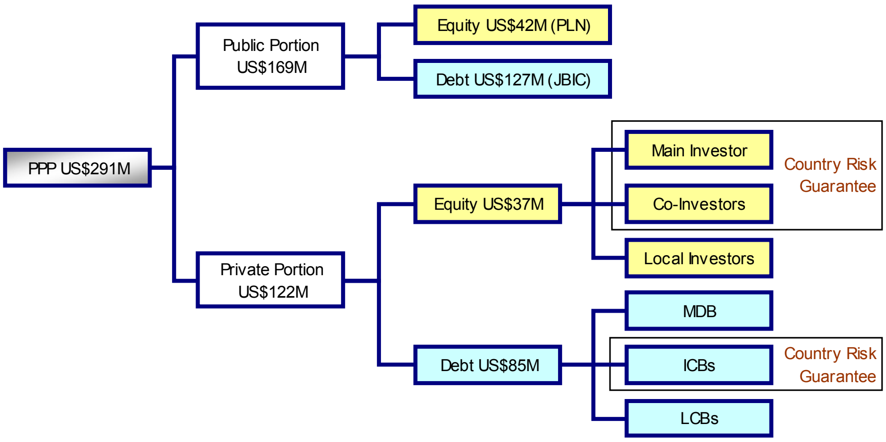
ii) It is reportedly said that the public and private projects are very different each other in their development speed. To have simultaneous completion of the both constructions, careful attention should be paid. Probably, the timing of the private sector procurement would be the important key for success.

iii) There might be a case such that a private company has made his own investigations and/or studies for superior projects. Careful treatment is needed on how such private investigation should be evaluated when selecting the business concessionair. The new decree to replace the presidential decree No. 67/2005 should be referred.

iv) Hybrid PPP can save the public expenditures. The saved public money should be utilized effectively, such as for the regional development.

(f) Financing of Malea Hydro Hybrid PPP

Figure 8.5.3 illustrates one of the likely financial arrangements for Malea Hydropower. In the figure, the Public Portion corresponds to a PLN scheme, which is formed by the Indonesian national financing and the Japanese ODA loan. The Private Portion stands for the private business part like a BOT, which is to be totally developed by the private sector, including financing. A country risk insurance should be expected at least for the loan offered by an foreign lender.

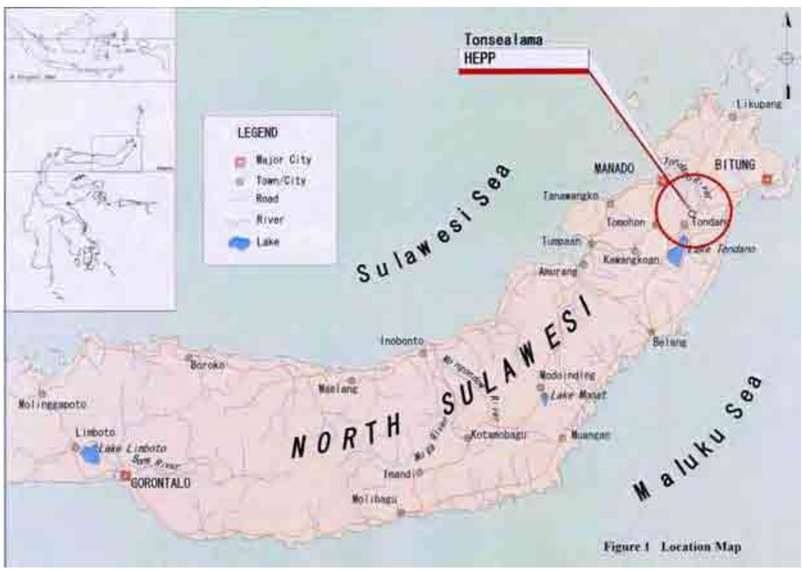


MDB: Multilateral Development Bank, ICBs: International Commercial Banks, LCBs: Local commercial Banks
Source: Study Team

Figure 8.5.3 Likely Financing for Malea Hydro Hybrid PPP

8.5.5 Rehabilitation of Tonsealama Hydropower Plant (renewal of the equipment)

There are three runoff type hydropower cascades in Tondano River at the east end of North Sulawesi. Tonsealama Hydropower Station (14.3 MW) is in the upper stream. Tanggari I (2 units × 9 MW) and Tanggari II (2 units × 9.5 MW) are in the just down stream of the Tonsealama. These three power plants are the main electricity source of North Sulawesi region.



Source: PLN

Figure 8.5.4 Location of Tonsealama Hydropower Station

The Unit No. 1 of Tonsealama Hydropower Station (4.4 MW) was brought from Yamura Hydropower Station in Yamanashi Prefecture in Japan to Tondano area by former Japanese

Army in 1942. The power station has started operation since 1950. It is more than ninety years from the manufacturing. The Unit No. 2 (4.5 MW) was installed in 1970 and the Unit No. 3 (5.4 MW) was installed in 1981 by PLN. Although the original installed capacity is 14.3 MW, the actual capacity has been down to 12.5 MW because of deterioration. It is said that the steel penstock has been decreasing its thickness until 1.0 safety factor.

The Tonsealama Power Station is still an important renewable energy source in North Sulawesi System. PLN has kept considering the total rehabilitation of the station. But PLN has not prepared the specific rehabilitation plan yet because of the limited budget.

Therefore the study team suggests the total rehabilitation of the first hydro turbine of Tonsealama Hydropower Station by a Japan's grant aid considering the history, the importance and the budget scale.

Table 8.5.6 shows the necessary rehabilitation works and table 8.5.7 shows the estimated cost for the rehabilitation.

Table 8.5.6 Necessary rehabilitation works for Tonsealama Hydropower Station

1.	Civil Works including Powerhouse No. 1	
	1.1	Improvement of Access Road to Intake
	1.2	Concrete Work for Rehabilitation of Waterway Facilities
	1.3	Diagnosis of Headrace Tunnel
	1.4	Concrete Plug in Headrace Tunnel
	1.5	Demolition and Re-construction of Valve House
	1.6	Repair and Modification of Anchor Blocks for Penstock
	1.7	Rehabilitation of Powerhouse Structure for Unit 1
2.	Intake and Penstock	
	2.1	Modification of Raking Equipment at Intake Weir
	2.2	Removal/ Renewal of Sand Flush Gate
	2.3	Removal/ Renewal of Butterfly Valve for Penstock No. 1
	2.4	Removal/ Renewal of Penstock No. 1 with Diameter of 1.6 m
3.	Unit No. 1 (Turbine and Generator)	
	3.1	Removal of Existing Generating Equipment to be renewed
	3.2	Renewal of Turbine and Auxiliary Equipment
	3.3	Renewal of Generator and Associated Equipment
	3.4	Renewal of Main Transformer
	3.5	Renewal of Generator Voltage Switchgear
	3.6	Renewal of Control and Relaying Equipment
	3.7	Renewal of OHT Crane
	3.8	Modification of Station-Service Power Supply System
	3.9	Miscellaneous Materials for Generating Equipment Unit No. 1

Source: PLN

Table 8.5.7 Estimated cost for rehabilitation of Tonsealama hydropower station

(Unit: million Yen)

Descriptions	Foreign cost	Local cost	Total
General engineering works	23	116	139
Rehabilitation of penstock	96	214	310
Rehabilitation of Unit No. 1	692	133	825
Rehabilitation of Unit No. 1	316	25	340
Total	1,127	487	1,615

Source：PLN (October 2005)

(a) Powerhouse (b) Hydro turbine

Figure 8.5.5 Current condition of Tonsealama Hydropower Station

8.5.6 Power Grid Interconnection Projects

Among the optimal power development plan shown in Section 8.2, the amount of investment for transmission development is shown again in Table 8.5.8

Table 8.5.8 Amount of Investment for Transmission Development

(Unit: MUSD)

Term	1st	2nd	3rd	4th	Total
	2008-2012	2013-2017	2018-2022	2023-2027	2008-2027
North Sulawesi	136	88	16	38	278
South Sulawesi	487	23	303	94	906
Total	623	110	319	132	1,185

As shown in Table 8.5.8, the half amount of total investment to transmission facilities concentrates on the first 4 years term (2008-2012) in this 20 years plan study. This is because the earlier small isolated systems are interconnected to the large system, the more the fuel cost of diesel generators is decreased. This term includes the following important projects:

I) Grid extension from Manado (Minahasa-Kotamobagu system) to Gorontalo Province
II) Grid extension from Makassar (Sulsel system) to Southeast Sulawesi Province
III) Grid extension in Central Sulawesi Province (from Parigi to Luwuki)

Among the above, the project I) forms backbone of the greater northern Sulawesi system, and II) and III) makes up the basis of greater Northern Sulawesi system. In this way, implementating the first term (2008 -2012) projects will form important backbone of the Sulawesi power system as shown in Figure 6.6.1.

These projects, at the same time, will form the basis of power supply not only city areas but also every area in the Island: as shown in Table 8.5.9, many on-grid substations are constructed also in such areas like Gorontalo, Central Sulawesi and South-east Sulawesi where no or just some substations ever exist.

Table 8.5.9 Number of On-grid Substations to be newly installed

Province	(Existing)	2008-12	2013-17	2018-22	2023-27
North Sulawesi	8	7	0	0	0
Gorontalo	0	4	0	0	0
Central Sulawesi	2	5	3	0	1
South Sulawesi	24	4	0	0	0
South East Sulawesi	0	4	0	0	0
West Sulawesi	2	1	0	0	0

On-grid substations enable 24 hour power supply, which can contribute to the improvement of living standards and the advancement of industry in these areas.

On the other hand, these first-term projects requires a lot of fund as shown in Table 8.5.8, which would be difficult to be all financed by PLN itself. It would be appropriate to apply Yen Loan to the first term transmission project because of its importance for satisfying power in Sulawesi, leading to regional development, and also because of publicity and relatively less burden to environment which is the nature of a transmission project.