5.3 RENEWABLE ENERGY

As explained in Section 3.2 "Outlook or Primary Energy for Ramu System toward 2030" in Chapter 3, the prospective renewable energy resources for the Ramu system at this moment are solar energy and biomass with plantation trees.

5.3.1 Solar Power Plant

There is no concrete plan so far with regard to the solar power plant for power generation in the Ramu system. The solar power plant envisaged for the future is as follows;

- Candidate location
  Somewhere in the east coast of the Morebe and Madang Provinces, as shown in Fig. 3.2-6.

- Output
  The expected output is 1 ~ 10 MW.

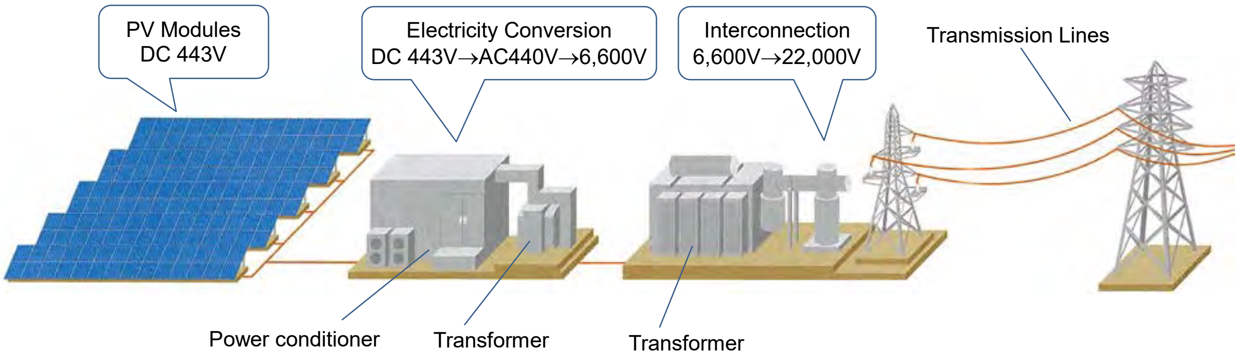
A 10-MW class solar power plant constructed in September 2011 by The Kansai Electric Power Co., Inc. (KANSAI) is shown as an example in this chapter. If the output is different, the plan can be easily modified by changing the number of PV modules.

(1) System of the Solar Power Plant

Fig. 5.3-5 shows the system of the solar power plant. Direct current electricity power generated by PV modules is transformed into alternating current electricity by the power conditioner.

The voltage of the electricity converted by the power conditioners is boosted by the transformer at the power station in steps until it reaches 22 kV. The electricity is then sent through a T/L to a substation.

Used ac voltage will vary according to the output of the plant and the adopted voltages for the existing T/L to be connected.



Source: Prepared by JICA Study Team

Fig. 5.3-1 System of Solar Power Plant

(2) Specifications and Plot Plan of the Solar Power Plant

Table 5.3-1 shows the specifications of the 10 MW solar power plant. Thin-film PV modules are used.

Table 5.3-1 Specifications of the 10 MW Solar Power Plant

Area		ca. 21 ha
Rated Output		10 MW
PV Module	Type	Thin-film PV module
	Output	135 W/module
	Size	1 m × 1.4 m
	Number of Modules	ca. 74,000
Power Generation Capacity		ca. 11,000 MWh/year

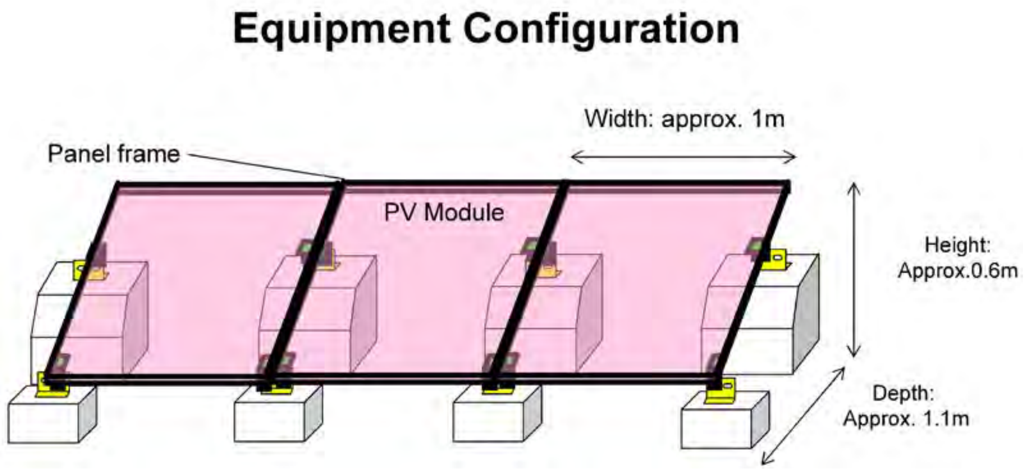
Source: KANSAI

Fig. 5.3-2 shows the plot plan of the 10-MW solar power plant. Around 74,000 PV-modules are arranged into three areas to fit the configuration of the plant site area.

Source: KANSAI

Fig. 5.3-2 Plot Plan of the 10 MW Solar Power Plant

Fig. 5.3-3 shows the configuration of the PV module panel. An inclination angle of 15° for the PV module panel is adopted to mitigate wind pressure and reduce the amount of concrete for the foundation blocks and steel stands.



Source: KANSAI

Fig. 5.3-3 Configuration of the Solar Module Panel

(3) Construction Schedule

Table 5.3-2 shows the actual construction schedule for the 10 MW solar power plant. Civil engineering and electrical works were carried out in order in each area, and the power generation facility was completed in about 2 years.

Table 5.3-2 Construction Schedule for the 10 MW Solar Power Plant

	1st Year		2nd Year	
Area 1	Preparation / Civil	Electrical Works		
Area 2		Civil	Electrical Works	
Area 3			Civil	Electrical Works

Source: KANSAI

5.3.2 Biomass Power Plant

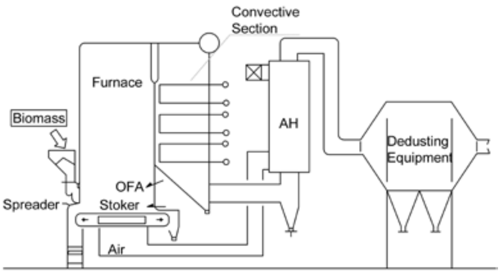
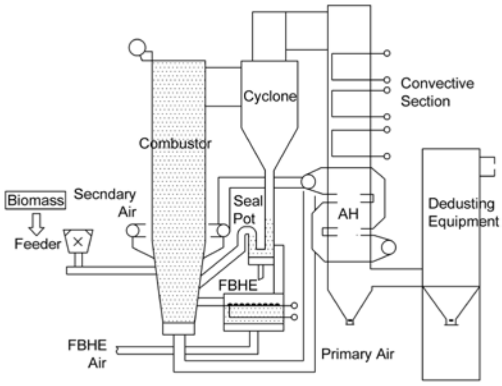
The "Biomass" (the candidate biomass power plant type) and raw material power sources for the Ramu system are as follows, as explained in Section 3.2.1 (9).

Power Plant Type	Direct Combustion System
Raw Material	Plantation trees

(1) Boiler Type

There are two types of boiler in the direct combustion system, i.e., the stoker boiler and Circulating Fluid Bed (CFB) boiler. Table 5.3-3 shows the merits and demerits of each boiler type.

Table 5.3-3 Comparison Table of Boiler Types

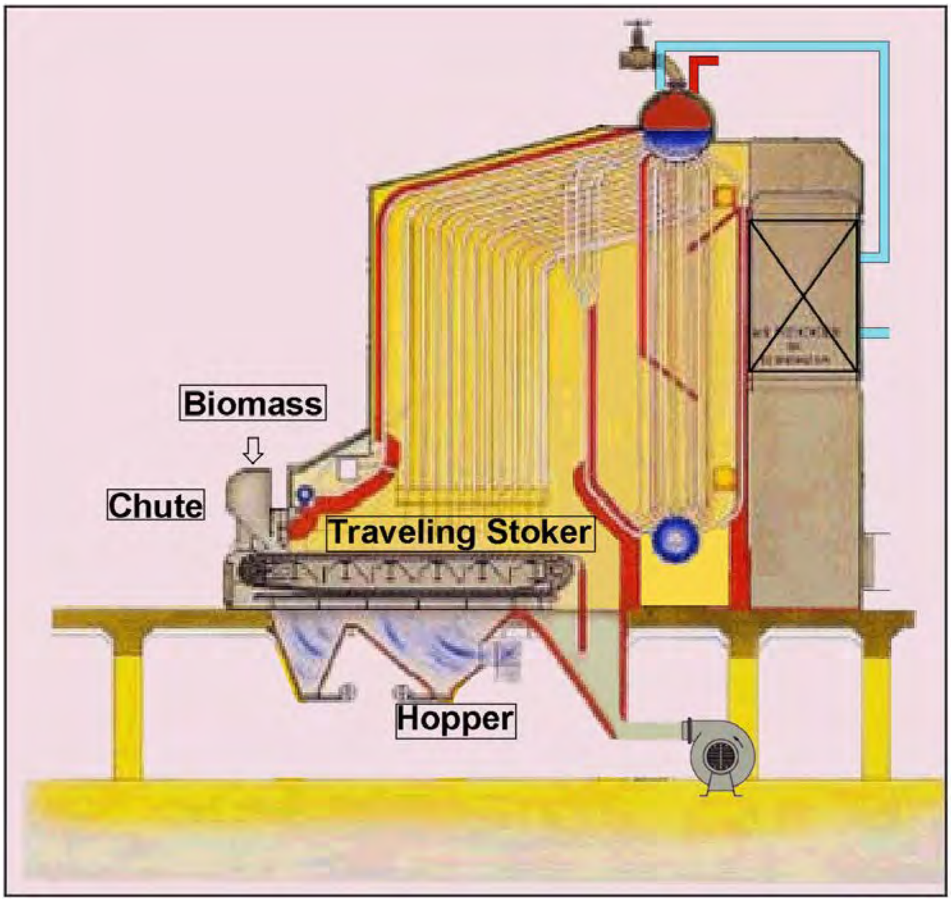
	Stoker Boiler	CFB* Boiler
System		
Boiler Capacity	5 ~ 150 t/h	50 ~ 1,000 t/h
Combustion Efficiency	Good	Excellent
Cost of Construction	Low	High

* Circulating Fluid Bed

Source: Prepared by JICA Study Team

The features of the stoker boiler are low construction cost, easy operation & maintenance, plenty of operating plants, and suitability for small-scale design (~ 50 MW). The features of the CFB boiler are high boiler efficiency, and suitability for medium- and large-scale design (~ 300 MW).

The stoker boiler seems to be suitable for the Ramu system because the envisaged unit power output is up to 50 MW. Fig. 5.3-4 shows a sample of a stoker boiler.

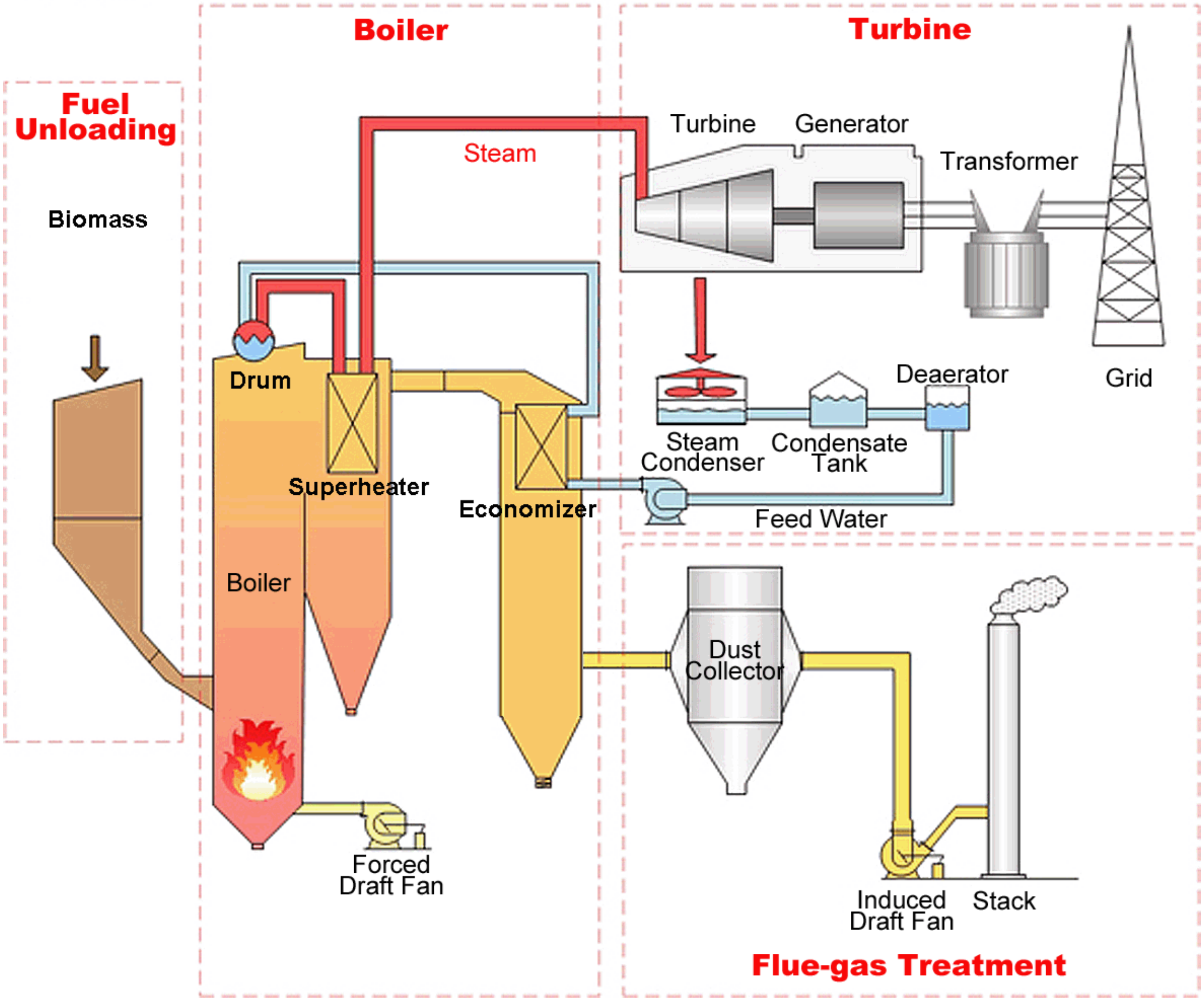


Source: Yoshimine

Fig. 5.3-4 Sample of a Stoker Boiler

(2) Biomass Power Generation System

Fig. 5.3-5 shows the biomass power generation system with a stoker boiler adopted. The biomass is introduced on the traveling stoker through biomass delivery chutes on one side of the boiler. The biomass is combusted on the traveling stoker and the ash is dropped into the hoppers on the other side of the chutes (see Fig. 5.3-4).



Source: Yokogawa

Fig. 5.3-5 Biomass Power Generation System

Combustion air is supplied through the forced draft fan at both the under-stoker and over-fire. High-temperature flue gas passes through the super heater and the economizer with heat exchanges, then low-temperature flue gas discharges into the atmosphere from the stack via the dust collector and the induced draft fan.

The saturated steam from the drum is superheated by the super heater and introduced into the steam turbine. The steam turbine generates the power and sends the power to the grid via the transformer. The exhausted steam is introduced to the steam condenser and changed to feed water. The feed water is supplied to the drum via the deaerator and economizer.

(3) Candidate location

Somewhere in the Markham Valley and/or in the east coast of the Morobe and Madang Provinces and/or in the highland areas, as shown in Fig. 3.2-6.

(4) Specifications of the Biomass Power Plant by Oil Search

As explained in Section 3.2.1 (9) "Biomass," Oil Search is proceeding with a 30 MW (15 MW × 2 units) Biomass Power Generation Project in the Markham Valley in Morobe Province by using plantation trees as fuel. The detailed specifications are shown in Table 5.3-4.

Table 5.3-4 Specifications of the Biomass Power Plant by Oil Search

Item	Specifications
Output	Gross: 36 MW (18 × 2), Net : 30 MW (15 × 2),
Auxiliary Power	6 MW is used to run the power plant and process the wood into chips.
Steam Conditions	75 ton/h, 1300 Psig × 500°C
Boiler Type	Stoker Boiler
Type of Tree	Eucalyptus pellita (The trees grow to maturity between 4-7 years)
Wood Tip Consumption	Approximately 200,000 tons of dry wood (BDMT[1]) /year
Land Area	Approximately 18,000 ha (the tree spacing will be approximately 3.5 m by 2.2 m)
NOx/SOx	NOx: far lower than that of fuel oil, SOx: none
Ash	The ash quantity is approximately 2% of wood tip and returned as nutrient to the plantations.

Source: Oil Search

1 Bone dry metric ton

Appendix 5.1

Hydropower

Appendix 5.1.1

Monthly Energy, Operating Hours & Mean Output of Each Unit of Hydropower Plant

Monthly Energy, Operating hours & Mean Output of Each Unit of Hydropower Plant (2013)

Unit: MWh/month

Plant	unit	item	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Ave
Ramu 1	#1	Gen. Energy	6,598	6,010	5,780	2,832	5,360	4,775	4,980	6,949	6,020	5,476	6,345	6,090	67,214	5,601
		Operation hr	708	625	708	351	548	500	453	644	609	582	651	670	7,048	80.5%
		Ave. Output	9.32	9.62	8.16	8.08	9.78	9.55	10.99	10.80	9.89	9.41	9.75	9.09		9.54
	#2	Gen. Energy	8,015	6,911	8,790	7,920	5,050	7,230	8,710	8,040	7,132	5,690	6,957	5,971	86,416	7,201
		Operation hr	726	628	745	705	442	656	741	937	664	604	664	693	8,205	93.7%
		Ave. Output	11.04	11.00	11.79	11.24	11.43	11.03	11.75	8.59	10.75	9.42	10.48	8.61		10.59
	#3	Gen. Energy	6,080	6,180	5,880	5,620	4,890	4,250	7,627	7,328	6,906	5,140	4,300	2,851	67,052	5,588
		Operation hr	660	618	689	650	514	389	741	705	687	590	481	356	7,080	80.8%
		Ave. Output	9.21	10.01	8.53	8.65	9.51	10.92	10.30	10.40	10.05	8.71	8.93	8.02		9.44
	#4	Gen. Energy	0	0	4,068	5,998	4,169	3,446	0	0	0	0	3,335	6,285	27,300	2,275
		Operation hr	0	0	565	622	455	339	0	0	0	0	308	533	2,822	32.2%
		Ave. Output	0.00	0.00	7.20	9.64	9.17	10.17	0.00	0.00	0.00	0.00	10.82	11.80		9.80
	#5	Gen. Energy	6,964	6,388	7,758	6,582	5,182	7,380	8,124	6,804	6,922	5,092	220	0	67,416	5,618
		Operation hr	715	618	745	687	505	674	743	651	699	584	35	0	6,656	76.6%
		Ave. Output	9.74	10.34	10.41	9.58	10.26	10.94	10.93	10.45	9.91	8.72	6.29	0.00		8.96
	total	Gen. Energy	27,657	25,489	32,276	28,952	24,651	27,081	29,441	29,121	26,980	21,397	21,157	21,197		
		Ave. Output	39.30	40.97	46.10	47.18	50.15	52.61	43.97	40.23	40.60	36.26	46.26	37.51		43.43
Pauanda	#1	Gen. Energy	758	1,081	1,311	2,022	1,067	1,839	541	0	78	1,790	987	1,624	13,097	1,091
		Operation hr	211	266	482	422	304	542	156	0	30	499	352	399	3,663	41.8%
		Ave. Output	3.60	4.06	2.72	4.80	3.51	3.39	3.48	0.00	2.62	3.59	2.80	4.07		3.51
	#2	Gen. Energy	1,362	1,267	2,892	2,766	2,076	2,703	2,596	2,488	3,159	2,517	3,037	3,036	29,899	2,492
		Operation hr	344	324	658	634	721	659	723	663	720	633	672	710	7,461	85.2%
		Ave. Output	3.96	3.91	4.40	4.36	2.88	4.10	3.59	3.75	4.39	3.97	4.52	4.28		4.01
	total	Gen. Energy	2,120	2,347	4,203	4,789	3,143	4,542	3,137	2,488	3,237	4,307	4,024	4,660		3,583
		Ave. Output	7.55	7.97	7.12	9.16	6.39	7.49	7.06	3.75	7.01	7.56	7.32	8.34		7.23
YTOD	#1	Gen. Energy											1,938	2,511	4,448	2,224
		Operation hr											323	418	740	50.6%
		Ave. Output											6.00	6.01		6.01
	#2	Gen. Energy											2,280	1,420	3,700	1,850
		Operation hr											375	250	626	42.7%
		Ave. Output											6.07	5.68		5.88
	total	Gen. Energy											4,218	3,930	8,148	4,074
		Ave. Output											6.04	5.89		5.97

YTOD power plant started generation from November 2013 with limited output. (6 – 7 MW)

(source: PPL)

Monthly Energy, Operating hours & Mean Output of Each Unit of Hydropower Plant (2014)

Unit: MWh/month

Plant	unit	item	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Ave
Ramu 1	#1	Gen. Energy	5,937	5,431	5,485	6,165	5,950	6,180	6,760	7,356	2,966	1,760	6,134	3,509	63,633	5,303
		Operation hr	722	648	653	710	677	666	708	726	289	199	693	410	7,104	81.1%
		Ave. Output	8.22	8.38	8.40	8.68	8.78	9.28	9.54	10.13	10.26	8.84	8.85	8.56		8.99
	#2	Gen. Energy	6,095	4,968	6,205	7,095	6,900	6,440	6,162	7,093	5,913	6,122	6,676	6,052	75,722	6,310
		Operation hr	673	568	663	717	743	677	661	693	544	622	677	632	7,870	89.8%
		Ave. Output	9.05	8.74	9.36	9.90	9.29	9.51	9.32	10.23	10.87	9.84	9.86	9.58		9.63
	#3	Gen. Energy	3,844	4,688	5,240	5,520	5,700	0	0	0	0	2,293	2,456	2,458	32,199	2,683
		Operation hr	560	605	653	716	696	0	0	0	0	310	338	317	4,195	47.9%
		Ave. Output	6.86	7.74	8.03	7.71	8.19	0.00	0.00	0.00	0.00	7.40	7.27	7.77		5.08
	#4	Gen. Energy	5,154	7,811	5,822	6,210	6,791	7,713	6,181	8,221	3,609	6,413	6,942	4,831	75,700	6,308
		Operation hr	447	645	536	512	653	643	532	698	310	602	682	550	6,808	77.7%
		Ave. Output	11.54	12.12	10.87	12.13	10.40	12.00	11.63	11.78	11.66	10.65	10.18	8.78		11.14
	#5	Gen. Energy	0	0	0	0	480	6,795	7,008	3,346	6,122	8,231	6,664	5,472	44,118	3,676
		Operation hr	0	0	0	0	43	585	589	307	490	713	604	629	3,959	45.2%
		Ave. Output	0.00	0.00	0.00	0.00	11.15	11.62	11.90	10.89	12.48	11.55	11.04	8.70		7.44
	total	Gen. Energy	21,030	22,898	22,752	24,990	25,821	27,128	26,112	26,016	18,610	24,819	28,872	22,323		24,281
		Ave. Output	35.67	36.98	36.66	38.42	47.82	42.41	42.39	43.02	45.27	48.28	47.19	43.39		42.29
Pauanda	#1	Gen. Energy	2,257	1,164	1,176	385	44	0	0	0	136	0	0	0	5,162	430
		Operation hr	569	364	328	103	8	0	0	0	48	0	0	0	1,420	16.2%
		Ave. Output	3.97	3.20	3.58	3.74	5.35	0.00	0.00	0.00	2.85	0.00	0.00	0.00		1.89
	#2	Gen. Energy	2,597	1,906	1,887	1,901	2,700	2,255	2,048	2,574	2,515	1,994	608	2,265	25,247	2,104
		Operation hr	608	559	646	696	640	657	612	708	624	645	589	672	7,653	87.4%
		Ave. Output	4.27	3.41	2.92	2.73	4.22	3.43	3.35	3.64	4.03	3.09	1.03	3.37		3.29
	total	Gen. Energy	4,854	3,070	3,063	2,286	2,744	2,255	2,048	2,574	2,651	1,994	608	2,265		2,534
		Ave. Output	8.24	6.61	6.50	6.47	9.57	3.43	3.35	3.64	6.89	3.09	1.03	3.37		5.18
YTOD	#1	Gen. Energy	1,960	2,834	4,567	2,065	4,825	3,236	0	2,810	2,949	3,770	3,981	2,188	35,184	2,932
		Operation hr	288	2,619	694	301	697	486	0	424	450	655	676	407	7,696	87.9%
		Ave. Output	6.80	1.08	6.58	6.86	6.93	6.66	0.00	6.63	6.55	5.76	5.89	5.38		5.43
	#2	Gen. Energy	2,372	1,467	181	2,085	0	584	4,325	2,026	1,095	378	0	1,731	16,243	1,354
		Operation hr	402	212	28	305	0	114	629	291	185	63	0	277	2,506	28.6%
		Ave. Output	5.90	6.92	6.45	6.83	0.00	5.12	6.87	6.96	5.92	6.03	0.00	6.25		5.27
	total	Gen. Energy	4,332	4,301	4,619	4,149	4,825	3,820	4,325	4,836	4,043	4,148	3,981	3,920		4,275
		Ave. Output	6.27	6.71	6.39	6.85	6.93	6.37	6.87	6.76	6.37	5.78	5.89	5.73		10.70

(source: PPL)

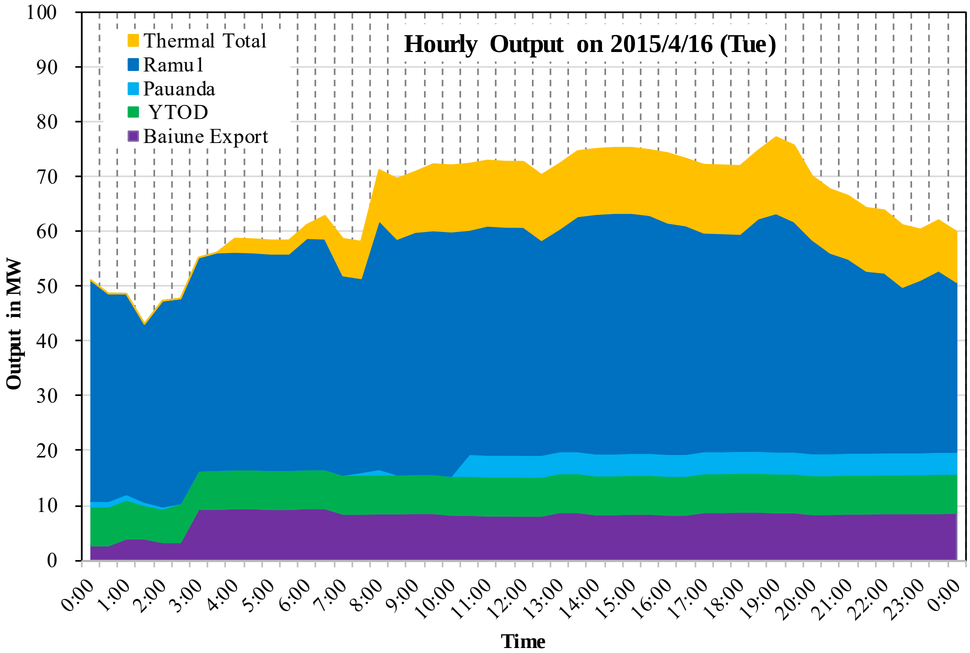
Note: Unit 1of Pauanda HEP has stopped since June 2014 order due to turbine bearing problems, Unit 2 of Pauandan HEP has a problem of turbine bearing due to high temperature.

Appendix 5.1.2

Daily Status Report of Ramu System on April 16, 2015

Generation Availability On April 17, 2015 (at 08:00 hrs)

Station	**Available units**		**Unavailable units**	**Available Mw**	**Loading at 08:00 hrs**	Remarks
	In Service	On Standby				
C/ Valve		1	2			No.1 opened, dam off spill
Ramu	1,3,4&5		2	50.0		U/1,2&3 load restricted to 10.0Mw. U/2 TGB ceased
YTOD	1	2		7.0		
Pauanda	2		1	4.8		U/1 on F/O for Bearing checks.
Baiune	Lwr & Upp			8.0		Water Level dropped
Taraka		5,8	1,2,4,7	2.0		D1&2 screen monitor out, D8 exhaust fan faulty
Aggreko		12x m/cs		9.6		
Milford		4,6,12		3.8		
Lae GT		GT1		23.0		
Madang		7,8 &12	5,&10	2.3		
Goroka		1	2	1.20		D/1 on SB for gen shortfall, D2 F/O
Kundiawa			1	0.00		
Mendi		4	1,2,3	0.90		D/4 SB for gen shortfall
Wabag		2,4	3	1.18		D/2&4 SB for gen shortfall
T Total Generation Mw MMJV - Energy Consumption = **332.0 MWHr**				**113.78**		System Max Demand (Estimated) – **78.0 Mw**



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PNG POWER Ltd

RAMU SYSTEM DAILY STATUS

From System Control: Please complete this form and email or fax to 323 4784 before 9:00am each day

Day: Friday Date: 17-Apr-2015 Time: 8:00 Hrs

Reservoir level (M):	1258.27	Vol (Mcm):	340.10	Max.Demand:	77.21	MW
		%	101.70%	Time:	19:00	Hrs
Spill Vol (m3/s):	25.59	Vol (Mcm):	341.36	Min. Demand:	43.12	MW
				Time:	1:30	Hrs

Transmission line Max. loads (Yesterday)				
601	47.80	Mw	Time	15:30
602	10.70	Mw	Time	14:00
506	22.00	Mw	Time	19:00

Max.Demand YTD = 86.78 MW @ 15:00 hrs on 05/03/15

Rainfall Today (mm):	Yonki:		Pauanda:		Aiyura:	n/a
Valve Releases (Previous Day)	Closed	cumecs	Unknown (meters faulty)			
		hours	24			

Generation Status:

Ramu - Hydro				
Unit	Rated (MW)	Available (MW)	Merit Order	109
Unit 1	15.0	10.0	1.0	10.0
Unit 2	15.0	0.0	4.0	FO
Unit 3	15.0	10.0	2.0	11.3
Unit 4	16.2	15.0	5.0	11.1
Unit 5	16.2	15.0	3.0	13.0
YTOD U1	9.0	7.0	1.0	7.0
YTOD U2	9.0	7.0	2.0	SB
Total	95.4	64.0		52.4
Pauanda - Hydro				
Unit 1	6.0	0.0	1.0	FO
Unit 2	6.0	4.8	2.0	4.4
Total	12.0	4.8		4.4
Total Hydro	107.4	68.8		56.8
% Hydro Availability	=		64.06%	

Milford (Thermal)				
Diesel 1	0.84	0.00	0	FO
Diesel 2	0.84	0.00	0	BOS
Diesel 3	2.50	0.00	0	FO
Diesel 4	2.50	1.80	3	SB
Diesel 5	3.20	0.00	1	FO
Diesel 6	3.20	2.00	2	SB
Diesel 7	3.26	0.00		FO
Diesel 8	3.26	0.00		FO
Diesel 9	3.26	0.00		FO
Diesel 10	3.26	0.00		FO
Diesel 11	3.26	0.00		FO
Diesel 12	1.60	0.50	4	SB
Total	30.98	4.30		0.00

Taraka (Thermal)				
Diesel 1	1.44	0.00	5	FO
Diesel 2	1.44	0.00	6	FO
Diesel 3	1.44	0.00	8	FO
Diesel 4	1.44	0.00	7	FO
Diesel 5	1.44	1.00	1	0.80
Diesel 6	Destroyed by fire			FO
Diesel 7	1.44	0.00	3	FO
Diesel 8	1.44	1.00	4	0.80
Total	10.08	2.00		1.60

Taraka Aggreko (Thermal)				
Diesel 1	1.10	0.83		
Diesel 2	1.10	0.83		
Diesel 3	1.10	0.83		
Diesel 4	1.10	0.83		
Diesel 5	1.10	0.83		
Diesel 6	1.10	0.83		
Diesel 7	1.10	0.83		
Diesel 8	1.10	0.83		
Diesel 9	1.10	0.83		
Diesel 10	1.10	0.83		
Diesel 11	1.10	0.83		
Diesel 12	1.10	0.83		
Total	13.20	9.60		

Madang -Thermal				
Unit	Rated (MW)	Available (MW)	Merit Order	Present
Diesel 1	Decommissioned and sent to Buka			US
Diesel 2	1.50	0.00		US
Diesel 3	1.43	0.00		US
Diesel 4	1.50	0.00		US
Diesel 5	3.20	0.00		FO
Diesel 6	3.20	0.00	Decommissioned	US
Diesel 7	1.12	0.50	2	SB
Diesel 8	1.12	0.50	1	SB
Diesel 9	1.12	0.00	3	FO
Diesel 10	1.80	0.00	4	FO
Diesel 11	1.80	0.00		FO
Diesel 12	1.80	1.30	5	SB
Total	19.59	2.30		0.00

Mendi- Thermal				
Diesel 1	0.0	0		OS
Diesel 2	0.0	0		OS
Diesel 3	0.0	0		OS
Diesel 4	1.5	0.9	1	SB
Total	1.50	0.90		0.00
Wabag - Thermal				
Diesel 1	0.30	0.00		FO
Diesel 2	0.23	0.18	1	SB
Diesel 3	0.62	0.00		FO
Diesel 4	1.40	1.00		SB
Total	2.55	1.18		0.00
Kundiawa - Thermal				
Diesel 1	1.44	0.00		FO
Total	1.44	0.00		0.00
Goroka - Thermal				
Diesel 1	1.44	1.20		SB
Diesel 2	0.00	0.00		FO
Total	1.44	1.20		0.00
Total Thermal	80.78	21.48		1.60
% Thermal Availability			=	26.59%

Ramu System Load Forecast - Today	
Total System MW (Hydro+thermal):	121.28
Estimated Max Demand (MW):	78.00
Estimated Load to be Shed (MW):	

Note to Symbols
US - Unserviceable
SB - Stand By
CF - Carry Forward
LS - Load Shed
FO - Forced Outage
PO/UO - Plan /Unplan Outage
UF - Under Frequency
EM - Emergency
IS - In Service (Line)
TR - Test Run On Load
R/R - Restricted Running (mc)

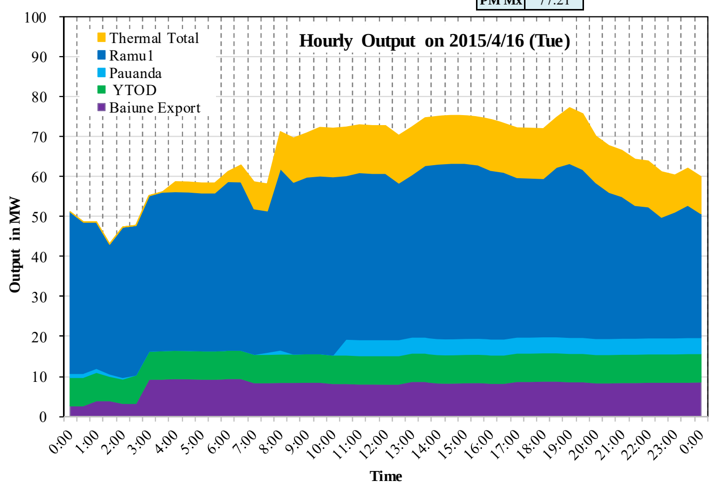
RAMU DAILY POWER SYSTEM GENERATION

Day:	Thursday	Date:	2015/4/16

STATION MEGAWATTS

Time	HYDRO (MW)					THERMAL (MW)										SYSTEM TOTAL (MW)	H/ Valley Import (MW)	Ramu Power/stn Machine (MW) Ramu Generation (Mw)						Time
	Ramu1	Pauanda	YTOD	Baiune Export	Hydro Total	Taraka	Taraka Aggreko	Milford	Lae GT	Madang	Goroka	Kundiawa	Mendi	Wabag	Thermal Total			U1	U2	U3	U4	U5	Total	
0:00	40.4	1.0	7.1	2.66	51.16										0.00	51.16	6.0	9.0	0.0	9.6	10.9	10.9	40.4	0:00
0:30	37.9	1.0	7.1	2.66	48.66										0.00	48.66	6.0	9.1	0.0	9.6	8.4	10.8	37.9	0:30
1:00	36.6	1.0	7.1	3.92	48.62										0.00	48.62	6.0	9.0	0.0	9.4	7.4	10.8	36.6	1:00
1:30	32.5	0.6	6.1	3.92	43.12										0.00	43.12	3.0	9.0	0.0	8.8	7.4	7.3	32.5	1:30
2:00	37.6	0.4	6.1	3.25	47.35										0.00	47.35	4.0	9.0	0.0	9.3	10.6	8.7	37.6	2:00
2:30	37.4	0.0	7.1	3.25	47.75										0.00	47.75	9.0	9.1	0.0	9.0	8.0	11.3	37.4	2:30
3:00	38.9	0.0	7.0	9.31	55.21										0.00	55.21	12.0	9.0	0.0	9.8	9.2	10.9	38.9	3:00
3:30	39.7	0.0	7.1	9.31	56.11		0.00								0.00	56.11	15.0	8.9	0.0	9.7	10.1	11.0	39.7	3:30
4:00	39.7	0.0	7.1	9.42	56.22		2.47								2.47	58.69	17.0	9.0	0.0	9.8	9.9	11.0	39.7	4:00
4:30	39.6	0.0	7.1	9.42	56.12		2.47								2.47	58.59	17.0	9.0	0.0	9.8	9.9	10.9	39.6	4:30
5:00	39.5	0.0	7.1	9.30	55.90		2.47								2.47	58.37	17.0	8.9	0.0	9.8	9.9	10.9	39.5	5:00
5:30	39.5	0.0	7.1	9.30	55.90		2.47								2.47	58.37	17.0	8.8	0.0	9.8	9.9	11.0	39.5	5:30
6:00	42.2	0.0	7.1	9.44	58.74		2.47								2.47	61.21	17.0	9.0	0.0	9.9	12.0	11.3	42.2	6:00
6:30	42.1	0.0	7.1	9.44	58.64		4.21								4.21	62.85	17.0	9.0	0.0	10.0	11.8	11.3	42.1	6:30
7:00	36.4	0.0	7.1	8.43	51.93		6.72								6.72	58.65	15.0	9.0	0.0	9.2	7.7	10.5	36.4	7:00
7:30	35.4	0.5	7.1	8.43	51.43		6.72								6.72	58.15	13.0	9.0	0.0	9.4	7.1	9.9	35.4	7:30
8:00	45.4	1.0	7.1	8.49	61.99	0.0	9.23								9.23	71.22	13.0	9.0	0.0	10.2	13.2	13.0	45.4	8:00
8:30	43.0	0.0	7.1	8.49	58.59	1.80	9.23								11.03	69.62	13.0	8.9	0.0	10.5	9.6	14.0	43.0	8:30
9:00	44.2	0.0	7.1	8.55	59.85	1.80	9.23			0.0					11.03	70.88	10.0	8.8	0.0	10.6	10.9	13.9	44.2	9:00
9:30	44.5	0.0	7.1	8.55	60.15	1.80	9.23			1.1					12.13	72.28	10.0	8.9	0.0	10.7	10.9	14.0	44.5	9:30
10:00	44.6	0.0	7.1	8.24	59.94	1.80	9.23			1.1					12.13	72.07	10.0	8.8	0.0	10.6	11.5	13.7	44.6	10:00
10:30	40.9	4.0	7.1	8.24	60.24	1.80	9.23			1.1					12.13	72.37	10.0	8.9	0.0	10.6	8.1	13.3	40.9	10:30
11:00	41.8	4.0	7.1	8.10	61.00	1.60	9.23			1.1					11.93	72.93	11.0	8.8	0.0	10.6	10.9	11.5	41.8	11:00
11:30	41.6	4.0	7.1	8.10	60.80	1.60	9.23			1.1					11.93	72.73	11.0	8.9	0.0	10.5	10.8	11.4	41.6	11:30
12:00	41.6	4.0	7.1	8.08	60.78	1.60	9.23			1.1					11.93	72.71	11.0	8.8	0.0	10.5	10.9	11.4	41.6	12:00
12:30	39.2	4.0	7.1	8.08	58.38	1.60	9.23			1.1					11.93	70.31	11.0	8.9	0.0	10.5	8.4	11.4	39.2	12:30
13:00	40.6	4.0	7.1	8.73	60.43	1.60	9.23			1.1					11.93	72.36	11.0	8.9	0.0	10.6	9.6	11.5	40.6	13:00
13:30	42.9	4.0	7.1	8.73	62.73	1.60	9.23			1.1					11.93	74.66	11.0	8.8	0.0	10.7	11.8	11.6	42.9	13:30
14:00	43.7	4.0	7.1	8.33	63.13	1.60	9.23			1.1					11.93	75.06	11.0	8.9	0.0	10.8	12.3	11.7	43.7	14:00
14:30	43.9	4.0	7.1	8.33	63.33	1.60	9.23			1.1					11.93	75.26	11.0	8.9	0.0	11.0	12.4	11.6	43.9	14:30
15:00	43.8	4.0	7.1	8.43	63.33	1.60	9.23			1.1					11.93	75.26	11.0	8.8	0.0	9.7	12.2	13.1	43.8	15:00
15:30	43.4	4.0	7.1	8.43	62.93	1.60	9.23			1.1					11.93	74.86	11.0	8.9	0.0	9.7	11.7	13.1	43.4	15:30
16:00	42.2	4.0	7.1	8.25	61.55	1.60	10.04			1.1					12.74	74.29	11.0	8.9	0.0	9.6	10.7	13.0	42.2	16:00
16:30	41.7	4.0	7.1	8.25	61.05	1.1	10.04			1.1					12.24	73.29	12.0	8.9	0.0	9.6	10.1	13.1	41.7	16:30
17:00	39.9	4.0	7.1	8.73	59.73	1.2	10.04			1.2					12.44	72.17	15.0	9.0	0.0	10.0	8.0	12.9	39.9	17:00
17:30	39.8	4.0	7.1	8.73	59.63	1.2	10.04			1.2					12.44	72.07	16.0	8.9	0.0	10.0	8.0	12.9	39.8	17:30
18:00	39.6	4.0	7.1	8.80	59.50	1.2	10.04			1.2					12.44	71.94	16.0	8.9	0.0	10.0	7.8	12.9	39.6	18:00
18:30	42.4	4.0	7.1	8.80	62.30	1.2	10.04	0.0		1.2					12.44	74.74	16.0	8.9	0.0	10.0	10.6	12.9	42.4	18:30
19:00	43.5	4.0	7.1	8.67	63.27	1.2	10.04	1.5		1.2					13.94	77.21	13.0	8.9	0.0	10.6	10.6	13.4	43.5	19:00
19:30	42.0	4.0	7.1	8.67	61.77	1.2	10.04	1.5		1.2					13.94	75.71	16.0	8.7	0.0	8.6	11.6	13.1	42.0	19:30
20:00	39.0	4.0	7.1	8.36	58.46		10.04	1.6		0.0					11.64	70.10	16.0	8.8	0.0	7.3	10.9	12.0	39.0	20:00
20:30	36.6	4.0	7.1	8.36	56.06		10.04	1.6							11.64	67.70	14.0	0.0	0.0	10.3	13.2	13.1	36.6	20:30
21:00	35.4	4.0	7.1	8.46	54.96		10.04	1.5							11.54	66.50	14.0	0.0	0.0	10.3	12.1	13.0	35.4	21:00
21:30	33.2	4.0	7.1	8.46	52.76		10.04	1.5							11.54	64.30	14.0	0.0	0.0	10.1	10.2	12.9	33.2	21:30
22:00	32.8	4.0	7.1	8.52	52.42		10.04	1.4							11.44	63.86	14.0	0.0	0.0	10.0	9.9	12.9	32.8	22:00
22:30	30.2	4.0	7.1	8.52	49.82		10.04	1.3							11.34	61.16	14.0	0.0	0.0	10.0	7.5	12.7	30.2	22:30
23:00	31.5	4.0	7.1	8.53	51.13		9.23	0.0							9.23	60.36	14.0	0.0	0.0	10.0	8.6	12.9	31.5	23:00
23:30	33.1	4.0	7.2	8.53	52.83		9.23								9.23	62.06	15.0	0.0	0.0	10.0	10.2	12.9	33.1	23:30
0:00	31.0	4.0	7.1	8.63	50.73		9.23								9.23	59.96	15.0	8.0	0.0	6.4	7.4	9.2	31.0	0:00
Total in MWh	948	58	169	191	1,366	17	170	6	0	12	0	0	0	0	204	1,570	300	183	0	237	241	286	948	
Max in MW	45.4	4.0	7.2	9.4	63.3	1.8	10.0	1.6	0.0	1.2	0.0	0.0	0.0	0.0	13.9	77.2	17.0	9.1	0.0	11.0	13.2	14.0	45.4	
Rate	60.4%	3.7%	10.8%	12.2%	87.0%	1.1%	10.8%	0.4%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	13.0%	100.0%		11.7%	0.0%	15.1%	15.4%	18.2%	60.4%	

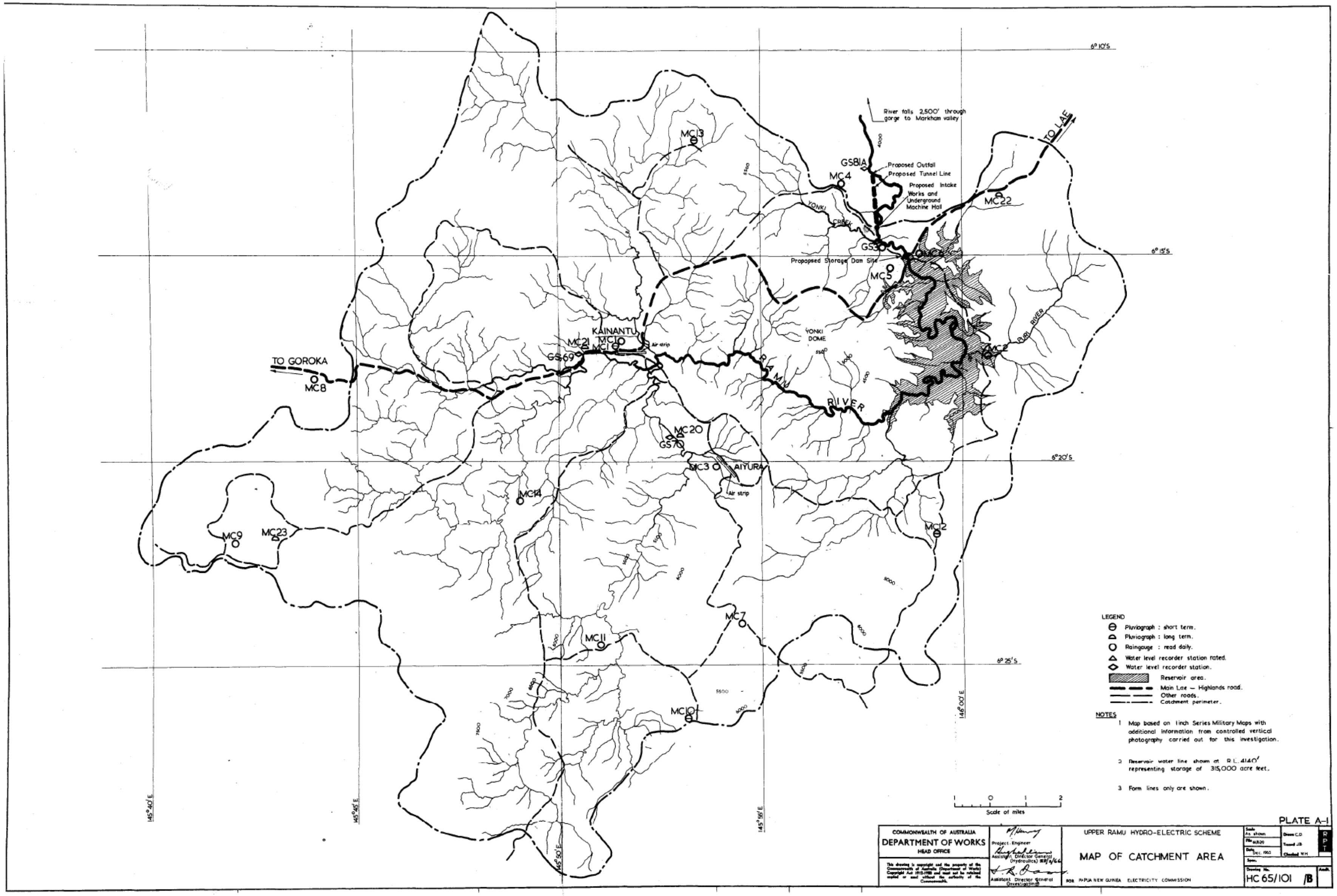
Max	77.21	max	9.1	0.0	11.0	13.2	14.0	45.4
Min	43.12							
AM Mx	72.93							
PM Mx	77.21							

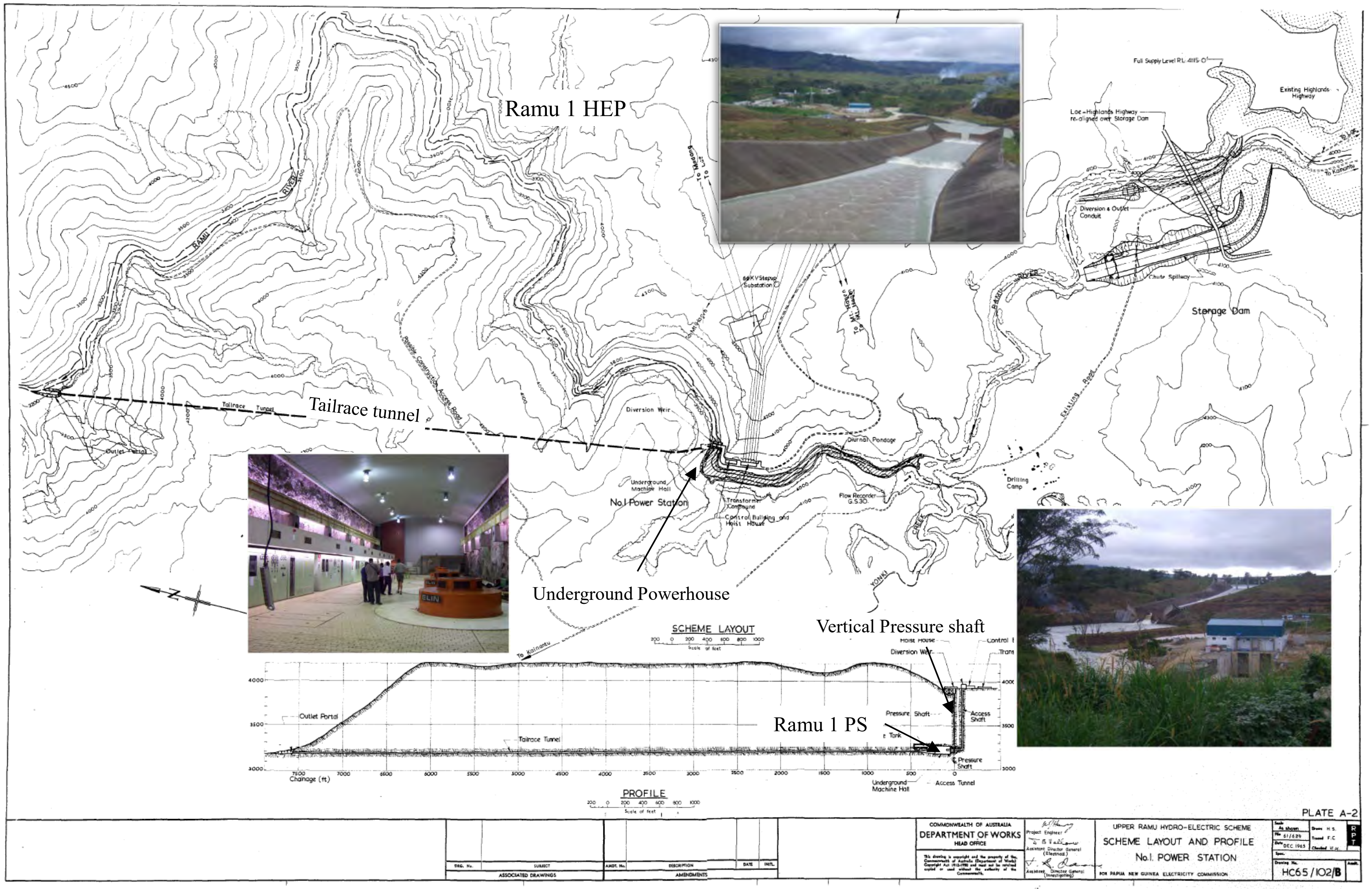


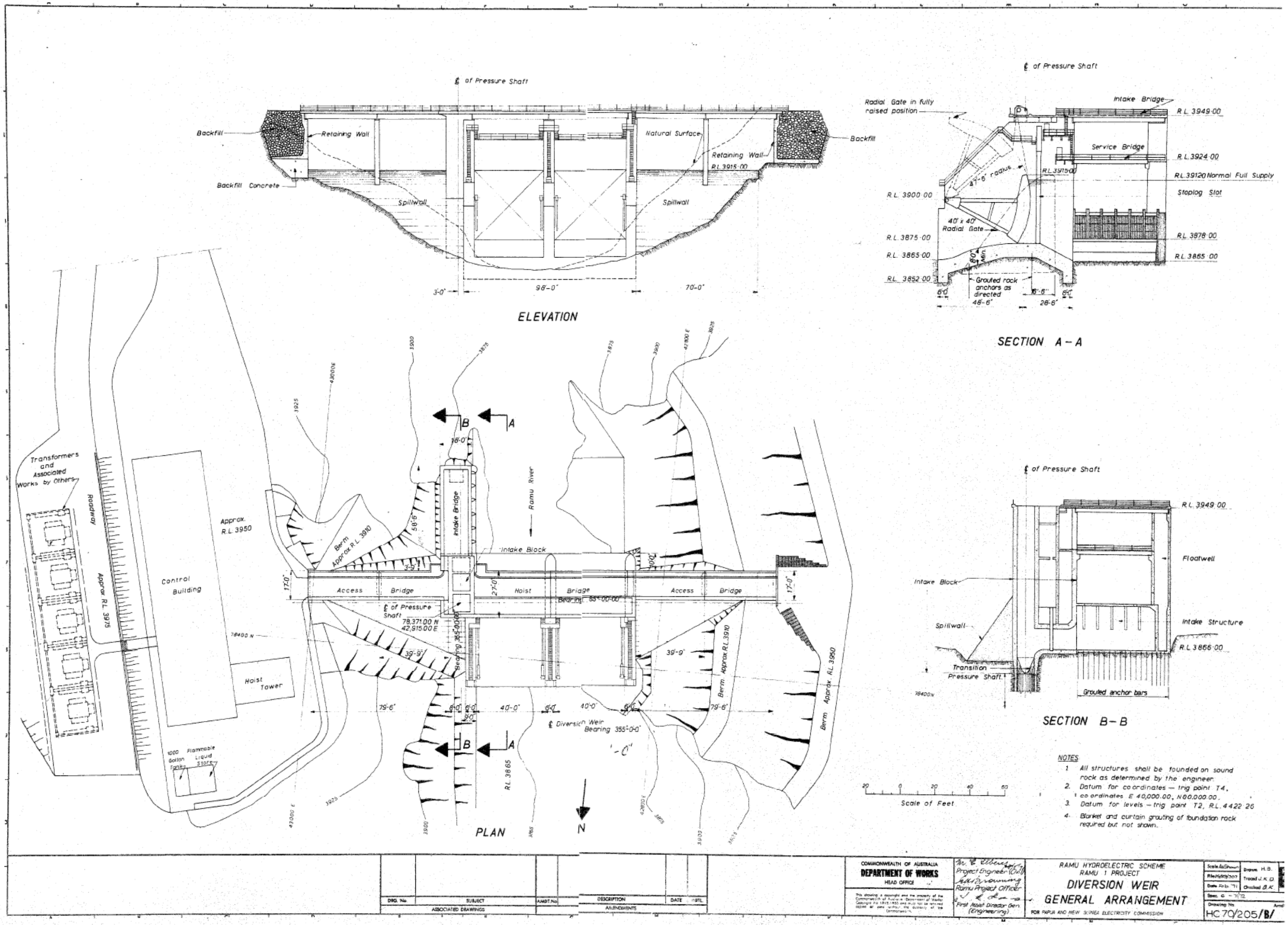
Appendix 5.1.3

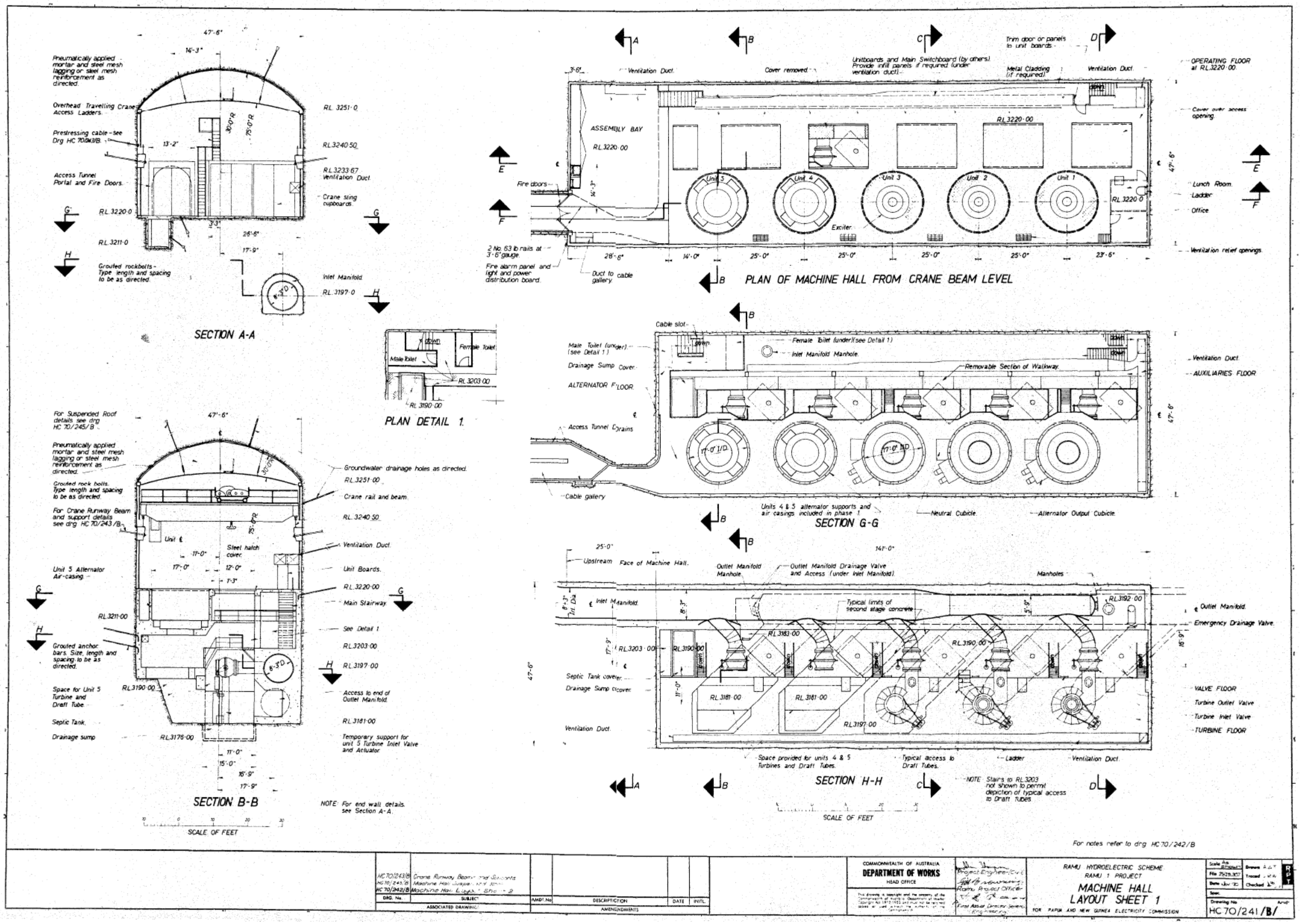
Drawings of Existing Hydropower Plants

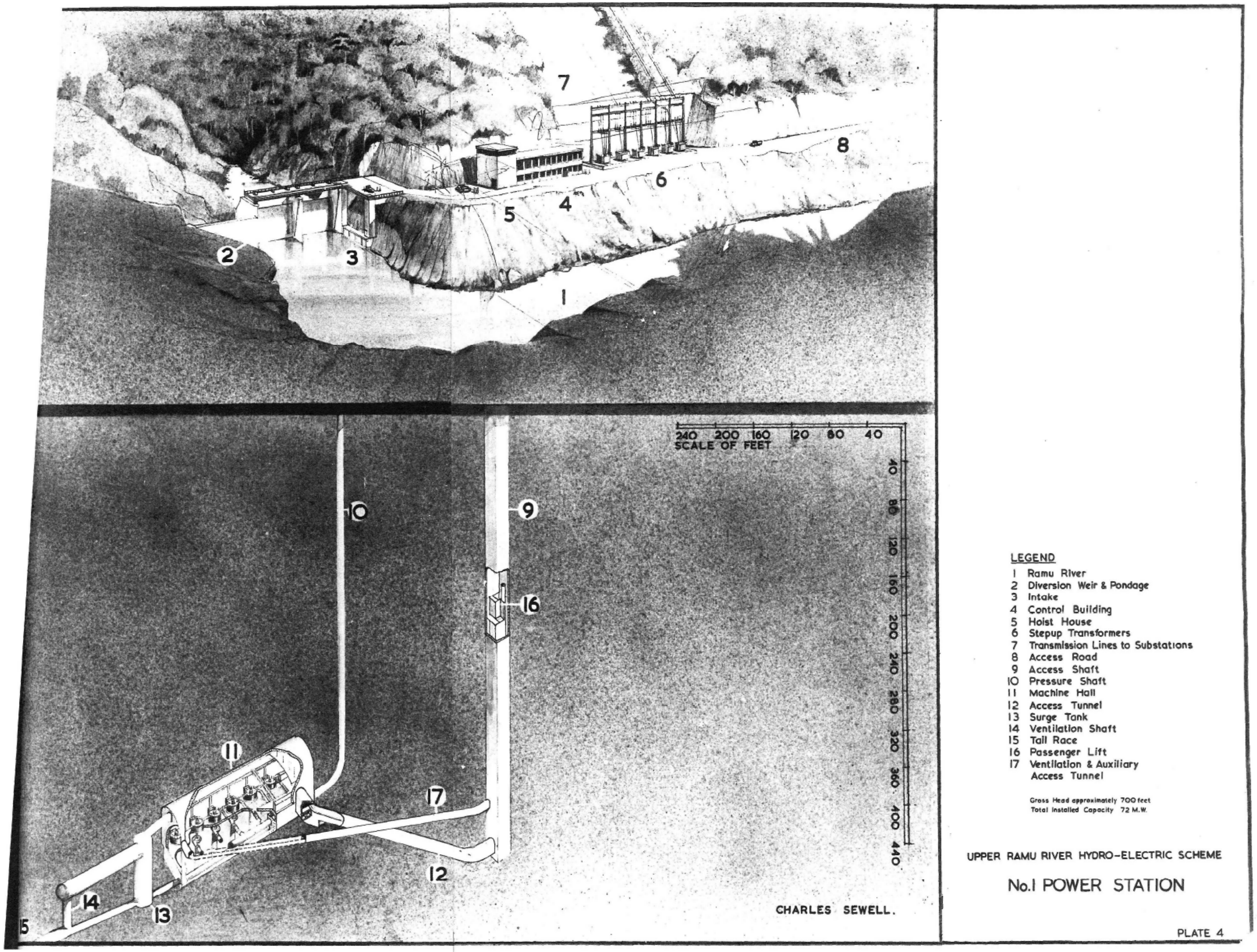
(1) Ramu1 Hydropower Project

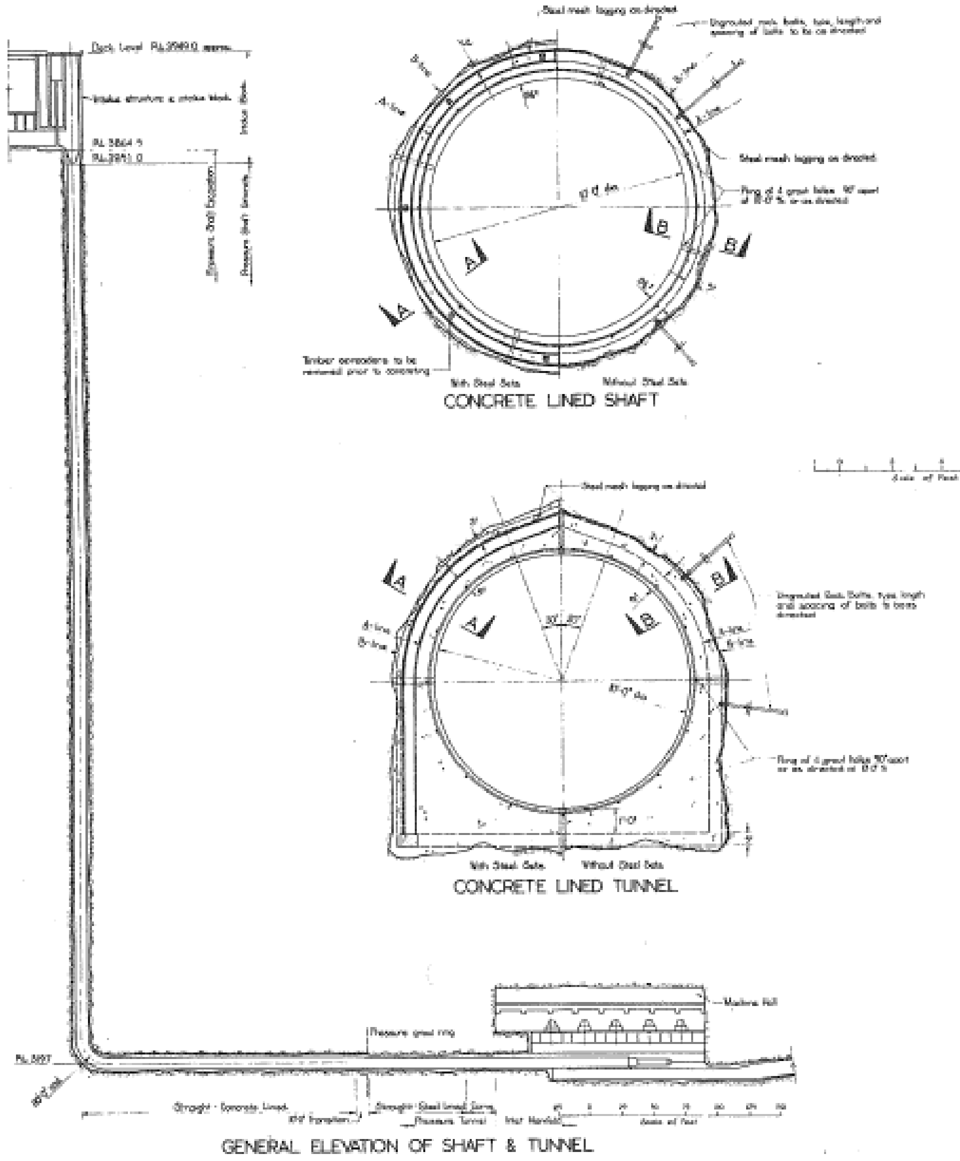

River falls 2,500' through gorge to Markham valley
TO LAE
GS81A
Proposed Outfall
Proposed Tunnel Line
Proposed Intake Works and Underground Machine Hall
MC13
MC4
MC22
YONKI CREEK
GS53
Proposed Storage Dam Site
MC5
KAINANTU
MC10
MC21
MC16
GS69
Air strip
TO GOROKA
MC8
YONKI DOME
RAMU RIVER
MC2
MC20
GS70
MC3
AIYURA
MC14
MC12
MC9
MC23
MC7
MC11
MC1
6° 10'S
6° 15'S
6° 20'S
6° 25'S
145°40'E
145°45'E
145°50'E
145°55'E
146°00'E
LEGEND
Pluviograph : short term.
Pluviograph : long term.
Raingauge : read daily.
Water level recorder station rated.
Water level recorder station.
Reservoir area.
Main Lae – Highlands road.
Other roads.
Catchment perimeter.
NOTES
1 Map based on 1 inch Series Military Maps with additional information from controlled vertical photography carried out for this investigation.
2 Reservoir water line shown at R.L. 4140' representing storage of 315,000 acre feet.
3 Form lines only are shown.
Scale of miles
PLATE A-1
COMMONWEALTH OF AUSTRALIA
DEPARTMENT OF WORKS
HEAD OFFICE
Project Engineer
Assistant Director General (Hydraulics)
Assistant Director General (Investigation)
UPPER RAMU HYDRO-ELECTRIC SCHEME
MAP OF CATCHMENT AREA
FOR PAPUA NEW GUINEA ELECTRICITY COMMISSION
HC 65/101 /B

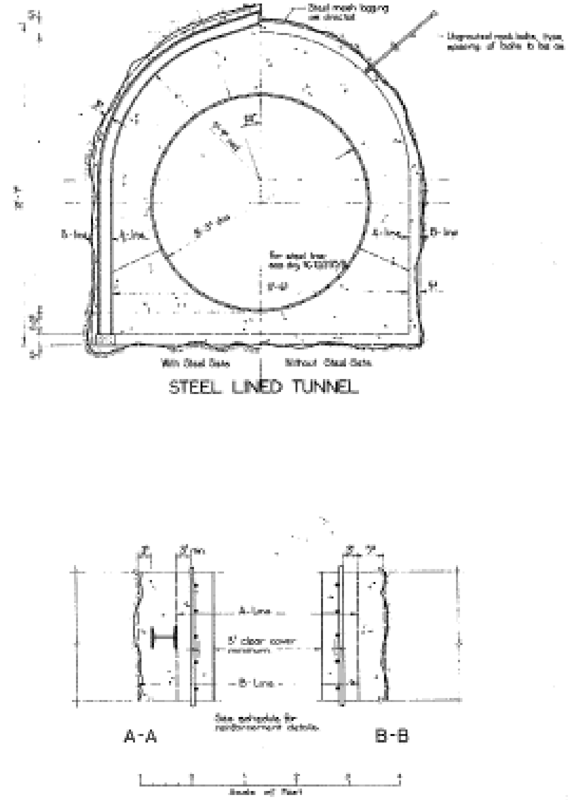

Ramu 1 HEP
Tailrace tunnel
Underground Powerhouse
Vertical Pressure shaft
Ramu 1 PS
Tailrace Tunnel
Outlet Portal
Diversion Weir
Underground Machine Hall
No.1 Power Station
Transformer Compound
Control Building and Hoist House
Diurnal Pondage
Flow Recorder G.S.30.
Drilling Camp
66 KV Stepup Substation
Storage Dam
Chute Spillway
Diversion & Outlet Conduit
Full Supply Level RL 4115·0
Existing Highlands Highway
Lae-Highlands Highway re-aligned over Storage Dam
Existing Road
To Kainantu
SCHEME LAYOUT
PROFILE
Pressure Shaft
Access Shaft
Access Tunnel
Hoist House
Chainage (ft)
PLATE A-2
COMMONWEALTH OF AUSTRALIA
DEPARTMENT OF WORKS
HEAD OFFICE
UPPER RAMU HYDRO-ELECTRIC SCHEME
SCHEME LAYOUT AND PROFILE
No.1 POWER STATION
FOR PAPUA NEW GUINEA ELECTRICITY COMMISSION
ASSOCIATED DRAWINGS
AMENDMENTS
HC65/102/B


ELEVATION
SECTION A – A
SECTION B – B
PLAN
Backfill
Retaining Wall
Natural Surface
Backfill Concrete
Spillwall
R.L. 3915·00
98'-0"
70'-0"
3'-0"
℄ of Pressure Shaft
Radial Gate in fully raised position
Intake Bridge
Service Bridge
R.L. 3949·00
R.L. 3924·00
R.L. 3912·0 Normal Full Supply
Stoplog Slot
R.L. 3900·00
40' x 40' Radial Gate
R.L. 3878·00
R.L. 3875·00
R.L. 3865·00
R.L. 3852·00
Grouted rock anchors as directed
Floatwell
Intake Block
Intake Structure
R.L. 3866·00
Transition Pressure Shaft
Grouted anchor bars
Transformers and Associated Works by Others
Roadway
Control Building
Approx. R.L. 3950
Approx. R.L. 3975
Hoist Tower
1000 Gallon Tanks
Flammable Liquid Store
Access Bridge
Hoist Bridge
Ramu River
Berm Approx. R.L. 3910
℄ Diversion Weir Bearing 355°0'0"
Scale of Feet
NOTES
1. All structures shall be founded on sound rock as determined by the engineer.
2. Datum for coordinates — trig point T4, coordinates E 40,000.00, N 80,000.00.
3. Datum for levels — trig point T2, R.L. 4422·26
4. Blanket and curtain grouting of foundation rock required but not shown.
COMMONWEALTH OF AUSTRALIA
DEPARTMENT OF WORKS
HEAD OFFICE
Project Engineer
Ramu Project Officer
First Asst Director Gen (Engineering)
RAMU HYDROELECTRIC SCHEME
RAMU 1 PROJECT
DIVERSION WEIR
GENERAL ARRANGEMENT
FOR PAPUA AND NEW GUINEA ELECTRICITY COMMISSION
HC 70/205/B/
ASSOCIATED DRAWINGS
AMENDMENTS


SECTION A-A
PLAN DETAIL 1
SECTION B-B
PLAN OF MACHINE HALL FROM CRANE BEAM LEVEL
SECTION G-G
SECTION H-H
SCALE OF FEET
ASSEMBLY BAY
RL 3220·00
Unit 5
Unit 4
Unit 3
Unit 2
Unit 1
OPERATING FLOOR at RL 3220·00
AUXILIARIES FLOOR
VALVE FLOOR
TURBINE FLOOR
NOTE: For end wall details see Section A-A.
For notes refer to drg. HC 70/242/B
COMMONWEALTH OF AUSTRALIA
DEPARTMENT OF WORKS
HEAD OFFICE
RAMU HYDROELECTRIC SCHEME
RAMU 1 PROJECT
MACHINE HALL
LAYOUT SHEET 1
FOR PAPUA AND NEW GUINEA ELECTRICITY COMMISSION
HC 70/241/B/
ASSOCIATED DRAWINGS
AMENDMENTS


1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
240 200 160 120 80 40
SCALE OF FEET
40 80 120 160 200 240 280 320 360 400 440
CHARLES SEWELL.
LEGEND
1 Ramu River
2 Diversion Weir & Pondage
3 Intake
4 Control Building
5 Hoist House
6 Stepup Transformers
7 Transmission Lines to Substations
8 Access Road
9 Access Shaft
10 Pressure Shaft
11 Machine Hall
12 Access Tunnel
13 Surge Tank
14 Ventilation Shaft
15 Tail Race
16 Passenger Lift
17 Ventilation & Auxiliary Access Tunnel
Gross Head approximately 700 feet
Total Installed Capacity 72 M.W.
UPPER RAMU RIVER HYDRO-ELECTRIC SCHEME
No.1 POWER STATION
PLATE 4



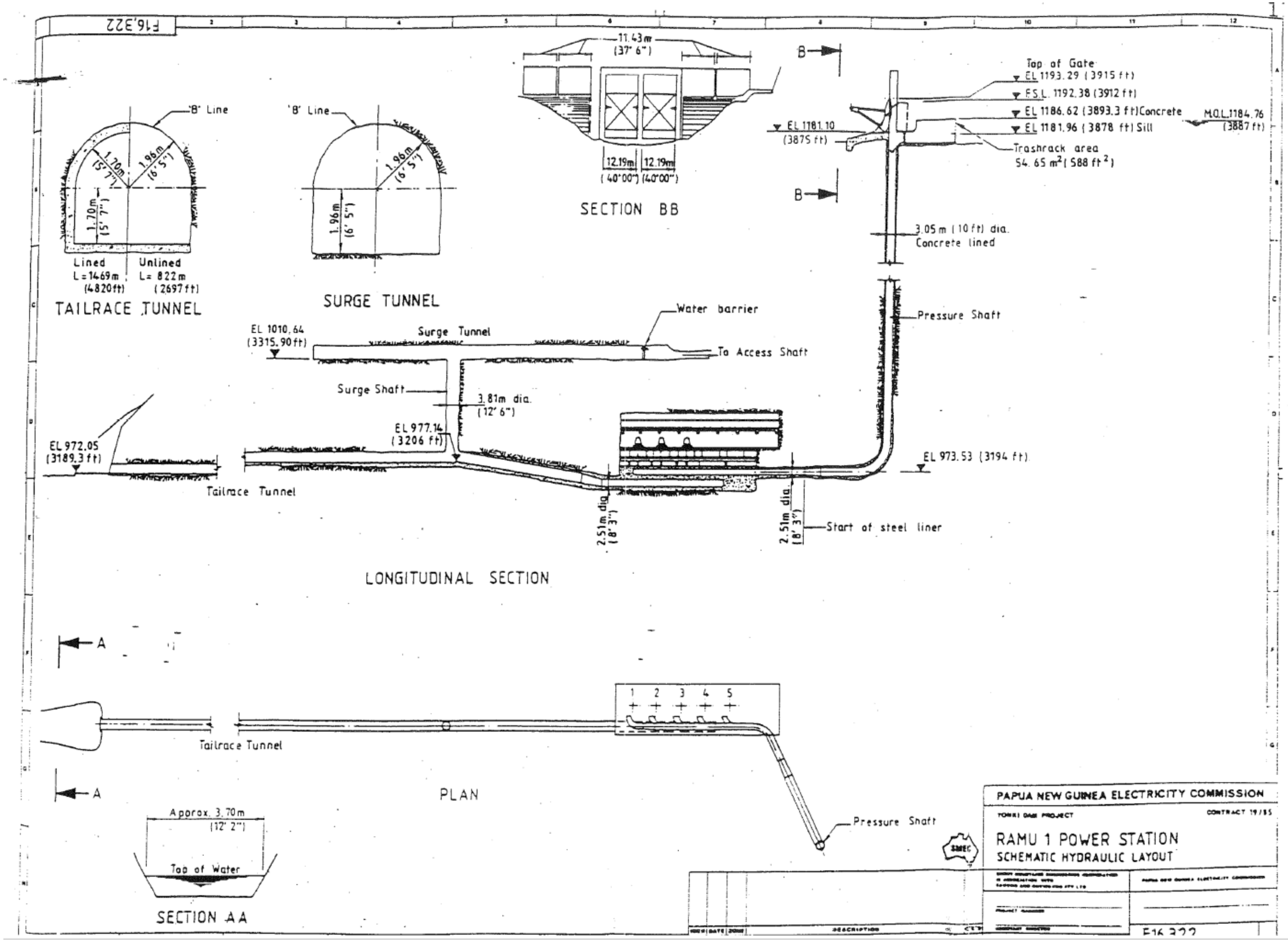


SCHEDULE OF REINFORCEMENT					
Reduced Level		Reinforcement			
		Hoop		Longitudinal	
From	To	Dia	Spacing	Dia	Spacing
3851	3800	1⅜"	9"	¾"	10"
3800	3735	1⅜"	10"	⅝"	10"
3735	3660	1⅜"	8"	⅝"	10"
3660	3535	1⅜"	12"	⅝"	10"
3535	3435	1⅜"	10"	⅝"	10"
3435	3305	1⅜"	8"	⅝"	10"
3305	3227	1⅜"	6"	⅝"	10"
Pressure Tunnel		1⅜"	5"	⅝"	10"

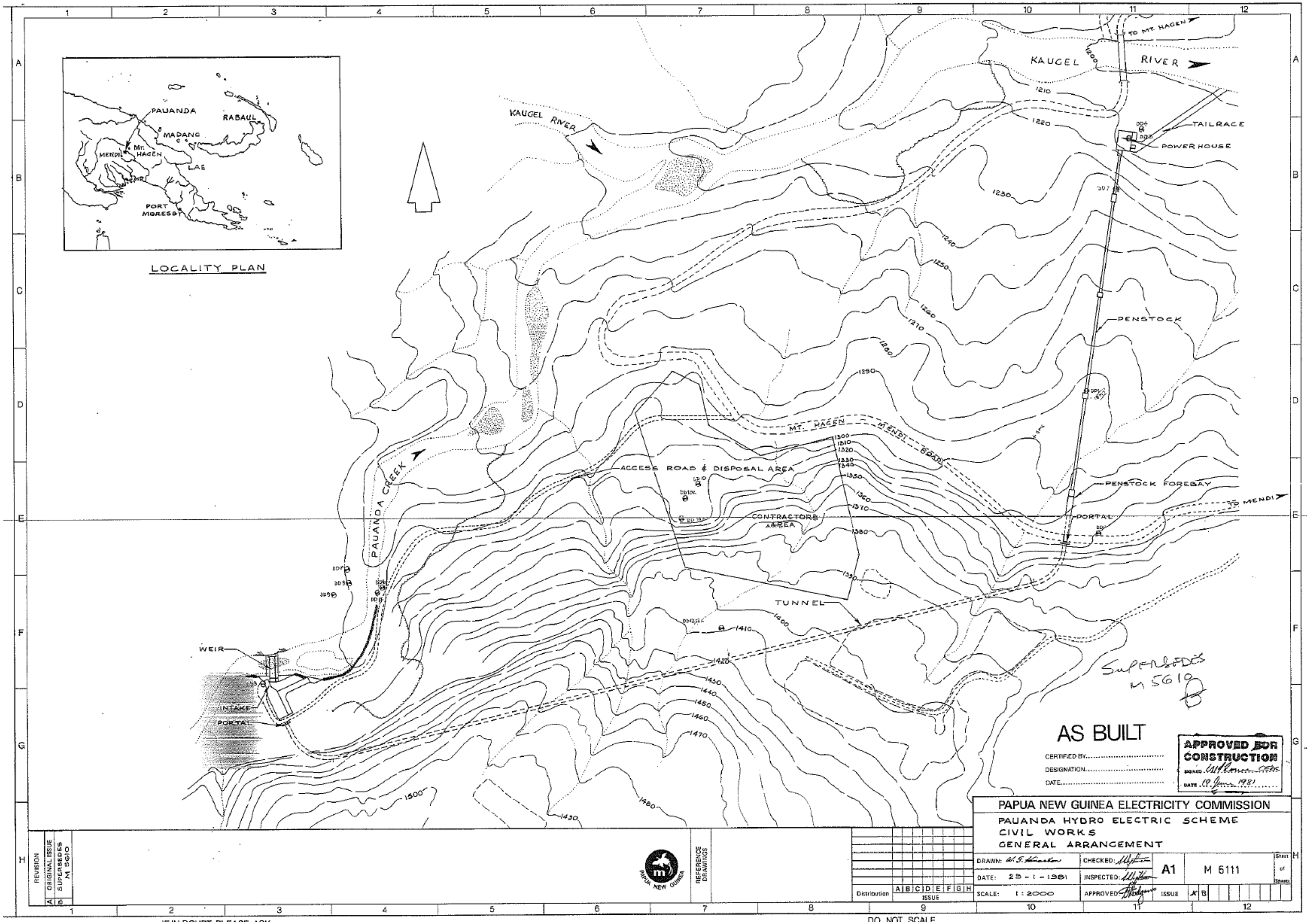
Notes:

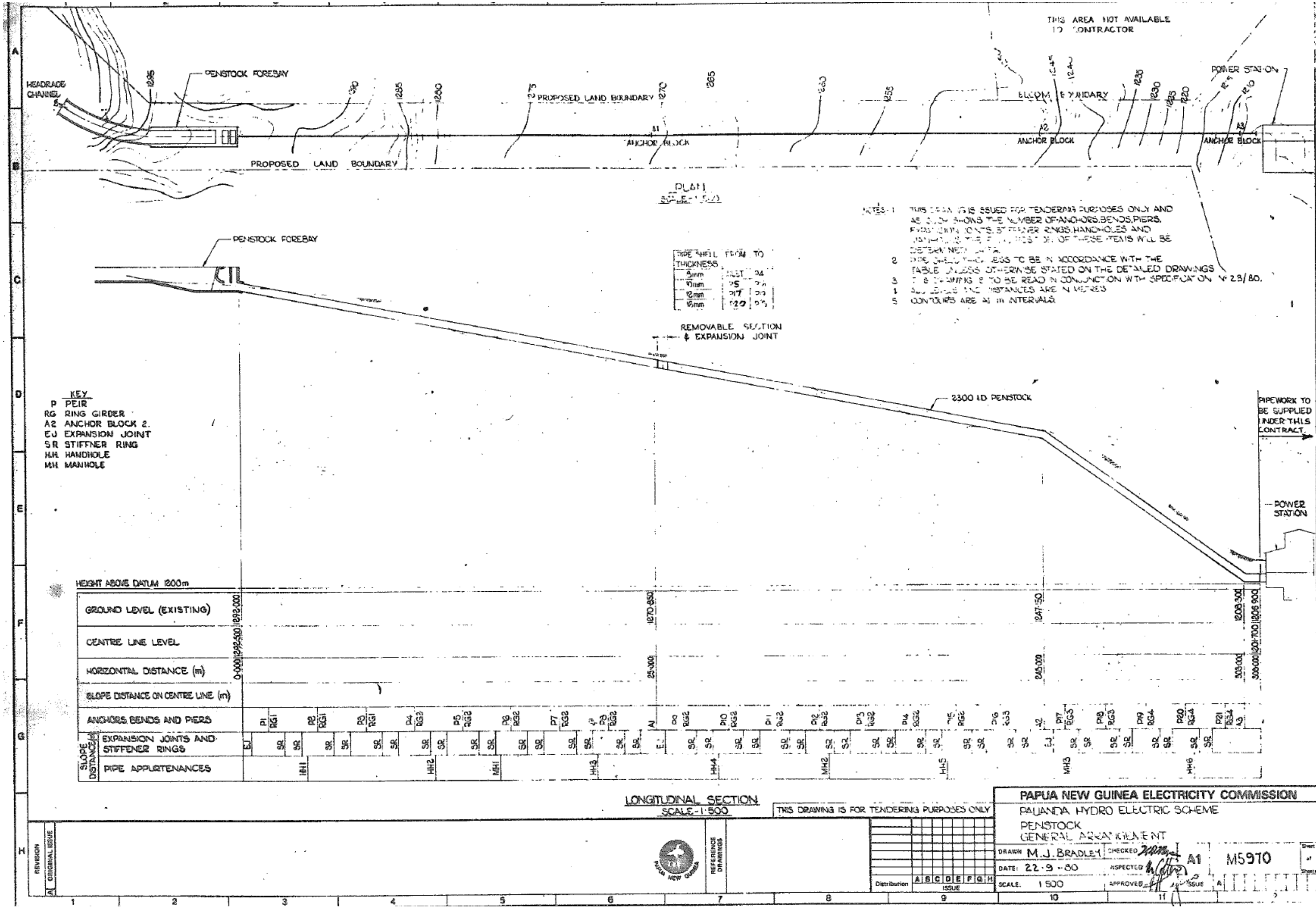
1. Design Strengths: Concrete f_c = 5000 psi at 90 days; Reinforcement f_s = 20,000 psi
2. Materials and workmanship to be in accordance with the Specif
3. Clear cover to reinforcement shall be:
   a) 3" on inside face of shaft and tunnel
   b) 3" between reinforcement and any rock.
4. All concrete aggregate shall be 1½" max. in accordance with th
5. All concrete surfaces shall be finished with Finish F2 in accorda
6. Pressure grouting in excess of Pressure Grout ring already sh
7. All reinforcement shall comply with AS A81 - 1969 and shall be structural grade round bars
8. Hoop reinforcement shall be welded using qualified butt welds or accordance with the requirements of AS CA8 Pt.3 and AS CA2 -
9. Lap length for longitudinal bars = 2'-6"

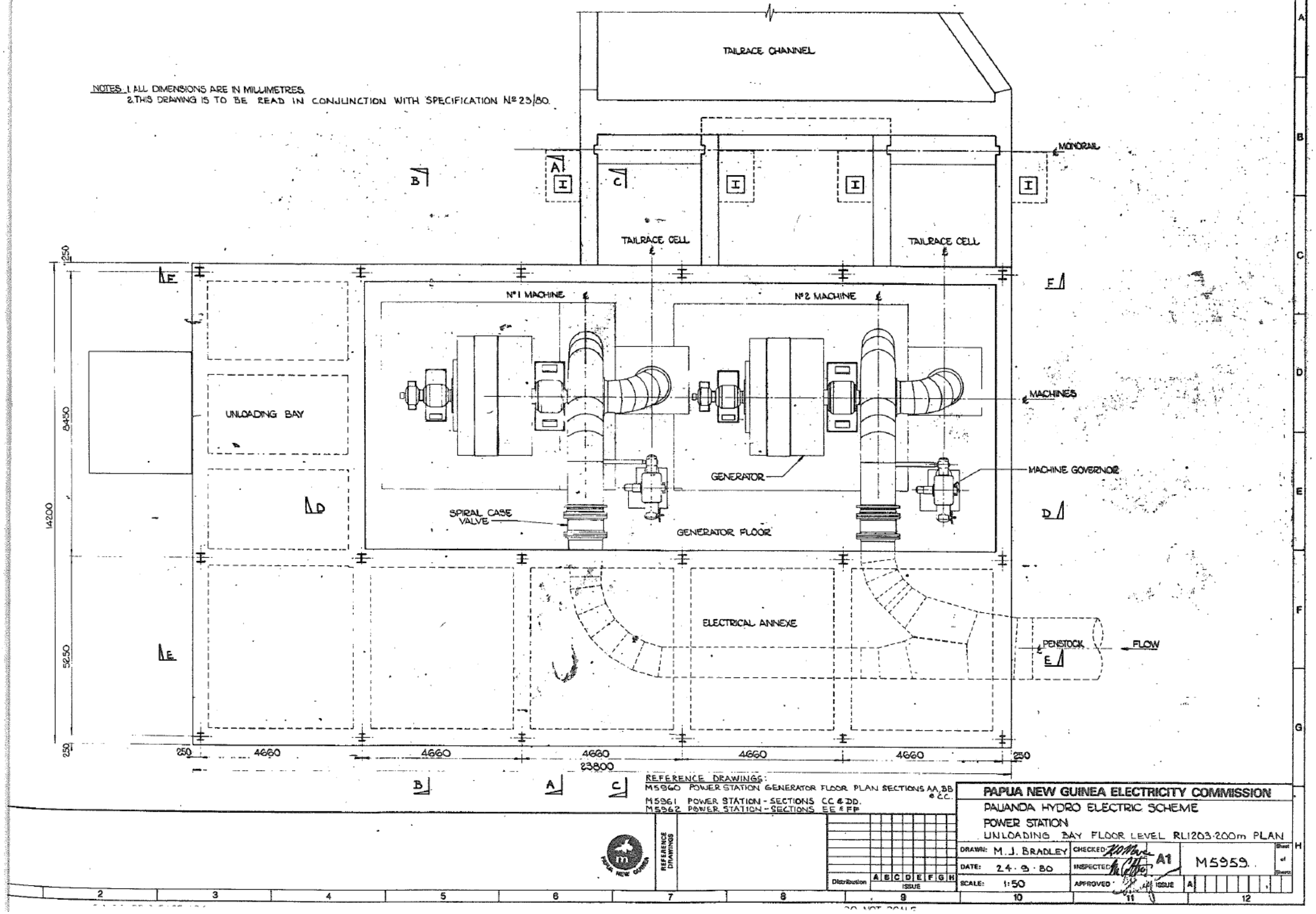
Pressure Shaft
Elevation and Cross Sections


F16,322
'B' Line
1.96m (6' 5")
1.70m (5' 7")
Lined L = 1469m (4820ft)
Unlined L = 822m (2697ft)
TAILRACE TUNNEL
SURGE TUNNEL
11.43m (37' 6")
12.19m (40'00")
12.19m (40'00")
SECTION BB
Top of Gate EL 1193.29 (3915 ft)
F.S.L. 1192.38 (3912 ft)
EL 1186.62 (3893.3 ft) Concrete
EL 1181.96 (3878 ft) Sill
M.O.L. 1184.76 (3887 ft)
EL 1181.10 (3875 ft)
Trashrack area 54.65 m² (588 ft²)
3.05m (10 ft) dia. Concrete lined
Pressure Shaft
Water barrier
EL 1010.64 (3315.90 ft)
Surge Tunnel
To Access Shaft
Surge Shaft
3.81m dia. (12' 6")
EL 977.14 (3206 ft)
EL 972.05 (3189.3 ft)
EL 973.53 (3194 ft)
Tailrace Tunnel
2.51m dia. (8' 3")
2.51m dia. (8' 3")
Start of steel liner
LONGITUDINAL SECTION
A
1 2 3 4 5
Tailrace Tunnel
PLAN
Pressure Shaft
Approx. 3.70m (12' 2")
Top of Water
SECTION AA
PAPUA NEW GUINEA ELECTRICITY COMMISSION
CONTRACT 19/85
RAMU 1 POWER STATION
SCHEMATIC HYDRAULIC LAYOUT
SMEC

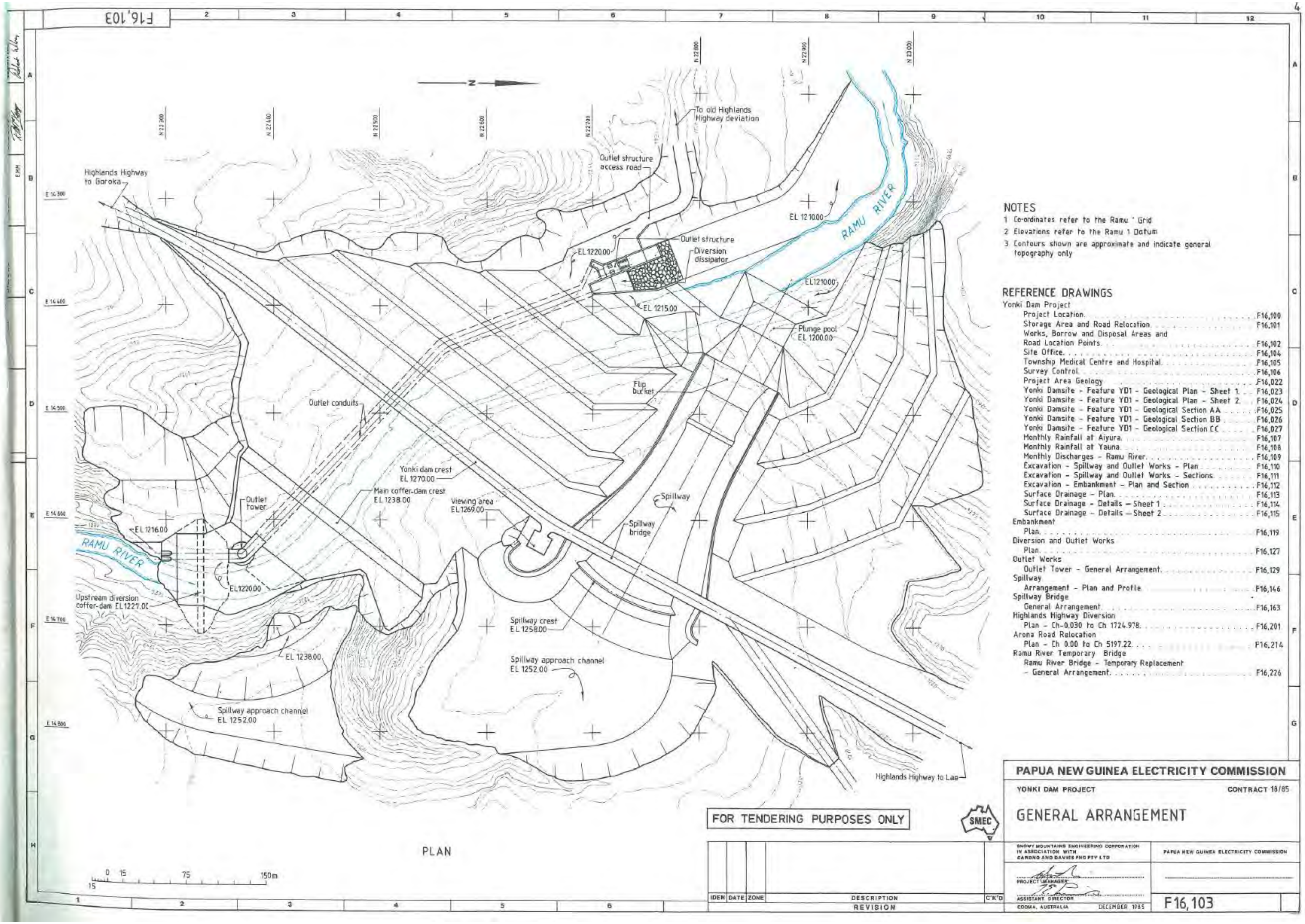
(2) Pauanda Hydropower Plant


LOCALITY PLAN
PAUANDA
RABAUL
MADANG
MT. HAGEN
MENDI
LAE
PORT MORESBY
KAUGEL RIVER
TO MT. HAGEN
TAILRACE
POWER HOUSE
PENSTOCK
MT. HAGEN — MENDI ROAD
ACCESS ROAD & DISPOSAL AREA
CONTRACTORS AREA
PENSTOCK FOREBAY
PORTAL
TO MENDI
PAUANDA CREEK
TUNNEL
WEIR
INTAKE
PORTAL
SUPERSEDES M 5610
AS BUILT
CERTIFIED BY
DESIGNATION
DATE
APPROVED FOR CONSTRUCTION
DATE 19 June 1981
PAPUA NEW GUINEA ELECTRICITY COMMISSION
PAUANDA HYDRO ELECTRIC SCHEME
CIVIL WORKS
GENERAL ARRANGEMENT
DRAWN:
CHECKED:
DATE: 25 - 1 - 1981
INSPECTED:
SCALE: 1 : 2000
APPROVED:
A1
M 6111
ISSUE
REVISION
ORIGINAL ISSUE
SUPERSEDES M 5610
REFERENCE DRAWINGS
PAPUA NEW GUINEA
DO NOT SCALE


HEADRACE CHANNEL
PENSTOCK FOREBAY
PROPOSED LAND BOUNDARY
ANCHOR BLOCK
POWER STATION
THIS AREA NOT AVAILABLE TO CONTRACTOR
PLAN
PIPE SHELL THICKNESS FROM TO
REMOVABLE SECTION & EXPANSION JOINT
2300 I.D. PENSTOCK
PIPEWORK TO BE SUPPLIED UNDER THIS CONTRACT.
KEY
P PEIR
RG RING GIRDER
A2 ANCHOR BLOCK 2.
EJ EXPANSION JOINT
SR STIFFNER RING
H.H. HANDHOLE
MH MANHOLE
HEIGHT ABOVE DATUM 1200m
GROUND LEVEL (EXISTING)
CENTRE LINE LEVEL
HORIZONTAL DISTANCE (m)
SLOPE DISTANCE ON CENTRE LINE (m)
ANCHORS BENDS AND PIERS
EXPANSION JOINTS AND STIFFENER RINGS
PIPE APPURTENANCES
LONGITUDINAL SECTION
SCALE - 1:500
THIS DRAWING IS FOR TENDERING PURPOSES ONLY
PAPUA NEW GUINEA ELECTRICITY COMMISSION
PAUANDA HYDRO ELECTRIC SCHEME
PENSTOCK
GENERAL ARRANGEMENT
DRAWN M.J. BRADLEY
DATE: 22 - 9 - 80
SCALE: 1:500
A1
M5970


NOTES 1. ALL DIMENSIONS ARE IN MILLIMETRES.
2. THIS DRAWING IS TO BE READ IN CONJUNCTION WITH SPECIFICATION Nº 23/80.
TAILRACE CHANNEL
MONORAIL
TAILRACE CELL
TAILRACE CELL
Nº1 MACHINE
Nº2 MACHINE
UNLOADING BAY
MACHINES
GENERATOR
MACHINE GOVERNOR
SPIRAL CASE VALVE
GENERATOR FLOOR
ELECTRICAL ANNEXE
PENSTOCK
FLOW
14200
8450
5250
250
4660
4660
4660
4660
4660
250
23800
REFERENCE DRAWINGS:
M5960 POWER STATION GENERATOR FLOOR PLAN SECTIONS AA, BB & CC.
M5961 POWER STATION - SECTIONS CC & DD.
M5962 POWER STATION - SECTIONS EE & FF
PAPUA NEW GUINEA ELECTRICITY COMMISSION
PAUANDA HYDRO ELECTRIC SCHEME
POWER STATION
UNLOADING BAY FLOOR LEVEL RL1203·200m PLAN
DRAWN: M. J. BRADLEY
DATE: 24 · 9 · 80
SCALE: 1:50
CHECKED
INSPECTED
APPROVED
A1
M5959.
ISSUE A
REFERENCE DRAWINGS
Distribution
ISSUE

(3) Yonki Toe of Dam (YTOD) Hydropower Plant


F16,103
Highlands Highway to Goroka
To old Highlands Highway deviation
Outlet structure access road
Outlet structure
Diversion dissipator
EL 1220.00
EL 1210.00
RAMU RIVER
EL 1215.00
Plunge pool EL 1200.00
Flip bucket
Outlet conduits
Yonki dam crest EL 1270.00
Main coffer-dam crest EL 1238.00
Viewing area EL 1269.00
Spillway
Spillway bridge
Outlet tower
EL 1216.00
RAMU RIVER
Upstream diversion coffer-dam EL 1227.00
EL 1220.00
EL 1238.00
Spillway crest EL 1258.00
Spillway approach channel EL 1252.00
Spillway approach channel EL 1252.00
Highlands Highway to Lae
NOTES
1 Co-ordinates refer to the Ramu 1 Grid
2 Elevations refer to the Ramu 1 Datum
3 Contours shown are approximate and indicate general topography only
REFERENCE DRAWINGS
Yonki Dam Project
Project Location F16,100
Storage Area and Road Relocation F16,101
Works, Borrow and Disposal Areas and Road Location Points F16,102
Site Office F16,104
Township Medical Centre and Hospital F16,105
Survey Control F16,106
Project Area Geology F16,022
Yonki Damsite - Feature YD1 - Geological Plan - Sheet 1 F16,023
Yonki Damsite - Feature YD1 - Geological Plan - Sheet 2 F16,024
Yonki Damsite - Feature YD1 - Geological Section AA F16,025
Yonki Damsite - Feature YD1 - Geological Section BB F16,026
Yonki Damsite - Feature YD1 - Geological Section CC F16,027
Monthly Rainfall at Aiyura F16,107
Monthly Rainfall at Yauna F16,108
Monthly Discharges - Ramu River F16,109
Excavation - Spillway and Outlet Works - Plan F16,110
Excavation - Spillway and Outlet Works - Sections F16,111
Excavation - Embankment - Plan and Section F16,112
Surface Drainage - Plan F16,113
Surface Drainage - Details - Sheet 1 F16,114
Surface Drainage - Details - Sheet 2 F16,115
Embankment
Plan F16,119
Diversion and Outlet Works
Plan F16,127
Outlet Works
Outlet Tower - General Arrangement F16,129
Spillway
Arrangement - Plan and Profile F16,146
Spillway Bridge
General Arrangement F16,163
Highlands Highway Diversion
Plan - Ch-0.030 to Ch 1724.978 F16,201
Arona Road Relocation
Plan - Ch 0.00 to Ch 5197.22 F16,214
Ramu River Temporary Bridge
Ramu River Bridge - Temporary Replacement - General Arrangement F16,226
PLAN
FOR TENDERING PURPOSES ONLY
SMEC
PAPUA NEW GUINEA ELECTRICITY COMMISSION
YONKI DAM PROJECT
CONTRACT 18/85
GENERAL ARRANGEMENT
SNOWY MOUNTAINS ENGINEERING CORPORATION IN ASSOCIATION WITH CAMERON AND DAVIES PNG PTY LTD
PAPUA NEW GUINEA ELECTRICITY COMMISSION
PROJECT MANAGER
ASSISTANT DIRECTOR
COOMA, AUSTRALIA
DECEMBER 1985
F16,103
IDEN DATE ZONE
DESCRIPTION
REVISION
C'K'D
0 15 75 150m

Appendix 5.1.4

Hydro Machine Details

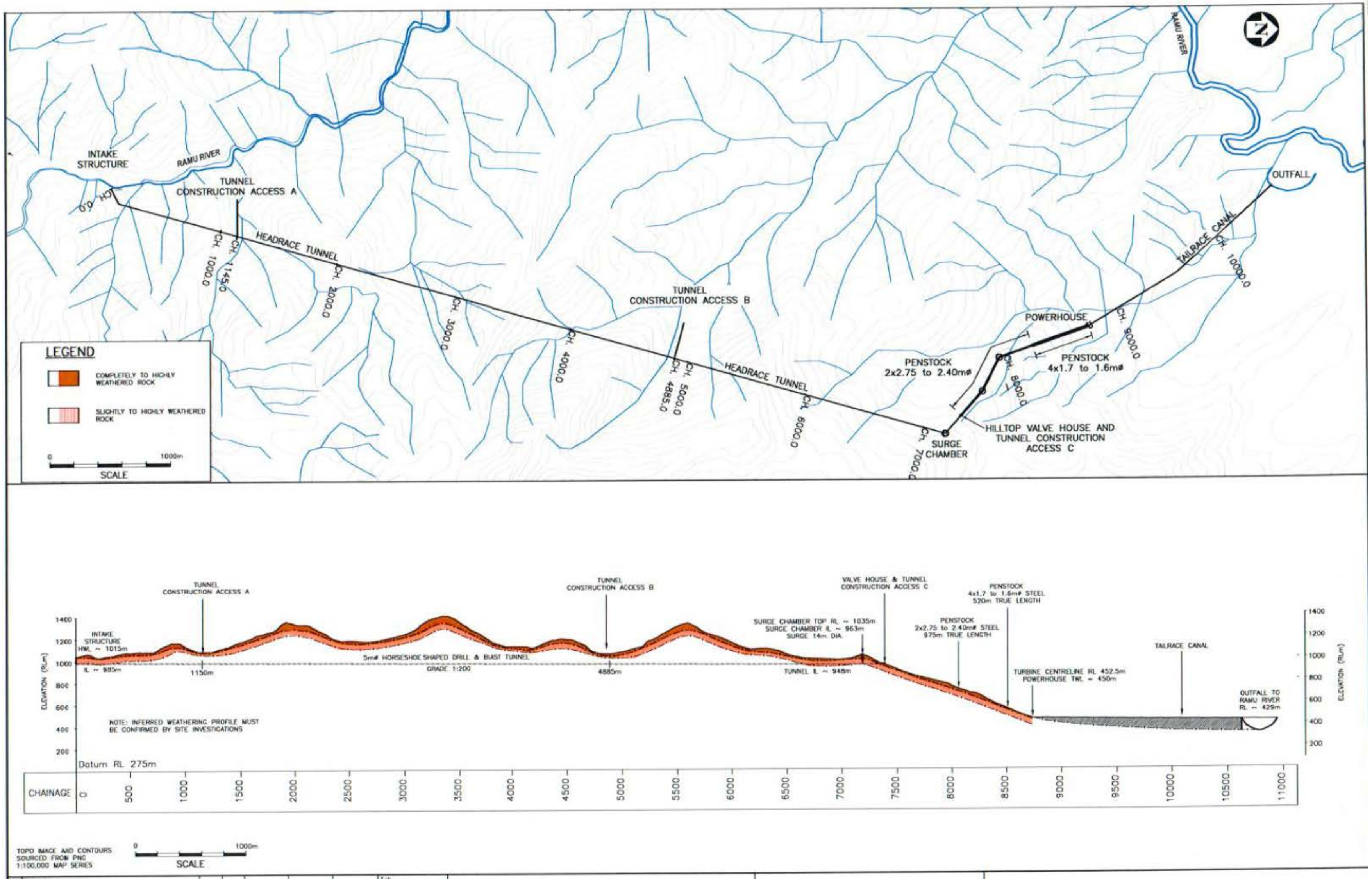
(1) Ramu1 Hydropower Project

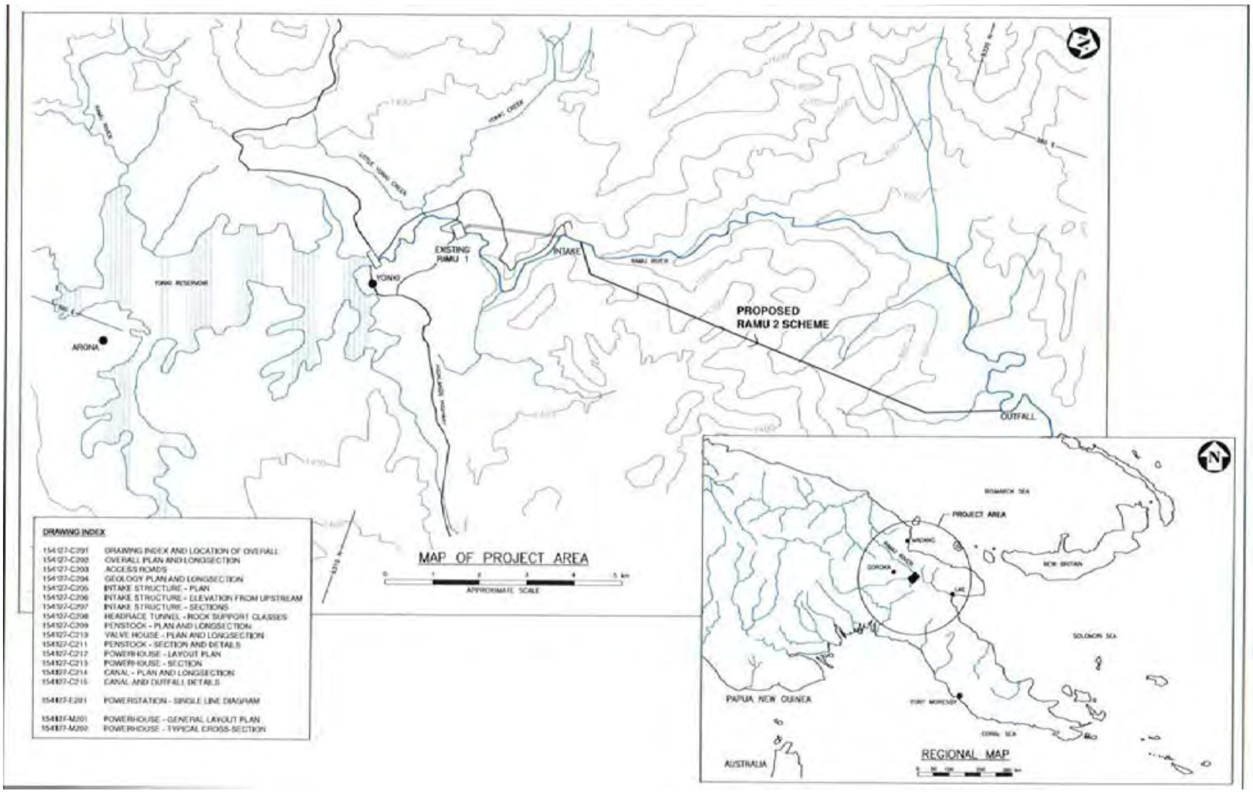
TURBINE									ALTERNATOR/GENERATOR								
Centre	STATION	M/C	MAKE	TYPE	SERIAL NO.	SPEED (rpm)	HEAD (m)	FLOW m3/s	MAKE	TYPE	SERIAL NO.	VOLTS	AMPS	P/F	KVA	KW	DATE COMM.
Port Moresby	Rouna 1	1	Boving	H/Francis	968	1000	118	1	M/Vickers	Synch.	260625/1/1	3,300	219	0.8	1,250	1,000	1957
		2	Boving	H/Francis	969	1000	118	1	M/Vickers	Synch.	260625/1/2	3,300	219	0.8	1,250	1,000	1957
		3	Boving	H/Francis	970	1000	118	1	M/Vickers	Synch.	260625/1/3	3,300	219	1	1,250	1,000	1957
		4	Boving	H/Francis	1024	750	118	2.5	P/Peebles	Synch.	77535	3,300	547	0.8	3,125	2,500	1961
	Rouna 2	1	Andritz	V/Francis	MB9018/1	1000	150	4.75	E/Union	Synch.	555410	11,000	394	0.8	7,500	8,000	2009
		2	Voest	V/Francis	MB9018/2	1000	150	4.75	E/Union	Synch.	555411	11,000	394	0.8	7,500	6,000	1967
		3	Voest	V/Francis	MB9018/3	1000	150	4.75	E/Union	Synch.	556084	11,000	394	0.8	7,500	6,000	1967
		4	Andritz	V/Francis	MB9018/4	1000	150	4.75	E/Union	Synch.	1227545	11,000	394	0.8	7,500	8,000	2008
		5	Andritz	V/Francis	MB9018/5	1000	150	4.75	E/Union	Synch.	1227547	11,000	394	0.8	7,500	8,000	2008
	Rouna 3	1	Bell	H/Francis	2042	500	119.3	5.814	P/Peebles	B/Synch.	ESW56127/1	11,000	394	0.8	7,500	6,000	1975
		2	Bell	H/Francis	2043	500	119.3	5.814	P/Peebles	B/Synch.	ESW56127/2	11,000	394	0.8	7,500	6,000	1975
	Rouna 4	1	Ebara	H/Francis	RE1021102 (1/2)	500	90.8	8.5	Shinko	B/Synch.	G09330010	11,000	435	0.8	8,281	6,325	1986
		2	Ebara	H/Francis	RE1021102 (2/2)	500	90.8	8.5	Shinko	B/Synch.	G093300102	11,000	435	0.8	8,281	6,325	1986
	Sirinumu	1	Andritz	V/Francis	1181	432	26	7	B/Boveri	A/Synch.	W813921	6,600	170	0.8	1,875	1,500	1973
Ramu	Ramu 1	1	Litistroj	V/Francis	18432	750	198.6	9.8	R/Koncar	Synch.	13451	11,000	1,017	0.9	16,660	15,000	1976
		2	Litistroj	V/Francis	18433	750	198.6	9.8	R/Koncar	Synch.	13453	11,000	1,017	0.9	16,660	15,000	1976
		3	Litistroj	V/Francis	18434	750	198.6	9.8	R/Koncar	Synch.	13455	11,000	1,017	0.9	16,660	15,000	1976
		4	Boving	V/Francis	18336	750	198.6	8.94	Elin	Synch.	163406	11,000	1,017	0.9	18,000	17,000	1990
		5	Boving	V/Francis	18337	750	198.6	8.94	Elin	Synch.	163407	11,000	1,017	0.9	18,000	17,000	1990
	Pauanda	1	Toyo Menka	H/Francis	RB10125.01	500	109.5	6.23	S/Electric	B/Synch.	PVLKIF 2240-T	11,000	656	0.8	7,500	6,000	1983
		2	Toyo Menka	H/Francis	RB10125.02	500	109.5	6.23	S/Electric	B/Synch.	PVLKIF 2240-T	11,000	656	0.8	7,500	6,000	1983
Gazelle	Warangoi	1	Sarumsand Verkstad	D/H Francis	N/A	500	46	6.4	N/Industry	Synch.	N/A	11,000	326	0.8	N/A	5,000	1983
		2	Sarumsand Verkstad	D/H Francis	N/A	500	46	6.4	N/Industry	Synch.	N/A	11,000	326	0.8	N/A	5,000	1983
Kimbe	Ru Creek	1	Ossberger	Crossflow	SH62/15G	1500	22	2.6	AVK	B/Synch.	54330/0	415	695	0.8	500	400	1982
		2	Ossberger	Crossflow	SH62/15G	1500	22	2.6	AVK	B/Synch.	54330/1	415	695	0.8	500	400	1982
Bialla	Lake Hargy	1	Ossberger	Crossflow	SH1093/20G	213	26	4	Siemens	Synch.	N/A	415	1,340	0.8	960	750	1989
		2	Ossberger	Crossflow	SH1093/20G	213	26	4	Siemens	Synch.	N/A	415	1,340	0.8	960	750	1995

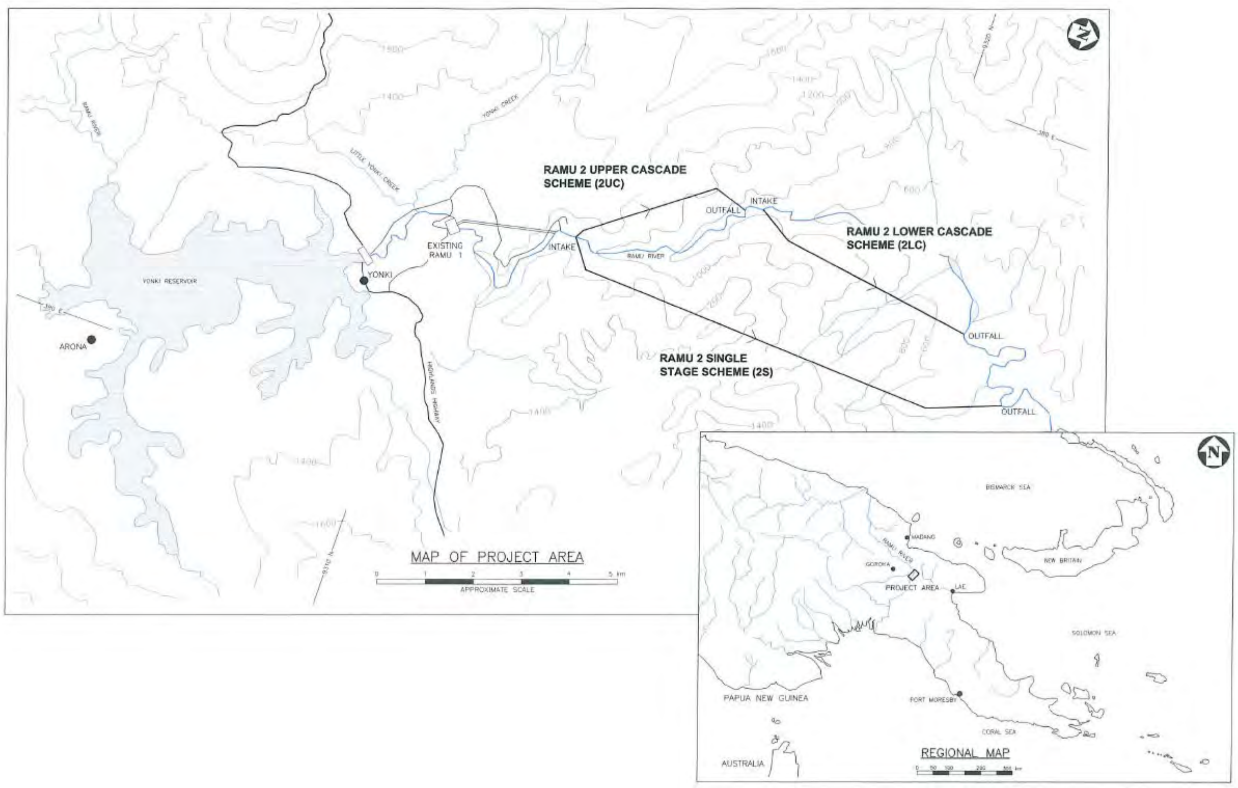
Appendix 5.1.5

Drawings of Hydropower Project

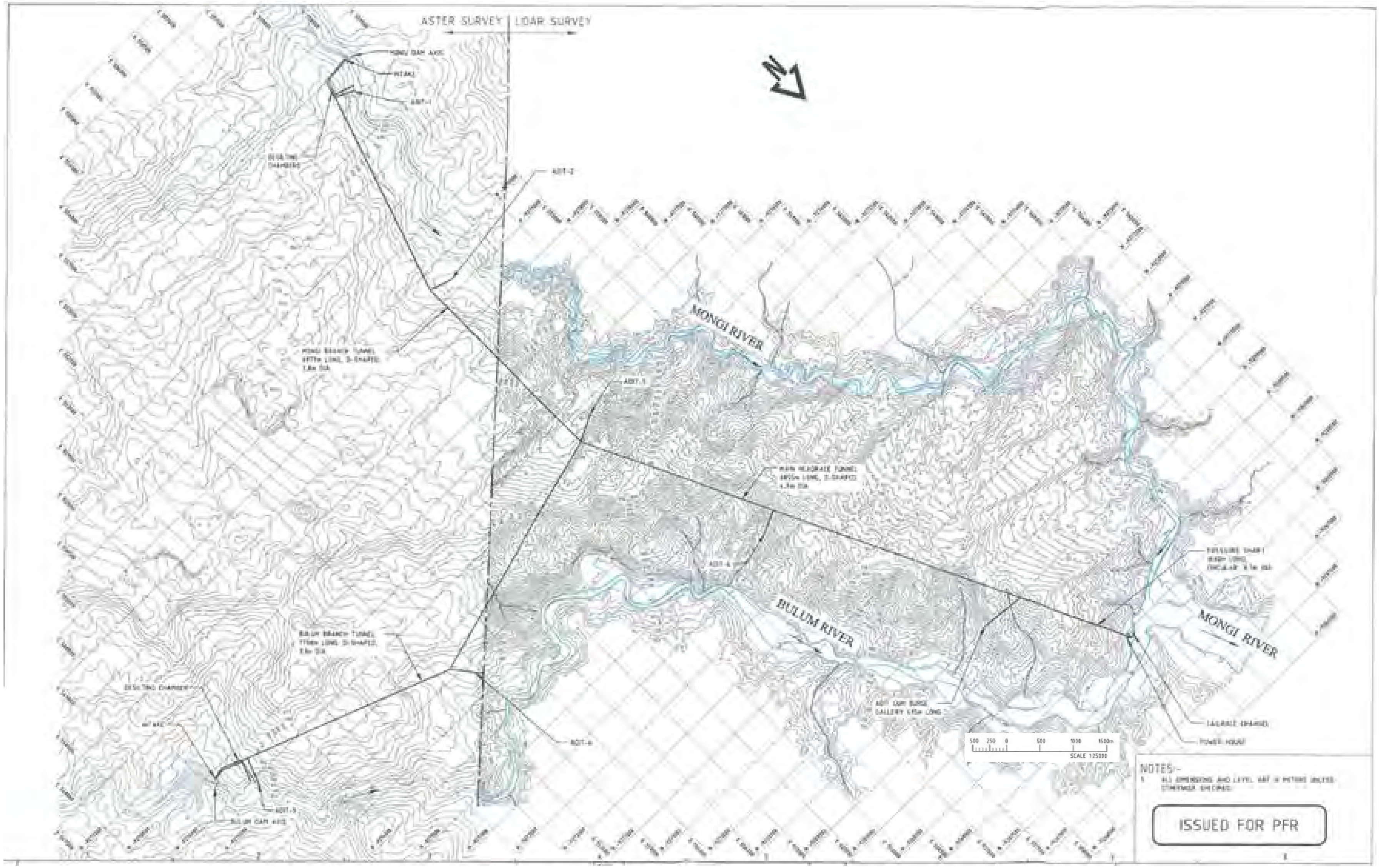
(1) Ramu 2 Hydropower Project



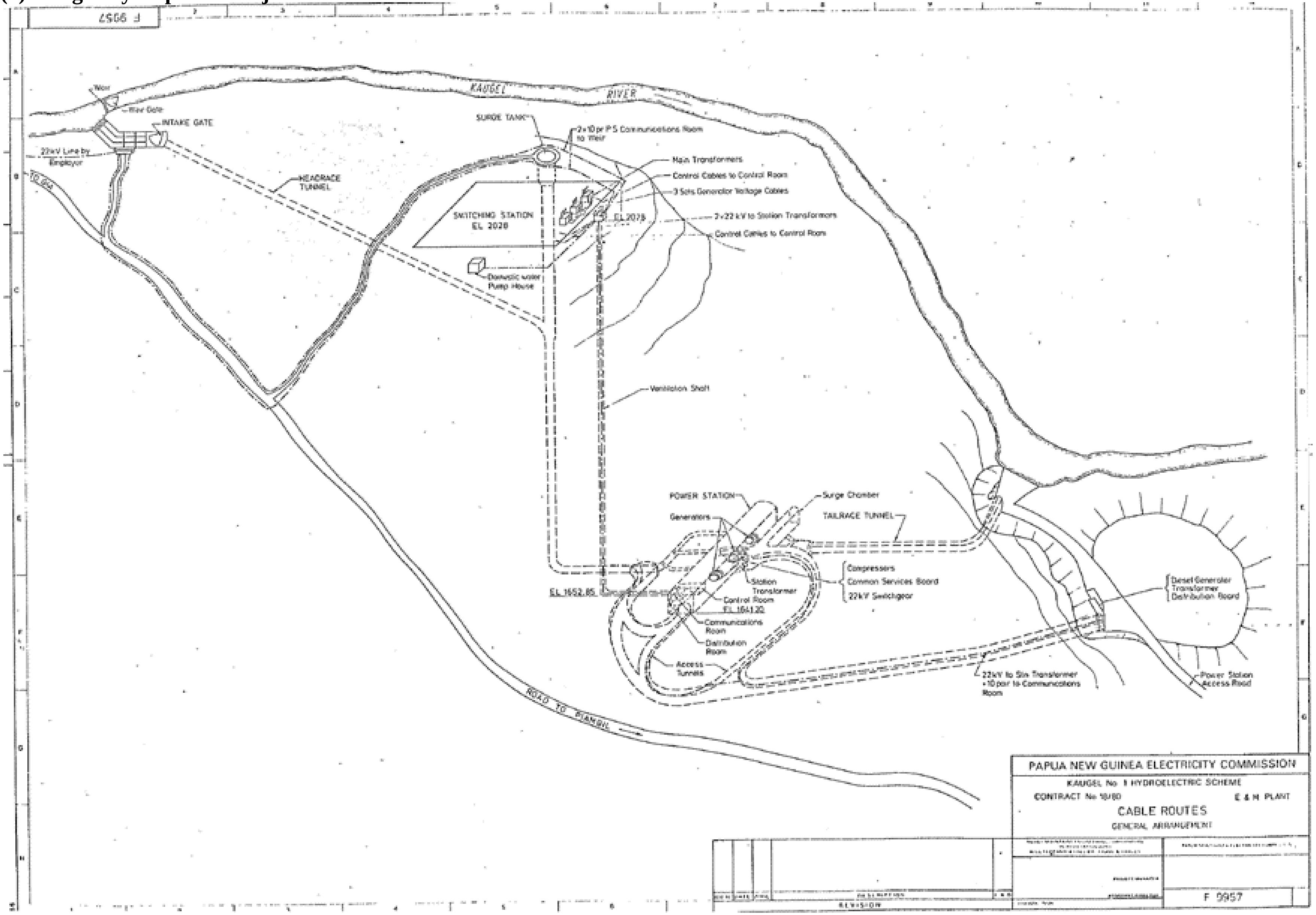

YONKI RESERVOIR
YONKI
ARONA
LITTLE YONKI CREEK
YONKI CREEK
EXISTING RAMU 1
INTAKE
RAMU RIVER
HIGHLANDS HIGHWAY
PROPOSED
RAMU 2 SCHEME
OUTFALL
MAP OF PROJECT AREA
APPROXIMATE SCALE
DRAWING INDEX
154127-C201 DRAWING INDEX AND LOCATION OF OVERALL
154127-C202 OVERALL PLAN AND LONGSECTION
154127-C203 ACCESS ROADS
154127-C204 GEOLOGY PLAN AND LONGSECTION
154127-C205 INTAKE STRUCTURE - PLAN
154127-C206 INTAKE STRUCTURE - ELEVATION FROM UPSTREAM
154127-C207 INTAKE STRUCTURE - SECTIONS
154127-C208 HEADRACE TUNNEL - ROCK SUPPORT CLASSES
154127-C209 PENSTOCK - PLAN AND LONGSECTION
154127-C210 VALVE HOUSE - PLAN AND LONGSECTION
154127-C211 PENSTOCK - SECTION AND DETAILS
154127-C212 POWERHOUSE - LAYOUT PLAN
154127-C213 POWERHOUSE - SECTION
154127-C214 CANAL - PLAN AND LONGSECTION
154127-C215 CANAL AND OUTFALL DETAILS
154127-E201 POWERSTATION - SINGLE LINE DIAGRAM
154127-M201 POWERHOUSE - GENERAL LAYOUT PLAN
154127-M202 POWERHOUSE - TYPICAL CROSS-SECTION
PROJECT AREA
BISMARCK SEA
NEW BRITAIN
SOLOMON SEA
PAPUA NEW GUINEA
PORT MORESBY
CORAL SEA
AUSTRALIA
REGIONAL MAP


YONKI RESERVOIR
YONKI
ARONA
LITTLE YONKI CREEK
YONKI CREEK
EXISTING RAMU 1
INTAKE
RAMU RIVER
HIGHLANDS HIGHWAY
RAMU 2 UPPER CASCADE SCHEME (2UC)
RAMU 2 LOWER CASCADE SCHEME (2LC)
RAMU 2 SINGLE STAGE SCHEME (2S)
OUTFALL
MAP OF PROJECT AREA
APPROXIMATE SCALE
BISMARCK SEA
MADANG
GOROKA
PROJECT AREA
LAE
NEW BRITAIN
SOLOMON SEA
PAPUA NEW GUINEA
PORT MORESBY
CORAL SEA
AUSTRALIA
REGIONAL MAP

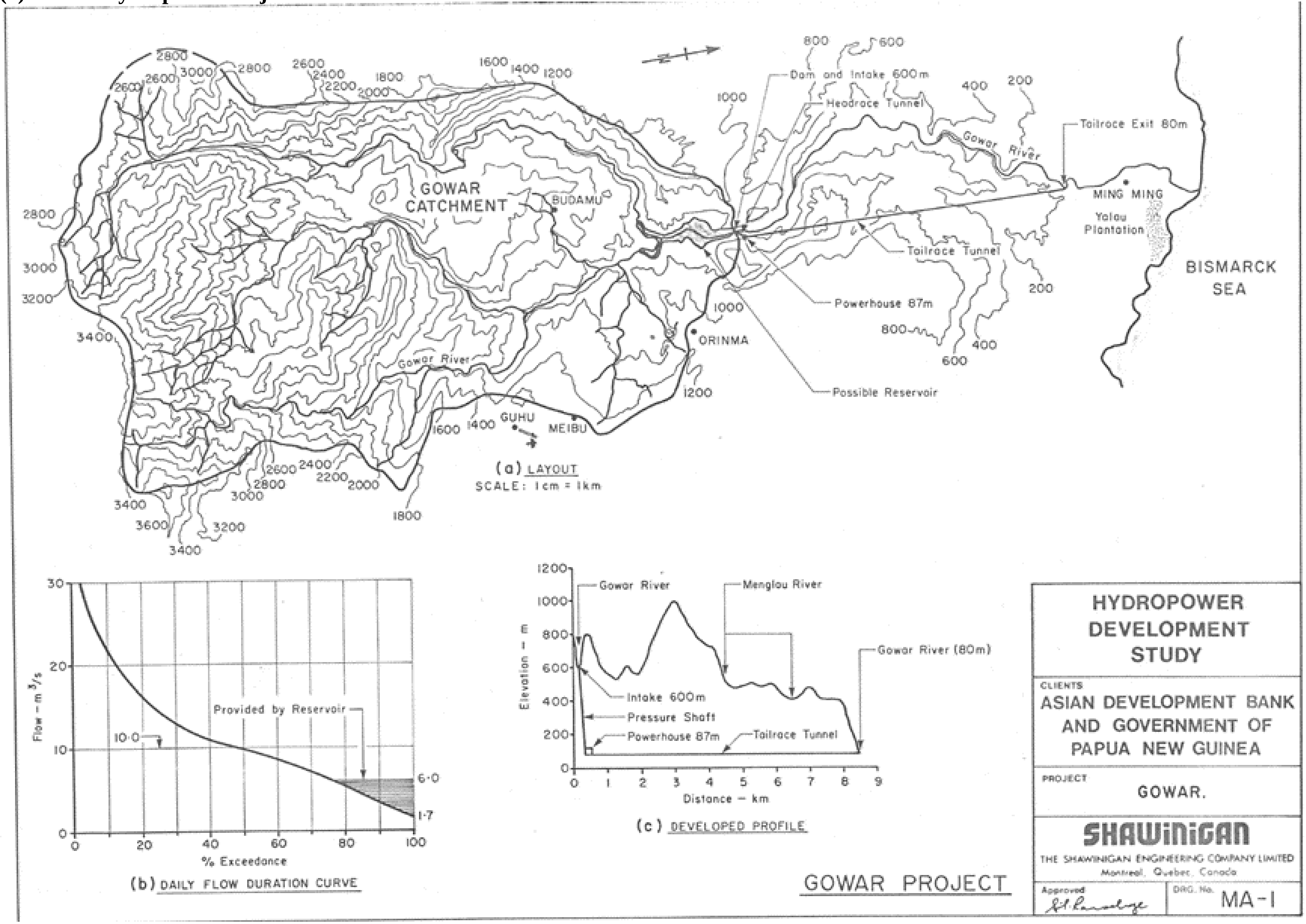
(2) Mongi - Bulum Hydropower Project



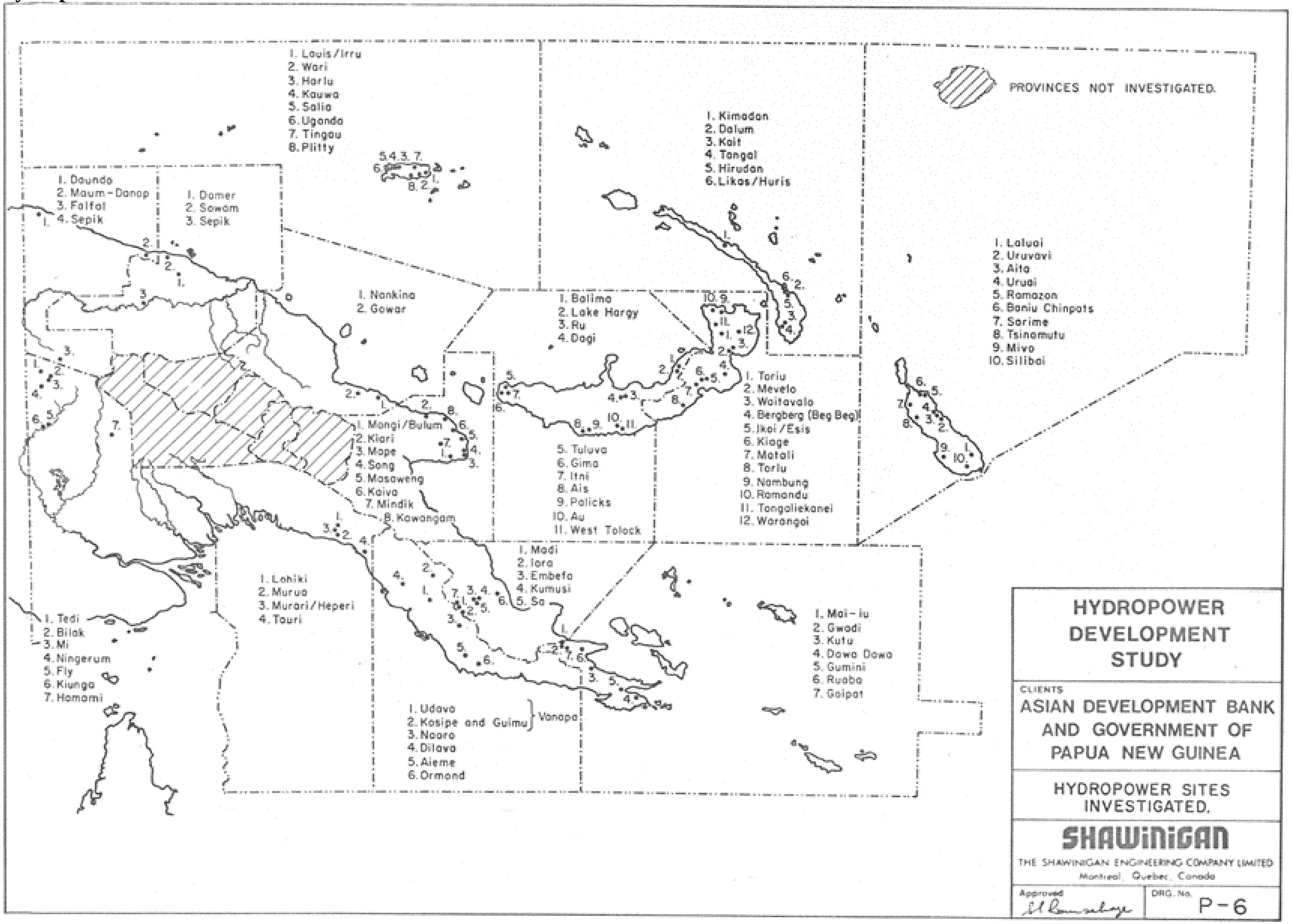
(3) Kaugel Hydropower Project



(4) Gowar Hydropower Project



(5) Hydropower Potential Sites



CHAPTER 6

OPTIMAL POWER GENERATION DEVELOPMENT PLAN

CHAPTER 6 OPTIMAL POWER GENERATION DEVELOPMENT PLAN

6.1 ISSUE OF POWER GENERATION DEVELOPMENT IN THE PDP

The government integrated its investment to lay the foundation for growth by addressing the supply-side constraints and expanding the productive capacity of the economy in the first Medium Term Development Plan (MTDP) 2011-2015.

The FYPDP has been compiled in order to better respond to the power requirements of PNG.

The main goal is to capture the developments of the Electricity Supply Industry based on National and Provincial Development Plans. Ideally, this approach should advance the provision of power supply within PNG in line with plans formulated by the National and Provincial Authorities and Planners.

(1) Current Power Supply Situation of the Ramu System

The main source of generation is the Ramu HP Station with an installed capacity of 75 MW (5 × 15 MW) and the newly installed 18 MW YTOD. This station, which was previously a run-of-river scheme, became a storage scheme when the Yonki Dam was commissioned in February 1991.

Supplementary hydropower generation comes from Pauanda HP, a run-of-river station in the Western Highlands Province with 12 MW (2 × 6 MW) installed capacity.

T/L outages, energy and peak demands are met by diesel plants at Madang, Lae, Mendi and Wabag. These plants serve as stand-by units.

Power is also purchased from the privately owned Baiune HP Station at Bulolo in Morobe Province when required. The amount purchased varies between 9 and 10 MW, depending on availability.

The Ramu system serves the load centers of Lae, Madang, and Gusap in the Momase Region and the Highlands centers of Wabag, Mendi, Jiwaka, Mount Hagen, Kundiawa, Goroka, Kainantu, and Yonki.

The economy of the regions supplied by the Ramu system is based on mining, oil, gas, coffee, tea, timber, and industrial production.

Three radial lines originating from the Ramu HP Station switchyard serve Lae, Madang, and the Highland Centres. Currently Madang and the Highlands Region are supplied at 66kV and Lae is supplied at 132kV. The Highlands line interconnected with Pauanda Hydro Station supplies the townships of Kainantu, Goroka, Kundiawa, Mt. Hagen, Wabag, and Mendi.

(2) Issues for the Power Development Plan

Based on the situation of the existing power plants and the geological location of power supply and demand centers, the following main issues seem to arise. These issues should be considered in the power development plan for the Ramu system.

1) Chronic shortage of power supply

As mentioned previously, the main power sources in the Ramu system are hydropower stations, and diesel generation facilities which are used as backup power sources.

The current total installed capacity is nearly double the maximum demand, but most of the power sources are becoming superannuated and power outputs are dropping or operation is becoming impossible due to aging and poor maintenance. Accordingly, many of the power plants are out of order and the output of many power plants has decreased.

Even though rotational power interruption is implemented and the power is purchased from IPP at present, power supply is in chronic shortage in the Ramu system.

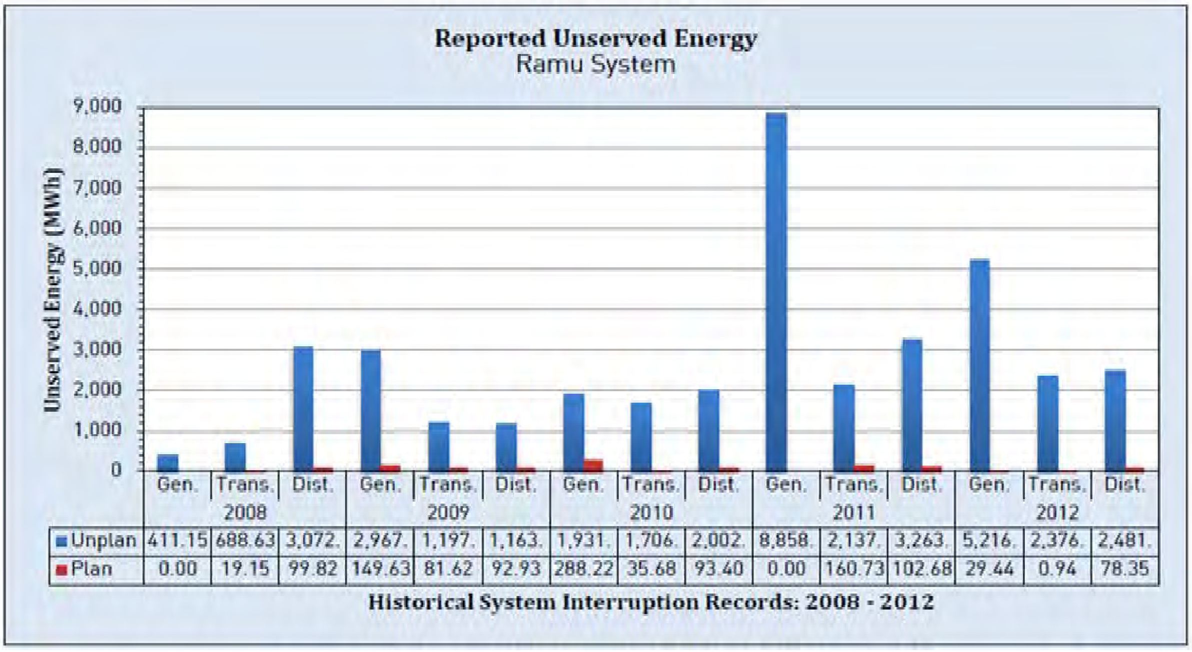
For the Ramu HP Station, Unit No.2 of the Pauanda HP Station is inoperative because of damage to the intake facility, and generation is suppressed due to defects in cooling water facility, cavitation, leakage of water from the turbine casing, etc.

Furthermore, the newly commissioned Yonki Toe HP Station can only generate 7 MW due to the no attachment of surge tank.

Many of the diesel generators are also inoperative due to aging and malfunctioning equipment.

2) Low-Reliability Performance

Due to the chronic shortage of power supply and a radial power system with one circuit, the power supply is fairly unreliable, as shown in Fig. 6.1-1, a plot of the total number of interruptions (planned & unplanned) in Generation, Transmission, and Distribution from 2008 to 2012.



	Gen. 2008	Trans. 2008	Dist. 2008	Gen. 2009	Trans. 2009	Dist. 2009	Gen. 2010	Trans. 2010	Dist. 2010	Gen. 2011	Trans. 2011	Dist. 2011	Gen. 2012	Trans. 2012	Dist. 2012
Unplan	411.15	688.63	3,072.	2,967.	1,197.	1,163.	1,931.	1,706.	2,002.	8,858.	2,137.	3,263.	5,216.	2,376.	2,481.
Plan	0.00	19.15	99.82	149.63	81.62	92.93	288.22	35.68	93.40	0.00	160.73	102.68	29.44	0.94	78.35

Fig. 6.1-1 Reported Unserved Energy for Ramu System

3) Demand forecast is uncertain due to the unforeseen development of large mines, industrial facilities, and so on.

4) Reliable power projects, such as new hydropower projects and gas thermal power projects, are lacking.

5) Financing for power generation projects might have uncertainty due to IPP / PPP by private sectors.

6) The financial condition of PPL is very weak.

These issues are addressed in each step in order to formulate an optimal power development plan, as mentioned hereafter.

6.2 POWER GENERATION DEVELOPMENT PLAN

(1) Main Objectives of the Power Generation Development Plan

The overall objective is to develop the most appropriate mode of power supply in terms of cost effectiveness, economy, financial viability, technical soundness, and sustainability to meet the Long-term Demand Forecast for electricity of the Ramu Grid in line with related policies for achieving the following;

- The Power Generation Development Plan (PGDP) shall identify the capacity, type, timing etc., in consideration of the national development goals, the power generation projects of the IPPs, and the power supply plan.
- The size and type of new generating capacity shall be determined based on economic analysis and shall meet the least-cost criteria under the evaluation of Strategic Environmental Assessment (SEA).
- The power development plan shall ensure that there is always sufficient power supply to meet the growing demand for electricity in the Ramu system on a least-cost development Basis.

(2) Concept for the power development plan

The MTDP guides the development of sector policies, plans and strategies. Vision 2050 and PNGDSP both provide economic development frameworks and performance indicators that enable policy proposals to be prioritized and closely monitored through the implementation of the MTDP, as follows.

1) Priority for the Power Sources

The development of hydro-based power remains a high priority wherever it is economically and financially justified, especially in the Ramu system due to its large potential for hydropower.

In line with this priority, the development of hydro resources for power generation will continue to be a high priority. However, other indigenous resources such as natural gas, other renewable sources, and fuel oil are being considered as strategic options.

In short-term development in particular, Oil-fired Gas turbine including DG or natural gas fuel and biomass generation (except planned hydropower) are candidate generation types, mainly due to restrictions in hydropower construction periods.

PPL is not involved in the planning of any new Mini or Micro Hydro stations at this time. However it has been helping the Department of Petroleum and Energy to develop projects and assess the viability of building Mini Hydro plants or of connecting certain government stations to the PPL System.

Some projects where the Department of Petroleum and Energy has built Mini/Micro Hydro facilities to replace diesel-powered generation at Government 'C' Centres may be considered for takeover by PPL or for operation by PPL on behalf of the government on an agent basis.

2) Planning Responsibility and Security of Power Supply

The 2013-2017 regulatory contract prescribes a significant improvement in reliability to be achieved within the contract period. These targets require changes to the planning criteria.

As Reliability Standards and criteria prescribed in the Grid Code, the power development plan shall meet the following reliability criteria mentioned below.

(a) Planning responsibility

With regard to the planning responsibility, the PGDP shall comply with existing policy and legal frameworks for obtaining access to land, mitigating environmental impacts, and complying with the Third Party Access Code and Grid Code.

This evaluation of environmental aspects for this Master Plan is described in Chapter 8 “Environmental and Social Consideration”.

(b) Security of Power Supply

The security of Power Supply criteria for the generation planning for all the power systems is assessed using Loss of Load Expectancy (LOLE) and Expected Unserved Energy (EUE) indexes to determine new capacity additions for generation expansion planning

a) Loss of Load Expectancy (LOLE)

This is a probabilistic index used by many utilities around the world to decide future generation capacity. It is defined as the average number of days on which the daily peak load is expected to exceed the available generating capacity. This criterion requires that all generation systems meet a given level of reliability expressed as LOLE and measured in days/year.

b) Expected Unserved Energy (EUE)

In addition to LOLE, many utilities measure the expected energy that will not be supplied due to those occasions when the load exceeds the available capacity. This index reflects risk and financial consequences more accurately as it encompasses the severity of the deficiencies as well as their likelihood.

The EUE, measured in GWH/year in the case of the Ramu system, is used as a basis for performing financial analysis. Input data required for the model includes maximum and minimum demands, annual energy forecasts, load forecasts, existing and future capacities, and availability factors for existing and future generation capacities.

According to the grid code, the power system shall be planned and operated so that the LOLE and EUE of the generation system (all generation units connected to the transmission network) shall not exceeded the following:

Loss of Load Expectancy (LOLE)	:	LOLE < 2 days per year (for Grids with demand of at least 10 MW)
Expected Unserved Energy (EUE)	:	EUE < 0.5% RC (Reserve Capacity)

The model simulates the operation of the system annually for a period of 15 years based on availability criteria and the projected load growth.

(3) Economic Criteria

The most appropriate mode of power supply to meet the increasing demand that is cost effective and economical shall be considered, as well as the integration of renewable energy resources in accordance with the national policies in PNG (in consideration of economic life costs such as the fixed and variable operation & maintenance costs, fuel costs, etc., of candidate power plants).

(4) Location of Power Plants

The Optimal Location of power plants shall be identified to meet the security and efficiency requirements of the Grid and to achieve least-cost development of generation transmission and distribution systems.

(5) Power supply plan for the future demand in PNG

The Generation Development Plan in PNG encompasses the following main plans.

- The short, medium and long-term development plans [Infrastructure Planning team]
- The FYPDP (2014-2028) [Strategic Planning and Business Department, April 2014]]

Although each plan is designed to achieve progress in every aspect of the power system development in PNG, Development plan in the early medium-term seems to be focused on for cooping to the increasing demand.

As the latest concrete power development plan, The FYPDP contains the PNG Power program to meet the increasing demand for electricity in the Ramu Power system.

Regarding the electrification plan for rural areas, approximately 90% of the population of PNG is said to live in rural areas in accordance with The FYPDP. A very small percentage of these rural people currently have access to an electricity supply. The government has a target value for enhancing the electrification ratio of 70% up to 2030.

For achieving the above target of 70% up to in order to identify other 2030, further investigations will continue in order to identify other possible areas for expansion. At present PPL's Rural Electrification program relies on making an electricity supply available to large captive loads in order to be economical and this permits the electrification of villages along the routes of these lines at the same time.

The need for external support for Rural Electrification is noted, as much of this work does not meet the Financial Rate of Return required for PNG Power to finance the projects.

The Rural Power Supply Plan identifies the need for an ongoing expansion program to extend electricity supply to rural areas of the country. Based on the Rural Power Supply Plan, large loads that are often identified to provide a basis for investigation of potential rural electrification project normally fit into one of the following categories;

- Rural Village Communities
- Community Infrastructure (Government Center, Offices, Hospitals, Missions, Scholes, etc.)
- Commercial Enterprises (Trade Stores, Workshops)
- Agriculture Based Processing Plants (Tree, Coffee, Coconut, Timber, Rubber)
- Small Scale Mining

Rural electrification will increase as power lines are extended into rural areas and to areas adjacent to existing power lines. Standalone systems will focus more on renewable energy such as solar, wind, and micro hydro.

(6) Current Power Development Plan of the Ramu Power System

In accordance with the FYPDP, the following power development plan has been established for the Ramu Power System.

With the rated capacity in total of the existing assets, very little additional generation is required to meet reliability criteria within the planning period for the base load, excluding the expected mining loads. However, several diesel generators are aging so that the actual output of these generators are low compared to the rated capacity of those or are not available for generation at this stage. Power supply reliability seems to be low as a consequence of ongoing operational issues at the Ramu 1 HP and also with the fragile one-circuit trunk 132 kV T/L.

To meet reliability criteria in a cost efficient way, the PPL plans to increase the operating performance of existing hydro assets. In the short term, rehabilitation of few underperforming diesel generators will be required to make up for the unreliable performance of the Ramu 1 HP.

Although some of the existing diesel generators are aging and unreliable, there seems to be no replacement plan in the planning period which should be considered in this study. There is a need for a new power station in Lae to accommodate the replacement of Milford generation and augmented capacity over time.

1) Current PPL’s short- term & long- term Infrastructure Plan

As per the summary for PPL’s Infrastructure Plan in accordance with the FYPDP, an additional 30~60 MW of low-cost generation may be required within the next 5 years, and another 25-30 MW may be required towards the end of the planning period in order to meet future increases in the base load.

Although there are some planned industrial developments in Lae and Madang that may add significant loads at some point, the exact timing and scope of these developments including the big mining loads, etc. are unclear. However, the additional major development of a low-cost generating resource is expected to coincidentally meet those big demands, as mentioned below.

(a) PPL’s short- term Infrastructure Plan

- Ramu 1 Rehabilitation Project
  This project is aimed at increasing current available capacity from 45 MW to 60 MW.
- Ramu 2 Hydropower Project
  A 120 MW power station is being planned downstream of the existing Ramu 1 Power Station.
- An additional 30 MW of low-cost generation, etc.

(b) PPL’s long- term Infrastructure Plan

In this long-term Infrastructure Plan, the development of renewable and substantial hydropower plants with IPP schemes is encouraged.

- Renewable energy sources of power: Markham Valley (biomass) use of natural gas for power generation (Subject to IPP Project).

- The development of Hydro power plant based on the Feasibility study: Mongi/Bulum 100 MW hydro resources near Finschhafen, Morobe Province and Kaugel HP resource.
- Additional Thermal Power generation, etc.
- Interconnection of POM system and Ramu system.

2) Current Generation Development Plan and Supply–Demand Balance

(a) Major Generation Development Plan and Required plans

a) Major generation development plan

The replacement of thermal-based generation with renewable energy resources, wherever economically justified, is a major objective of PPL. Investigation of suitably situated rivers with potential for hydroelectric development has therefore remained one of PPL's priorities. Yet the ongoing financial constraints have adversely affected investigations over recent years.

However, the deregulation and development of new generation systems by the government as part of the corporatization process of PPL is an incentive for prospective investors to invest in this area of development.

Past investigations have established the need to place the Ramu systems on a firm hydro standing based on economic considerations. The development will require a large amount of capital expenditure.

The Rehabilitation & Refurbishment of YTOD in particular is a significant development in securing the needs of the Ramu system for some time in the future.

Rehabilitating existing Ramu 1 HPs is by far the most attractive option. The rehabilitation program involves a generator over haul, governor, and control system upgrades, as well as other auxiliary equipment. The expected generation capacity increase is 15 MW, with a significant boost to system stability.

There is also the plan to rehabilitate or replace existing diesel generators in the Ramu Power system. More than 20 MW of diesel generations are currently out of service due to superannuation or poor operating and maintenance routines.

With the expectation of a major hydro resource being developed in the Ramu system within the planning period, the least cost development plan is to continue adding small amounts of diesel generation during the planning period to tentatively meet the increasing demand. The planned substation/power station at Singawa in Lae is an ideal place to do this.

b) Current Requirement Plans

The following plans are required for keeping the supply-demand balance in the future.

- Ramu 2 HPP is the most attractive and advanced project. Optimization, timing, and suitable unit output in the Ramu system will be studied.
- Promotion of financing and project implementation of Ramu 2 HPP will be

initiated by the PNG government.

- The feasible hydropower projects next to Ramu 2 HPP will be developed.
- The promising hydropower potential will be identified from technical, economic, and environmental viewpoints.

PPL's generation requirement plans and development plans for the Ramu system for the planning period [2014-2028] are summarized in Table 6.2-1, Table 6.2-2, and Table 6.2-3.

Table 6.2-1 Existing Hydro Power Plants and Rehabilitation / Refurbishment Plan

Name of power plant	Completion year	type	Rating Output (MW)	Actual as of 2014.10 (MW)	Rehabilitation & Refurbishment
Pauanda #1	1983	Run-of-River	6.0	1.0	Damaged bearing of #2 turbine shall be replaced (the order has been placed). The bearing temperature of the #2 unit shall be monitored.
Pauanda #2	1983		6.0	0.0	
YTOD #1	2013	Reservoir	9.0	3.0	The total max output of the two units was limited to 6 MW due to large water pulsation (caused by the lack of a surge chamber). The turbine cooling system is also to be repaired.
YTOD #2	2013		9.0	3.0	
Ramu 1 #1	1976	Reservoir	15.0	45	Refurbishment of the #1, #2, #3 units was completed and refurbishment of #4 and #5 is postponed due to budget shortages. The total max output of the five units is around 45 MW due to limited flow capacity of the tailrace tunnel (25m^3/sec).
Ramu 1 #2	1976		15.0		
Ramu 1 #3	1976		15.0		
Ramu 1 #4	1990		16.2		
Ramu 1 #5	1990		16.2		
Baiune #1	2013	Reservoir	6.5	4.7	IPP power plant owned by Forest Product Ltd. supplies electricity to Hidden Valley Mine.
Baiune #2	2013		6.5	4.7	
Total			**120.40**	**61.4**	Actual output is around 51% of total rating output.

Table 6.2-2 Summary of PPL's Generation Expansion & Refurbishment Plan for 2014 - 2028

(Unit: MW)

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Ramu System	22	18	30		36						30				

Table 6.2-3 Development Plans for the Ramu System

Year	Capacity (MW)	Key Objective(s)	Timing
Additional Thermal Generation (IPP)	30	- Maintain Reliability - Improve Capacity	2015
Refurbishment of Ramu 1	15	- Maintain Reliability - Improve Capacity - Maximize Water Usage - Reduce the Unit Cost of Production	2015
Additional Thermal Generation (IPP)	30	- Maintain Reliability - Improve Capacity	2022
Mongi/Bulum HP Scheme	100	- Reduce the Unit Cost of Production - Improve Capacity - Meet Reliability Requirements	2015 - 2027 (depending on support for mining loads)
Ramu 2 HP Scheme	120		
Kaugel HP Scheme	60		
Markham Valley Biomass	30		

c) The Supply–Demand Balance of the Ramu System

Based on the demand forecast and the power supply plants (including the candidate) in the future, a model simulation has been done by PPL. The model estimates how many days a year (LOLE) shortages in generating capacity will negatively affect some of PPL's customers and their operations. The model also measures the EUE and the Reserve Capacity (RC).

As a summary of the model simulation, the supply-demand balance for the Base Load is shown in Fig. 6.2-1.

The results on power supply reliability for the above development are shown in Table 6.2-4, as well.

These results of the study by PPL were authorized and incorporated into theFYPDP (2014-2028) [Strategic Planning and Business Department, April 2014]

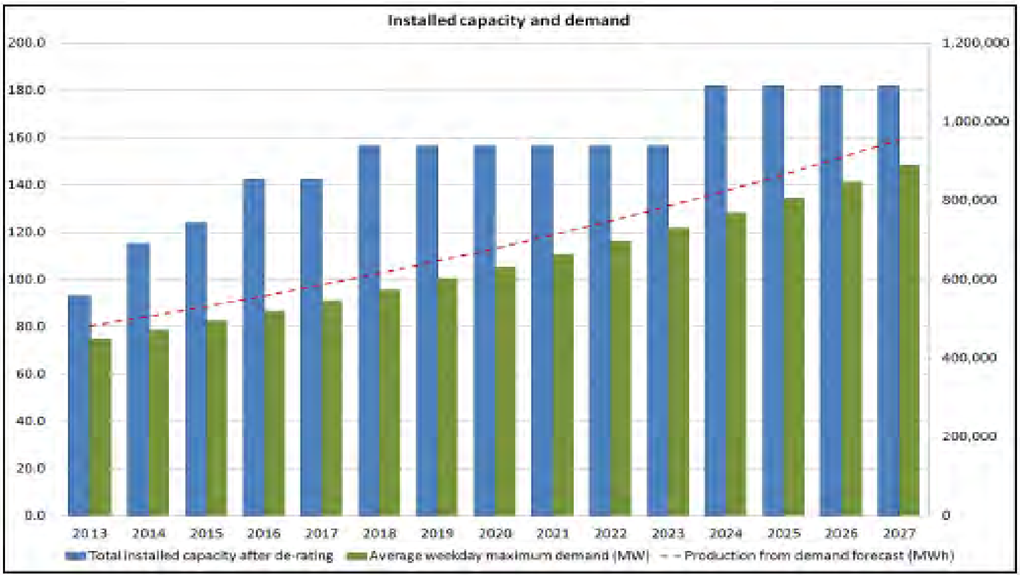


Fig. 6.2-1 Relationship of System Capacity vs. System Load for Base Load in the Ramu System

Table 6.2-4 Result of LOLE & EUE from the Model Simulation

Loss of Load Expectation and Expected Unserved Energy (LOLE & EUE)

System	Ramu
Commencement year	2013
Units	MW

	Max (MW	Min (MW	No. of occurrences (days)
Weekday 2013	75	53	253
Weekend 2013	63	45	112

Demand Forecast

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Production from demand forec	482,491	506,616	531,946	558,544	586,471	615,794	646,584	678,913	712,859	748,502	785,927	825,223	866,485	909,809	955,299
Average weekday maximum de	75	79	83	87	91	96	101	106	111	116	122	128	135	141	148
Average weekday minimum de	53	56	58	61	64	68	71	75	78	82	86	91	95	100	105
Average weekend maximum de	63	66	69	73	77	80	84	89	93	98	103	108	113	119	125
Average weekend minimum de	45	47	50	52	55	57	60	63	66	70	73	77	81	85	89

Machine details (existing capacity)

Variables	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12	TOTAL
Engine/Machine	NEW	Madang	Taraka	Paunda	TOD	Milford	Ramu 1	Ramu 2	Ramu 3	Ramu 4	Ramu 5	NEW	
First comissioning year		2007	2008		2013	1988							
Name plate rating (MW)		9.5	14.4	12.0	18.0	29.0	15.0	15.0	15.0	16.2	16.2		160.30
RPM		1,500	1,500			600							
No. of cylinders		12				12							
commencement year (from last major overhaul)		5,000	5,000			5,000							
De-rating due to age and usag	1.00	1.00	0.80	0.80	1.00	0.50	0.80	0.80	0.80	0.80	0.80	1.00	
De-rating due to site condition	1.00	0.50	0.80	1.00	0.50	0.80	1.00	1.00	1.00	0.00	1.00	1.00	
Net rating (MW)		4.8	9.2	9.6	9.0	11.6	12.0	12.0	12.0	0.0	13.0		93.13
Availability	0.90	0.80	0.85	0.90	0.90	0.80	0.90	0.90	0.90	0.90	0.90	0.90	
Reserve requirement	100%										100%		14%

Expansion, refurbishment, and reti

R=refurbishment; 0=retirement; "any number"=new installation of "any number" **net rating**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
M1		22				36									
M2												30			
M3															
M4															
M5			18												
M6				0											
M7															
M8															
M9															
M10															
M11															
M12				30											
talled capacity after de-rating	93.1	115.1	124.1	142.5	142.5	156.5	156.5	156.5	156.5	156.5	156.5	181.8	181.8	181.8	181.8
Reserve capacity requirement	26.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0

Performance Indicators

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Plant Utilisation Factor	81%	68%	67%	61%	64%	61%	64%	67%	71%	74%	78%	71%	74%	78%	82%
Plant Capacity Factor	59%	50%	49%	45%	47%	45%	47%	50%	52%	55%	57%	52%	54%	57%	60%
Loss of Load Expectation (days	1.23	0.39	0.36	0.09	0.14	0.17	0.25	0.37	0.54	0.79	1.15	0.89	1.36	2.09	3.24
Loss of Load criteria (days/yea	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Reserve Requirement	90%	102%	108%	124%	118%	127%	121%	115%	110%	104%	99%	114%	109%	104%	99%

6.3 SCENARIO OF POWER DEVELOPMENT PLAN

Referring to the power development, the optimal power development plan was developed in the study based on the same planning criteria with revised demand and power candidates as described hereafter.

For optimal power development in the Ramu system, two scenarios were adopted and developed based on the following two scenarios mentioned in Chapter 4 “Power Demand Forecast” is as follows.

Demand in normal-demand and high-demand scenarios is shown in Fig. 6.3-1 and Fig. 6.3-2, respectively.

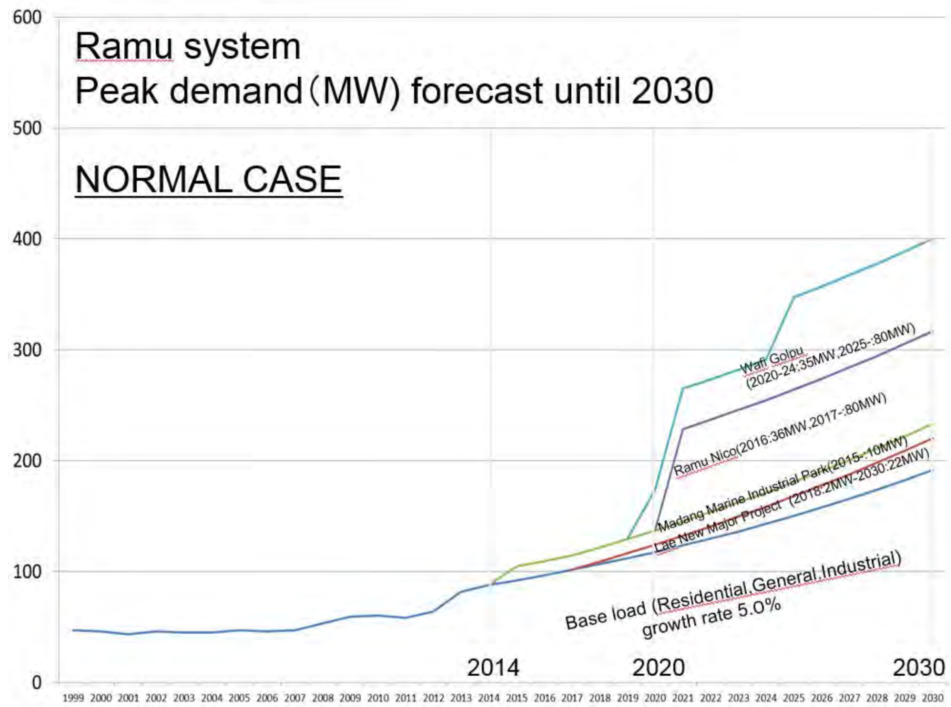


Fig. 6.3-1 Normal-Demand Scenario ①

- Normal-demand scenario ① : The growth rate of the base loads is 5% and relatively assured mining loads are included
- High-demand scenario ② : The growth rate of the base loads is 6% and uncertain mining loads are additionally included (e.g., Yandera mining, etc.)

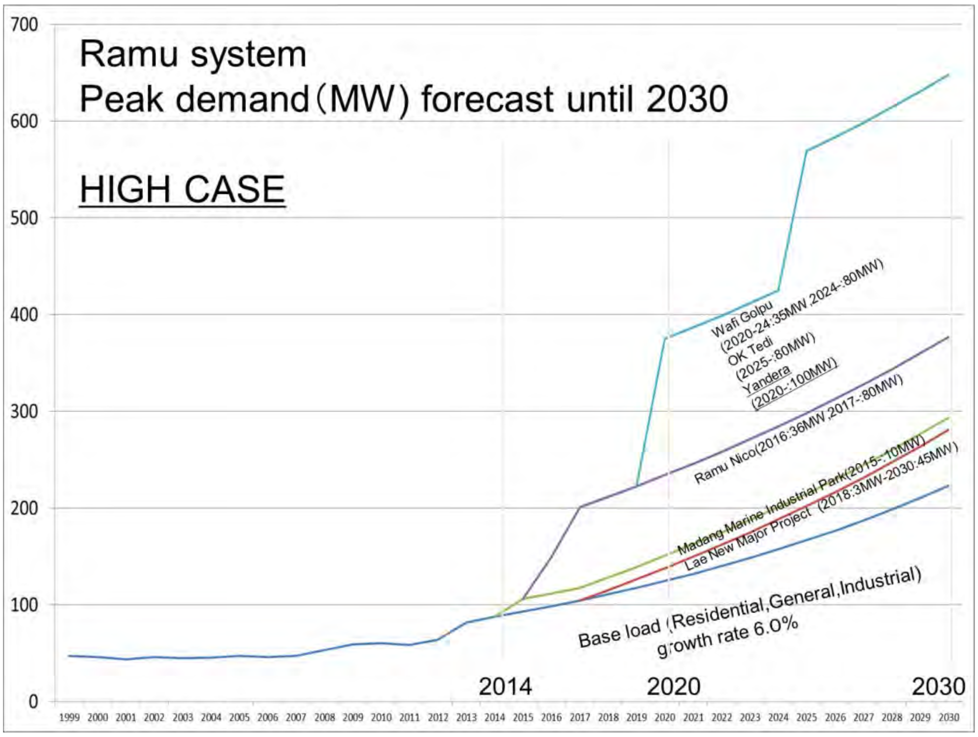


Fig. 6.3-2   High-Demand Scenario ②

The Normal-Demand scenario ① assumes reasonable demand encompassing base load demand, with an annual increase ratio of 5% and mostly certain mining demand.

The High-Demand scenario ② assumes the expected highest demand encompassing base load demand, with an annual increase ratio of 6% and maximum mining demand based on data gathered in hearings with major mining companies.

6.4 CURRENT SITUATION OF THE RAMU SYSTEM AND POSSIBLE POWER SOURCE

(1) Current Situation of Ramu System

The Ramu power system has been well served by the Ramu 1 hydroelectric scheme. LOLE modeling indicates that the reliability criteria have been easily met in the past.

Recent demand growth has put some pressure on the system, mainly due to recurring operational problems at Ramu 1 and recurring unplanned outages.

The supply problems were exacerbated in early 2011 when the T/L between Erap S/S and Hidden Valley mining operations was energized. The expected load was initially on the order of 14 MW and increased to 19 MW in 2013.

This additional load had great impact on the generating capability and had a negative impact on supply reliability until the YTOD (18 MW) was commissioned at the end of October 2013.

(2) Possible Power Source

Regarding the Priority Power Sources to be introduced for the PGDP, the following menu is selected.

As a common element, the decommissioning plan for the existing diesel power plants is considered in this study even though there is no specific information or documents.

1) Power Source for Short-Term Planning (~Year around 2018)

The FYPDP in PNG has stated that new gas thermal plants and biomass power plants (mainly by IPP projects) and Rehabilitation / Refurbishment will be important for power supply in the short term by around 2018 because of their relatively short construction periods. As the FYPDP in PNG is the base of this study, the plan will be reviewed in consideration of the various demand forecasts and construction delays.

In short-term planning, present issues will at first be enumerated and prioritized in order to mitigate the power supply shortage.

As mentioned in Section 6.2, available power supply capacity will be reviewed initially, and the next step will be a simulation analysis using an optimal power generation planning program based on the revised capacity and so on.

Regarding the candidate power plants in the near future, rehabilitation and thermal generation with oil fuel, etc., are expected to contribute to the power supply mainly in light of the short construction periods for generation.

The following options are also selected as emergency power sources to cope with the shortfall of power supply.

- Increasing capacity by rehabilitating of existing hydropower stations
- Increasing capacity by rehabilitating of existing diesel power stations and rental of diesel generators

- Power source option
  - Energy-saving type thermal power station
  - Gas-fired thermal power station
  - Biomass generation, etc.

2) Power Source for Middle- and Long-Term Planning (~Year 2030)

In accordance with the Revised Demand forecast, the power generation plan will be developed with a combination of Hydro, Gas, Renewable Energy (Biomass), etc., based on the least-cost development method with a focus on coping with the large power demand of the mining companies.

The FYPDP in PNG shows the various power generation plants listed for middle-term planning by 2020 and long-term planning by 2030.

As possible candidate power plants, the following gradation types are expected to contribute to the power supply mostly in accordance with the PNG Policy of least-cost development.

The possible candidate power plants for middle-term and long-term planning are as follows;

- New hydropower project
- Biomass power project
- Natural gas power project
-Solar power project [Depending on Cost Reduction]

The following shall be included in both planning frameworks.

- Abolishment of existing diesel power plants
- Rehabilitation of existing hydropower plants

6.5 DEVELOPMENT POLICY IN THE RAMU SYSTEM

Based on the revised power demand forecast in this study, the optimum power generation development plan is developed basically with the least-cost development though the life cycle period of each facility to cope with the power demand in consideration of the following points to note and the assurance of a certain level of electric power supply reliability.

Regarding the Ramu system, the mountainous side of the Ramu area has abundant water resources that have been developed for power generation. On the other hand, electric power demand comes mainly from the Lae region and secondly from the mining companies. Due to geographic features such as the load center of the Lae area, the location of the main hydropower plants on the mountainous side, and the power system configuration which a fragile 132 kV trunk line and 1 circuit, etc., the Ramu system has those special characteristics summarized in later sections, characteristics that are to be considered as thoroughly as possible on a least-cost development basis.

Later sections will describe the actual procedure for the power generation development plan in the Ramu system based on the above policy.

(1) Concept for successful development

The success of the development plan will depend on how well strategies and expenditure are sequenced for implementation.

As the common policy of the PGDP, the following basic policy is described in the FYPDP (2014-2028) [Strategic Planning and Business Department, April 2014].

- The development of hydro-based power remains a high priority wherever it is economically and financially justified, due to the high operating and maintenance costs of diesel sets.

- The "general prospectus" for the development of renewable energy sources will be distributed in due course or upon request to prospective donor governments or their agencies.

The installation of new thermal units will still be required to meet the forecast load growths and replacement for aging generation sets.

For the development of power generation in the Ramu system based on the abovementioned policy, the optimum power generation development plan is examined on a least-cost development basis over estimated lifecycles for the respective facilities. This was done in order to determine their ability to cope with the power demand, while in consideration of the following points and also considering the assurance of electric power supply reliability to a certain level.

For securing the power supply reliability, the same criteria used by PPL was adopted for this study:

- Balance of peak output and demand
  - Expansion Plan at Minimum Cost under the following Condition

- Reliability of Power Supply ----- [LOLE: 2 Days/Year]

(2) Generation Expansion Plan for Normal- & High-Demand Scenarios

Demand is forecasted based on the yearly increase rate of GDP of PNG and historical data incorporating the industrial and possible mining demands, as mentioned in Chapter 4 "Power Demand Forecast."

This report presents two (2) scenarios, the "Normal- & High-Demand Scenarios", described in Section 6.3.

(3) Concept for Countermeasures for the Special Characteristics in the Ramu System

As the major premise of the PGDP, it is necessary to develop and recommend countermeasures to the problems caused by the aforementioned special characteristics in the Ramu system, etc.

The concept for countermeasures for the special characteristics is mentioned below. The current study results and countermeasures should be elaborated with further study.

1) Priority for the development of hydropower generation

The potential hydropower sources amenable to development are in the Highlands Region and Lae/Madang, and the lifecycle cost is cheaper for hydropower than for the other generation options [Refer to Fig. 6.6-14]. It is therefore recommended that PPL develops hydropower as early as possible, provided that PPL can secure the necessary budget or funds. The introduction of IPP or PPP funds to accelerate development is also recommended.

The development of hydropower also helps to reduce the power supplied by diesel generation, the generation costs, and the environmental impact. It will therefore also contribute to the improvement of PPL's fiscal well- being.

2) Tentative thermal generation with oil fuel

The development of hydropower requires large funds and longer construction periods. Thermal generation with oil fuel should therefore be introduced in the interim. If PPL has difficulties in securing funds or budget, it would be possible to introduce a plant on lease.

Also, power supply to the city area of Lae, an important base load, relies on the 132 kV backbone T/L from the hydropower in the Highlands Region (Ramu Hydro) to Taraka S/S.

3) Evaluation of the delay of a large mining load in the total Ramu System

In Ramu system, although there are appearance of huge mining loads and corresponding big hydropower plants at certain years, there is uncertainty for the coincidence between huge mining load and corresponding big hydropower plant which seems to be affected to the Ramu system largely. So, evaluation of this uncertainty between new big mining load and corresponding big hydropower plant is an especially important point to consider.

4) Risk of system separation in the Ramu system

Although this 132 kV T/L will be reinforced with the construction of a new 132 kV double-circuit T/L to be designed from the 1st quarter of 2015, some of the towers of the existing 132 kV T/L are located in the middle of the rivers. There is therefore a risk of damage to the tower bodies due to inundation by extraordinary floods of the type mentioned in Fig. 6.5-1. Although the risk is small, floods seem to have a tremendous influence on the Ramu system, requiring long periods for line restoration once accidents occur. Countermeasures should certainly be taken to mitigate this risk in order to avoid long outages of significant loads.

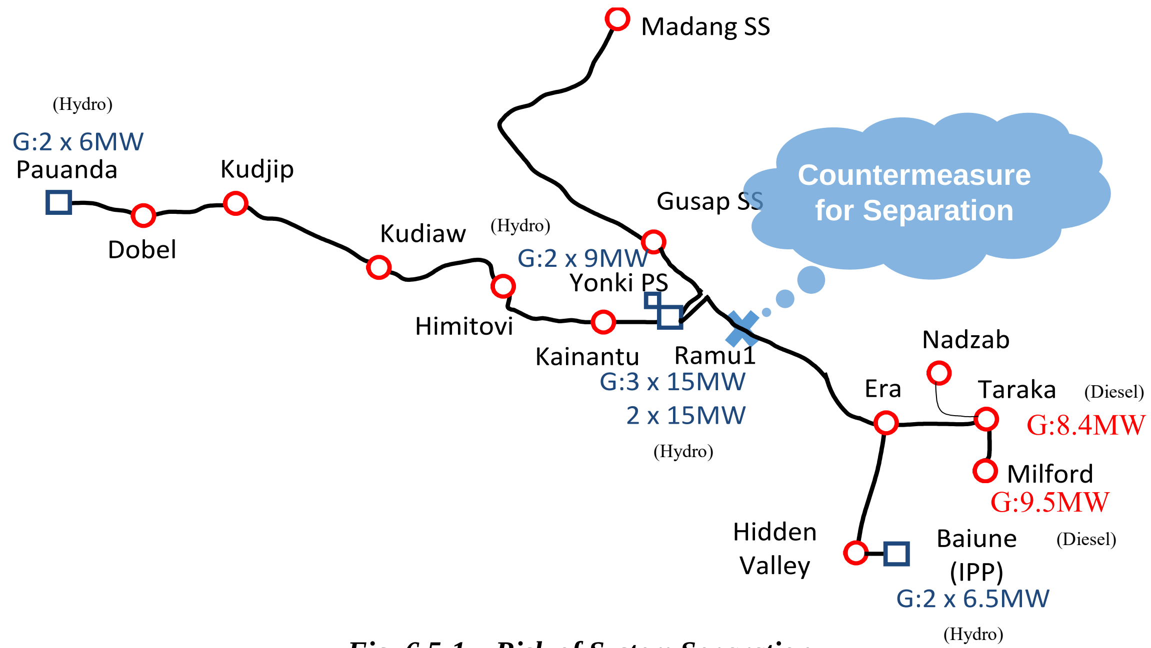


Fig. 6.5-1 Risk of System Separation

6.6 OPTIMAL POWER GENERATION DEVELOPMENT PLAN

Considering the basic and given conditions and the practical development period based on the supply-demand balance (excluding restrictions), the optimum power development capable of securing the required level of supply reliability was developed for short- and long-term plans. This was done in accordance with the revised demand based on the same criteria for power supply reliability, etc., with priority placed on the development of hydropower plants in the future.

The development of the PGDP was also guided by thoroughgoing deliberations of the concerns mentioned in the previous section on the Power Generation Development program, such as the impact of system separation etc., on a least-cost development basis.

The study was conducted using an optimal power generation development program capable of analyzing the cost and power supply reliability in each scenario.

Throughout the study, JICA Study Team would like to propose a best-mix scheme for power generation development from the viewpoints of economy and reliability for middle- and long-term development.

The primary objective in planning a system's generation requirements is to ensure that the forecast peak demand can be met with the available capacity under the defined probabilistic conditions mentioned below.

- The site (operational) rating for thermal plants
- The firm river flow for hydro centers
- The number, age, and reliability of installed plants
- The daily load curve of the center
- The ability of installed machines to operate above their site ratings for short durations

6.6.1 Existing and Potential Power Development

For planning of PGDP, lists of existing & future Plant(s) have been collected by JICA Study Team.

The total installed capacity of existing power plants in the Ramu system is around 200MW. However, the total available output of existing power plants is around 105MW mainly due to the aging of power plants (about 52% of installed capacity) according to the Data collected; hydropower generation (around 60MW of available output) and oil-fired power generation (around 45MW of available output) are described in Chapter 5 in detail. The installed capacity of each existing power plant is shown in Table 6.6-1 and Table 6.6-2.

Concerning future planning, 4 new HPPs are planned with a total installed capacity of over 400 MW as shown in Table 6.6-3. On the other hand, with regards to the TPP, around 6 new thermal power plants are planned or expected as available potential projects as shown in Table 6.6-4.

Based on this information, analysis of optimal power demand-supply balance was conducted for meeting the encroaching future demand as described in the Section 6.6.5 “Optimal Generation Expansion Plan”.

(1) Existing Power Plants, Ongoing Projects, and Committed Projects

1) Existing Power Plants

(a) Existing Hydropower Plants and the Status of Rehabilitation

Table 6.6-1 lists the existing hydropower plants and rehabilitation / replacement / abolishment (either completed or planned).

Table 6.6-1 List of the Existing Hydropower Plants

Plant Name	Type	Total Rated Output (MW)	Available Output (MW)	Date Commissioning	Owner	Rehabilitation & Refurbishment etc.
Ramu 1	Reservoir	78	45 - 50	1976~1990	PPL	-Refurbishment of #1-#3 units was finished -Refurbishment of #4,#5 units is postponed -Max. output of total 5 units is around 45~50MW due to limited flow capacity of tailrace tunnel
Pauanda	Run-of-River	12	8 - 10	1983	PPL	-Baring temperature of #2 shall be monitored
YTOD	Reservoir	18.6	6	2013	PPL	-Max. output of total 2 units is limited up to 6MW -Expansion work will be completed soon
Baiune	Run-of-River	11.4 (Upper Baiune)	8 - 10	2013	IPP	-IPP P/P mainly supplies to Hidden valley mine (Max 16 MW)
		3.5 (Lower Baiune)		2006	IPP	

(b) Existing thermal power plants

Table 6.6-2 shows lists the existing thermal power plants and reduction / replacement plans.

Table 6.6-2 List of Existing Thermal Power Plants

Plant Name	Unit	Total Rated Output (kW)	Available Output (kW)	Date Commissioning	Owner	Rehabilitation & Refurbishment etc.
Milford	10	28,0812	17,900	1969~2008		- Retire for aging of 3 units within around 5 years - Additional 30MW around in 2024
Taraka	8	11,520	7,000	2009	PPL	
	12	13,200	9,600	2014	Aggreco	- Finishing the rental within 10 Years
Madang	9	14,656	11,600	1965~2008		- Retire for aging of 3 units within a few years
Mendi	1	1,360	1,000	1999		
Wabag	4	2,339	1,950	1979~2012		- Retire for aging of 2 units within a few years
Ramu(Aux)	1	800	600	1990		
Pauanda Aux.	1	50	50	-		
Goroka	2	2,880	2,700	2008~2009		
Goroka	1	1,440	1,200	2009		
Total Available Capacity (kW)			**53,600**	-	-	

The thermal plants at major centers provide supplementary energy during the dry season and when major T/L or hydro station outages occur.

The thermal installation program in centers will entail large investments over the next few years. This has been necessitated by the aging of generating units in these centers, and a lack of economical alternative sources of energy in the immediate vicinity of loads.

The available output of individual units have been used to calculate the total actual supply capacity of the Ramu system. The site ratings are based on the field experience of the power generated per unit, and factors such as site conditions, the ages of engines, rpm ranges, scheduled maintenance, running hours, and the numbers of cylinders.

The general retirement criteria used by PPL for the various speed ranges of diesel generating units in its thermal generation plants are as follows;

Medium-Speed Engines (up to 1000 RPM)	100,000 operating hours or 20 years of service, whichever comes first
High-Speed Engines (Above 1000 RPM)	50,000 operating hours or 10 years of service, whichever comes first

Therefore, a number of old units are being retired and will be replaced over the next ten to fifteen years.

However, the retirement schedule for these plants has not yet been authorized or finalized.

2) Ongoing Projects and Candidate Projects

Table 6.6-3 and Table 6.6-4 list the ongoing & candidate projects used in the power source development plan. These tables also include the expected years of commercial operation for each plant. These data are mostly provided by PPL.

Table 6.6-3 List of the Ongoing & Candidate Projects for New Hydropower Plants

Plant Name	Capacity (MW)	Stage	Installed Cost (Exc.T/L) (O&M cost)	Supply destination	Commissioning
Ramu 2	180	F/S (2014)	293million US$ (0.6$/kW-month)	Ramu Nico Mine Wafi/Golupu Mine	2021
Mongi/Bulum	116	Pre-F/S (2014)	642million US$ (0.6$/kW-month)	Yandera Mine	2024
Kaugel	84	F/S (1979)	82million US$ (0.6$/kW-month)	In case to supply Mining Load etc.	2024
Gowar	44	Map Study (1980)	70million US$ (0.6$/kW-month)	In case to supply Mining Load etc.	2026

Source: PPL

Table 6.6-4 List of the Ongoing & Candidate Projects for New Thermal Power Plants

Plant Name	Capacity (MW)	Stage	Installed Cost	Type	Commissioning	Remarks
Lae Wharf	26	Under Construction	-	G/T (Light Oil)	2015	
Lae IPP	30	Under negotiation		Diesel	2015	
Taraka [Rental]	10				2024	
Madang [Rental]	10				2024	
Markham Valley	15	Under negotiation		Biomass	2017	
	15				-	Depending Load Required
Hides	20	Under negotiation		G/T (Natural Gas)	2020	
	20~40	Under negotiation			2024~2027	

Source: PPL

3) Potential Power Sources of Hydropower Plants in the Future (not to be used)

With today’s soaring prices for oil-based fuel, a hydropower plant, especially a reservoir type, seems to be a satisfactory option in spite of the rather large initial investment required in comparison with TPPs. According to the information from PPL, the following hydropower projects in the Ramu area are recommended to proceed to the ranking survey stage. This is based on the results of hydropower potential studies with topographic maps conducted in the 1980s, as described in Section 5.1.4 “Current HP Development Plan”.

Potential hydropower sites identified in Madang, Morobe, and Gulf Provinces in or near the Ramu Grid are listed in Table 6.6-5.

According to additional information obtained from PPL, another huge hydropower potential of run-of river schemes which have not been studied or surveyed is estimated in provinces as well.

Although the recommended hydropower projects are used as candidates for hydropower plants, these candidate hydropower plants do not appear in the optimal power development plan due to sufficient power supply ability with the ongoing and candidate projects mentioned above.

Table 6.6-5 Potential of Hydropower Plants

Plant Name		Capacity (MW)	Plant Name		Capacity (MW)
Madang Province	Nahkina	3.75	Gulf Province	Tauri	115
	Zed2	0.45		Lahiki	18
Morobe Province	Mongi/Bulum	60		Murua	3
	Kaiva	0.95		Murai/Heperi	0.6
	Kawangan	0.3			
	Song	0.8			
	Masaweng	1.05			
	Kiari	0.15			
	Mape	1.4			
	Mindik	0.15			

(2) Potential Candidates for another type of power generation

PNG has abundant energy resources excluding hydropower and natural gas. Especially with regard to renewable energy, PNG has potential for geothermal, solar, biomass and wind etc.

According to the survey result of Primary Energy described in Chapter 3, there seems to be another type of resource for power generation as a possible candidate for power generation at this stage, as summarized in Table 6.6-6 and Table 6.6-7 toward 2030, excluding candidate projects mentioned previously.

Table 6.6-6 Summarizing the Promising Energy Resources in the Ramu System

Type of Energy	Availability/ Feasibility	Reserve	Explanation
Solar Energy	○	160-200Wh/cm^2 (yearly)	The eastern coastlines of Madang and Morobe Provinces are suitable for solar power plants, including mega-solar systems.
Wind Energy	?	Under research by WB	The feasibility of wind energy has to be judged from the study results by WB.
Biomass with Plantation Trees	○	-	Oil Search is developing 30 MW project in the Markham Valley. There are other suitable areas for power generation to the Ramu system.
Biomass with Plantation Tree Waste	?	-	There seem to be prospects for power generation. However, a feasibility study should be required.
Natural Gas	○	15.6 TCF (Proven) in PNG	In the Hides area, there is a potential for Large scale GT plant of Max around 500MW. There is a plan for a power station which is unclear right now.
Oil	○	70 Billion bbl (Proven) in PNG	Diesel oil is expected to be a temporary supply candidate if required.

○: Available & Feasible ?: Further study is needed Source: Prepared by JICA Study Team

Judging by the above prospective energy resources, and restrictions based on technical consideration of the system's condition, the Promising Energy Resources listed in Table 6.6-6 were considered as possible alternative candidates to the study in case of the delay or disappearance of large hydropower plant for compensating the capacity of that of large hydropower plant.

Table 6.6-7 Potential Candidates for Possible Alternative Power Plants in the Ramu System

Type of Energy	Capacity recommended	Installation Cost (O&M cost)	Explanation
Solar Energy	Total 5~10MW	3,000US$/kW (US 9$/kW)	- There seems to be the potential in Ramu system area - There still seems to be high generation costs
Wind Energy		1,000US$/kW (0.60% of capital cost)	- Depends on the research results of WB. - It appears to be unsuitable, with poor wind conditions
Biomass with Plantation Trees	30MW (15MW/unit)	1700~4000US$/kW (7% of capital, US¢ 10/kWh)	- There are other suitable areas for power generation in the Ramu system.
Natural Gas	Max 200MW (30~50MW/unit)	1,100US$/kW (US 2$/MWh, US 54$/kW)	- In the Hides area, around 200MW seems to be expected as a possible power source
Oil	30MW (2MW/unit)	1,000US$/kW (US200$/MWh, US100$/kW)	- Diesel oil is expected to be a temporary supply candidate (including Rental scheme) if required

Source: Prepared by JICA Study Team based on information from PPL and experience

In accordance with the above scenario, the following conclusion for other types of candidates was developed in general.

(Solar & wind Energy)

- With regard to utilization of solar & wind energy, the maximum installation capacity should preferably be under 10MW in total because of the unstable output of generated power.
- In other words, to avoid severe effects to the Ramu system [currently about 100MW] such as fluctuation of system frequency or difficulty of system operation due to the fluctuation of the output of solar & wind generation, it is recommended that the total capacity of unstable power generation should be reduced to under around 10% of the total system capacity.
- Therefore, this type of gelation should not become a substantial power supply source without stabilizing equipment such as a battery system, etc., which might lead to high generation costs with low capacity factors compared to other types of power generation plants.

(Biomass Energy)

- This type of power generation plan uses proven technology and has been operation in commercial bases in other countries.
  In the Ramu system area, similar project was planned and are proceeding to under negotiation of IPP contract with PPL in the Markham Valley.
- According to the information obtained, there are other suitable areas for this type of power generation in the Ramu system area, in the vicinity of the heavy load area of Lae city.
- Therefore, this type of power generation is considered to have the potential to expand by 2030 as a substantial power source in the Ramu system, subject to competitive generation cost.

(Natural Gas energy)

- According to the information obtained, there is potential for a large scale gas turbine plant of a maximum of around 500MW in the Hides area.
- There seems to be a plan for a power station, including the development of a mining factory, which is unclear at this time.
- As surplus energy, around 200MW is expected as a possible power source with reinforcement of the power system for connection with the Ramu system.

(Oil energy)

- Currently, this type of power generation is widely used in the Ramu system.
- Therefore, it is expected to be a temporary supply candidate (including a Rental or IPP scheme) due to the short period of commissioning without heavy civil construction work in the case of required from the power supply-demand balance, especially during short term periods.
- In the long-term, this type of power should be taken over by mainly hydropower generation, bearing in mind the high costs, as well as high level of CO_2 emission and air pollutants.

A list and values in Table 6.6-7 was arranged by JICA Study Team based on documents & information obtained, and assumptions based on experience.

Accordingly, these pre-conditions should be reevaluated should the values of this table change significantly for any reason, such as technical breakthroughs etc., especially for solar and wind utilization toward 2030.

6.6.2 Power Development Scenario

(1) Concept and concerning issue of Power Development

To determine the optimum power development plan, we first need to identify the most important factors in a power development plan, such as economy, stability and reliability of the power supply and the environment in defining the optimal power mix.

PNG's energy policy for the Ramu system seems to be focusing at the moment on reducing oil consumption by taking over large hydropower or other types of power generation, such as biomass and natural gas, with least cost development taking the actual commissioning periods, budget restrictions and environmental impacts, all into consideration.

On the other hand, in order to develop power supply facilities and power system components of the Ramu system for meeting the increasing demand, two particular situations should be considered primarily due to the special characteristics of the Ramu system as mentioned below.

(Two Particular situations)

- One : Large mining loads compared to the Ramu system capacity are expected to be connected to the Ramu system suddenly in certain years, along with the development of corresponding large hydropower plants.
  With respect to one particular situation of the appearance of a large mining load with corresponding power plants, the in coincidence of the timing between the appearance of load and generation will largely affect the total power supply-demand balance of the Ramu system.
- The other : There seems to be uncertainty concerning the development of large hydropower plants under the IPP/PPP scheme due to budgetary and environmental restrictions, among other reasons.
  Regarding the other situation concerning the uncertainty of the development of large hydropower plants under the IPP/PPP scheme, it seems to be largely affected by the Ramu system in terms of Power Supply-Demand Balance as well. In this case, other types of generation are necessary to compensate for the large capacity of large hydropower plant which might be disappeared to keep Power Supply-Demand Balance.

So, for the above two situations, the impact to the Ramu system should be evaluated and some countermeasures should be developed if required, in order to either avoid or overcome these huge risk of disappearance beforehand.

Under this context, the following scenarios were proposed for evaluating the above risks.

(2) Basic and Alternative Scenario

With the background mentioned above, the two scenarios (**Basic scenario** and **Alternative scenario**) were set for the optimal power development plans as described below.

- **Basic scenario** : Based on the revised demand forecast for each case of Normal and High demand, the optimal power development plan was simulated and evaluated utilizing the possible power generation candidates mostly mentioned in the FYPDP of PPL.
  The one particular situation was evaluated in this scenario with a high demand case as a severe condition.

- **Alternative scenario** : Based on the revised demand forecast of High demand as severe case, the optimal power development plan was simulated and evaluated utilizing the possible power generation candidates mostly mentioned in the FYPDP of PPL just only excluding Mongi/Bulum HP project.
  So, the other particular situation was evaluated in this scenario with the addition of another type of possible power generation candidate instead of Mongi/Bulum P/P

1) Basic Scenario

This scenario aims at developing hydropower plants in accordance with FYPDP (April 2014 PPL) from the policy-oriented scenario for decreasing Oil consumption and least cost development.

In this scenario, Hydro is assumed to be developed up to around 70% of total capacity following the policy. On the basis of the above assumptions and conditions, Wien Automatic System Planning (WASP), the least cost power development analysis software, was applied to calculate the power plant scheduling and energy production.

Renewable energy is negligible because of its high initial cost and small share in the system.

Although gas generation in the Hides area is still uncertain, only certain gas projects are taken into the basic scenario as shown in Table 6.6-8.

In the middle or long-term, gas, biomass and hydropower, which are likely to be implemented, are taken into the scenario.

However, for optimal simulation, the capacity of Ramu 2 of 180MW seems to be too big for optimizing the combination of power generation due to the covering almost the demand at year 2030 under normal demand case.

In this Basic scenario, one particular situation regarding the uncertainty of mining load appearance or the actual delay for those ongoing corresponding hydropower project, was evaluated in order to ensure the impact of this event in high demand cases.

Table 6.6-8 Summary of List of the Candidate Power Plants for Basic Scenario
(Commissioning year means the earliest Possible Commissioning)

Year	Ramu System
2015	- Lae Wharf (26MW) - Lae IPP (30MW)
2017	- Markham Valley (15MW) -MarkhamValley (15MW): Depending on Load Required
2020	- Hidas (20MW)
≀	
2021	- Ramu 2 (180MW)
≀	
2024	- Mongi/Bulum (116MW) - Kaugel (84MW) - Taraka (10MW) - Madang (10MW)
2024~2027	- Hidas (20~40MW)
≀	
2025	- Gowar (44MW)

2) Alternative Scenario

In the policy of the Alternative scenario, excessive dependence on hydropower might have some risks such as the disappearance of large candidate hydropower plants, and short supply from hydropower generation due to an extremely dry season and so on. Therefore, this priority is less focused on power source diversification in order to avoid the risk mentioned previously where procurement in the future is quite uncertain. Thus power sources shall be diversified instead of the Mongi/Bulum HP project for evaluation of the impact of this event.

Biomass, gas and renewable power are to be developed more expansively if the disappearance risk of large candidate hydropower projects is taken into consideration in order to reduce the larger impact and diversification of power generation, in combination with the goals of output reduction of hydropower generation during the dry season, etc.

Therefore, in this scenario, biomass and natural gas should be developed more than in preceding scenarios. Renewable energy solar power, wind power, and biomass fuel should be developed, in order to diversify primary energy sources more subject to least cost development among these diversified candidates although the generation cost might be increased in total for avoiding the risk mentioned above. Furthermore these fuel sources are domestically produced, and may be utilized as stable energy sources.

On the other hand, there are potential geothermal resources in the Ramu system as mentioned in Chapter 3 “Primary Energy”. However, it would to take a long time to harness these resources because no site investigations for potential locations of geothermal resources have been done so far. Therefore, geothermal generation is removed from this scenario as a candidate for power sources though 2030.

This time, Mongi/Bulum HPP was targeted to disappearance project with the following reasons just for finding out the impact of this project through simulation as Alternative Scenario.

- A huge capacity following Ramu 2 HPP and large impact to power balance

- More uncertainty compared to Ramu 2 HPP etc., due to high cost under the IPP/PPP scheme
- To be expected to commissioning following Ramu 2 HPP

Therefore, Mongi/Bulum HPP was selected for evaluating the impact to the Ramu system in case of disappearance of large hydropower projects. There is Time allowance for developing the some countermeasure for this event of disappearance project if requoted.

In this scenario, the main concern was given priority on how to cope with the risk of disappearance of large hydropower projects as mentioned previously.

In order to achieve the optimal power development combination in case of the disappearance of the Mongi/Bulum HPP, the possible available alternative candidate power plants were selected by utilizing domestic resources as described in Section 6.6.1 (3) and summarized in Table 6.6-9.

Table 6.6-9 Summary of List of the Candidate Power Plants for Alternative Scenario
(Commissioning year means the earliest possible Commissioning)

Year	Ramu System
2015	- Lae Wharf (26MW) - Lae IPP (30MW)
2017	- Markham Valley (15MW) - Markham Valley(15MW): Depending on Load Required
2020	- Hidas (20MW) - Natural GT (200MW)[Balance]
≀	
2021	- Ramu 2 (180MW)
≀	
2024	- Kaugel (84MW) - Taraka (10MW) - Madang (10MW) - Solar & Wind (5~10MW)
2024~2027	- Hidas (20~40MW)
≀	
2025	- Gowar (44MW)

Thus, the Basic scenario is mostly compatible with the current power generation plan in PNG, while the Alternative scenario will give some priority to conquering the uncertainties of power development.

Of course, both scenarios are conducted to encourage optimal power development within possible power generation candidates and some comparisons are described hereafter.

(3) Development Plan concept for Power Generation

Regarding both scenarios, the following themes were given priority in power development planning as basic concepts according to the policy in PNG:

a. Least cost generation development (among possible candidate power plants),
b. Reliable and stable power supply system while keeping the reliability target of 2 days [LOLE],

This is coinciding with the PNG energy policy or concept that is currently focusing on reducing oil consumption in the Ramu system, to be taken over by hydropower plants in the future. This is mainly due to high generation costs and environment issues etc.

On the other hand, it is difficult to secure sufficient power sources to substitute for oil-burning plants during the short term period, where large hydropower development has not yet begun. The plan for a large natural gas power plant is still uncertain, and the supply's potential source site is located in the Hides area which requires the reinforcement of the power system for sending the generated power to the Ramu system.

Therefore, oil-fired power plant development and biomass power plant development etc., are being advanced in accordance with the rapid increase of power demand as planned in "FYPDP" (April 2014 PPL) due to short period of commissioning required to meet the increasing power demand for the short & middle term periods..

As for current power sources mentioned in the previous chapter, hydro is used to meet the base load and oil and gas, the middle to peak load. Hydro, biomass and natural gas will be main candidates for base load generators under the demand increase in the future. Oil based- GT and reservoir type hydro are the main candidate power sources for peak loads. Small hydro, wind and solar etc., are expected as renewable sources, subject to their compatibility.

6.6.3 Basic Conditions for the Power Generation Development Plan

(1) Common Assumptions

The common assumptions used in the power source development plan are shown in Table 6.6-10. Duration Curve of Ramu system which means the Electric Demand in order during a year shows in Fig6.6-1 as well.

Table 6.6-10 Common Assumptions

Items	Conditions	Remarks
Study Period	16 years	16 years from 2014 to 2030
Demand Forecast	Normal & High demand Case	5% and 6% average power growth rates
Load Duration Curve	Typical Duration Curve as shown in Fig. 6.6-1	Developed with annual operation data for the year 2014 provided by PPL
Minimum Reserve Margin	30 %	Minimum Reserve Margin = Supply Capacity / Peak Load ≧ 130 %
Loss of Load Expectancy	≤ 0.548 %	Less than or equal to one (2) day / pear

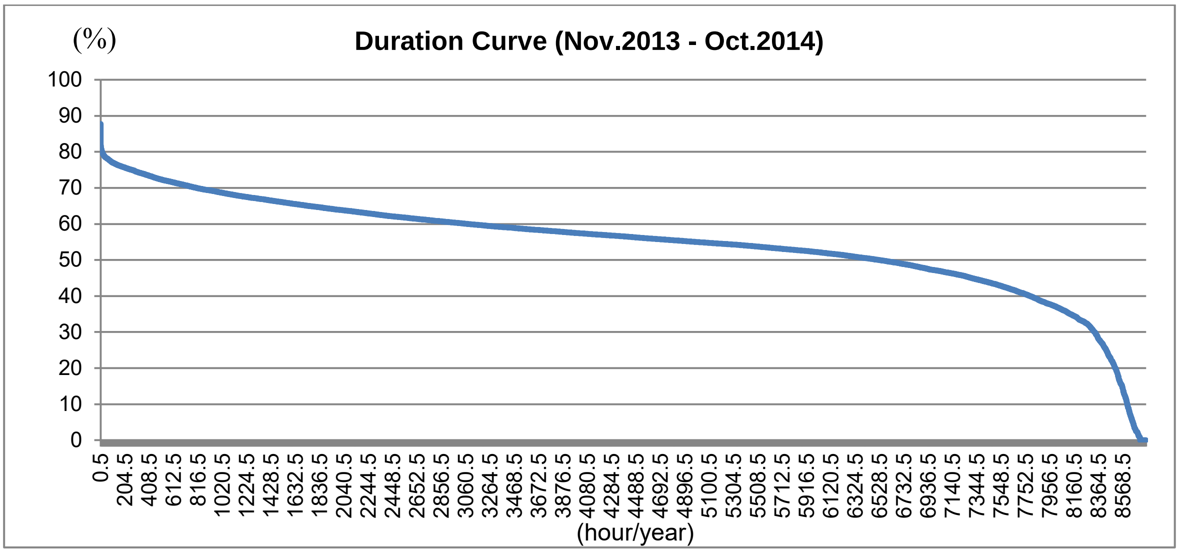


Fig. 6.6-1 Load Duration Curve for the Year

Regarding the reserve margin mentioned in Table 6.6-10, the following assumption is adopted tentatively. The value of the reserve margin should therefore be re-evaluated in accordance with the review of common assumptions in the future.

<u>Reserve Margin</u>

In general, the average reserve margin of the utility companies in Japan has been fluctuating between roughly 10% to 15%. The target reserve margin of thirty percent (30%) for the Ramu system is high in comparison with that of Japan (10%). This is because the target reserve margin of thirty percent (30%) in the Ramu system includes the following uncertainties.

- Once generation equipment breaks or malfunctions, the duration for restoration cannot be estimated, and tends to take a long time because the main parts and/or spare parts for power generation equipment must be procured from abroad.
- Negotiations on conditions between PPL and international financial institutions sometimes delay project implementation.
- Since peak load always occurs during the summer season (July or August) in Japan, periodical maintenance for generation facilities is scheduled in other seasons. Unlike Japan, however, the timing (month/dates) of peak loads in the Ramu system cannot be forecasted in advance. There is, accordingly, a possibility that some of the power stations will be under periodical maintenance when a peak load occurs. A larger reserve margin is therefore required.
- Generation by hydropower fluctuates between the dry season and the wet season.
- Deterioration of existing generation facilities, especially diesel and hydropower plants

Based on the above observations, the target reserve margin of 30 % will be kept for the whole planning period at the moment.

(2) Construction Costs of Candidates

1) Hydropower Plants

The construction costs for hydropower plants (listed in Table 6.6-11) are determined at 2014 price levels.

2) Other Plants

Construction costs for other power plants (listed in Table 6.6-12) are also determined at 2014 price levels.

Table 6.6-11 Construction Costs for Hydropower Plants

Name	Unit cost as of 2014 (US$/kW)
Mongi/Bulum	Around 6000~7000
Gowar	Around 2900~3100
Ram 2	Around 1800~4000
Kaugel	Around 3000

Source: Information from PPL

Table 6.6-12 Construction Costs for Other Plants

Name	Unit cost as of 2014 (US$/kW)
Biomass (Mark Valay)	Around 4000
LNG P/P (Hidas)	Around 1100
Dersel P/P (IPP)	Around 1000
Photovoltaic	Around 3600 (Incl. Battery)
Wind	Around 1600 (Incl. Battery)

Source: Prepared by JICA Study Team based on information from PPL and experience

(3) Salient Features of Candidates

As a summary of salient features of each type of candidate, the following are arranged based on the above JICA studies.

1) Hydropower Project

Table 6.6-13 summarizes the salient features of the hydropower plant candidates.

Table 6.6-13 Summary of Salient Features of Hydropower Plants (Pre-FS, FS)

Name	Bime	Ramu2	Kaugel	Mongi/Bulum
Type	Run-of- River	Reservoir	Run-of- River	Run-of- River
Capacity (MW)	10	180	84	116
Firm output (MW)	Wet: 10 Dry: 8		Firm: 56	Firm: 60
Firm output (MW)	70.1	900	345.6	875.9
Firm Energy (GWh)	56.1 (80% of annual Energy)	855	Normal: 274.5 Off-Peak: 71.1	125.9
Construction Period	4 years	4 years	68 months	4 years
Life Cycle	25 years		25 years	25 years
Power purchase Cost (US$/kWh)	0.15	0.2	0.4~0.8	0.567
Current Situation	Under nego. of PPA	FS: 2014	FS: 1979	Pre-FS: 2014

6.6.4 Optimal Power Generation Development Program

The “optimal power generation development program: WASP” used in this study was developed by the International Atomic Energy Agency (IAEA) and has been used to optimize power generation development in various countries. The sequential operation of power generation facilities with lower construction and operation costs is simulated based on the load duration curve as shown in Fig. 6.6-2 and Fig. 6.6-3.

The most economical option is adopted as the object of this study for development of the optimal PGDP based on the PNG policy mentioned in FYPDP and Grid Corde, etc.

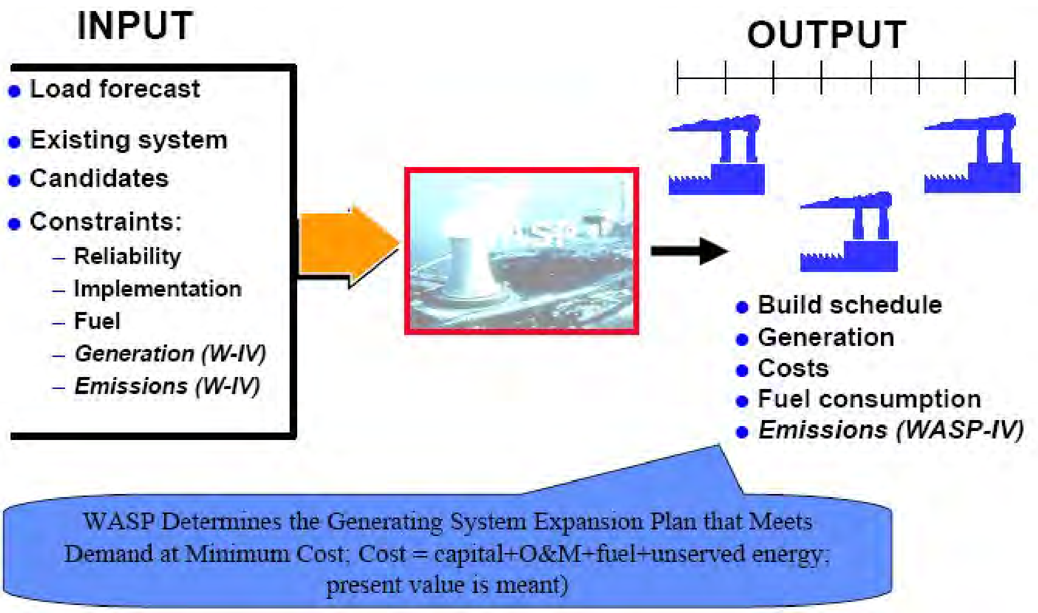


Fig. 6.6-2 WASP Theory of Least Cost Power Development Concept

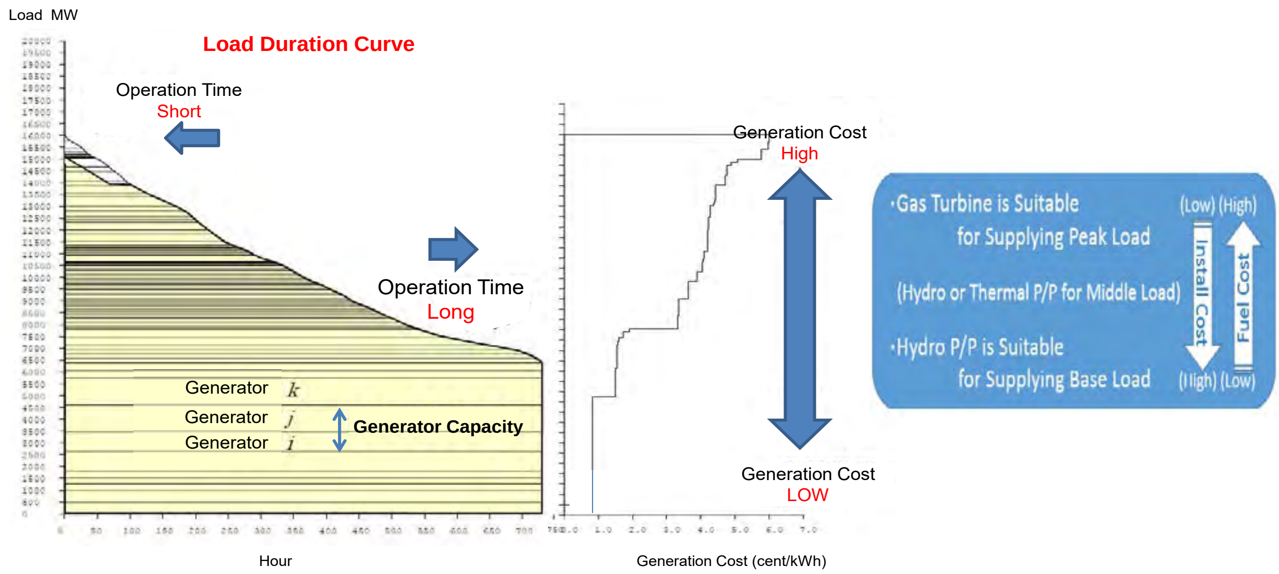


Fig. 6.6-3 Image of Power Supply by Type of Generation

The following input data for power plants are applied to calculate the generation costs by means of a screening curve (see the example in Fig. 6.6-4)

✓Main input data for power plant:
- Installed capacity (MW)
- Fuel type (lignite, oil, natural gas, GT)
- Heating rate (Kcal/kWh)
- Fuel cost (cents/million kcals)
- Fixed O&M cost (USD/ (kW･month))
- Schedule maintenance days per year (days)
- Forced outage rate (%)
- Capital cost (USD/kW)

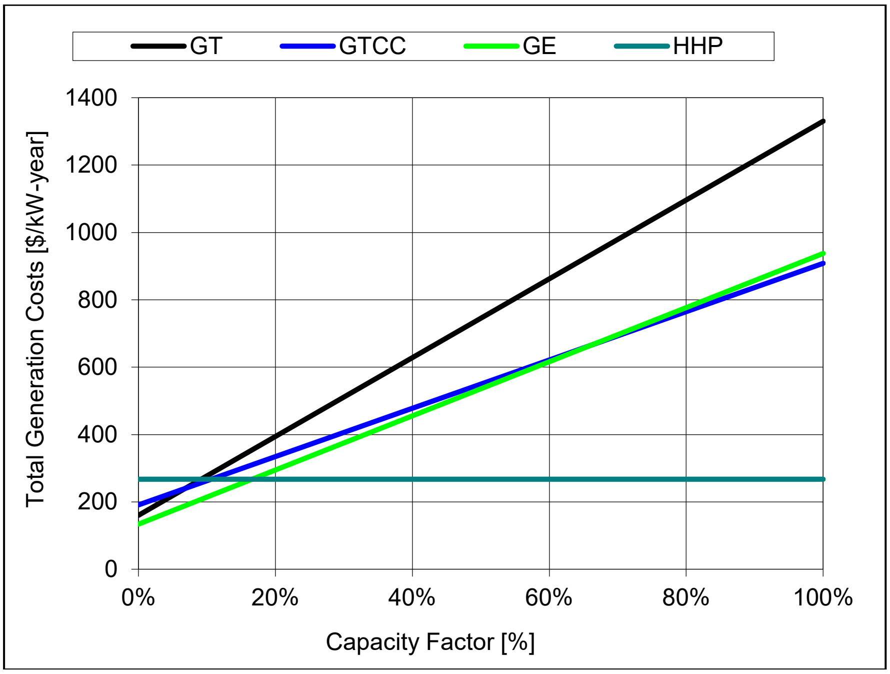


Fig. 6.6-4 Example of a Screening Curve

The WASP program's input and execution screen is shown in Fig. 6.6-5. New power plants, total generation costs, outage probability, and so on can be sorted by priority, and calculated by the simulation for each year. The optimal power generation development based on the simulation is then verified and proposed.

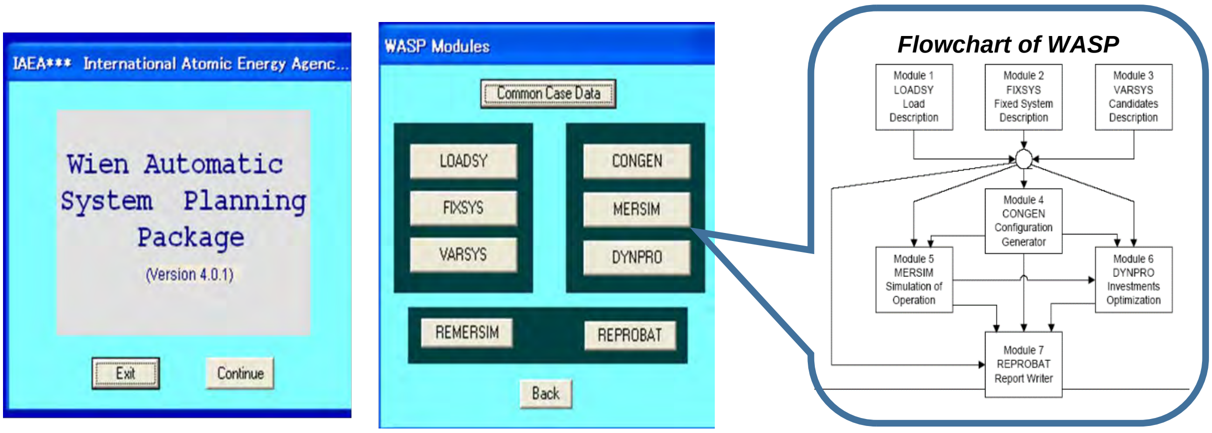


Fig. 6.6-5 WASP Input & Execution Screen

A power generation development analysis was done using WASP based on the above-mentioned principles and expectations. The main analysis conditions for the calculation were based on the following. Power Demand Forecast was based on the results in Chapter 4. The locations of future candidate HPPs and TPPs are described in Fig. 6.6-6.

✔ **Basic Plan for each power development** scenario

- Base Load Demand will reach 192MW [Normal case], 223MW [High Case] in 2030 with annual Peak Demand increase rate, 5% [Normal case] and 6%[High Case] respectively (Kw basis)
- Actual capacity of power supply side should meet the demand with suitable reserve margin for keeping supply reliability of 0.548%[LOLE] (kW Basis)
- Existing power supply is based on the results of survey and information from PPL. (Actual power Output of arch Power Generation Basis)
- Effect of existing power plant’s rehabilitation is based on the hearing from PPL
- Future possible candidates of power plants were arranged based on the related document and data obtained from PPL with some assumption by JICA Study Team such as additional Hides P/P and Biomes P/P, etc.

Basic conditions, including capital costs, were determined based on the evaluation of collected data such as existing projects, reports, interviews with relevant persons from each department and related international publications in the electric power sector.

✔ Future power plants

Resource	Capital Cost (USD/kW)	Efficiency (%)	Fuel Cost ($/MMbtu)	O&M COST Fixed ($/kW-month)	O&M COST Variable ($/MWh)	Remarks
Hydropower						
Ramu 2	1800~4000	-	0	0.6	0	Capacity Factor 60% on average overall hydro p/s record. - Small and medium hydro's capital cost is same as large one, depending on site, scale, compensation and other elements.
Mongi/Bulum	6000~7000					
Kaugel	3000					
Gowar	2900~3100					
Thermal						
Gas-Turbine	1,100	31.1	11.19 (Gas)	0.6~0.74 [C/kWh]	2	- Gas fuel cost includes the construction cost for gas pipeline and appurtenant infrastructures. - Capital cost and Efficiency of GT,OG & DG is based on the information from PPL etc
Diesel- Engine	1000	29~42	20	1.9	2	
DG(Rental)						- 0.25$/kWh??
Renewable Energy						
Photovoltaic (PV)	3,600 ~1,800	-	0	0.6	0	- Capacity Factor 17% PV cost is based on the assumption by JICA Study Team - Battery cost of 600 USD/kW is included in Capital Cost for the power system stability. - Low Capital Cost is assumed roughly toward 2030
Wind	1,600 ~1,200	-	0	1.0	0	- Capacity Factor around 6% wind cost is based on the assumption by JICA Study Team - Battery cost of 600 USD/kW is included in Capital Cost for the power system stability - Low Capital Cost is assumed roughly toward 2030
Biomass	4000	25	10.6 [c/kWh]	2.7	-	- Purchase Price seems to be around 0.23US$/kWh

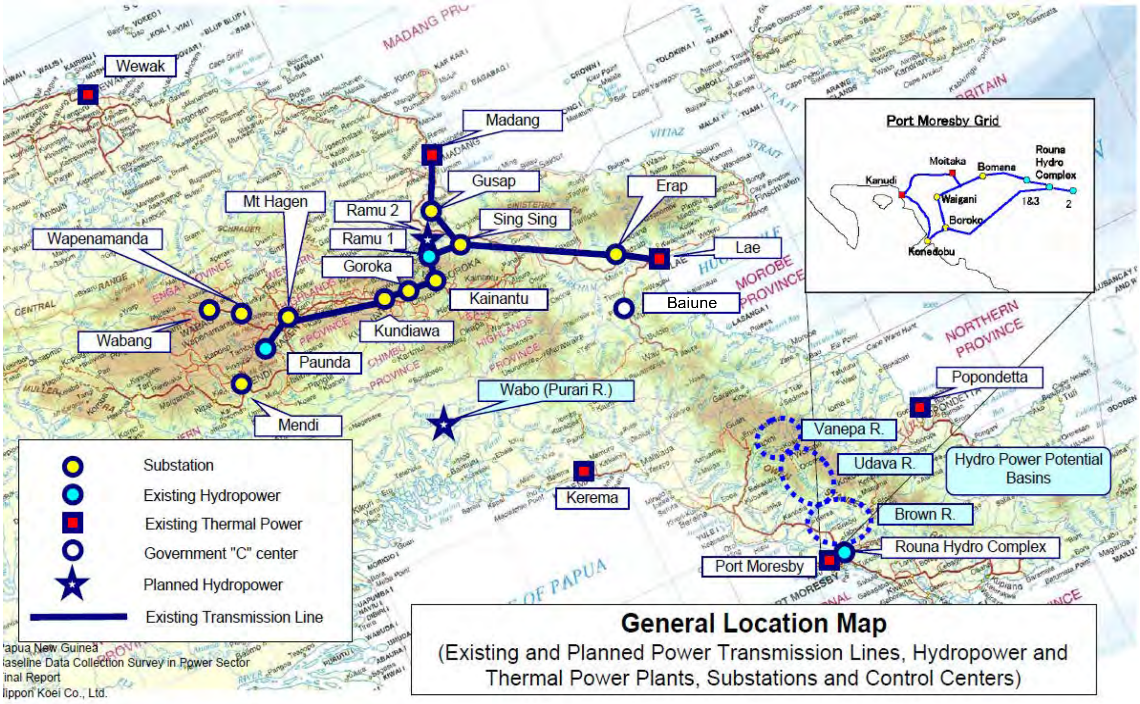


Fig. 6.6-6 Locations of Future HPPs by IPPs (JV/IPP)

(1) Data Arrangement for Simulation

1) Arrangement of power demand Data

Based on the normal- and high-demand forecast scenarios mentioned in Chapter 4, power supply balances were arranged respectively for the two cases below to develop optimal power generation expansion plans.

- Normal-Demand case ① : The growth rate of base loads is 5% and relatively assured mining loads are included.
- High-Demand case ② : The growth rate of base loads is 6% and uncertain mining loads such as Yandera Mining, etc., are additionally included.

2) Arrangement of Candidate power source Data

The power source development plan for the year 2015 to 2030 is divided into three (3) stages, (a) Ongoing and committed projects development stage, (b) Prospective projects development stage, and (c) Potential projects development stage as follows;

(a) Ongoing and committed projects development stage (2015 ~ 2020)
Ongoing and committed projects in FYPDP in PPL are to be developed in this stage.

(b) Prospective projects development stage (2021 ~ 2025)
Prospective projects mean the projects whose sites are identified specifically in the relevant studies. Pre-FS, and/or FS are to be carried out for the future implementation. Regarding the Alternative scenario, additional biomass, natural gas (in the Hides area) and solar generation etc., were tentatively assumed to be candidates for power sources without definite back-ground or reason as listed in Table 6.6-8 for compensation of the huge capacity of the Mongi/Bulum HP project for impact evaluation purposes.

(c) Potential projects development stage (2026 ~ 2030)
Potential projects mean those projects whose sites have not yet been identified. Inventory lists will be prepared and realization methods will be studied and prepared especially for natural gas, biomass and renewable energy development.

6.6.5 Optimal Generation Expansion Plan

The Power Generation Expansion Plan for the Ramu system was revised and developed by JICA Study Team, utilizing the related WASP simulation software.

The overall generation cost of the revised Power Generation Expansion Plan was set to be minimized based on the PNG Policy of least-cost development.

Recommendations were prepared for the middle- and long-term plans in view of economic performance, reliability, etc., for each scenario, as mentioned below.

(1) Results of Power Source Development Plan for Basic Scenario

The optimal simulation for this study was done assuming both Normal and High load demand respectively.

Judging from the simulation results:

- For short-term development, gas turbine or biomass plants should be developed to meet the increasing power demand due to the short construction periods.

- For the long-term Power Generation Expansion Plan, hydropower plants should be developed from the viewpoint of economy and future policies. As a result, the ratio of hydropower to total supply power should be increased in accordance with the development of hydropower generation.

However, this development of the Optimal PDP should be evaluated and modified by additionally considering the aforementioned concerns.

Coping with delays or uncertainty of the demands of big mining is an especially important point to consider and will require the development of some countermeasure concepts.

Countermeasures for coping with these issues are evaluated in Section 6.6.5.

The simulation results of the two scenarios are described below in more detail.

1) Power Supply and demand balance for the normal-demand case

Regarding the normal-demand case, demand will reach 192 MW in 2030 (assuming an annual energy increase rate of 5% (kWh basis) for base load).

This development plan is defined as a normal-demand case of the Basic scenario. The main features of this scenario are as follows.

The development of power generation seems to be almost identical to the FYPDP of PPL due to the similar demand forecast, especially for the base load increase of 5% annually (kW base).

In this case, power supply is insufficient when new mining loads appeared around 2020~2021 and new additional generation should be required in accordance with new mining loads in order to keep the supply-demand balance.

Thermal generations will be required to meet demand for the short term, as described below.

➢ There does not seem to be a defined separation between the dry and wet seasons. Therefore, actual hydro capacity of around 70 MW through the year should meet the demand.

➢ From the survey and hearing results by JICA Study Team, the aging diesel generator will be expected to retire as mentioned in Table 6.6-2 for reference.

➢ Introduction of the Lae GT and Munum Diesel Generation might give affordability to the introduction of Highland GT and reinforcement of related power systems, and also the introduction of Biomass Generation in Markham Valley is temporarily subject to the normal demand increase.

➢ Munum Diesel Generation is expected to have an important role for having a stable power supply and also in the enhancement of system reliability, especially in the mountain side area during the short term period. Furthermore, this DG and Lae GT will make the retirement or movement of Taraka or Milford diesel generation able and expected to conquer the environmental issues in the Lae city area.

➢ The existing oil-fired TPPs' power supply might have a capacity around 54 MW, according to the hearing with PPL, given the aging of the facilities.

- PPL provided the future power plant candidates.
- Oil-fired TPPs and biomass TPPs will be necessary for short-term power supply and will be developed up to 60 MW, a level equivalent to the sum of the listed projects.
- The existing DG seems to serve as a supply reserve and to supply just peak demand in accordance with the development of HPP in the future.
- The gas-fired TPPs are assumed to use natural gas in the highland area due to the resource potential and low cost of generation.
- For the huge mining demand of Ramu Nico and Wafi & Golupu in 2020, the Ramu 2 HPP should be required coincidentally with this demand to supply the power.
- Additional generation from the Kaugel HPP might be required to keep the supply–demand balance and maintain system reliability around in 2025.
- Regarding the Ramu 2 Power Plant, the capacity of this plant is huge compared to the expected Ramu system capacity at year 2020, so that it almost covers the increased demand over a long term period in this normal demand scenario. Hence, it might be affordable to introduce it one year later in 2021, compared to the original fastest projection for the year 2020, due to introduction of biomass and new GT, etc., Main results of the simulation by WASP IV are presented in Table 6.6-15.

Table 6.6-14 Input Data for Normal Demand of Basic Scenario

Year					2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand(MW) Normal Scenario					87.8	105.01	109.62	114.46	121.76	129.31	173.58	265.01	273.4	282.1	291.13	347.37	357.09	367.19	377.68	388.59	399.93
	Fuel Type	P/P Name	Rated Capacity(MW)	Actual Out-Put(MW)																	
Existing Thermal P/P & Plaaned P/P	Diesel	Milford	7.8	4.5	4.5	4.5	4.5	4.5	4.5	4.5											
			15.476	10	12	10	10	10	10	10											
			1.71	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
		Taraka	10.08	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
		(Lease)	13.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6						
		Madang	4.64	3	3	3	3	3	3	3											
			1.5	1	1	1	1	1	1	1											
			8.516	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
		Mendi	1.36	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Wabag	0.776	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575
			0.624	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
		(Lease)	1.14	1	1	1	1	1	1	1	1	1	1	1	1						
		Ramn Aux	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		Pauanda Aux	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
		Goroka	2.88	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
		Kundiawa	1.44	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
		Lae GT	26	26		26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	Hydro Power Plant	Baiune PNGFP(IPP)	14.9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Pauanda #1	6	5	1	1	1	1	1	5	5	5	5	5	5	5	5	5	5	5	5
		Pauanda #2	6	5	0	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		YTOD #1	9.3	6.1	6.1	6.1	6.1	6.1	9	9	9	9	9	9	9	9	9	9	9	9	9
		YTOD #2	9	(6.1)	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9	9
		Ramu 1 #1	15	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
		Ramu 1 #2	15																		
		Ramu 1 #3	15																		
		Ramu 1 #4	16.5	25							25	25	25	25	25	25	25	25	25	25	25
		Ramu 1 #5	16.5																		
Candidate Power Plants	Natural Gas	Highland G/T		20~60							20	20	20	20	40	40	40	60	60	60	60
	Diesel Gen	Munum	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Biomass	Markham Valley	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	For Balance	Additional Thermal Plant	30	30		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
		Additional Thermal Plant	30	30									30	30	30	30	30	30	30	30	30
	Hydro Power Plant	Mongi/Bulum(Pre-FS)	116	60											60	60	60	60	60	60	60
		Ram 2(FS)	180	180								180	180	180	180	180	180	180	180	180	180
		Kaugel(FS)	84	56											56	56	56	56	56	56	56
		Baime[by PNGFP]	10	8					8	8	8	8	8	8	8	8	8	8	8	8	8
		Gowar (Potential)	54	43.5												43.5	43.5	43.5	43.5	43.5	43.5

Table 6.6-15 Main Development Plan for the Normal-Demand Scenario from the Simulation

Option	Capacity (MW)	Key Objective(s)	Timing
Lae GT	26	✓ Maintain Reliability ✓ Improve Capacity	2015
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2016
Munum	30	✓ Maintain Reliability ✓ Improve Capacity	2017
Refurbishment of YTOD	12	✓ Maintain Reliability ✓ Improve Capacity	2018
Baiune PNGFP	10	✓ Supply to Hidden Valley mine ✓ Improve Capacity	2018
Markham Valley Biomass	15	✓ Maintain Reliability ✓ Improve Capacity	2019
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2019
Refurbishment of Ramu 1	25	✓ Maintain Reliability ✓ Improve Capacity	2020
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2020
Ramu 2 Hydropower Scheme	120	✓ Supply to Ramu Nico and Wafi & Golupu ✓ Improve Capacity ✓ Maintain Reliability	2021
Ramu 2 Hydropower Scheme	60	✓ Improve Capacity ✓ Maintain Reliability	2022
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2024
Kaugel Hydropower Scheme	**84**	✓ Improve Capacity ✓ Maintain Reliability	2025
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2027
Mongi/Bulum Hydropower Scheme	116	✓ Supply to Yandela Mining ✓ Improve Capacity ✓ Maintain Reliability	2027

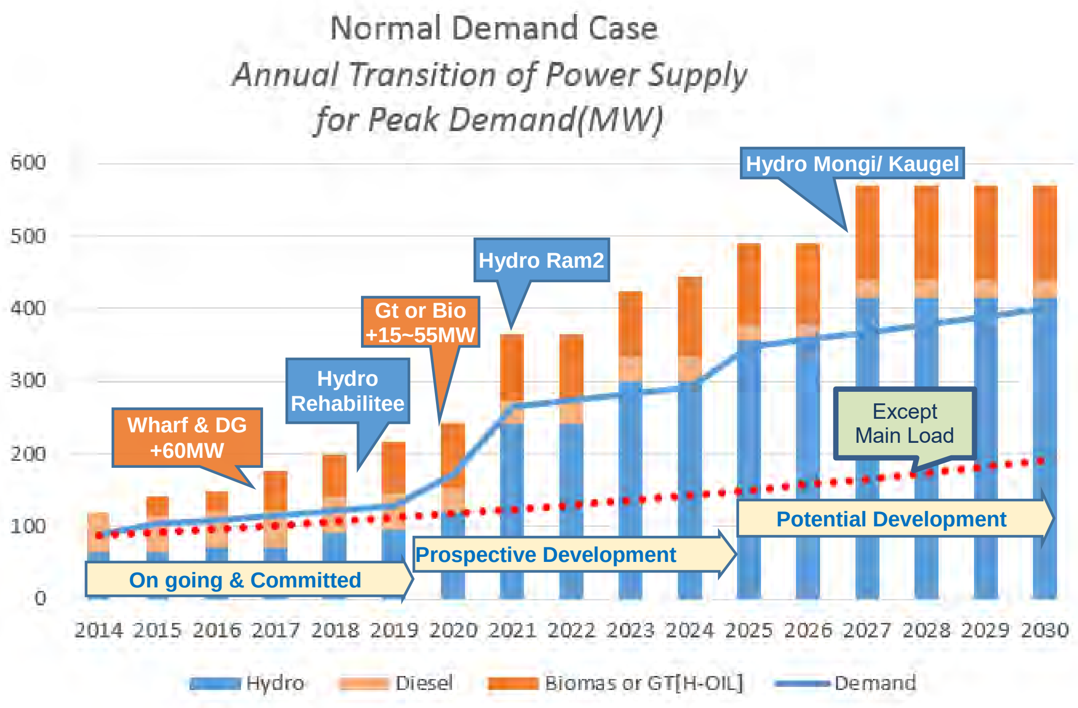


Fig. 6.6-7 Review Result of Normal-Demand Case on the Least-Cost Basis

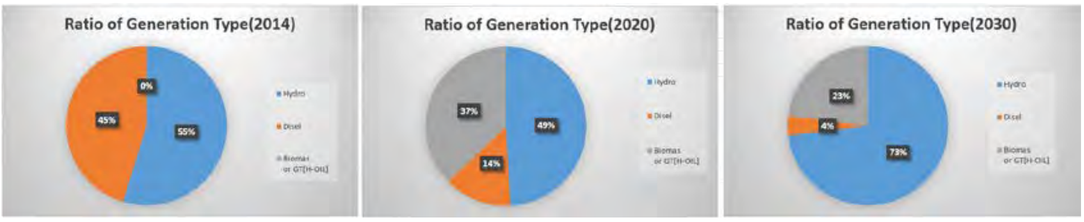


Fig. 6.6-8 Power Supply Composition of Least Cost (2014, 2020, 2030)

2) Power Supply and demand balance for high-demand cases

In the normal-demand scenario, demand will reach around 223 MW in 2030 at an assumed annual energy increase rate of 6% (kWh basis) for the base load.

This development plan is defined as a high-demand scenario. The main features of this scenario are as follows.

In this case, the overall trend of the power supply-demand balance is the same as that in the aforementioned normal-demand scenario, excluding the rapid increase of base load and mining load.

The need for new generation is therefore higher than in the normal-demand case, in accordance with the rapid increase of total demand mentioned below.

- More output of around 180 MW from the Ramu 2 HP should be required compared to the normal demand case by the year 2021.

- Contrary to the normal-demand scenario, the introduction of the Ramu 2 Power Plant at least in the year 2021 must be prepared to cope with the appearance of huge mining load of Ramu Nico & Wafi & Golupu subject to the timely appearance of this mining load by the year 2020.

- To maintain system reliability, additional power generation of around 90 MW would be required from the year around 2020 for coping the appearance of big mining load of Ramu Nico, Waif/Golup and Yandera in order. So, Planned big HP project should be proceed as schedule subject to the rapid increase of electricity power demand.

- To meet the rapidly increasing demand, the development of a big HPP seems to be reasonable from an economic viewpoint in the future.

- Furthermore, the Mongi/Bulum HPP and Gowar HPP should be developed and required around 2025 for coping the huge mining demand mentioned above as well.

- Munum Diesel Generation is expected to play an important role not only for the enhancement of system reliability but also for the improvement of environmental issues in the Lae city area as mentioned previously.

- As mentioned later, although the generation costs of renewable energy (such as solar or wind power generation) have been still high compared to conventional means of power generation, it might be recommended to introduce (within a tolerable capacity) approximately fewer than 10MW. This should be done on a trial or experimental basis for as a precursor to further introduction in the future, should there be a chance or opportunity for development of renewable energy in some reasonable way. The generation cost of solar energy is expected to reduce in the future which might add competitiveness to the conventional generation sources and enable the utilization of domestic resources.

The tentative result from the WASP simulation shown in Table 6.6-17 and Fig. 6.6-9.

Table 6.6-16 Input Data for High Demand of Basic Scenario

Year+C128:H154C128:H165C130C128:H149C12C128:Q220					2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand(MW) High Demand Scenario					87.8	105.89	111.47	117.39	128.09	139.17	291.28	386.51	398.86	411.68	425.01	569.08	583.51	598.54	614.2	630.54	647.59
	Fuel Type	P/P Name	Rated Capacity(MW)	Actual Out-Put(MW)																	
Existing Thermal P/P & Plaaned P/P	Diesel	Milford	7.8	4.5	4.5	4.5	4.5	4.5	4.5	4.5											
			15.476	10	12	10	10	10	10	10											
			1.71	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
		Taraka	10.08	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
		(Lease)	13.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6						
		Madang	4.64	3	3	3	3	3	3	3											
			1.5	1	1	1	1	1	1	1											
			8.516	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
		Mendi	1.36	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Wabag	0.776	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575
			0.624	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
		(Lease)	1.14	1	1	1	1	1	1	1	1	1	1	1	1						
		Ramn Aux	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		Pauanda Aux	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
		Goroka	2.88	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
		Kundiawa	1.44	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
		Lae GT	26	26		26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	Hydro Power Plant	Baiune PNGFP(IPP)	14.9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Pauanda #1	6	5	1	1	1	1	1	5	5	5	5	5	5	5	5	5	5	5	5
		Pauanda #2	6	5	0	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		YTOD #1	9.3	6.1	6.1	6.1	6.1	6.1	9	9	9	9	9	9	9	9	9	9	9	9	9
		YTOD #2	9	(6.1)	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9	9
		Ramu 1 #1	15	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
		Ramu 1 #2	15																		
		Ramu 1 #3	15																		
		Ramu 1 #4	16.5	25							25	25	25	25	25	25	25	25	25	25	25
		Ramu 1 #5	16.5																		
Candidate Power Plants	Natural Gas	Highland G/T		20~60							20	20	20	20	40	40	40	60	60	60	60
	Diesel Gen	Munum	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Biomass	Markham Valley	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	For Balance	dditional Thermal Plant	30	30		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
		Additional Thermal Plant	30	30									30	30	30	30	30	30	30	30	30
		Natural GT	200	200							200	200	200	200	200	200	200	200	200	200	200
	Renewable	Soler or Wind	10	10														10	10	10	10
	Hydro Power Plant	Mongi/Bulum(Pre-FS)	116	60											60	60	60	60	60	60	60
		Ram 2(FS)	180	180								180	180	180	180	180	180	180	180	180	180
		Kaugel(FS)	84	56											56	56	56	56	56	56	56
		Baime[by PNGFP]	10	8					8	8	8	8	8	8	8	8	8	8	8	8	8
		Gowar (Potential)	54	43.5												43.5	43.5	43.5	43.5	43.5	43.5

Table 6.6-17 Main Development Plan for High Demand Scenario from the Simulation

Option	Capacity (MW)	Key Objective(s)	Timing
Lae GT	26	✓ Maintain Reliability ✓ Improve Capacity	2015
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2016
Munum	30	✓ Maintain Reliability ✓ Improve Capacity	2017
Markham Valley Biomass	15	✓ Maintain Reliability ✓ Improve Capacity	2017
Refurbishment of YTOD	12	✓ Maintain Reliability ✓ Improve Capacity	2018
Baime PNGFP	10	✓ Supply to Hidden Valley mine ✓ Improve Capacity	2018
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2019
Refurbishment of Ramu 1	25	✓ Maintain Reliability ✓ Improve Capacity	2020
Markham Valley Biomass	15	✓ Maintain Reliability ✓ Improve Capacity	2020
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2020
Natural GT [Balance]	90	✓ Maintain Reliability ✓ Improve Capacity	2020
Ramu 2 Hydropower Scheme	180	✓ Supply to Ramu Nico and Wafi & Golupu ✓ Improve Capacity ✓ Maintain Reliability	2021
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2024
Gower Hydropower Scheme	54	✓ Improve Capacity ✓ Maintain Reliability	2025
Natural GT [Balance]	60	✓ Maintain Reliability ✓ Improve Capacity	2025
Mongi/Bulum Hydropower Scheme	116	✓ Improve Capacity ✓ Maintain Reliability	2025
Kaugel Hydropower Scheme	84	✓ Improve Capacity ✓ Maintain Reliability	2025
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2027
Natural GT [Balance]	30	✓ Maintain Reliability ✓ Improve Capacity	2028
Natural GT [Balance]	30	✓ Maintain Reliability ✓ Improve Capacity	2030

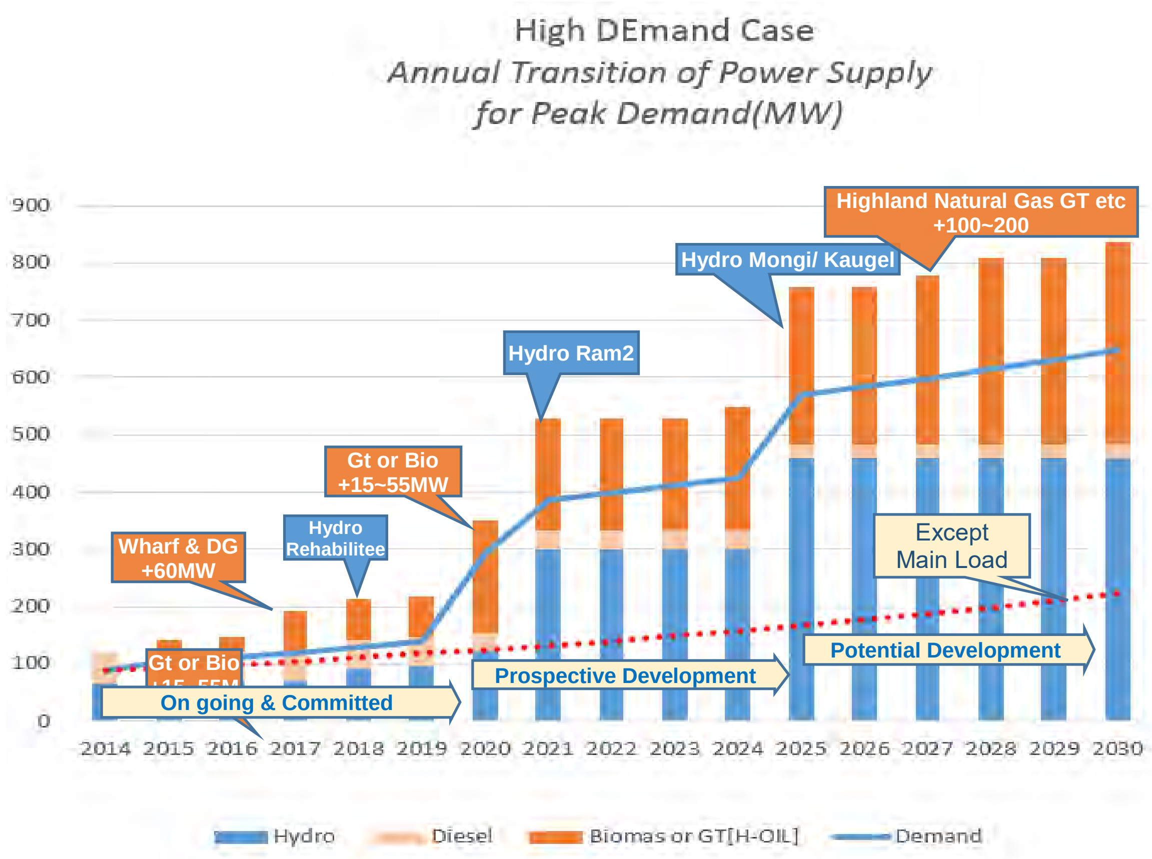


Fig. 6.6-9 Review Result of High-Demand Scenario on the Least-Cost Basis

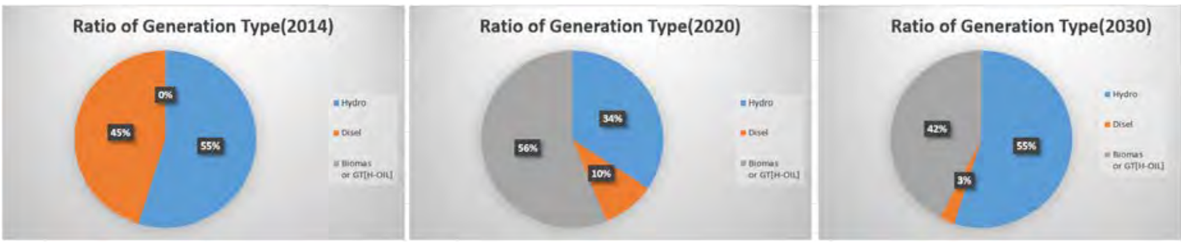


Fig. 6.6-10 Power Supply Composition of Least Cost (2014, 2020, 2030)

(2) Results of Power Source Development Plan for Alternative Scenario

This case was simulated and evaluated just in case of the disappearance of the huge hydro project during the middle and long term period. This time the Mongi/Bulum HP project was set, which has the second largest capacity following the Ramu 2 project that is proceeding the procedure as mentioned previously for evaluating the impact to the Ramu system.

The optimal simulation for this study was done under the High demand scenario as a severe case for supply and demand balance.

As a summary of the evaluation of this case, the impact of this event to the Ramu system seems to be big because there is no substantial or definite candidate power plant to compensate for the large capacity of the Mongi/Bulum power project. Therefore, the GT in the Highland area was tentatively assumed to be a substantial candidate without any particular reason or background in order to maintain the supply - demand balance. However this substantial natural gas generation is expected to contribute to the development of the economic corridor in the highland and to send generated power to the POM system through interconnection T/Ls, but it also risks avoiding the Ram system under severe dry conditions in the future, which has a high ratio of hydropower capacity to the total supply capacity.

Judging from the simulation result, the evaluation in detail is as follows;

- Lae GT, Munum DG, biomass in Markham Valley and Highland G/T, etc., are expected to be supply sources during the middle and long term period and expansion is expected if possible under generation cost competiveness.

- Especially in this alternative scenario, the development of Highland GT utilizing domestic natural gas is strongly anticipated for not only avoiding the short supply but also those other reasons mentioned before.
  Therefore a certain level of diversification of supply sources should be considered in order to avoid the risks incurred by too high ratio of large hydropower sources to total supply capacity utilizing the domestic resources such as natural-based gas turbine or biomass resources which seems to keep competiveness compared to HPP under reason installed cost and high CF for stable power supply.

- Renewable energy from solar and wind resources, which are promising potential resources, are also expected to be introduced within certain capacity of around 10MW in total as initial stage for helping supply energy.

Regardless, the installation cost of the Mongi/Bulum project seems to be relatively high compared to other candidate hydropower projects. However, this project remains competitive with other types of generation as mentioned in the next section. Furthermore the impact on the supply-demand balance of the Ramu system is so big that developing a plan for the Mongi/Bulum project should be being proceeded by concurring budgetary and environmental issues.

Table 6.6-18 Input Data for High Demand of Alternative Scenario

	Fuel Type	P/P Name	Rated Capacity(MW)	Actual Out-Put(MW)																	
Existing Thermal P/P & Plaaned P/P	Diesel	Milford	7.8	4.5	4.5	4.5	4.5	4.5	4.5	4.5											
			15.476	10	12	10	10	10	10	10											
			1.71	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
		Taraka	10.08	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
		(Lease)	13.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6						
		Madang	4.64	3	3	3	3	3	3	3											
			1.5	1	1	1	1	1	1	1											
			8.516	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
		Mendi	1.36	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		Wabag	0.776	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575	0.575
			0.624	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
		(Lease)	1.14	1	1	1	1	1	1	1	1	1	1	1	1						
		Ramn Aux	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
		Pauanda Aux	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
		Goroka	2.88	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
		Kundiawa	1.44	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
		Lae GT	26	26		26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	Hydro Power Plant	Baiune PNGFP(IPP)	14.9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
		Pauanda #1	6	5	1	1	1	1	1	5	5	5	5	5	5	5	5	5	5	5	5
		Pauanda #2	6	5	0	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		YTOD #1	9.3	6.1	6.1	6.1	6.1	6.1	9	9	9	9	9	9	9	9	9	9	9	9	9
		YTOD #2	9	(6.1)	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9	9
		Ramu 1 #1	15																		
		Ramu 1 #2	15	50							50	50	50	50	50	50	50	50	50	50	50
		Ramu 1 #3	15		50	50	50	50	50	50											
		Ramu 1 #4	16.5	25							25	25	25	25	25	25	25	25	25	25	25
		Ramu 1 #5	16.5																		
Candidate Power Plants	Natural Gas	Highland G/T		20~60							20	20	20	20	40	40	40	60	60	60	60
	Diesel Gen	Munum	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Biomass	Markham Valley	30	30				30	30	30	30	30	30	30	30	30	30	30	30	30	30
	For Balance	Additional Thermal Plant	30	30		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
		Additional Thermal Plant	30	30									30	30	30	30	30	30	30	30	30
		Natural GT	10月26日	300							300	300	300	300	300	300	300	300	300	300	300
	Renewable	Soler or Wind	10	10														10	10	10	10
	Hydro Power Plant	Mongi/Bulum(Pre-FS)	116	60																	
		Ram 2(FS)	180	180								180	180	180	180	180	180	180	180	180	180
		Kaugel(FS)	84	56											56	56	56	56	56	56	56
		Baime[by PNGFP]	10	8					8	8	8	8	8	8	8	8	8	8	8	8	8
		Gowar (Potential)	54	43.5												43.5	43.5	43.5	43.5	43.5	43.5

Table 6.6-19 Main Development Plan for Alternative Scenario from the Simulation

Option	Capacity (MW)	Key Objective(s)	Timing
Lae GT	26	✓ Maintain Reliability ✓ Improve Capacity	2015
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2016
Munum	30	✓ Maintain Reliability ✓ Improve Capacity	2017
Markham Valley Biomass	15	✓ Maintain Reliability ✓ Improve Capacity	2017
Refurbishment of YTOD	12	✓ Maintain Reliability ✓ Improve Capacity	2018
Baime PNGFP	10	✓ Supply to Hidden Valley mine ✓ Improve Capacity	2018
Refurbishment of Pauanda	5	✓ Maintain Reliability ✓ Improve Capacity	2019
Refurbishment of Ramu 1	25	✓ Maintain Reliability ✓ Improve Capacity	2020
Markham Valley Biomass	15	✓ Maintain Reliability ✓ Improve Capacity	2020
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2020
Natural GT [Balance]	90	✓ Maintain Reliability ✓ Improve Capacity	2020
Ramu 2 Hydropower Scheme	180	✓ Supply to Ramu Nico and Wafi & Golupu ✓ Improve Capacity ✓ Maintain Reliability	2021
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2024
Gower Hydropower Scheme	54	✓ Improve Capacity ✓ Maintain Reliability	2025
Natural GT [Balance]	105	✓ Maintain Reliability ✓ Improve Capacity	2025
Kaugel Hydropower Scheme	84	✓ Improve Capacity ✓ Maintain Reliability	2025
Natural GT [Balance]	15	✓ Maintain Reliability ✓ Improve Capacity	2026
Highland G/T	20	✓ Maintain Reliability ✓ Improve Capacity	2027
Natural GT [Balance]	15	✓ Maintain Reliability ✓ Improve Capacity	2028
Natural GT [Balance]	30	✓ Maintain Reliability ✓ Improve Capacity	2029
Natural GT [Balance]	15	✓ Maintain Reliability ✓ Improve Capacity	2030

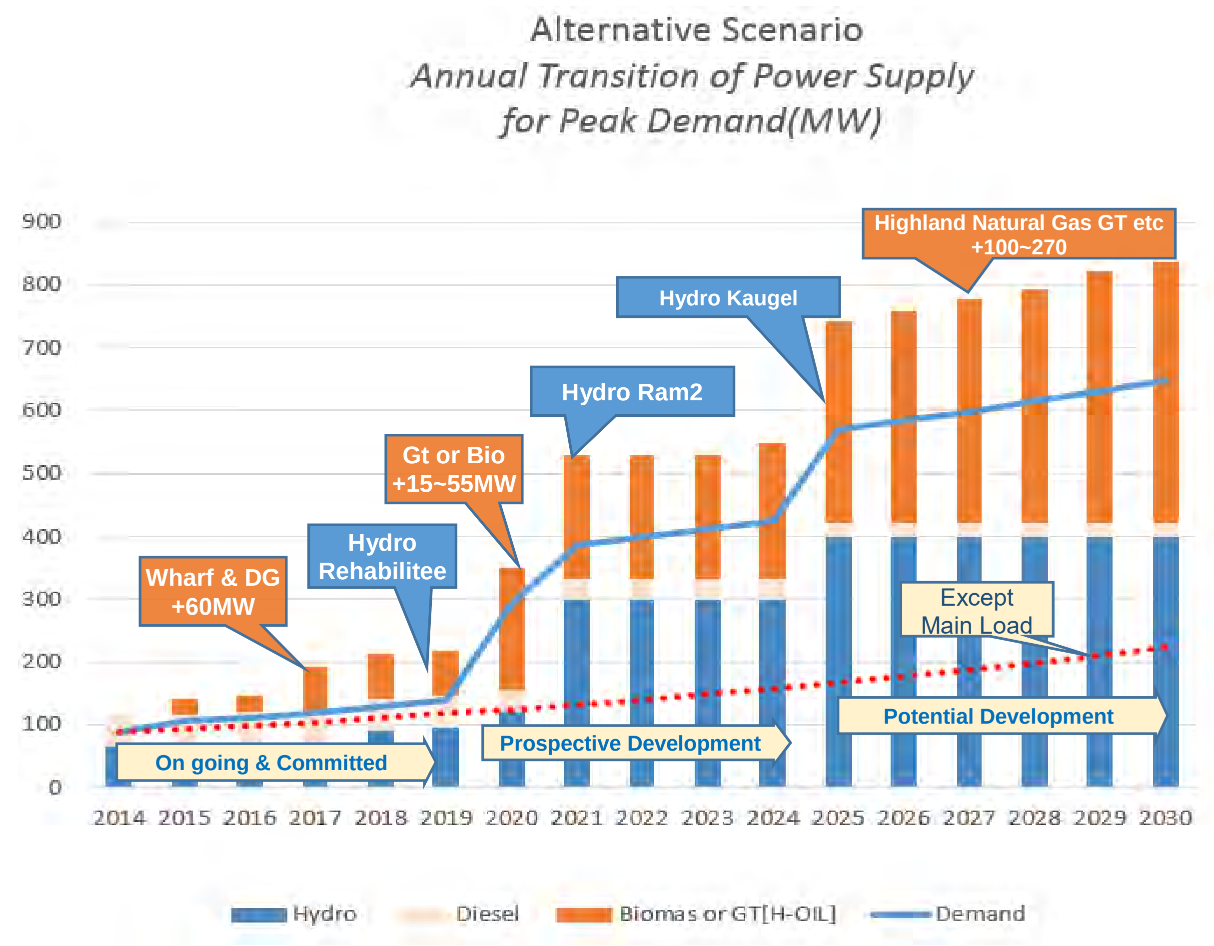


Fig. 6.6-11 Review Result of Alternative Scenario on the Least-Cost Basis

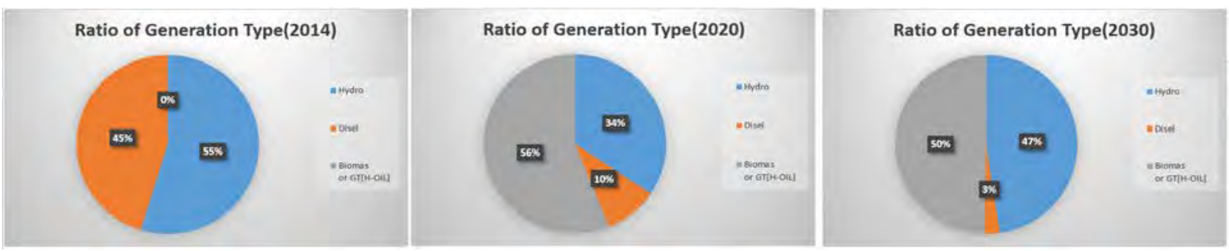


Fig. 6.6-12 Power Supply Composition of Least Cost (2014, 2020, 2030)

6.6.6 Comparison of Each Scenario

(1) Basic Scenario

In this scenario, the power development plan between Normal demand and High demand cases was compared as follows;

In general, the development plan of the normal case for the Basic scenario is almost the same as FYPDP of PPL due to almost identical demand forecasts.

As a main difference between both cases, although the capacity of Ramu 2 accounts for a large share of the total supply capacity for both cases, the little delay of conditioning of Ramu 2 seems to be tolerable in Normal demand cases. However, the commissioning of Ramu 2 as scheduled is necessary in High demand cases in order to meet the huge mining demand by the year 2020.

Since the evaluation of each case is described in previous sections in detail, only a summary of the comparison between each case of the Basic scenario is mentioned in Table 6.6-20.

Table 6.6-20 Summary of Power Development Comparison between Normal and High Demand Cases

Items	Normal Demand Case	High demand Case
Short term Period	Same	
Middle term period	There might be some affordability or tolerability for the little delay of Ramu 2 commissioning and other candidate power plants as well.	Ramu 2 should be commissioned as scheduled by 2020, coincident with Ramu Nico & Wafi/ Golupu Mining.
Long term period	The increasing demand will be almost covered by the Ramu 2 Project, even though other candidates will also be required to develop for keeping supply reliability.	The planned candidate power plants shall be commissioned as scheduled for meeting the increasing demand including base and mining demand. Additional power plants shall be required to be installed for keeping supply reliability.
Remarks	Almost Same to FYPDP of PLL	Requirement of earlier commissioning of candidate power plant compared to FYPDP of PPL
	Particular attention or focus is required on the system operation under huge demand and corresponding power plants compared to the Ramu system capacity.	

(2) Alternative scenario

In this Alternative scenario, the focus rests on the impact evaluation of the disappearance of the huge Mongi/Bulum HP project. So, the comparison was made on the power supply-demand balance between with and without Mongi/Bulum HPP under the high scenario case as severe case as Alternative scenario.

So, the comparison was made between the High demand case and an alternative scenario, which forces to the tentative introduction of many candidate power plants to compensate for the supply capacity instead of that of Mongi/Bulum HPP as mentioned previously.

The evaluation result is described hereafter and summarized in Table 6.6-21.

Table 6.6-21 Summary of Power Development Comparison between High Demand Case and Alternative Scenario

Items	High-Demand Case of Basic scenario	Alternative Scenario under High-demand
Short term Period	Same	
Middle term period	Ramu 2 should be commissioned as scheduled at 2020 coincident with Ramu Nico & Wafi/Golupu Mining	Up to Ramu 2 commissioning for Ramu Nico & Wafi/Golupu Mining, the developing plans is similar to that of the High-Demand Case of the Basic scenario
Long term period	The planned candidate power plants shall be commissioned as scheduled for meeting the increasing demand including base and mining demand. Additional power plants shall be required to be installed for keeping supply reliability.	Instead of Mongi/Bulum HPP, the other types of power generation such as biomass and natural gas base generation should be introduced for keeping the supply-demand balance. However, these additional power generation sources have no significant background at present. Solar and wind power are also potential options for generation in the future under certain capacity levels.
Remarks	Requirement of earlier commissioning of candidate power plant compared to FYPDP of PPL.	Required of other types of substantial power generation especially natural gas –base generation for compensating the capacity of the Mongi/Bulum HPP.

The generation cost of each candidate is an important key factor for evaluation, comparison and decision making.

Therefore, the generation cost of each candidate power plant was roughly evaluated in detail as described in this section later.

In the future, the ratio of supply energy from Hydro generation seems to be increased from the least cost development scheme. In that case, it appears to be better to keep utilizing the relatively large gas generation for domestic resources due to the following reasons.

[Evaluation result]

- For the too high ratio of hydropower capacity to total supply capacity, the development or introduction of substantial natural gas generation should be expected to reduce the risk of the short supply of electric power energy, which might occur from the hydropower generation in the severe dry season.

- The highland area has not only natural gas resources but also mining resources, and is expected to be developed as an economic corridor. Accordingly, it seems to be better to develop the substantial natural power generation in this area for the purpose of supplying stable power to those important customers who might appear in the future and for avoiding the risks mentioned above as well.

- Judging from the generation cost comparison as mentioned later, although the Mongi/Bulum project has a high cost of installation compared to the other hydropower projects, this project seems to still be competitive compared to other types of generation. So it is better to proceed with this project from the view point of the least cost development. However, it is also recommended to develop the natural gas-based power plant in the Highland area due to competitive generation costs for the reason mentioned above etc., if there is any opportunity for developing this kind of gas generation.

- Particularly, the divergence of supply generation is a key factor and is recommended to ensure a stable power supply, and for the best combination the electric energy supply area such as peak load, base load, etc., should be divided from the least cost view point as well.

- There is also the option to introduce solar and wind if there are opportunities or facilitation decisions for utilizing natural energy, which is expected to have prospective potential or the possibility to have a reduced cost of installation in the future as mentioned later.
However, the total capacity of these unstable power sources without a battery system should be restricted to certain levels to ensure stable operation of the Ramu system.

- The development of transmission with high system voltage for connecting this area to the Ramu system seems to be an essential and effective contribution to the economic development of this area. This is due not only to sending the power from the Ramu system to these economic areas, but also sending the stable power generated by substantial natural gas-base generation or Hydro in this area to the Ramu or POM system through the interconnection transmission.

Fig. 6.6-13 shows the projection of future development of the Highland area and reinforcement of the power system, including the location of natural gas and Hydro resources.

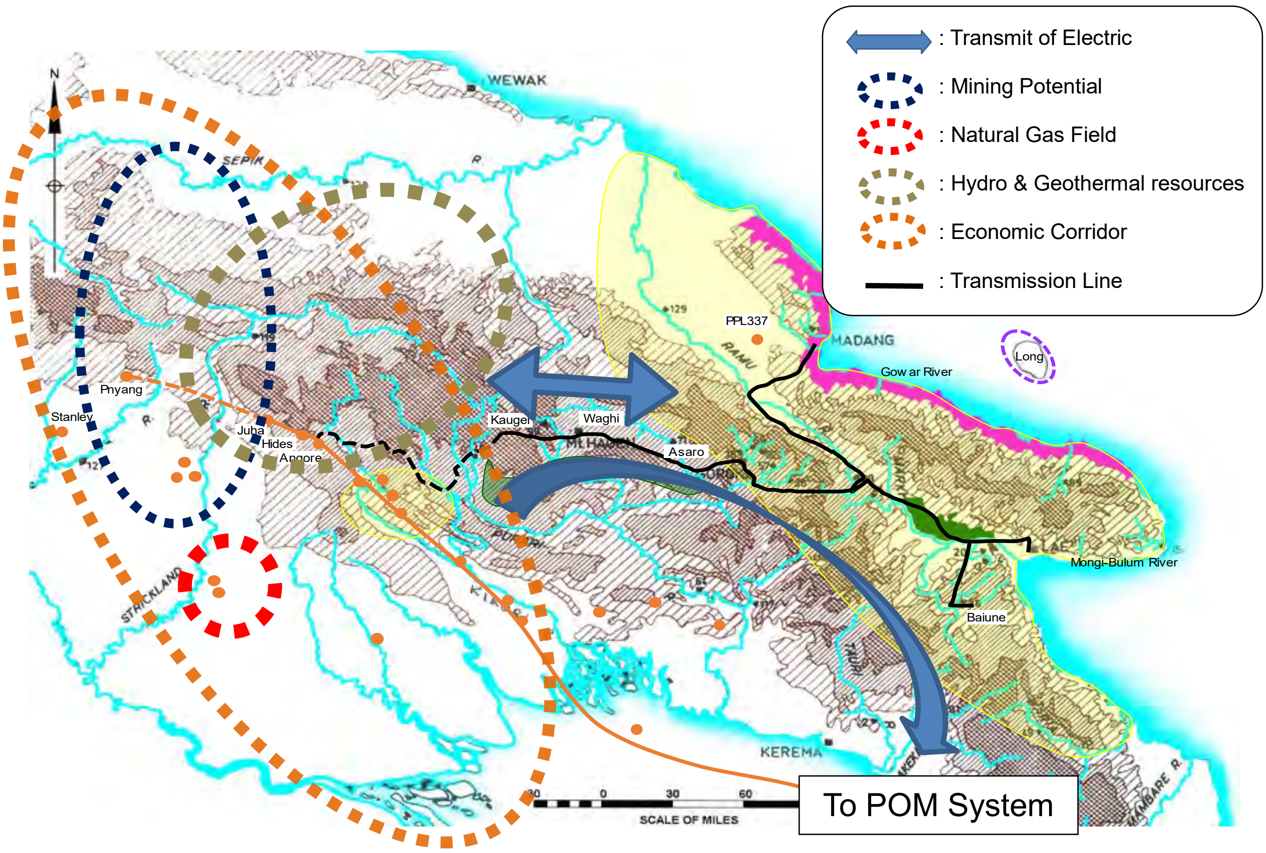


Fig. 6.6-13 Future Image of Development of Highland Area and Reinforcement of Power System

1) Comparison of generation cost for each candidate power plant

At first, for the comparison of generation costs for each type of candidate power plant, the generation cost of each candidate power plant was calculated roughly based on the assumption as mentioned below.

The result of the calculation is shown in Fig. 6.6-14.

Judging from the calculation results of generation costs for each type of candidate power plant, The Mongi/Bulum P/P seems to have competiveness among the several types of candidate power plants as stated above.

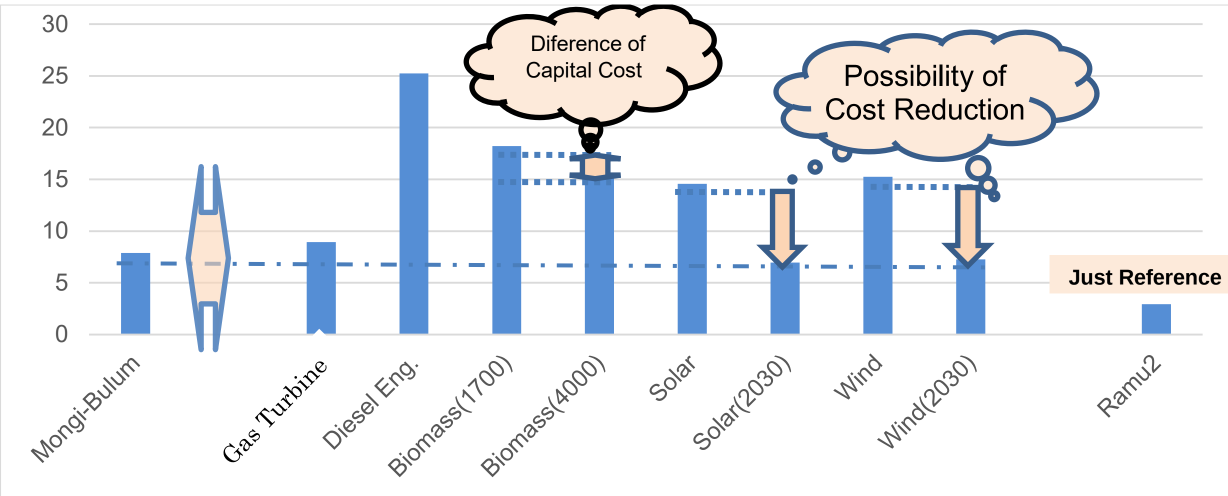


Fig. 6.6-14 Comparison of Unit Costs for Each Power Resource

2) Assumptions for Calculation

For the Alternative power development scenario, the capital requirement for investment was estimated for comparison purposes. The assumptions made for the estimation are as follows.

- As for candidate power plants, it is assumed that the average capacity factors by solar (PV), wind power and biomass are 15%, 20% and 43%, respectively, to calculate the capacities to be developed. Unit costs of each generation including renewables are assumed as follows.

  Unit Cost [cents/kWh] = (Annual Capital Cost [USD/kW] + Annual Fixed O&M Cost [USD/kW·year] × Life Time [year]) × 100 /(Life Time [year] × 8760 hours/year× CF[-]) + Annual Fuel Cost [UScents/kWh]+ Annual Variable O&M Cost [cents/kWh]

- Costs for T/Ls, distribution lines and S/Ss are not included here for rough comparison purposes. So, a definite value for the project cost etc., should be found out at the F/S stage.

- It is assumed that solar generation is not done by PPL. The investment of solar generation equipment is therefore assumed by JICA Study Team and is not included in capital requirement calculations.

- ♦ The capacity factor of solar (PV) units in the table above is set at 15% by JICA Study Team based on similar experience.

- ♦ Depreciation and interest of current assets and debts are tentatively assumed to be constant for the planning period by JICA Study Team.

- ♦ Regarding the solar and wind generation, the cost of battery power for stabilizing the output of generation from these generation types is not included in the installed cost shown in Table 6.6-22.

Table 6.6-22 Unit Costs of Generation for Each Type

[All the values are in 2014 prices inflation is considered]

Candidate Power plant		Mongi/ Bulum	Alternative Power Plant					Reference
			Gas Turbine	Diesel Eng.	Biomass	Solar	Wind	Ramu2
Type		Hydro	Natural Gas	Oil	Wood	-	-	Hydro
Capacity [MW]		116	30	30	30	10	10	200
Project Period	Construction	4	2	2	3	2	2	4
	Book Life time	25	20	20	15	20	20	25
Capital Cost [US$/kW]		8000	1100	1000	1700~4000	3000~1500	1000~750	4000
O&M cost [per Year]		1.30% of capital cost	US2$/MWh US54$/kW	US200$/MWh US100$/kW	7% of capital, US¢10/kWh	US9$/kW	0.60% of capital cost	1.30% of capital cost
Discount Rate (%)		10	10	10	10	10	10	10
Residual(%) after Operation		10	10	10	10	10	10	10
Capacity Factor (%)		60	35	35	43	15	5~10	70
Generation Cost [US¢/kWh]		7.87	8.94	25.24	15.29~18.21	6.94~14.57	7.15~15.25	2.92

6.6.7 Countermeasures for Current Issues

The PGDP was reviewed based on the revised demand and possible candidate power plants on a least-cost basis. However, as mentioned in section 6.5, the following issues arise mainly as a consequence of the special characteristics of the Ramu power system;

- ➢ The geological difference between the locations of the main hydropower plants and the load center of the Lae area,
- ➢ System conditions of the trunk T/L connecting the main power plants and the Lae load center,
- ➢ Uncertainty about the appearance of huge mining demands, etc.

These issues might affect not only the power supply reliability, but also any power expansion plans.

Therefore, there is a need to develop countermeasures for the abovementioned issues from the viewpoint of Power Generation Development, as well.

The following countermeasures were developed and recommended in this study.

(1) Countermeasure for the system separation

There is a possibility of system separation due to big unexpected flooding inundating transmission towers constructed in rivers, a scenario where long outages of important load may occur in the Lae area, as mentioned in Fig. 6.6-15 again.

In considering the countermeasure against system separation, JICA Study Team assumed a power flow mainly from hydropower plants to the load center of the Lae city area.

The flow is assumed to increase in accordance with the development of big hydropower plants in the mountain areas up to around 60~80 MW by 2030, as mentioned later.

So, the development of a biomass power plant in the Markham Valley is strongly recommended. In addition, a new oil-based GT should be installed in the Lae load center area to maintain system reliability with short-term power development, as described in more detail below.

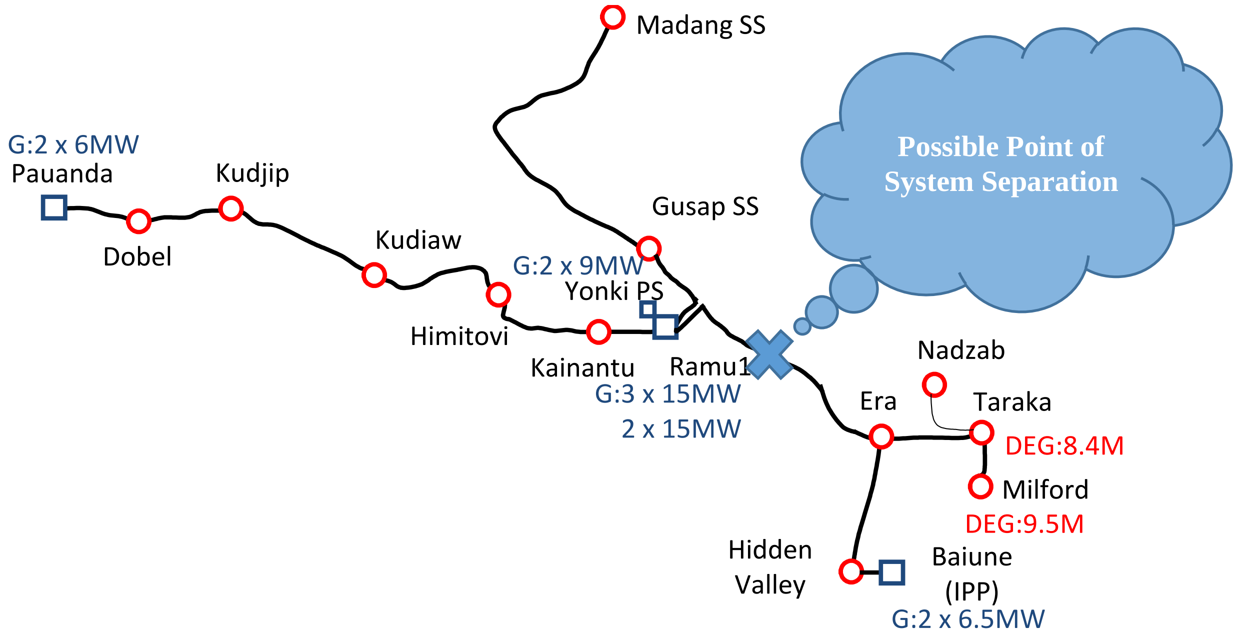


Fig. 6.6-15 Possible Point of System Separation

1) Avoiding long outages of the Lae city area, an important load center [City Loads]

First, the power flow of the system separation point shown in Fig. 6.6-16 was assumed as follows, taking into consideration the location of power generation and load centers for the normal-demand and high-demand cases, respectively.

From the results of this assumption, the power flow will increase at the system separation point where the power flows from the mountain side to the Lae load center, in accordance with the development of hydropower stations on the mountainous side in the future.

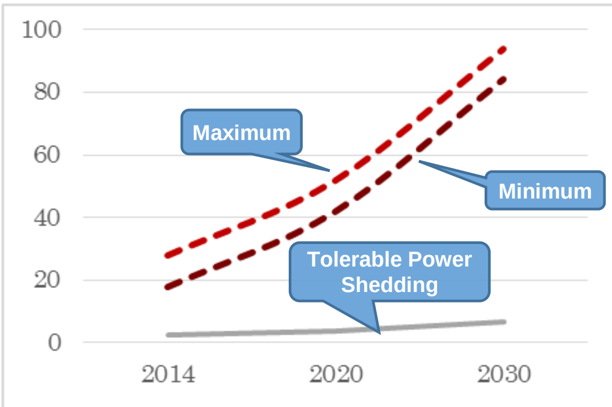


Fig. 6.6-16 Assumed Power Flow

As a countermeasure, oil-based gas generation is introduced in the Lae city area to meet the increased demand requirements in the short-term power development plan.

Oil-based gas generation is introduced in the Lae city area, not only to reduce the above risk below a certain level, but also to enhance the profit by partially supplying power to the mining operations in the first stage, while there is still uncertainty about when the large-scale power supply will be required.

- Introduction of oil-based gas generation in the Lae city area [around 30~60 MW]

  For avoiding the above risk and supplying power, the installation of new gas generation of around 60 MW capacity might be considered appropriate due to the power supply from the hydropower energy located on the mountain side to the urban area.

  According to the supply-demand balance forecast for the short term, the power supply is presumed to be insufficient.

  Therefore, this new gas generation might be required for meeting the increased base load for the short term.

  This gas generation might also be used to cope with the temporary or partial power supply to initially uncertain mining loads, etc., at the first stage, as well as in the future, and it might facilitate the takeover of the aging DG and captive power, as well.

  If the power demands of mining increase as expected, it will be necessary and recommendable to promote the development of hydropower further in the Highlands Region. However, it will take a long time to construct a hydropower plant.

- Introduction of biomass generation in a satellite town:

  For this purpose, the development of biomass generation in a satellite town is also recommended, as it would be more economical and environmentally friendly than diesel generation. The installed capacity of biomass generation is recommended to be approximately 30 MW at the initial stage, considering the scale merit of the plant. Combined with the above gas-fired generation, it will contribute to a low risk of power interruption over the long term. In the short-term it will supply the mining demand, a demand that is not yet certain in terms of timing or power requirements. The introduction of biomass generation might help reduce diesel fuel consumption, as well.

2) Avoiding long outages of significant loads such as mining loads [Highland side mining load]

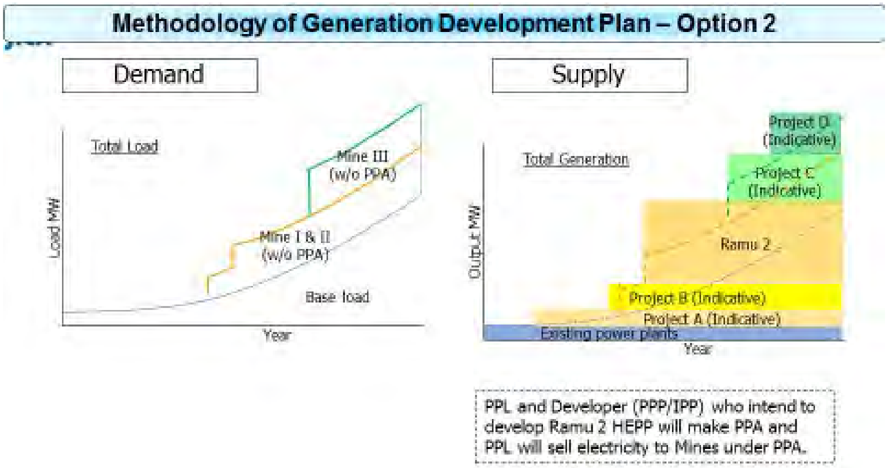
In order to consider the separation of the power system, it is important to take some countermeasures not only for the Lae city area as mentioned above, but also for the Highland side to secure the power supply to an important load, such as a mining load.

- Transfer of the diesel generators in the Lae city area to Singsing S/S

  Until such time that the development of hydropower is implemented in the Highlands Region for supplying power to meet possible mining demands, a plan to transfer the diesel generators in the Lae city area to the Singsing S/S may be an efficient way to improve the environmental impact (e.g., noise and air pollution in the urban area). This will also raise the power supply reliability, especially for the Highland side. If the power supply reliability goes up, ensuring a stable power supply to the mining load will be possible.

6.6.8 Impact of the Uncertainty of Large Mining Demands

(1) Evaluation of the delay of a large mining load in the total Ramu System



As mentioned in Section 6.5 (3) 3) "Evaluation of the delay of a large mining load in the total Ramu System", the Ramu system has the special characteristic of appearance of huge mining loads and corresponding big hydropower plants at certain years. The amount of huge mining load and corresponding big hydropower plant is very large compared to the capacity of the Ramu system. So, the introduction of huge load and power plant seems to affect to the Ramu system largely. Therefore, it is required to evaluate these impact beforehand to consider some countermeasure if required as described below.

The scheme is like this;

First, evaluate several cases by changing the parameters mentioned below.

Next, compare each case mostly from economic viewpoints.

Finally, make recommendations considering the possibilities for delay and find out the insurance or compensation required to contract with the IPP/PPP developer.

The study results are described in order below.

(2) Evaluation case

With regard to the cases, there seems to be the following two combinations of installation of corresponding large hydropower plants and related mine demand.

Among these combinations, the combination of the Ramu 2 case [Ramu 2 and Ramu Nico & Wafi & Golupu Mining Demand at year 2020] for huge-demand scenarios was set for evaluation because this case seems to have a large impact on the Ramu system compared to the Mongi/Bulum case.

Therefore, the impact of possible delays on the realization of mining demands was evaluated on this Ramu 2 case while considering several delay patterns as mentioned in the following.

Judging from the evaluation results of the Ramu 2 case, almost the same conclusion from the Ramu 2 case might be adapted to the Mongi/Bulum case.

- Ramu 2 case : Ramu 2 (180 MW) and Ramu Nico [80] & Wafi & Golupu [80] Demand at year 2020

- Mongi/Bulum case : Mongi/Bulum (116 MW) and Yandela [100] at year 2025

Table 6.6-23 Evaluation Case

Project	Capacity [MW]	Commissioning Year	Corresponding Mine Demand [MW]	Evaluation Base Case
Ramu 2	180	2020~	Ramu Nico [80] & Wafi & Golupu [80]	Year :2020 Power Generation: 180 MW Demand: 160 MW

➢ Uncertainty in mining demand compared to the scheduled installation of corresponding new hydropower plants varies from the appearance of large demands one year earlier to a delay in demand by one or two years, as shown below;

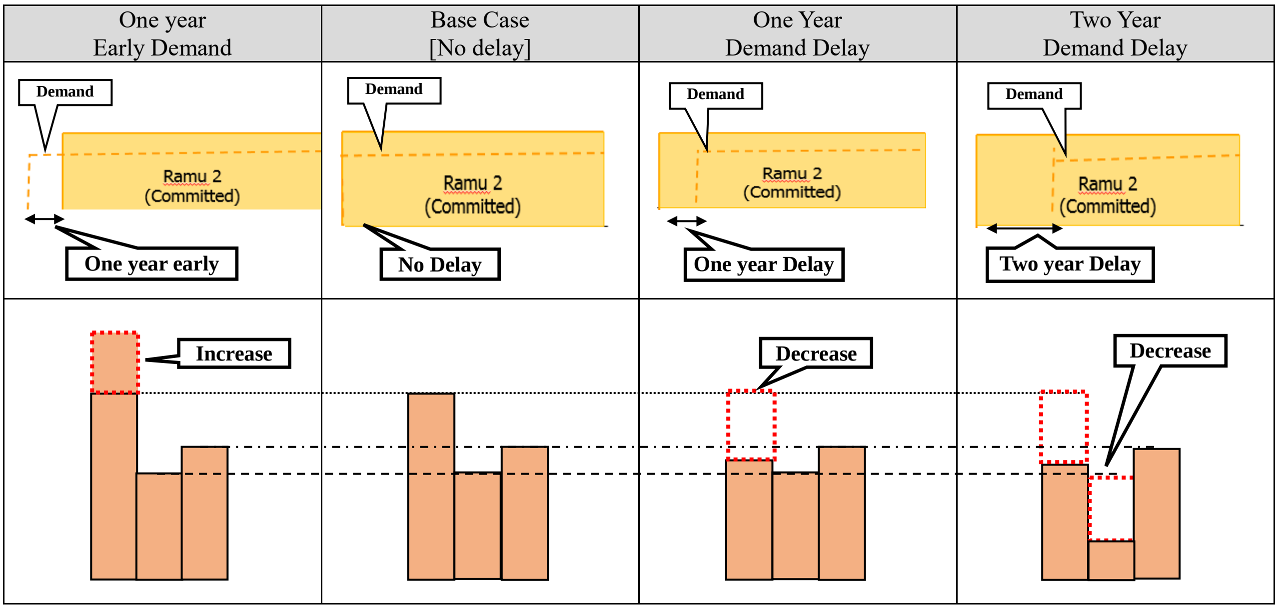


Image of Oil Consumption

(3) Evaluation Result

1) Evaluation Result on the Ramu 2 case

This time, only one case is evaluated tentatively as shown below.

High Demand scenario

a) Simulation Result

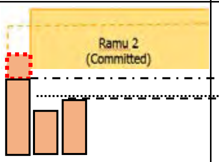
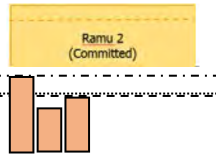
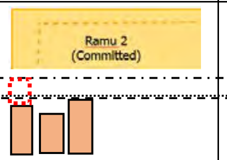
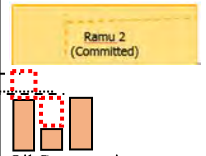
The figure of this case is as follows;

- Combination of installation of the hydropower plant Ramu 2 and the mining demand at Ramu Nico, Wafi, and Golupu mines under the huge-demand scenario.

  - Generation Capacity at Ramu 2 hydro : 180 MW
  - Demand at mines : Ramu Nico [80 MW], Wafi & Golupu [80 MW]
  - Commissioning year : 2020 for Ramu 2 hydro and three mines

- Four cases were considered: -1 year (early), 0 years (no delay), 1 year (delay), and 2 years (delay).

Table 6.6-24 Evaluation Result [Year 2020, Power Generation: 180 MW: Mining Demand: 160 MW]

Case No / Items		HD20+1	HD20+0	HD20-1	HD20-2	Remarks or Assumption
		One year Early Demand	Base Case [No delay]	One Year Demand Delay	Two Year Demand Delay	
		 Oil Consumption	 Oil Consumption	 Oil Consumption	 Oil Consumption	
Purchase Price or Generation cost (1)		------------	---------	**75MUS$**	**162MUS$**	-0.4Kina/kWh -0.4US$/Kina
Energy generated by PPL's own DG plants (GWh)	2019	735 (+498)	Base (237)	449	449	-Oil Price 2.6Kina/L (at 2014) -About 0.3US$/kWh
	2020	466	Base (466)	0 (▲466)	0 (▲466)	
	2021	1014	Base (1014)	1014	0 (▲1014)	
	2022	1082	Base (1082)	1082	1082	
Additional Fuel Cost [A]		**149MUS$**	----------	**▲140MUS$**	**▲304MUS$**	-About 0.3US$/kWh
Energy sales from mines		**174MUS$**	----------	---------	----------	-0.35US$/kWh
Annual Expenses for Hydro P/P [B]		-----	Base (**25MUS$**)	Base (**25MUS$**)	Base (**25MUS$**)	-4000US$/kW -O&M 1.25% -25 years uniform
Total Evaluation		- Supply by utilizing surplus energy of Hydro/ high-efficiency DG - Receive power energy under 50% to total demand	----------	Acceptable even when considering the installed cost of hydropower	Acceptable even when considering the installed cost of hydropower	Revision required in case of changes in pre-conditions and for getting the precise values mentioned in this table.

b) Summary of evaluation

Summary of the evaluation result is explained as follows;

In this case the mining load is assumed to appear one year earlier compared to the original schedule.

Explanation;

- Tariffs and additional income is substantial compared to the increase of the fuel price for generating the electric power to meet the new earlier demand.
- The contribution of the new mine load would contribute tremendously to the GDP of PNG.
- One negative impact of the additional electric power generation of DG would increase CO_2 emissions. However, this negative economic impact would be canceled out by the positive economic impact, as mentioned previously.
- In the case of an early appearance of mine demand, an insufficient power supply situation seems to occur. Although the mine load might receive about 50% of the electric energy required, it would be recommendable from an economic viewpoint for PNG/PPL to send as much power as possible to the mine load utilizing the surplus energy mostly generated by diesel generation.

- The power supply–demand balance is kept at a certain level and is permissible from a power balance viewpoint. However, there are many concerns for keeping a stable power supply with big demands and corresponding power plants compared to the system capacity excluded MINE Demand from power system configuration, operation and protection which are common concerns to all cases as mentioned in Chapter 7.
- So, the new oil-based gas generation (around 30 MW*2 units) required for keeping the supply-demand balance as a short-term countermeasure might serve not only to enhance the system reliability and to take over the aging DG, but also to send the electric power to meet the huge mining demands at the initial stage.
- In the case where the huge mining demands are delayed, generation energy from DG might be mostly absorbed or taken over by a new hydropower plant with no consideration of system restrictions such as partial low-voltage problems, etc.
- Judging from the results of the evaluation summarized in Table 6.6-24, it seems to be better, economically, to incorporate new big power plants into the Ramu system and utilize the power energy generated by new hydropower stations once developed even though there is a delay of the corresponding mine load.
- However, much attention should be focused on how to operate these big power plants and meet demands, given that these big power plants and demands have tremendous impact on the smooth operation of the Ramu system. Some countermeasures are therefore required, as mentioned previously.

Overall, the new mining demand is preferable for PNG because of the contribution to PNG's GDP as the tariff increases for PPL.

Therefore, as much electric power as possible should be sent to meet new mine demands using the surplus power at that time, with a focus on power operation and protection issues, etc.

(4) Evaluation Method

JICA Study Team attempted to evaluate the impact of delaying the mine demand, which seems to largely affect not only the power supply-demand balance but also the economics.

JICA Study Team therefore attempted to evaluate the approximate impact, because these situations vary from year to year. A rough evaluation was carried out to determine an outline of these impacts without straying from the evaluation purposes mentioned below.

1) Evaluation of annual expenses, starting from the power plant installation cost

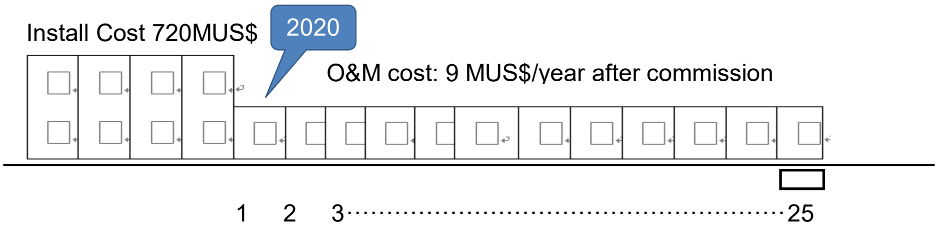
The following pre-conditions were tentatively assumed to be a rough calculation of the annual expenses of the project.

The total costs consist of expenses incurred for the implementation and operation of the project.

- Project Period : 29 years
  (Assuming a 4-year construction period and 25-year operation period),
- Project Cost : total project cost mentioned above,

- O&M cost : 1.25% to total installation cost per year
- Discount Rate : 10%
- Residual : 10% after 25 years

So, this time the annual expense was estimated with the following equation.



The following is an example of the calculation equation. The actual value of each expense every year is shown in

- Equation(x)[Annual Expenses] = {720/4*E(4)i=10*D(25)i=10-720*0.1*C(25)i=10+9}*B(1+i=0.1)-1
  = {720/4*4.641*0.11017-720*0.1*0.01017+9}*0.9009
  = 25MUS$/Year

2) Reduction of oil consumption

Utilizing the WASP simulation, the amount of consumption reduction was calculated. The oil cost value for calculating the oil reduction benefit is assumed to be 2.6 Kina/L as a pre-condition value for this study.

(5) Additional Benefit

The additional benefit for the new Hydro & Demand is considered. However, the benefit value is vague or uncertain at this stage of the study. So the only concept for this benefit is mentioned below.

1) Contribution to GDP with Power Supply

This study estimated the contribution of the early mine demand in terms of the relation between the GDP and power consumption (electricity sales) in PNG.

The figure below illustrates the relationship between the GDP and electricity sales in PNG from 1993 to 2014.

GDP and electricity sales correlate with each other to some extent as shown in the figure and the new mining load seems to have more positive impact on production compared to the electricity sale of PNG since most of the industries use electricity for production. For this reason, the study estimates that a GNP contribution of new mining load seems to be around 1.16 US$/per kWh.

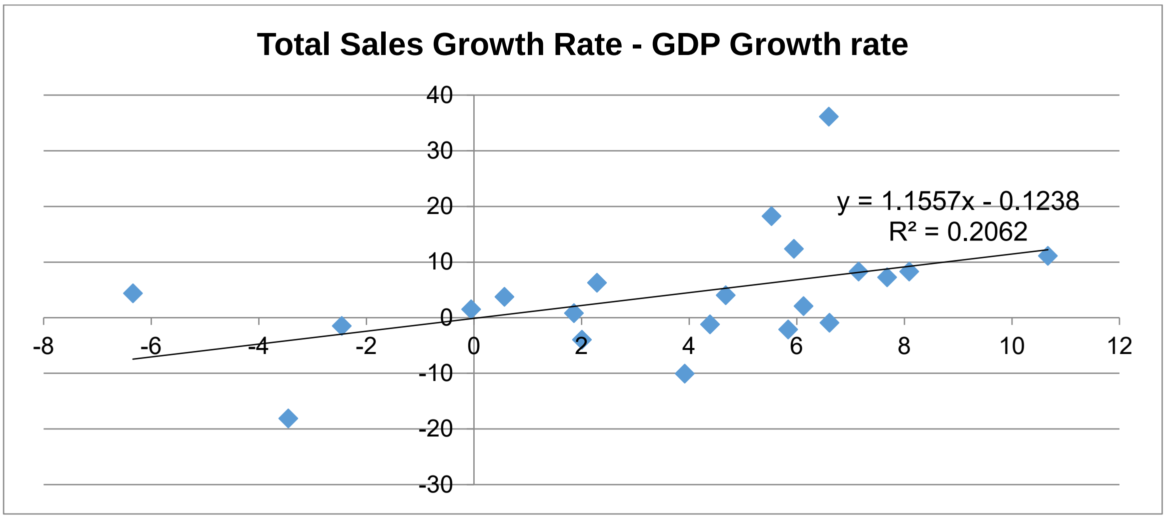


Fig. 6.6-17 Relationship between GDP and Electricity Sales

JICA Study Team has calculated the values for other countries and found the same value of 1USD per kWh as a contribution of electricity sale.

So it seems to be reasonable to say that the contribution cost of PNG is at least 1.0USD per kWh.

However, this examination is the result for all electricity sale of PNG. So, the contribution of an industry load, such as a mining load to PNG's GDP seems to be large compared to that of total electricity sale. Therefore, the contribution of new mining load the GDP is assumed to be more than 1USD per kWh.

2) Effect of CO_2 Emission Reduction

This is assumed to be an evaluation of CDM benefit for the reduction of CO_2 emissions for the delay of the mine load. On the contrary, an earlier appearance of mine loads seems to increase CO_2 emissions. The impact is therefore negative.

Hence, in order to evaluate the impact of CO_2 emitted in relation to the production of the energy for each case, the amount of GWh generated from thermal power plants was calculated through the WASP simulation as shown in Table 6.6-24.

Although the amount of GWh is mostly generated by diesel generators, there is no definite information for the CO_2 being emitted by diesel generators. So, 1.0 ton of CO_2 per MWh was assumed for this study.

The value of resulting certified emission reduction (CER) seems to fluctuate roughly from $10 to $100. In this study, as the CDM benefit, the value of USD $10 is used for evaluation as the minimal benefit.

6.7 RECOMMENDATIONS FOR THE POWER GENERATION EXPANSION PLAN

(1) Updating of the Power Development Plan

JICA Study Team collected information which is necessary for drafting plans for power supply, power supply composition, power supply introduction date, power supply point, and so on. The power supply composition proposed in this report is based on this basic information.

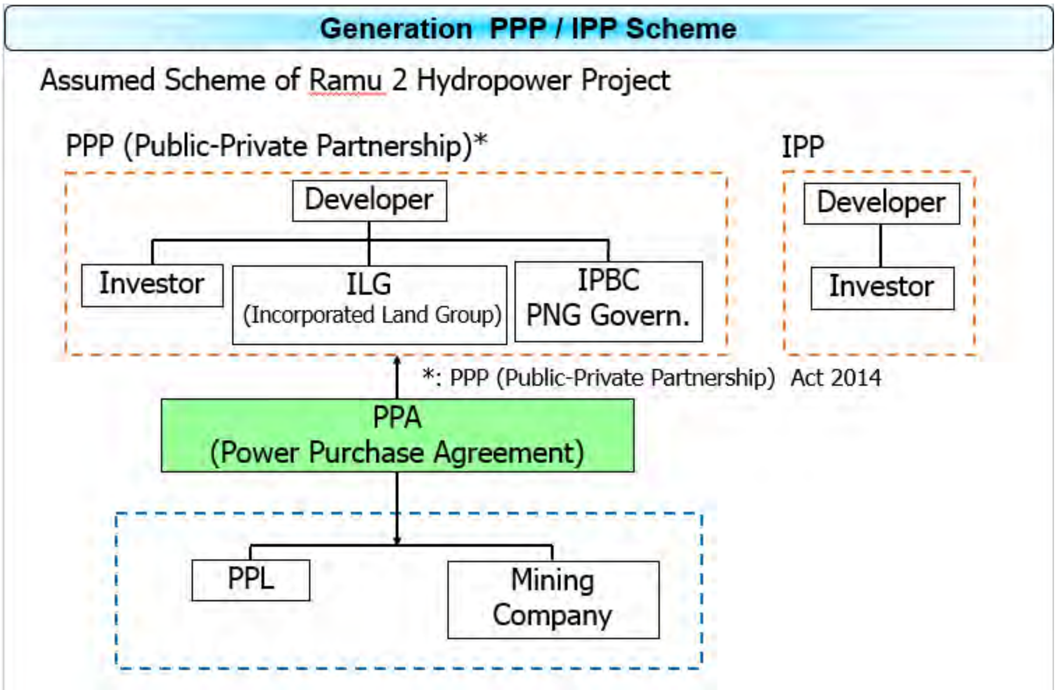
So, the current PDP shall be reviewed and updated periodically in the following instances.

- The power development Plan shall be updated annually according the changes in preconditions such as revised demand forecasts or modifications of related restriction cords, etc.
- The PDP shell be reviewed and updated if there emerges any new big demand that will have significant impact on the power development plan, as well.

(2) Introduction of investors for new hydro power plants

The development of HP should basically be put on first priority for reducing the generation cost and Oil consumption as well.

However, huge budgets are required for the development of a new hydropower plant. Hence, the following scheme might be considered for the introduction of PPP/IPP investors (the organization themselves have not yet been fixed).



The new Mining Load is preferable for PPL/PNG for increasing the national economy and enhancing PPL's financial balance.

However, it might take a long time to reach an IPP/PPP project agreement in light of the risk for investors.

It therefore might be better for PPL to play an intermediate role by joining the project organization and facilitating an earlier agreement by providing some compensation for investor risk, e.g., by purchasing the electric energy generated from the IPP/PPP's hydropower, etc.

(3) Diversify of the power supply sources

Optimum power generation composition for the Ramu system should be further studied by the PPL considering best utilization of domestic energy resources, supply conditions for each primary energy source and energy security especially Highland Gas resources.

In addition, the power supply composition proposed in this report depends upon various assumptions and uncertainties including the development situation and reserves of domestic gas, the international market price of oil and so on. Therefore, it will be necessary to revise and update the Power Generation Expansion Plan periodically.

Sensitivity analyses concerning various conditions of the PGDP are expected to be key issues in the future.

(4) Short Term Countermeasures

Rehabilitation or replacement of power plants with poor fuel efficiency is effective as short term countermeasures to increase supply capacity. In addition, rehabilitation or replacement of failed parts is effective for some existing HPPs whose output has decreased because of deterioration. Rehabilitation or repowering projects need to be planned in a timely manner.

(5) Allocation of Gas Resources and power supply combination for total power systems

In the context of appropriate allocation of limited gas resources, setting criteria for combustion efficiency and reviewing the IPP plans which do not meet these criteria, prioritization based on combustion efficiency could be used to determine allocation of gas for each power plant.

Certain amount of Natural gas resources should be utilized to generate and supply stable electric energy in site for the purpose not only to enhance the rural area economic but also to supply POM system through the interconnection T/L.

In other words, the capacity of GT utilizing domestic natural gas resources might become the substantial power supply resources because the cost generated with domestic natural gas resources in site seems to have competiveness to that generated by other resources including hydro resources. So, it seems to be better to be developed taking the total system after POM and Ramu system being connected into consideration in the future. This also is expected to contribute to diversify the power supply sources and to abide the risk caused by too high ratio of HP capacity to total capacity such as short supply in heavy dry season etc. as mentioned in Section 6.6.5 "Optimal Generation Expansion Plan"

(6) Technical Transfer of the Simulation

This Power Generation Expansion Plan should be revised and updated in accordance with changes in the surrounding situation as mentioned above. So, Technical transfer concerning not only simulation software and calculation tools but also establishment of criteria or standard for each sector might be also effective for them to better handle the Power Generation Expansion Plan by themselves in accordance with their intention.

[Technical Transfer of each power sector in PPL]

It is recommended to transfer technology related to the following upon their request:

- Power system development technology
  - Planning theory Criteria including arrangement Criteria and planning document for developing the optimal power supply & demand balance and effective reinforcement of power system [Generation under IPP/PPP scheme, etc., Transmission and Substation]
  - System operation and system protection technology for avoiding savior accident such as total system break down etc.
  - Transfer of related soft wear or procedure training [PSS, WASP, etc.]
- Distribution planning and O/M technology
  - Mainly effective planning for meeting increasing demand by area including development of related criteria document etc.
  - Operation and Maintenance method including arrangement of related document
  - Related software or system for effective O/M
- Overseas Training at the similar countries

CHAPTER 7

POWER SYSTEM DEVELOPMENT PLAN

CHAPTER 7 POWER SYSTEM DEVELOPMENT PLAN

7.1 OUTLINE OF THE RAMU POWER SYSTEM

In 2014, the demand of the Ramu system was 87.8 MW, about 40% of which for the Lae area and about 15% for the Madang area. The demand forecast shown in Chapter 4 presumes about 75% of demand belongs to the Lae and Madang areas. The main power source is hydropower, which accounts for more than 90% of all power generated in the Ramu system. Moreover, more than 80% of the power generated in hydroP/Ss is generated at the Ramu1 hydropower station, with the remaining 10% generated in the Pauanda hydroP/S. The power source and demand center are connected via a single 132 kV T/L.

The features of the Ramu system are summarized below;

- The demand center is located in the eastern and northern areas.
- The power source is located in the central and western areas.
- The T/L comprises a single circuit line, which connects eastern and western areas, then branches north.

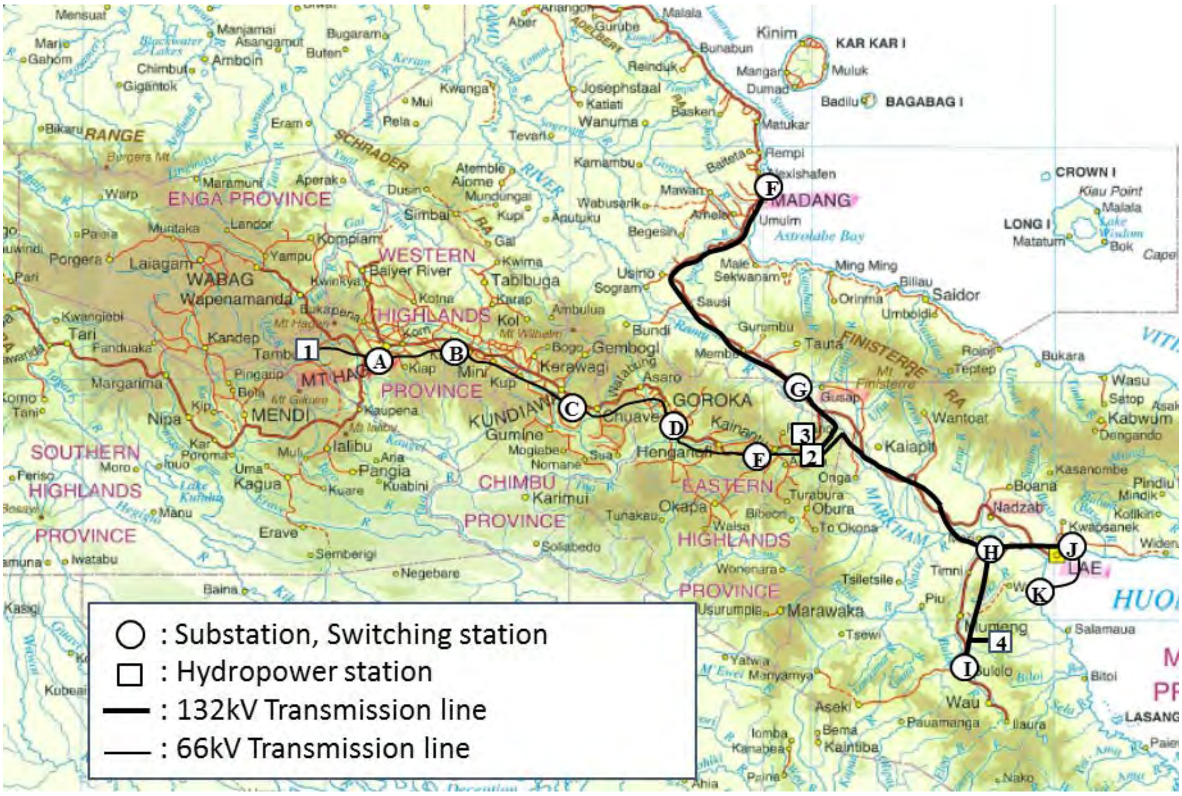
A diagram of the existing Ramu system is shown in Fig. 7.1-1.

The volume of existing facilities on T/Ls and substations (S/S) is shown in Table 7.1-1.

Table 7.1-1 Volume of Facilities on Transmission Lines and Substations in the Ramu System (as of 2014)

	132 kV	66 kV	**Total**
Number of T/Ls	6	12	**18**
Distance of T/Ls (km)	447	316	**763**
Number of S/Ss	6	9	**15**
Capacity of S/Ss (MVA)	308	200	**474**

(Source: FYPDP 2014-2028)



No	Substation, Switching station
A	Dobel
B	Kudjip
C	Kundiawa
D	Himitovi
E	Kainantu
F	Meiro
G	Gusap
H	Erap
I	Hidden Valley
J	Taraka
K	Milford

No	Hydropower station
1	Pauanda
2	Ramu 1
3	YTOD
4	Baiune (IPP)

(Source: JICA Study Team)

Fig. 7.1-1 Existing Ramu System Diagram

7.2 OUTLINE OF THE RAMU POWER SYSTEM DEVELOPMENT PLAN

Table 7.2-1 shows the Ramu power system development plan as listed in FYPDP (2014-2028), which was compiled by PPL. Symbols Ⓐ ~ Ⓕ respectively refer to the same plan.

Table 7.2-1 Ramu Power System Development Plan

	Ⓐ Commence second Ramu - Lae 132 kV transmission detail design Ⓑ Commence Gusap - Meiro line rehabilitation for 132 kV operation Ⓒ Design of 132 kV loop-in/loop-out T/L to Lae IPP1 at Munum
	Ⓑ Complete Ramu - Meiro line rehabilitation for 132 kV operation Ⓒ Construction of 132 kV loop-in/loop-out transmission interconnections to Lae IPP1 Power Plant
	Ⓐ Commence double 132 kV T/L from Singsing - Erap station Ⓐ Commence single 132 kV T/L from Erap station – Taraka
	Ⓐ Complete double 132 kV T/L from Singsing - Erap station Ⓐ Complete single 132 kV T/L from Erap station – Taraka
	Ⓓ Commence Ramu 2 to Singsing 132 kV T/L
	Ⓔ T/L interconnection to Lae IPP2 Power Plant
	Ⓓ Complete Ramu 2 to Singsing 132 kV T/L Ⓕ Review Interconnection to POM system - this development depends on the availability of major generation capacity in Ramu or POM.

(Source: FYPDP 2014-2028)

The progress of each plan Ⓐ ~ Ⓕ is shown below.

Ⓐ Commence second Ramu - Lae 132 kV transmission detail design

This project is part of the Ramu Transmission System Reinforcement Project, funded by a JICA ODA loan. This project starts on September 2015. Precise information is shown in Section 7.2 (1).

Ⓑ Commence Gusap - Meiro line rehabilitation for 132 kV operation

The T/L towers from Gusap S/S to Meiro S/S are designed under the 132 kV system for future voltage step-up, although this line is currently operated at 66 kV. However, considerable time has elapsed since construction and the specification of the insulators remains unclear. Construction work on voltage step-ups, including confirmation of existing T/Ls, has been planned but no concrete plans has yet been determined as of October 2015.

Ⓒ Design of 132 kV loop-in/loop-out transmission line to Lae IPP 1 at Munum

This project involved construction work of IPP at Munum, located near Lae. This IPP will be constructed in 2017.

Ⓓ Commence Ramu 2 to Singsing 132 kV transmission line

This project links up the Ramu 2 power station and Singsing S/S, and the T/L needs to be constructed before the Ramu 2 commissioning. FYPDP shows commencement in 2018 and completion in 2027 but this is contingent on the Ramu 2 construction schedule.

Ⓔ **Transmission line interconnection to Lae IPP 2 (Biomas) Power Plant**

This project is the connection of IPP, built in the Lae area and the Ramu power system. Constructing this T/L depends on the IPP construction schedule.

Ⓔ **Review Interconnection to POM system – this development depends on the availability of major generation capacity in Ramu or POM.**

This project involves connecting the POM and Ramu power systems and is currently just a conceptual plan. As shown in FYPDP, this development depends on the availability of major generation capacity in Ramu or POM. In this Master Plan, a review of this interconnection is undertaken in Section 7.7.8, based on the constraints of the power development plan.

(1) Major project

A project coming in the near future is the Ramu Transmission System Reinforcement Project, funded by a JICA ODA loan and summarized below.

The main objectives

1) To reinforce the efficiency of the Ramu grid, which is considered to lead directly toward stabilizing the electrical power supply and economic development of Lae.

2) To increase the opportunities for reliable and stable electrical connections in the communities around the project sites.

Project scope

The project comprises the following two components:

1) Transmission line components

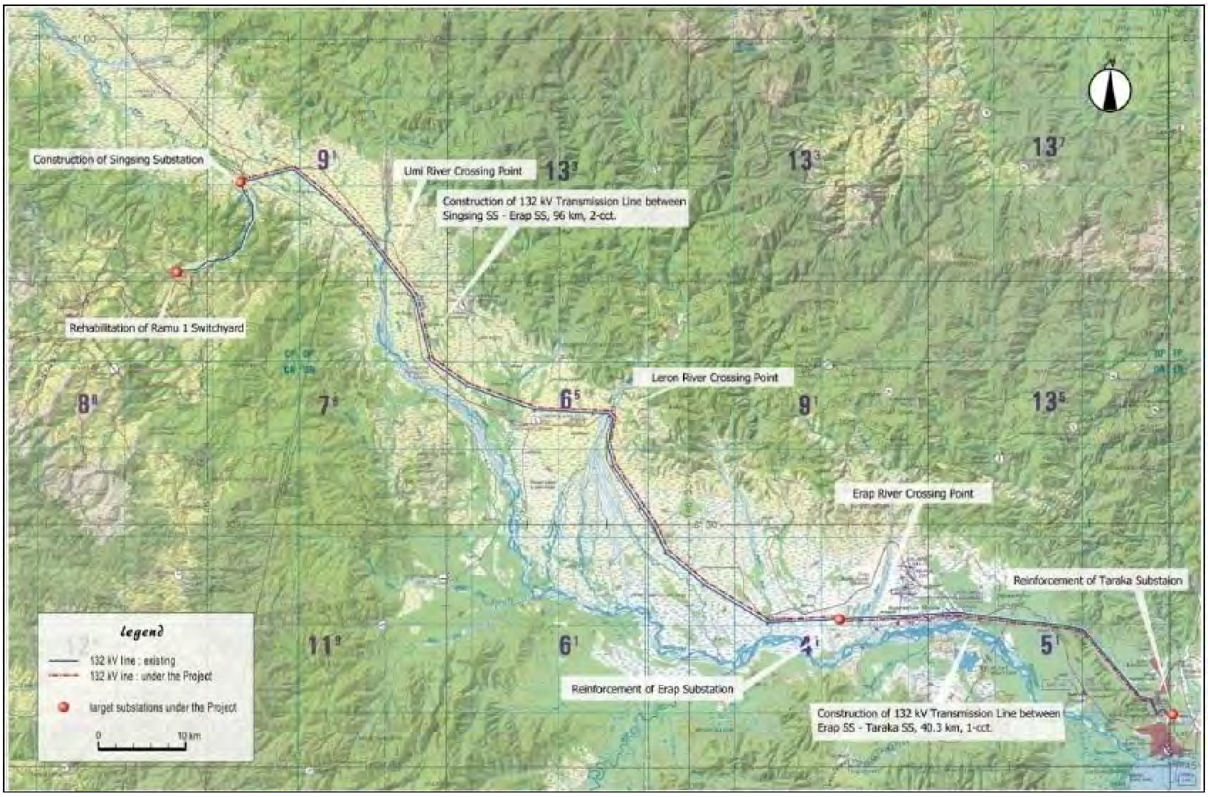
i) 132 kV dual-circuits overhead T/L from Taraka S/S to Taraka Junction, 0.7 km and 132 kV single-circuits overhead T/L from Taraka Junction to Erap S/S, 39.7 km

ii) 132 kV dual-circuits overhead T/L between Erap S/S and new Singsing S/S, 97.2 km

2) Substation components

i) Rehabilitation of the Ramu 1 switchyard
ii) Construction of the Singsing S/S
iii) Expansion of the Erap S/S
iv) Rehabilitation of the Taraka S/S with three alternative plans, including a further additional 132 kV T/L bay

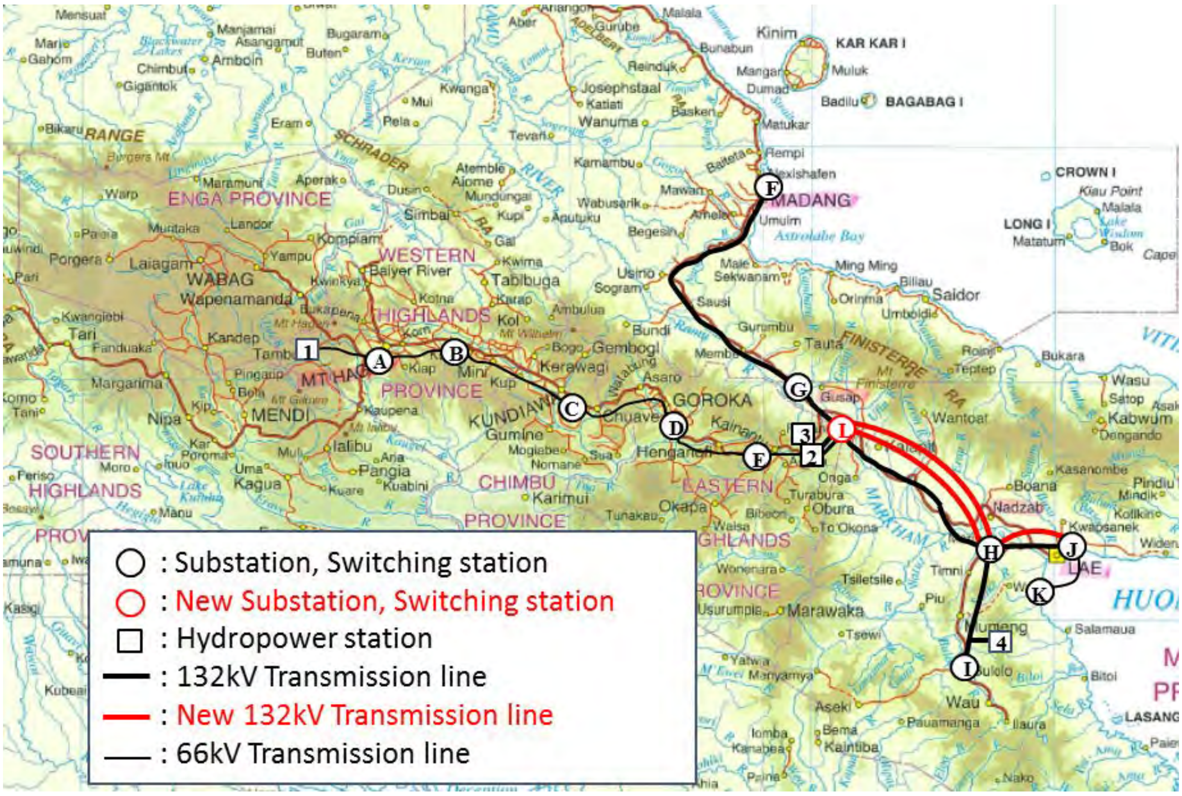
Fig. 7.2-1 shows the project scope.



(Source: FYPDP2014-2028)

Fig. 7.2-1 Scope of the Ramu Transmission System Reinforcement Project

Fig. 7.2-2 shows the Ramu power system grid after the project in 2020. The project is expected to contribute to stable power supply in the Lae area.



No	Substation, Switching station
A	Dobel
B	Kudjip
C	Kundiawa
D	Himitovi
E	Kainantu
F	Meiro
G	Gusap
H	Erap
I	Hidden Valley
J	Taraka
K	Milford
L	Singsing (New)

No	Hydropower station
1	Pauanda
2	Ramu 1
3	YTOD
4	Baiune (IPP)

(Source: JICA Study Team)

Fig. 7.2-2 Ramu Power System Grid (as of 2020)

7.3 TRANSMISSION PLANNING CRITERIA

The transmission planning criteria, as prescribed in FYPDP and Grid Code, are as follows;

(1) Voltage levels

The criteria regarding voltage levels are prescribed in FYPDP. The same criteria as shown below are adopted in this study.

Under normal operating conditions, with all plants in service, variations should not exceed + 5%. Under emergency conditions, the voltage variations should not exceed + 10% measured on the high voltage busbar of the zone S/Ss.

(2) Overload levels

The criteria for overload levels are prescribed in FYPDP. The same criteria as shown below are adopted in this study.

Transmission lines — line currents are not to exceed the thermal limits with the conductor at 75°C, ambient of 32 °C and 0.5 m/s wind velocity.

Transformers — under normal operating conditions, the load is not to exceed the rating allowable by the mode of cooling applied. Under emergency conditions, short time (1 hour) overload of 20 % is not to be exceeded providing the load immediately prior to emergency does not exceed 80 % of rating allowable by the cooling mode.

(3) Supply security

The quality of service at any load centre supplied from the transmission system, for emergency conditions caused by the loss of a single major transmission component, (e.g., a T/L or a zone S/S transformer) is defined as follows;

Table 7.3-1 Definitions for emergency conditions

Class I	Service is not interrupted or is re-established within minutes by switching operations.
Class II	Service is re-established within hours using stand-by generation. Two alternatives are possible in this case, depending on available generation.
Class IIA	Service is fully restored with adequate standby generation.
Class IIB	Service is only partially restored due to limited generation.
Class III	Service is re-established within days (allowing time to construct a temporary line by-pass or to transfer a spare transformer or mobile generator from another site).

(Source: FYPDP 2014-2028)

(4) Short-circuit capacity

The criteria for short-circuit capacity are prescribed in the Grid Code. The same criteria as shown below are adopted in this study.

Fault Level

(i) The maximum allowable short circuit or ground fault current in the Transmission Network and Connection Point at 132 kV is 31.5 kA.

(ii) The maximum allowable short circuit or ground fault current in the Transmission Network and Connection Point at 66 kV is 25 kA.

(iii) The maximum allowable short circuit or ground fault current at 11 kV to 33 kV is 12.5 kA.

(5) Rating current

The criteria for the rating current are prescribed in FYPDP. The same criteria as shown below are adopted in this study.

1) Transmission Line Rating

Installed rating is based on ampere capacity of conductors.

2) Transformer Rating

The continuous rating is based on natural cooling system. Higher figures refer to forced air or forced oil cooling where such is installed.
(Ex) the rating of a 132/11 kV transformer in Taraka s/s: 15/20 MVA ONAN/ONAF, which means 15 MVA at Oil Natural Air Natural (ONAN) and 20 MVA at Oil Natural Air Forced (ONAF).

(6) Transient and steady state stability guidelines

The criteria for transient and steady state stability are prescribed in FYPDP. The same criteria as shown below are adopted in this study.

1) Transient and Steady State Stability Guidelines

The transient stability guidelines are intended for the Ramu and POM systems. Either as isolated or interconnected systems, these systems must be able to sustain any single contingency. These include loss of a single generator (the largest in the system), or transmission element or the clearing of any two phases to ground, or single circuit fault by primary protection and should maintain the following performance;

(i) The system must remain in synchronism.
(ii) All plant must operate within thermal capability.
(iii) Loads other than interruptible loads (e.g. domestic, commercial or industrial/ manufacturing which are interruptible under service agreements) must not be shed.
(iv) Damping of system oscillations must be adequate with no prospect of long term instability.
(v) Voltage stability criteria must be satisfied.

The steady state stability guideline as applied across the system requires that in the event of loss of generation or transmission element without a system fault, the subsequent operation shall be steady state stable with all oscillations decaying to half value in less than 5 seconds with a 90% probability.

7.4 CURRENT ISSUES OF THE POWER TRANSMISSION SYSTEM

This section covers the current issues of the Power Transmission System.

(1) Weak transmission system

The 132 kV T/L in the Ramu system comprises a single circuit.

Generally, high-voltage T/Ls comprise dual-circuits so that power can be continuously supplied during single line outages caused by natural disasters and deliberate single line stops for maintenance. It is necessary to construct a transmission system which meets the N-1 criteria and enhance supply reliability.

Power is usually transmitted from Ramu 1 P/S to demand areas in the Ramu system (Lae, Madang and Highland). Accordingly, a single line fault leads to an outage on the load side of T/Ls and moreover, to the outage of distribution lines.

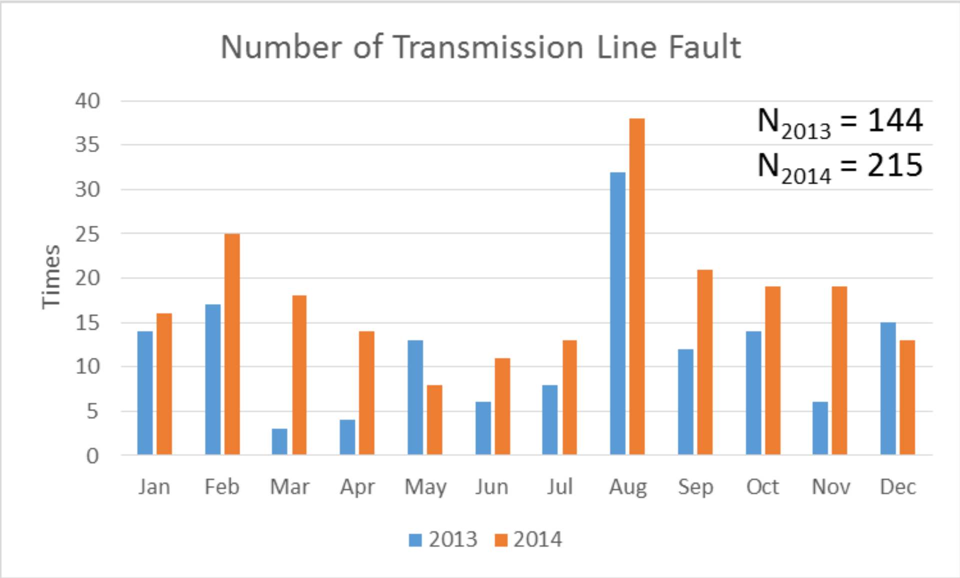
Records of distribution outages are shown below. On 28 January, 2014 at 5:10 am, a fault occurred at the 132 kV T/L from Ramu1 SW/S (Switching Station) to Erap SW/S (L601). "Remarks" show that the outages of all 11 distribution lines in Milford and Taraka S/S came from the outage of the T/L. As this fault, the problem of the existing Ramu system is that a fault in the T/L causes customer outages.

Date	Feeders	Fdr #	Off	On	Mins	Hrs	MW	MWHr	Cause	Status	Remarks
28-Jan-14	Milford	1	5:10	7:59	169.20	2.82	1.10	3.1020	C1	up	Line L601 fault tripped fdr
28-Jan-14	Milford	2	5:10	7:58	168.60	2.81	2.10	5.9010	C1	up	Line L601 fault tripped fdr
28-Jan-14	Milford	3	5:10	7:55	165.00	2.75	2.90	7.9750	C1	up	Line L601 fault tripped fdr
28-Jan-14	Milford	4	5:10	7:57	167.40	2.79	3.10	8.6490	C1	up	Line L601 fault tripped fdr
28-Jan-14	Milford	5	5:10	6:12	61.80	1.03	2.70	2.7810	C1	up	Line L601 fault tripped fdr
28-Jan-14	Milford	6	5:10	6:12	61.80	1.03	1.50	1.5450	C1	up	Line L601 fault tripped fdr
28-Jan-14	Taraka	1	5:10	7:41	151.20	2.52	2.10	5.2920	C1	up	Line L601 fault tripped fdr
28-Jan-14	Taraka	2	5:10	7:41	151.20	2.52	1.80	4.5360	C1	up	Line L601 fault tripped fdr
28-Jan-14	Taraka	3	5:10	7:38	147.60	2.46	2.90	7.1340	C1	up	Line L601 fault tripped fdr
28-Jan-14	Taraka	4	5:10	7:40	150.00	2.50	2.70	6.7500	C1	up	Line L601 fault tripped fdr
28-Jan-14	Taraka	5	5:10	7:39	149.40	2.49	2.40	5.9760	C1	up	Line L601 fault tripped fdr

(Source: PPL)

When the outage is extended and power from Ramu 1 hydropower station is not supplied for an extended period, a DG, which is costlier to run than hydropower, begins operating in demand centers such as Lae and Madang.

Fig. 7.4-1 shows a record of T/L faults from 2013 to 2014.



(Source: record from PPL)

Fig. 7.4-1 Transmission Line Faults (January 2013 – December 2014)

As mentioned above, the single line from Singsing S/S to Erap S/S (L601) will be reinforced to become three lines and a single line from Erap S/S to Taraka S/S (L603) will be reinforced to become two lines. After the construction, even if a fault occurs at one of the T/Ls, the other T/Ls will still be able to supply power to the Lae area continuously, which will meet about half of total demand in the Ramu system in 2030. This project will help reduce fuel costs because the hydropower can supply demand of Lae area when one T/L failure without operate DG at Taraka and Milford.

Next, Table 7.4-1 shows the outage duration of T/Ls, which increases for the following two reasons;

1) Power system comprising a single transmission line

Generally speaking, because most T/L faults are temporary, such as lightning faults, when a T/L is a dual-circuit system, an auto-reclose function is usually used and power transmission is recovered automatically. If dual-circuits connecting two power systems are installed, the two power systems synchronize during single line outage affecting the other line and auto-reclose can be applied. However, the single line configuration means two systems connected by the T/L will be separated in case of a fault on the line. Moreover, the system on the demand side is subject to total blackout in some cases because the supply source is disconnected, whereupon it takes considerable time to recover. It is desirable to construct a double T/L system and apply an auto-reclose function to recover to the ordinary system.

2) Insufficient SCADA system

When a fault occurs, it is preferable to confirm the kind of fault having occurred and the situation after the fault in the Ramu system. It is impossible for the system operator in the Ramu 1 P/S to supervise all P/Ss and S/Ss in the Ramu system because SCADA is not completely installed. The system operator calls the P/Ss and S/Ss to confirm the post-fault situation, which is considered very time-consuming. Moreover, the only way to confirm the post-fault situation in unmanned S/Ss is to go and check in person, e.g. whether or not circuit breakers have operated. This movement and confirmation is also considered to take time. If the system operator can instantly determine the situation in the overall Ramu system via SCADA, he/she begins considering the fault recovery process soon, reducing the overall outage duration.

Table 7.4-1 Outage Duration of the Transmission Line in the Ramu System

Year	Number of outages	Total outage duration	Average outage duration
2013	144 times	479 hours	3.3 hours/times
2014	214 times	1136 hours	5.3 hours/times

* Since accidents involving a tower collapse (outage duration of 720 hours) between Gusap S/S – Meiro S/S (L605) are considered very rare faults, they were excluded from the above result for 2014.

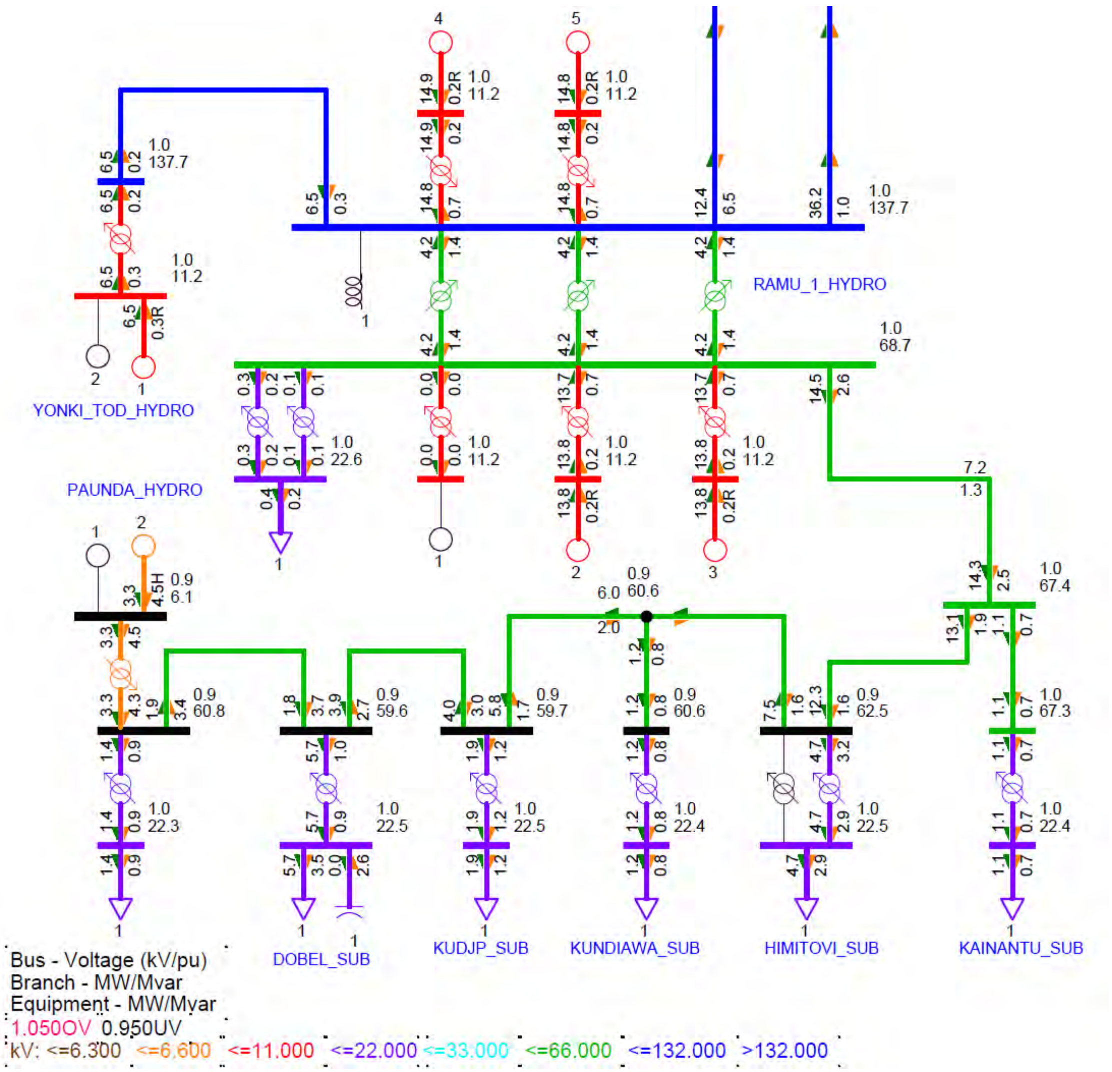
(Source: record from PPL)

(2) Voltage drop

In an interview with the PPL staff, since there was information on a voltage-drop phenomenon having occurred in Highland while only one of the generators of the Pauanda P/S was operating, the phenomenon was confirmed in the simulation (Power flow analysis) using PSS@E, the result of which is shown below.

The simulation was performed using supply and demand data of the generating capacity peak time in 2014 (Max. Generation = 87.8 MW, 2014/10/21, 17:30). The output of the Pauanda P/S (6 MW × 2) is 3.3 MW and equivalent to one-unit operation, while the power factor of the load was uniformly set to 85%.

The voltage drop in the Highland area was confirmed as a result of the simulation. As shown in Fig. 7.4-2, the 66 kV bus voltages of the Highland area S/Ss decline to about 0.9 p.u. (reference voltage exceeds 0.95 p.u.). The cause of this voltage drop is having to supply power from Ramu 1 P/S, located at a distance of 250 km or more, when the power supply from Pauanda P/S to the Highland area decreases.



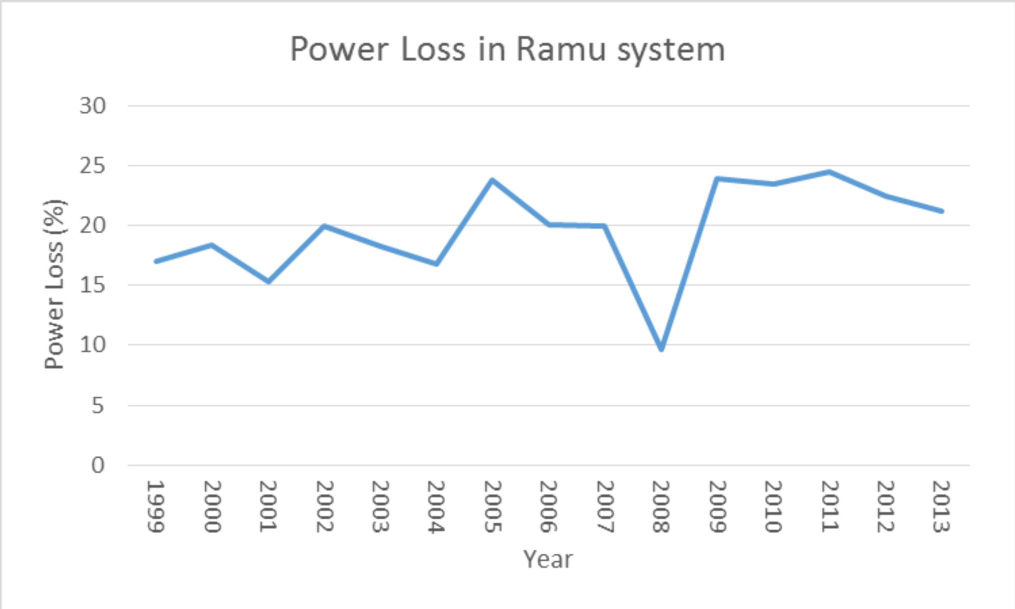
(Source: JICA Study Team)

Fig. 7.4-2 Result of Simulation using PSS@E

(3) Power loss

Fig. 7.4-3 shows the trend of power loss of the whole Ramu system (hereinafter referred to as power loss). The figure shows power loss is on the increase. This upward tendency was considered dependent on the increase in demand and certain countermeasures to mitigate power loss are deemed required given likely future demand.

In PPL, only the amount of power generation and power selling is collected as data and the difference between the two figures is considered to equate to system loss. Transmission and distribution loss are mixed and no individual values exist. For studying effective countermeasures for power loss reduction in future, it is necessary to separate power loss into generation, transmission and distribution loss.



(Source: data from FYPDP)

Fig. 7.4-3 Power System Loss in the Ramu System

(4) Tight transmission capacity between east and west

It is thought that demand in the Ramu system will mainly increase in the Lae and Madang areas. Moreover, the Ramu system is dotted with major mining company customers, each of which requires a power supply via each method. To supply power to meet such demand, the construction of hydropower plants is planned in the northern part area (Madang), the central area (Ramu) and eastern and western areas (Mongi and Pauanda). Accordingly, power developments are planned for all locations and all power sources are connected to the Ramu system. However, the backbone T/L of the Ramu system is only a T/L between eastern and western parts and the tightness of the T/L capacity will become a particular issue.

(5) Separation risk of power transmission system

In April 2014, a 132 kV transmission tower between Ramu and Madang collapsed due to the river flooding and restoration took around one month. During the restoration, DG in Madang P/S supplied power to the Madang area.

Before that, a 132 kV transmission tower collapsed between the Ramu1 and Erap switching stations due to a river flooding. During the restoration, DG in Taraka and Milford S/Ss supplied power to the Lae area.

Accordingly, some transmission towers in the Ramu system are at risk of collapse, which is induced by a flooding and prevent the transmission of power. It is necessary to plan power transmission system so as not for all the system to be affected by the separation of T/L due to the tower collapse. For example, when additional T/Ls are constructed, it is desirable to construct new towers apart from existing towers. Moreover, it is necessary to plan for power system protection relays to avoid power transmission system breakdown.

7.5 REVIEW FOR SHORT-TERM POWER SYSTEM DEVELOPMENT PLANNING

(1) Evaluation for reliability of power system in 2020

The demand forecast for each S/S over the whole Ramu grid is shown in Chapter 4. According to this demand forecast, Power flow calculations are performed for the Ramu system in 2020, which were reinforced by the Ramu Transmission System Reinforcement Project, to confirm the reliability of the power supply and voltage stability and whether or not a power overload exists. For further information, based on the power development plan, the rehabilitation of the following hydropower station is assumed to be finished to make demand and supply balanced.

- Ramu 1 P/S output will be 75 MW in 2020
- Yonki P/S output will be 18 MW in 2019
- Pauanda P/S output will be 10 MW in 2016

The result of the Power flow calculation and the load status of the result are shown in Fig. 7.5-1 and Fig. 7.5-2. There will be no overload equipment under normal operational conditions in 2020, nor any problem for voltage regarding the criteria.

Next, the reliability of N-1 criteria, which concern one T/L fault or transformer fault, are addressed based on a power supply reliability regulation owned by PPL, as shown in Table 7.3-1. The evaluation result is shown in Table 7.5-1.

Class I is a level allowing recovery within a few minutes by changing the power system or without outage. Class II is a level allowing system-wide recovery within a few hours and includes a few methods of recovery. Class II A is also a level allowing system-wide recovery within a few hours too and includes one method of recovery or multiple recovery methods which need to be combined. Class II B is a level equating to continuous outage but allowing partial recovery within a few hours. Class III is a level requiring a few days for recovery. The sample of Class III showed that it took about one month to temporarily reconstruct the 66 kV transmission tower from Gusap to Meiro when the transmission tower collapsed. Moreover, there is no movable transformer, and even if it were, a technician would be needed to install a movable transformer. Therefore, when an outage occurs due to a transformer fault, outage will continue because there is no dealing with the transformer fault. Another countermeasure for equipment must be established.

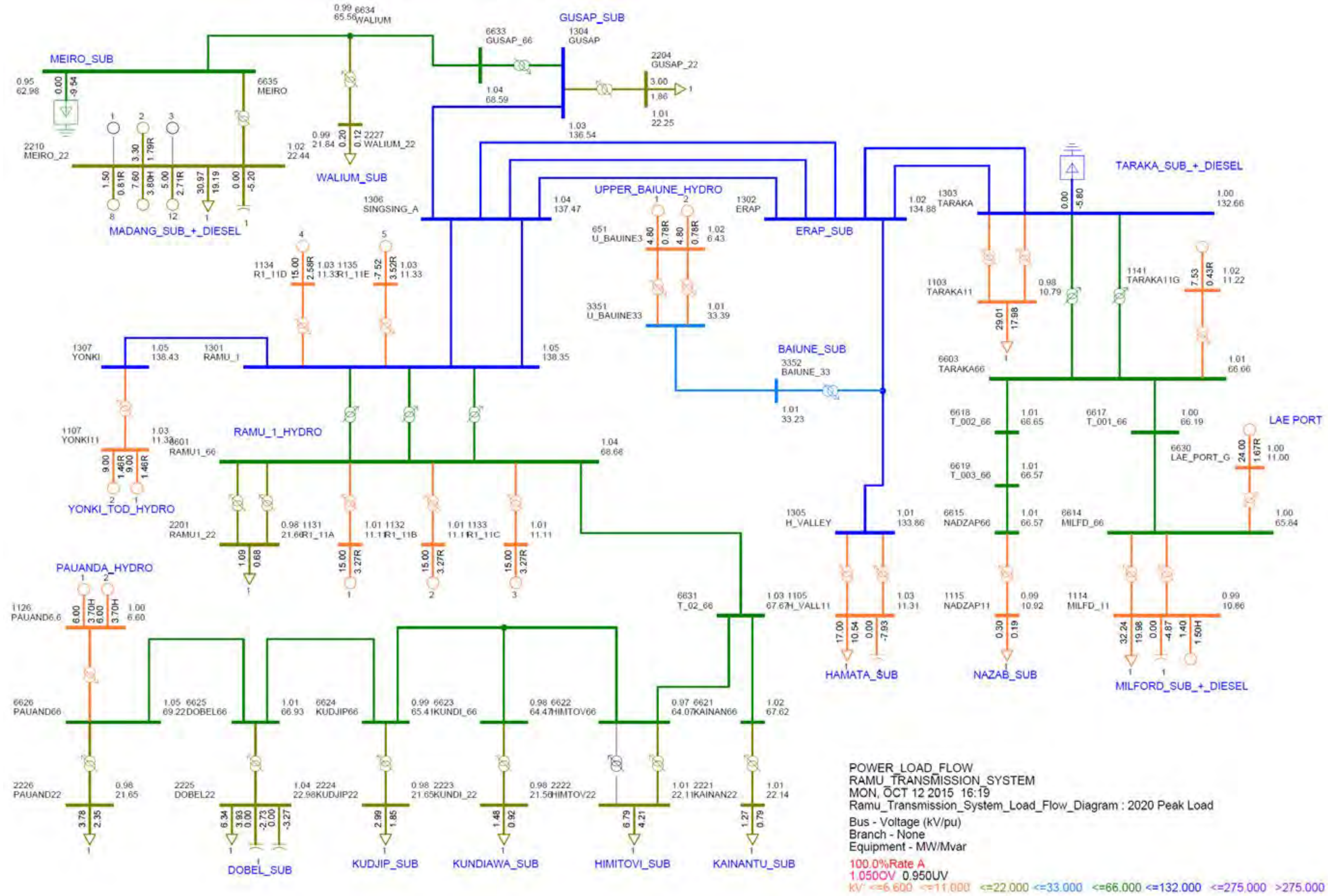


Fig. 7.5-1 Power Flow for the Ramu System – Year 2020 during Peak Load Conditions

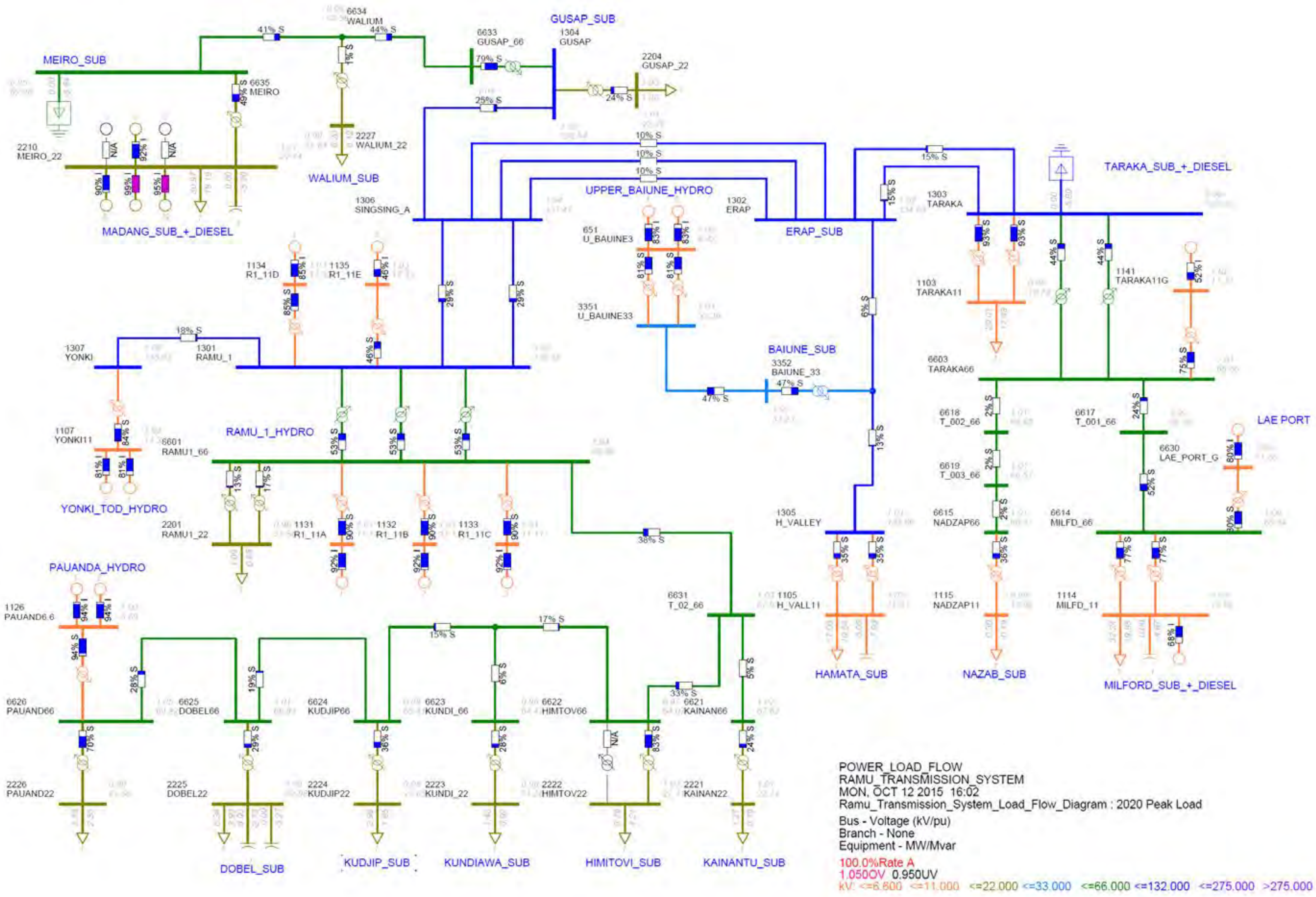


Fig. 7.5-2 Loading Status of Power Flow – Year 2020 during Peak Load Conditions

Table 7.5-1 Evaluation of Power Supply Reliability in 2020

		Single Transmission line fault		Single Transformer fault	
Area	S/S	Supply Reliability	Restoration Method	Supply Reliability	Restoration Method
Lae	Milford	Class II (509)	by Lae GT by Milford DG by switching distribution network	Class II	by Milford DG by switching distribution network
	Taraka	Class I		Class II	by Milford DG by switching distribution network
	Erap	Class I		Class I	
Madang	Singsing	Class I		Class IIA	by switching distribution network
	Gusap	Class IIA	by switching distribution network	Class IIA	by switching distribution network
	Walium	Class III		Class III	
	Meiro	Class IIB	by Madang DG	Class IIB	by Madang DG
Highland	Kainantu	Class III		Class III	
	Himitovi	Class IIB	by Goroka DG	Class IIB	by Goroka DG
	Kundiawa	Class IIB	by Kundiawa DG	Class IIB	by Kundiawa DG
	Kudjip	Class IIB	by Pauanda Hydro by Mendi, Wabag	Class III	
	Dobel	Class IIA	by Pauanda Hydro by Mendi, Wabag	Class IIA	by Pauanda Hydro by Mendi, Wabag

(Source: JICA Study Team)

As shown in Table 7.5-1, in the Lae area, a power supply outage will occur in the event of a T/L fault between Taraka and Milford S/Ss and one transformer affected by a Milford S/S fault. In that case, a few hours will be required for recovery. In the Madang area, a power supply outage will occur when one T/L fault between Gusap and Meiro S/Ss and one transformer at Meiro S/S fault. In that case, a continuous service outage will result, despite partial recovery within a few hours. In future, because demand for the Lae and Madang areas will increase, it is desirable to reinforce T/Ls and transformers as soon as possible.

Conversely, in the Highland area, overall reliability is low. As there is Ramu1 station and Pauanda station power in each T/L end, when one T/L is subject to a fault, the other T/L can seemingly meet the demand for the Highland area. However, since the output of the Pauanda station after the rehabilitation is limited to 10MW, the T/L fault which occurred near Ramu1 P/S in particular may make it impossible to supply each S/S, Kudjip, Kundiawa, Himitovi, Kainantu. Furthermore, since Kudjip, Kundiawa, Kainantu, Dobel, Pauanda except Himitovi have only one transformer, when the transformer is subject to a fault, a power supply problem will occur and persist. Though DG, located at Goroka and Kundiawa, help solve power service outages, reinforced T/Ls and transformers are desirable as soon as possible in the Highland area.

(2) Current power system around the Erap substation and recommended plan

As of 2014, the power system around the Erap S/S is shown in Fig. 7.5-3.

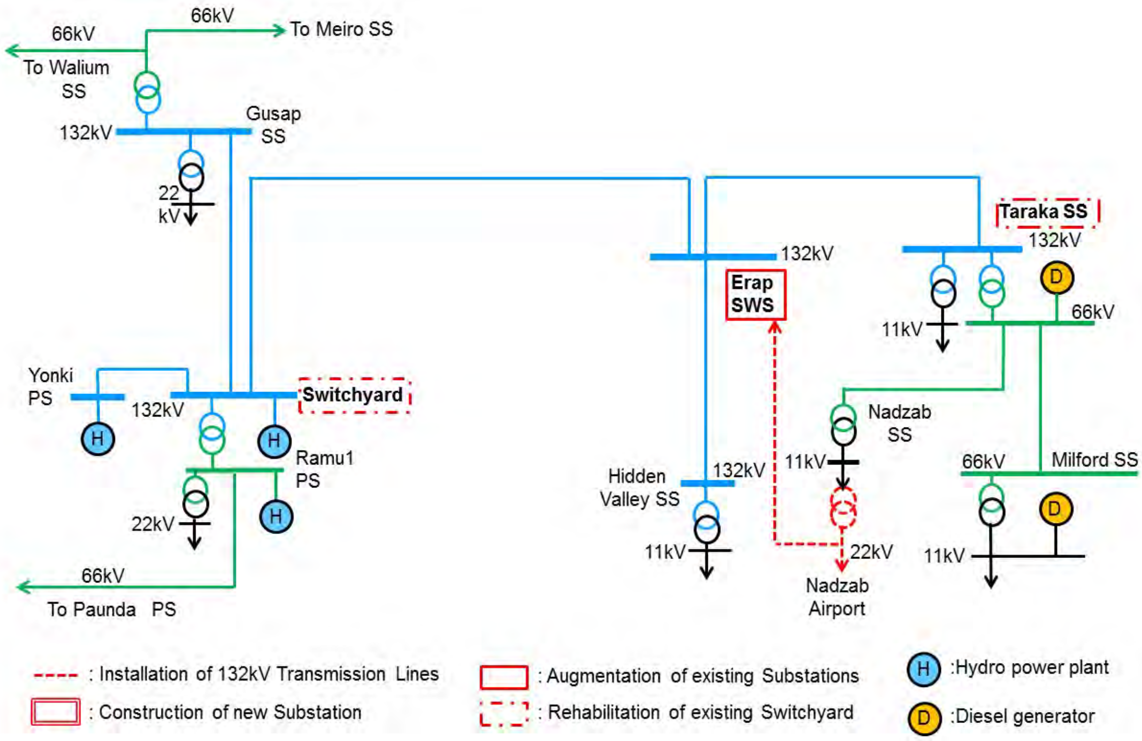


Fig. 7.5-3 Power System around Erap Substation in 2014

Erap is switching station. The station service of Erap is received from a single 22 kV distribution line, the power source of which is Taraka S/S. In other words, the power source is two 132/66 kV 20 MVA transformers of Taraka S/S and one 66 kV T/L connected from Taraka S/S supply to Nadzab S/S.

The Nadzab S/S has two 66/11 kV 1 MVA transformers. The TANAMI area is supplied via an 11 kV distribution line and there is an 11/22 kV 1 MVA Tie transformer near Nadzab S/S. One 22 kV distribution line supplies Nadzab airport and station service of Erap and 80km to the Mutsing area. As there is only one 22 kV distribution line, if this distribution malfunctions, a power failure occurs for the Erap switching station and Nadzab airport. The distribution system in the Lae area is shown in Fig. 7.5-4.

Fig. 7.5-4 Distribution System in the Lae Area

Currently, Nadzab airport only has domestic flights, mainly connecting POM, but in 2020 there is a plan to enhance the airport. Therefore, it is necessary to boost reliability. The main reasons to enhance the airport are as follows;

- To extend terminal area for the increasing demand of domestic flights
- To deal with large-scale planes (B737 type)
- To have alternative role to POM airport in emergency conditions
- To start international flights

In the Ramu Transmission System Reinforcement Project, there are plans to change T/Ls to a double-track system from a single line, and to improve power supply reliability for Nadzab airport, to install two 132/66/33 kV 10 MVA transformers in Erap S/S and construct one 66 kV T/L to supply Nadzab airport. Accordingly, as Nadzab airport have two power sources, namely Taraka and Erap S/Ss, if either T/L malfunctions, changing the power system will make it possible to supply Nadzab airport and hence considerably boost reliability. The power system for the current plan is shown in Fig. 7.5-5.

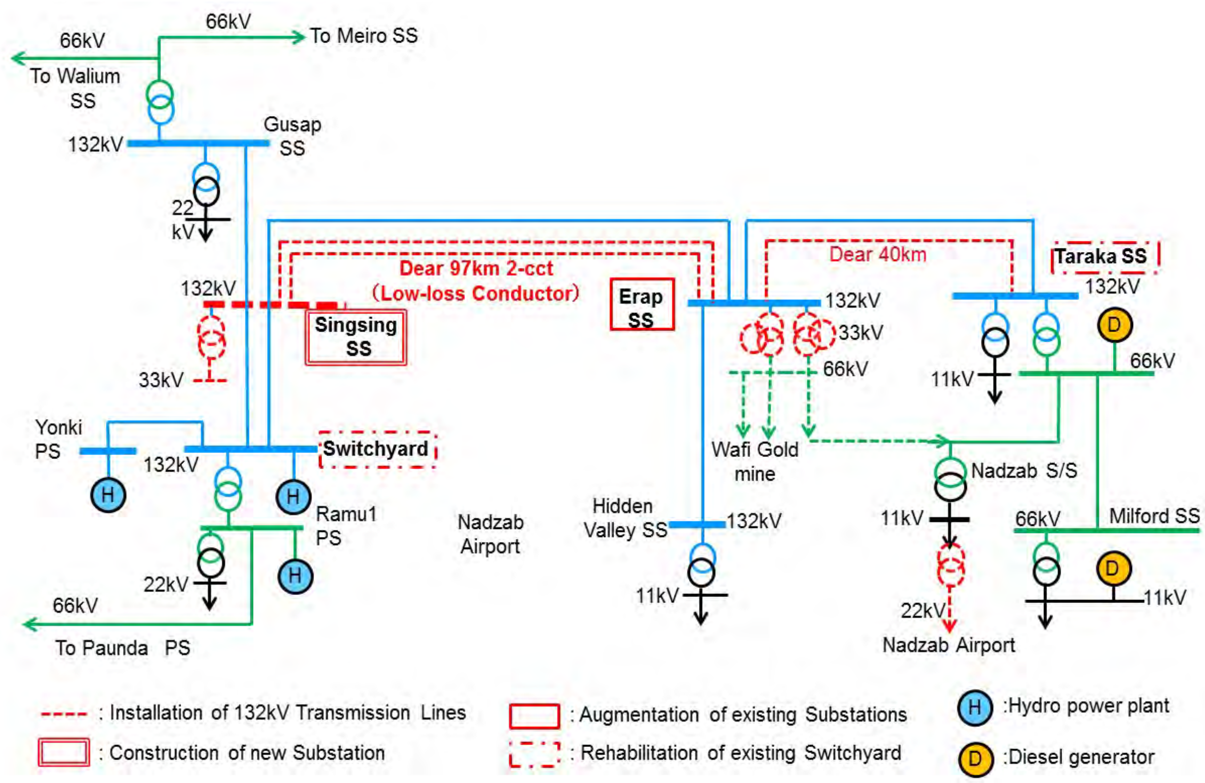


Fig. 7.5-5 Ramu Transmission System Reinforcement Project

However, when Nadzab airport is enhanced, there is a plan to remove the existing Nadzab S/S due to obstacles to expansion of the airport. As a result, the point connected to the 66 kV T/L from Taraka S/S will be lost.

There are the following issues in the current plan:

First, regarding the supply to Nadzab airport, according to a feasibility study by the Nadzab Airport Redevelopment Project, the equipment receiving power is 22 kV and there are plans to install twin 1,000 and 350 MVA transformers respectively. Demand at Jacson’s International Airport in POM is 1.5MW, and the same applies to Nadzab airport. In view of the capacity, the voltage 22 kV is sufficient, not necessarily 66 kV. If there are plans to supply Nadzab Airport with 66 kV, 132/66 kV transformers have to be installed at Taraka S/S and also at Erap S/S, and it is necessary to install 66kV switching equipment in Erap S/S. Therefore a lot of equipment for T/L and S/S have to be installed. If there are many equipment, it is necessary to maintain for those equipment.

Next, there is a 22 kV distribution line around Erap S/S, when two 132/66/33 kV transformers are installed at Erap S/S, there is a need to replace the insulator from 22 kV for 33 kV and change all pole transformers from for 22 kV/400 V to for 33 kV/400 V. In case existing distribution line will not be replaced, 33 kV and 22 kV distribution lines will be mixed. The former requires considerable cost and manpower and extended downtime to replace equipment to 33 kV over about 80km. The latter may require a long time to recover the power supply when one distribution line malfunctions because most distribution lines have more than two lines and are connected to a proper location to back up other distribution lines but 22kV system and 33kV system can’t be connected. In addition, the latter may comprise dangerous equipment due to confusion between 22 kV and 33 kV based on human error.

The following plan is recommended:

The secondary voltage of the transformer at Erap S/S is 22 kV and two distribution lines from switching equipment will be constructed and connected to the existing 22 kV distribution line. By connecting the existing 22 kV distribution line to Erap S/S, power to the Mutsing area is supplied from transformers installed in Erap S/S.

Moreover, Nadzab airport will be supplied by two distribution lines from Erap S/S. One distribution line is always connected for operation and the other is always a reserve in case the other distribution line fails. By constructing distribution lines and secondary voltage of transformers accordingly, when one distribution line or transformer malfunctions, it is possible to recover power service from outages quickly within a few minutes or so.

Regarding to East side of Erap S/S, there is highway between Milford and Erap about 40km. Demand is forecasted to increase in the future along highway. As of 2014, there are two 11 kV distribution lines along highway from Milford S/S. The voltage drop may be more than 10% if Milford S/S supply the area near Erap S/S.

When increasing demand along the highway, Milford S/S supply area which is 10km from Milford S/S by a 11 kV distribution lines and the area which Erap S/S supply is the west side of the 10km area. By replacing the distribution equipment from 11 kV to 22 kV between existing Nadzab S/S and TANAMI area, Erap S/S can supply power to east side area using existing distribution route, which will help reduce power losses and voltage drops.

Regarding the supply method for the Wafi gold mine, the current plan is to supply by 66 kV and the capacity of the 132/66 kV transformer is 10 MVA. However, as the forecast demand of the Wafi gold mine is about 80 MW, the required transformer capacity is 100 MVA and two transformers are needed. The transformer capacity is evidently too small. Based on the above, it is desirable to supply the Wafi gold mine using two 132 kV T/Ls, which help reduce 66 kV yard at Erap S/S and reduce power loss to quarter.

Thus, if secondary voltage of Erap S/S is changed to be 22kV and power is supplied to the Nadzab airport or its surrounding area from Erap S/S, the efficient system will be composed by utilizing the existing distribution line. The 132/66 kV transformers of Taraka S/S, 132/66 kV transformers of Erap S/S and 66 kV switchyard of Erap S/S become unnecessary. But, to remove 132/66 kV transformers at Taraka S/S, Milford S/S has to be upgraded to 132 kV. This point is described at Section 7.6.1(2).

Next, regarding to Singsing S/S, in the present plan, one 132/33 kV transformer is installed. Around Singsing S/S, Ramu1 switchyard is located at 20km on the south, Gusap S/S is located at 25km on the west, and the secondary voltage of both S/Ss is 22kV. Since about 17km of 22 kV distribution line is along expressway to Singsing S/S from Gusap S/S, if about 8km of 22 kV distribution line is extended, Singsing S/S can be connected to Gusap S/S by 22 kV distribution line. Since only one transformer is planned to be installed in Singsing S/S, if this transformer malfunctions, station service will be outage. Therefore, it is advisable to connect Gusap S/S and Singsing S/S with a 22kV power distribution line as backup of this fault. This 22 kV distribution line is not only for back up but also to supply power around Singsing area in case demand increase. As mentioned above, as for secondary side voltage of the transformer installed in Singsing S/S, 22kV is advisable also in order to be able to utilize existing facilities effectively. Recommended plan for the system is shown Fig. 7.5-6.

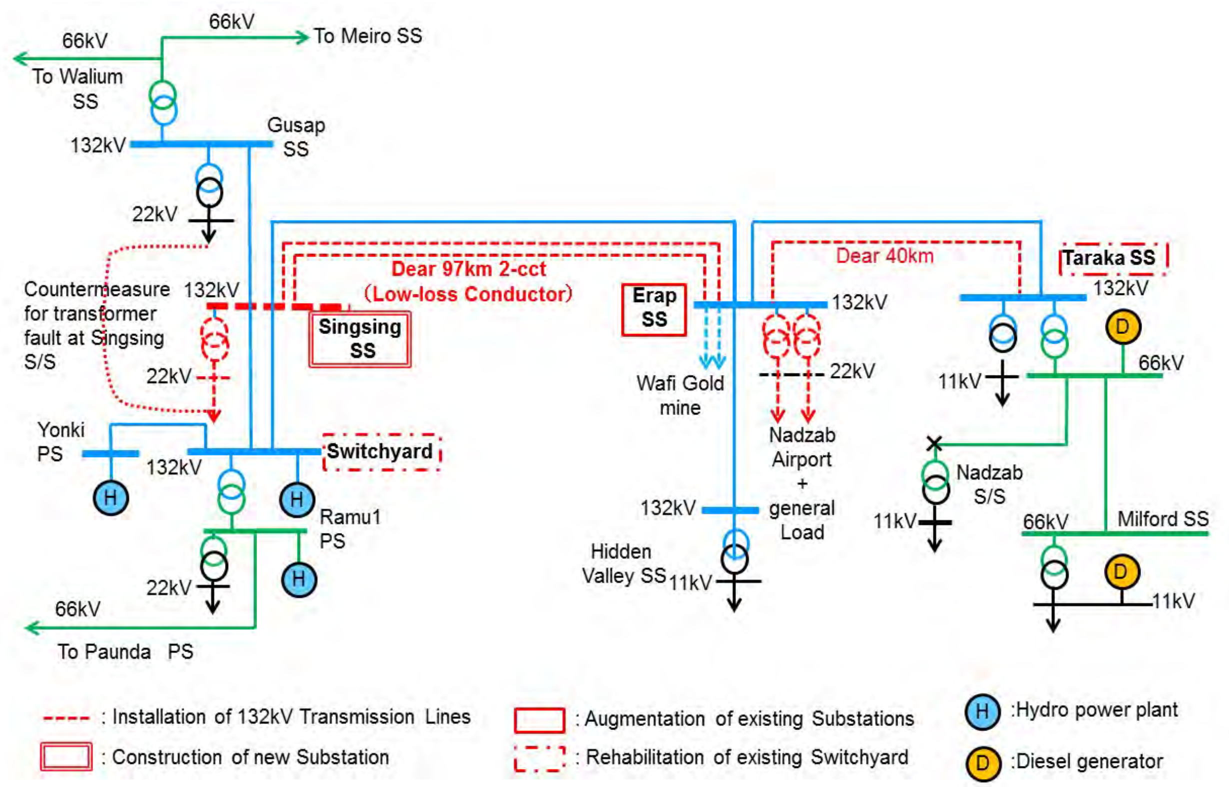


Fig. 7.5-6 Recommended Plan for the Ramu Transmission System

7.6 CONSIDERATION OF POWER SYSTEM DEVELOPMENT PLAN FOR MIDDLE-LONG TERM

7.6.1 Consideration of Power System Development Plan as Demand Forecast

(1) Demand forecast in 2030

In Chapter 4, demand forecast is addressed for the whole Ramu power system and each S/S. Based on this demand forecast, the resulting demand forecast for each S/S is shown in Table 7.6-1. In 2030, demand will increase to 125MW in the Lae area, 50MW in the Madang area and 40MW in the Highland area, a response to which will be required in each case.

Table 7.6-1 Result of Demand Forecast for Each Substation

[MW]

Area	2015	2020	2025	2030
Lae	40.3	61.2	90.6	124.3
Hidden Valley	17.0	17.0	17.0	17.0
Meiro	25.6	31.0	38.2	47.7
Gusap	3.0	3.0	3.0	3.0
Yonki	0.5	1.1	2.5	5.6
Kainantu	1.2	1.3	1.3	1.3
Himitovi	5.2	6.8	8.7	10.9
Kundiawa	1.3	1.5	1.6	1.8
Kudjip	2.1	3.0	4.1	5.6
Dobel	6.0	6.3	6.6	6.7
Pauanda	2.7	3.8	5.1	6.8

(Source: JICA Study Team)

(2) Consideration of how to supply for the Lae area

As of 2014, the Lae area is mainly supplied by two 132/11 kV 20 MVA transformers in Taraka S/S and 66/11 kV 20 MVA and 66/11 kV 30 MVA transformers in Milford S/S. In Erap area, power is supplied by a 66/11kV 1MVA transformer in Nadzab S/S which is connected to 66kV single T/L and power source is two 132/66kV 20MVA transformers. The east side of Erap area is supplied by an 11 kV distribution and its west side to Mutsing 80km away from Erap is supplied by a 22 kV distribution line through an 11/22 kV 1 MVA tie transformer for step-up. The area supplied by each S/S is shown in Fig. 7.6-1.

As of 2014, the peak demand of Taraka S/S is 18.42 MW (February, 2014) and that of Milford S/S is 22.36 MW (December, 2014). Taraka S/S has five distribution lines and Milford S/S has six distribution lines.

Under normal operational conditions, each transformer of each S/S is operated under its rated capacity and there is no overload. However, if the 66/11 kV 30 MVA transformer at Milford malfunctions, demand exceeding 2 MW cannot be supplied by the other 66/11 kV 20 MVA transformer. Therefore the first alternative method of supply is to use four distribution lines connected to Taraka S/S. No.6 feeder in Milford S/S (M6) and No.5 feeder in Taraka S/S (T5) is connected. M5-T3, M5-T4 and M2-T4 are also connected. The second alternative is via 16.6MW DG installed at Taraka and 17.9 MW DG at Milford. As of 2014, DG have enough supply capacity for emergency.

The supply area based on the demand forecast is shown in Fig. 7.6-1.

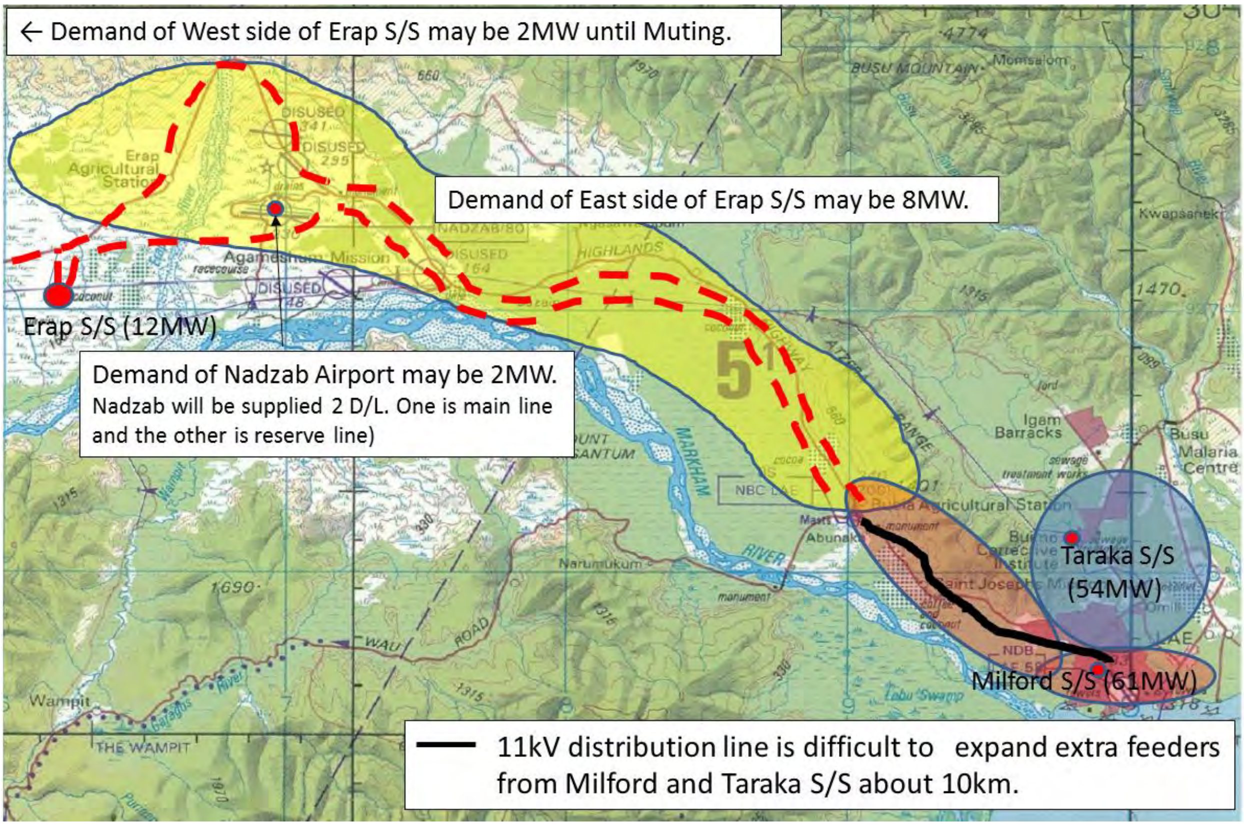


Fig. 7.6-1 Supplied Area by Each Substation in the Lae Area

In 2030, the total demand for the Lae area is forecasted to be 125 MW, while that for Lae city is forecasted to be 115 MW. Since the power supplied by Erap S/S is described in 7.5(2), the way of supply Lae city is described as below. As of 2014, Lae city is supplied by Taraka and Milford S/Ss. Peak demand and supplied are of each distribution line is shown in Fig. 7.6-2. T#1 means No1 feeder at Taraka S/S.

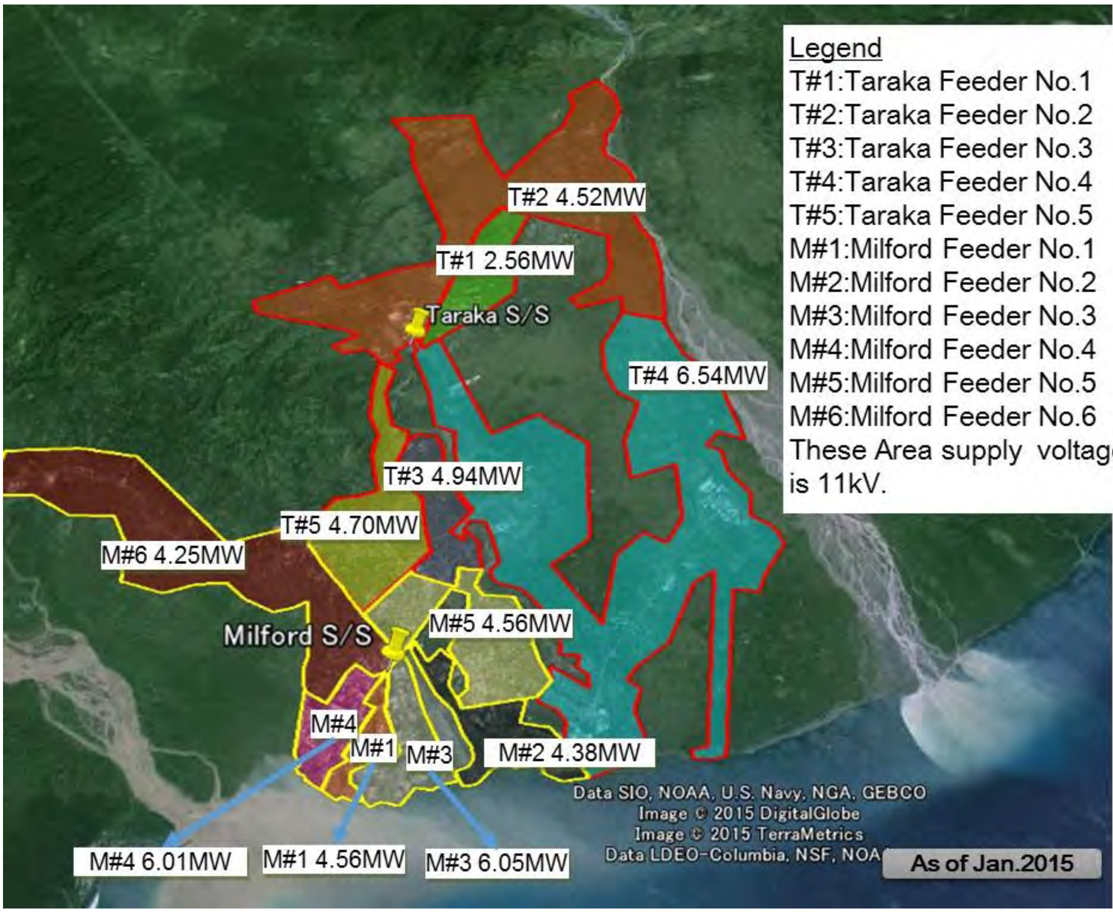


Fig. 7.6-2 Power Supply Area and Maximum Power Demand

Power supply area and maximum power demand is made by JICA Study Team and demand density, it is presumed that M#1, M#3 and M#4 are mainly used for industry loads and have high-demand density exceeding 4 MW/km^2, T#3, M#2 and M#5 are mainly used for commercial loads and have demand density of about 2 – 4 MW/km^2, and T#1, T#2, T#4, T#5 and M#6 are mainly used for home loads. In future, houses and commercial facilities will be constructed on the south side of Taraka S/S, and factories will be constructed in coastal area. Accordingly, the demand density is forecasted to be increasing and supply area to be expanding. The transition of demand in Lae city from 2014 to 2030 is shown in Fig. 7.6-3. Detail information is described in Part B Sections 5.1.1 and 5.1.2.

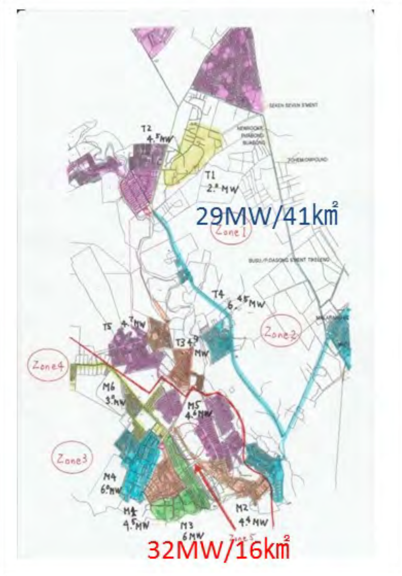
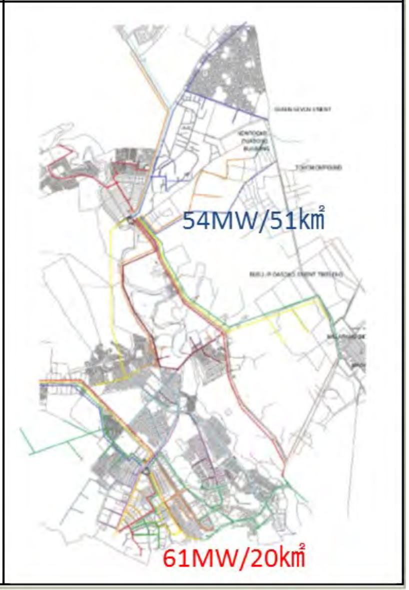
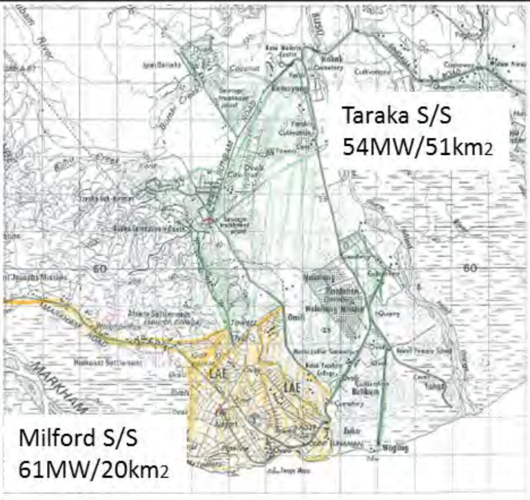
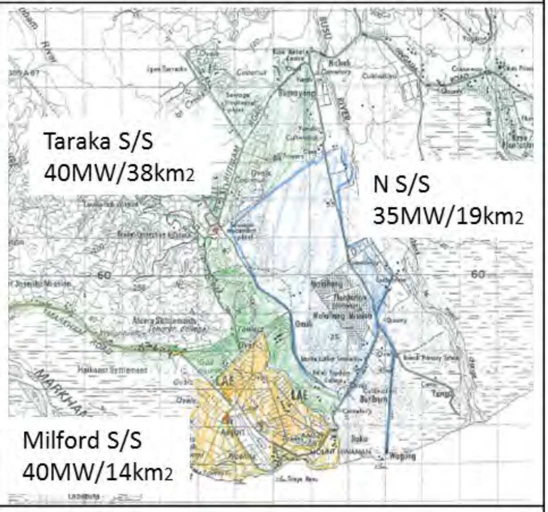
In 2014	In 2020	In 2030
		

Fig. 7.6-3 Transition of Demand in Lae City from 2014 to 2030

It is important to limit increment cost by utilizing existing facilities to the maximum extent in order to supply Lae city efficiently. As the future configuration of S/Ss in Lae city, three units of transformers per one S/S is considered to be advantageous configuration in view of quick recovery from outage and cost.

A comparison of Plans A and B is shown in Table 7.6-2. According to the PPL criteria, the rate of transformer utilization is 80%. Plan A involves supplying by two S/Ss, while Taraka and Milford S/Ss have three 30MVA transformers respectively. Plan B involves supplying by three S/Ss and Taraka and Milford S/Ss have three 20 MVA transformers respectively as well as a new S/S capable of installing three 20MVA transformers to be constructed.

Table 7.6-2 Compared how to supply to Lae City

	PlanA : 2 substations **Taraka S/S : 30MVA × 3** **Milford S/S : 30MVA × 3**	**PlanB : 3 substations** **Taraka S/S : 20MVA × 3** **Milford S/S : 20MVA × 3** **N S/S : 20MVA × 3**
Area Drawing		
reliability	It can satisfy N-1 criteria	Same left
Cost	Base mUS$	Base + 5.87 mUS$
evaluation	Recommended Plan	Plan B is much expensive than Plan A

Based on demand forecast in 2030, plan A shows less cost than plan B.

Here, it is important that it is necessary to upgrade Milford S/S to 132 kV. As of 2014, Milford S/S is supplied by the 66kV one circuit transmission by using two units of 132/66 kV 20MVA transformers in Taraka S/S as a power source. The conductor of this T/L is so-called “Tiger”, which is one type of British Aluminum Conductor Steel Reinforced (ACSR) and has only 45 MW supply capability. Therefore, in case of one circuit fault of the T/L, Milford S/S will be supplied by existing 19.7MW DG and 26MW DG installed in the Lae Port P/S in 2015. However, when the load of Milford S/S exceeds 45 MW, in case of one circuit fault of the T/L, supply capability will be insufficient in DG of two P/Ss. Moreover, as of 2030, it is forecasted that the load of Milford S/S increases to 61 MW according to Part B Table 5.1-1. As the countermeasure which secures the supply capability over the increase of demand and the supply reliability of one circuit fault of the T/L the following three plans are suggested; Plan 1: Construct the 132kV T/L of two circuits, Plan 2: Construct two 66kV T/L (Tiger : one type of British ACSR) of one circuit, as same as the conductor type of the existing T/L and one is for back up when one T/L failure, and Plan 3: Construct one 66kV T/L (Tiger) and using Lae Port GT for back up when T/L failure.. As a result of comparing these plans, Plan A is advantageous in cost. In particular, in the case of Plan B, it is necessary to extend the 132/66 kV transformer installed in Taraka S/S with the increase in load of Milford S/S. Namely, additional transformer is necessary compared with other plans.

From the above, in 2030, it will be desirable to supply Lae city by two S/Ss, namely Taraka and Milford. Moreover, by 2025, it is desirable for Milford S/S to be boosted up to 132 kV voltage. As a result, the Ramu power transmission system in Lae city will secure power supply reliability and satisfies N-1 criteria and expenditure for 132/66kV transformers in Taraka will be reduced.

The changing step from the present power system in Lae city to the system in 2030 is shown in Fig. 7.6-4 and Fig. 7.6-5.

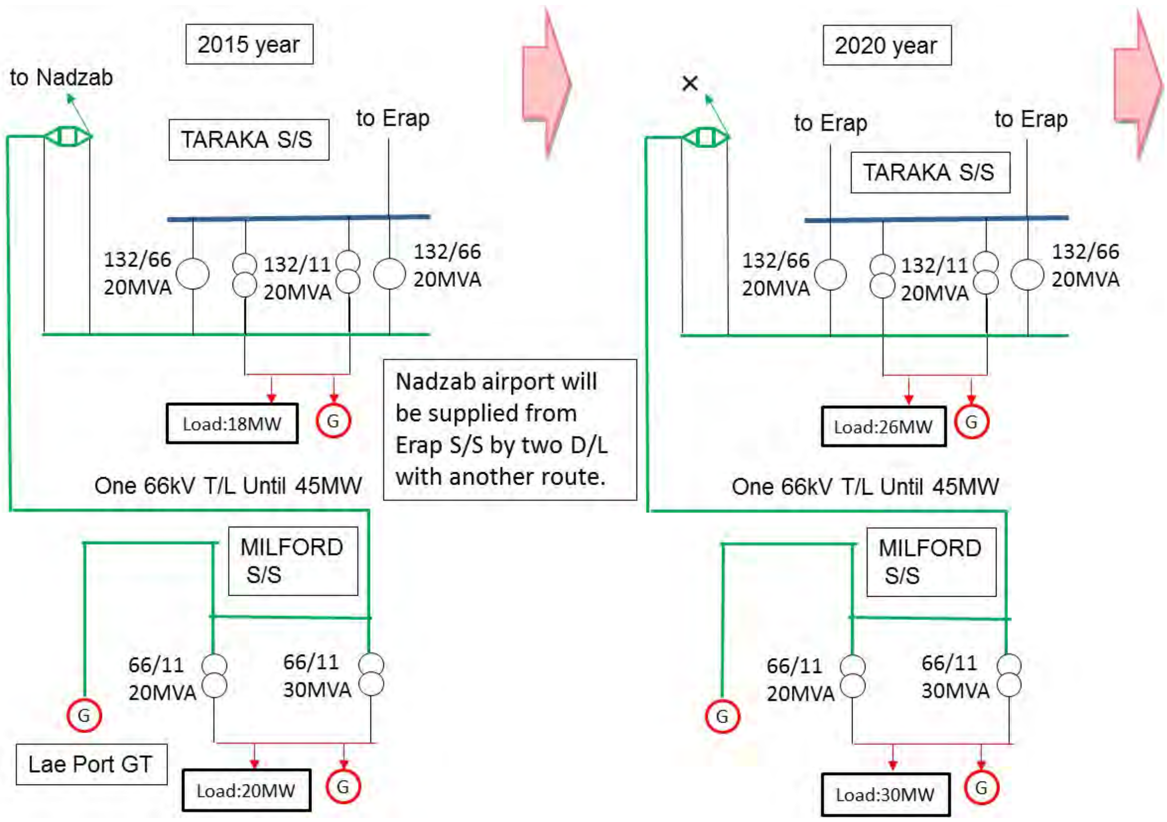


Fig. 7.6-4 Changing Step from 2014 to 2020 in Lae City Power System

In 2020, the existing Nadzab S/S or Nadzab airport will be supplied with two sets of 22 kV distribution lines connected to two 132/22 kV 10 MVA transformers at Erap S/S, which will be reinforced by Ramu Transmission System Reinforcement Project. As a result, the distribution network in Erap area will be separated from the power system supplied by two 132/66 kV 20 MVA transformers in Taraka.

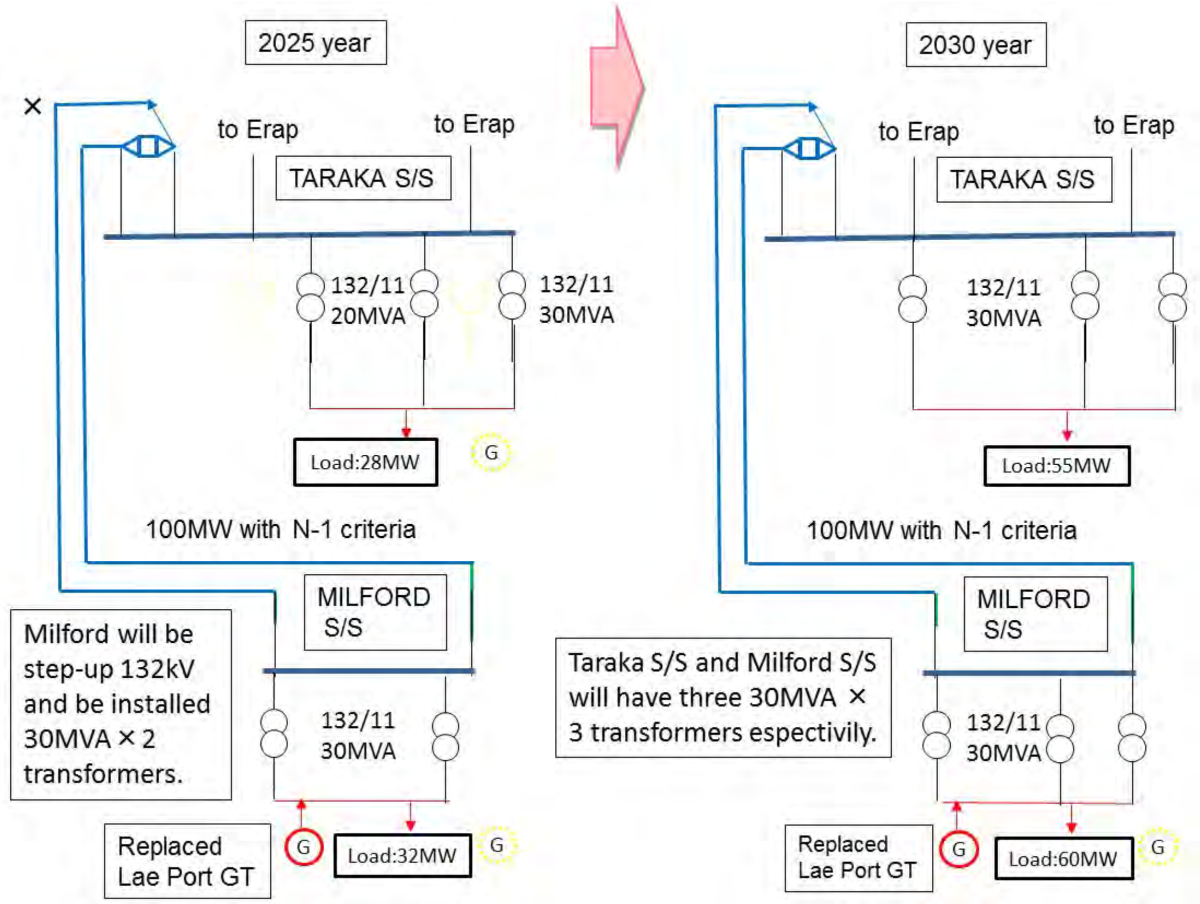


Fig. 7.6-5 Changing Step from 2020 to 2025 and from 2025 to 2030 in Lae City Power System

One 132/11 kV 30 MVA transformer, additional 11 kV switchgears and 11 kV distribution lines are installed in Taraka S/S according to the increase of demand in Lae city from 2020 to 2025.

It is desirable that Milford S/S is boosted up to 132 kV voltage and 132 kV two T/Ls are constructed and two existing transformers are replaced to two 132/11 kV 30 MVA transformers according to the increase of demand. The reason are as below.

- There is only one T/L between Taraka S/S and Milford S/S. If one T/L will occur fault, Milford S/S is not only all outage but also load shedding regarding to power system.

- As the capacity of this T/L have only 37MW, Demand of Milford will increase, it is necessary to supply by DG at Milford or Walf GT if without power system extension.

- Power source of Milford S/S is two bank for 132/66kV 20MVA at Taraka S/S. Therefore when demand of Milford S/S increase, it is necessary to reinforce 132/66kV 20MVA at Taraka. Namely, it is necessary to be double investment.

- Recommended plan is cheapest and most high reliability as shown Table 7.6-3

Table 7.6-3 Compared how to supply to Milford Substation

Demand of Milford	**Plan A** **Transmission line reinforce 132kV 2circuit from Taraka to milford and Milford 132kV step up voltage**	**Plan B** **Transmission line reinforce 66kV 2circuit from Taraka to milford**	**Plan C** **Existing Transmission line is 66kV one circuit and Lae Port GT**
2020 – 2025 32MW – 46MW	Milford 132kV step-up ・132kV GIS ・132/11kV 30MVA × 2 ・ 11kV F × 10 132kV 2cct T/L × 5km Cost of Hydro power (37MW × 8760h × 0.1US$ × 0.6)	Taraka ・132/66kV 30MVA × 2 Milford:4.9 mUS$ ・66/11kV 30MVA × 1 ・11kV F × 10 66kV 1cct T/L × 5km Cost of Hydro power (37MW × 8760h × 0.1US$ × 0.6)	Taraka ・132/66kV 30MVA × 2 Milford ・66/11kV 30MVA × 1 ・11kV F × 10 66kV 1cct T/L × 5km Cost of Hydro power (37MW × 8760h × 0.1US$ × 0.6)
2025 – 2030 47MW – 63MW	Milford: 2.9mUS$ ・132/11kV 30MVA × 1 Cost of Hydro power (46MW × 8760h × 0.1 US$ × 0.6)	Taraka ・132/66kV 30MVA × 1, 66kV F × 1 Milford ・66/11kV 30MVA × 2, 66kV F × 1 66kV 1cct T/L × 5km Cost of Hydro power (46MW × 8760h × 0.1 US$ × 0.6)	26MW Lae Port GT Cost of Hydro power (46MW × 8760h × 0.1 US$ × 0.6)
Total Evaluation	Plan A can supply until 150MW with satisfy N-1 criteria. Construction cost is cheapest of Plan A.	Plan B can supply until 74MW with satisfy N-1 criteria.	Plan C can supply until 74MW with satisfy N-1 criteria. It takes operational cost for DEG when one transmission line failure.

In case of constructing 132 kV T/L, it is necessary to address how to replace with minimum service outage. For example, one method is first, temporary 132 kV one T/L is constructed and Milford S/S is supplied by this line, then existing 66 kV transmission towers are replaced to be two 132 kV T/L towers. New lines are along with existing T/L route. Another method is B: first, two 132 kV T/Ls are constructed, which need new land to construct, then existing 66 kV T/Ls are removed. If land for T/L is able to be acquired, the latter is cheaper.

The existing 66/11 kV transformers at Milford were made in 1988 and 2007. Though the transformer made in 1988 will be removed due to aging, the transformer made in 2007 should be transferred to other S/S which have only one transformer in Highland area to satisfy N-1 criteria. Conversely, two 132/66 kV 20 MVA transformers at the Taraka S/S were made in 1981 and 1993. Both transformers will be removed for aging because the voltage 66kV is not necessary if Milford S/S is upgraded to 132kV.

Existing 132/11kV 20MVA transformers in Taraka S/S are replaced to 132/11kV 30MVA transformers for aging in 2030 after 2025 according to the increase of the demand in Lae city. Through this replacement, installed capacity is reinforced. Moreover, one 132/11 kV 30 MVA transformer is installed in Milford S/S. As a result, in addition to Taraka S/S, Lae city is supplied by two S/Ss which have three 30MVA transformers respectively.

The demand and the supply area in POM in 2013 are shown in Fig. 7.6-6 at reference. The almost same supply area as Lae city is located in the center of POM. The power there is supplied from two S/Ss, Konedobu (20MVA × 2) and Boroko (30MVA × 2) S/Ss. Konedobu S/S has 31.4 MW demand and about 3km^2 supply area, and Boroko S/S has 37.6 MW demand and about 4km^2 supply area. Both of the S/Ss have a plan to extend one unit of a transformer, and the demand centers of POM is scheduled to be supplied by two S/Ss which have three units of transformers. There is a plan to construct KILAKILA S/S in the middle place of two S/Ss.

The situation of the Lae area after about ten years is considered to be that in the present POM. In Lae city, the whole city area is on the lease from the indigenous landowners and designated as "National Lease Hold Area." Therefore, when demand of electricity in Lae city increases more than the presently forecasted, a 3rd S/S will have to be constructed.

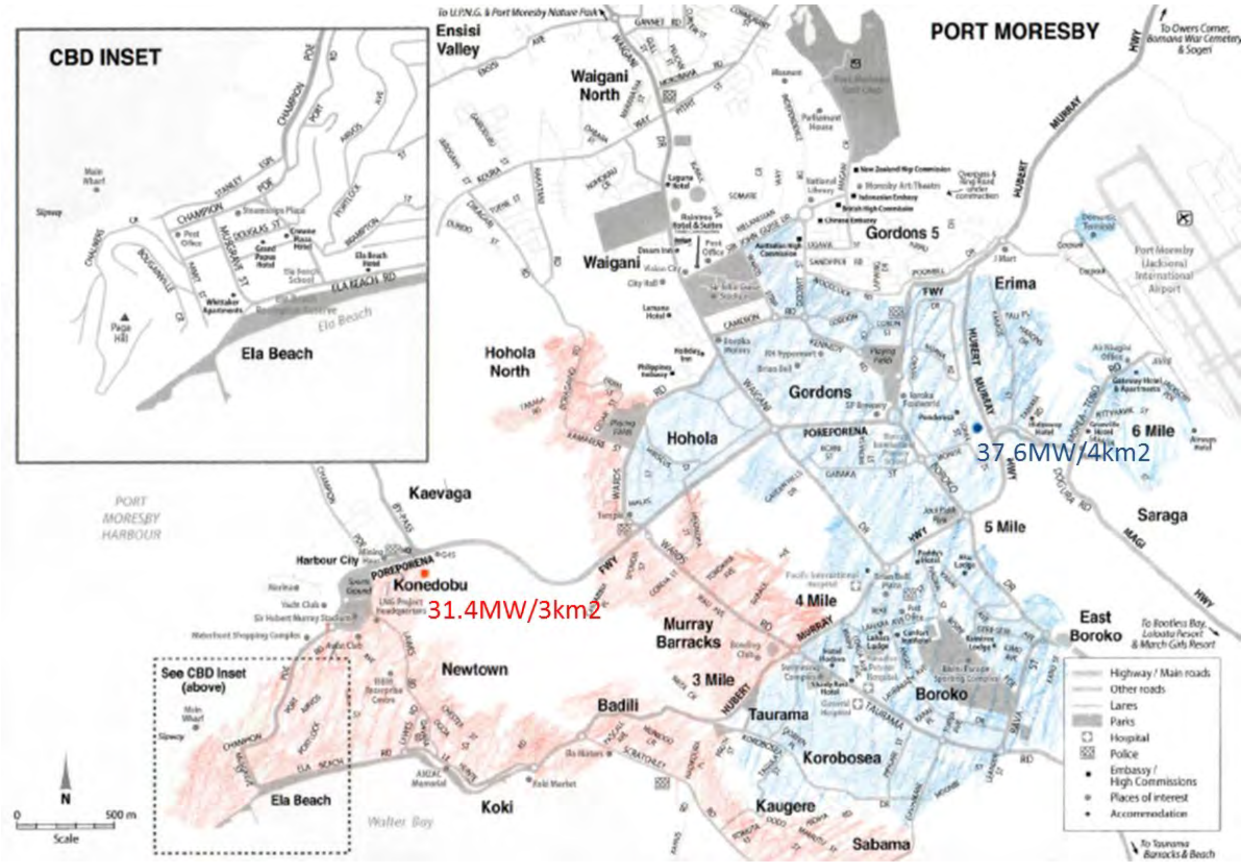


Fig. 7.6-6 Supply Area in Center of POM Demand in 2013

It is important for a master plan to be updated, grasping an annual demand track record exactly. In around 2025, it is advisable to forecast the demand in 2030 anew and to ascertain whether existing two S/Ss can supply the demand or a new S/S needs to be constructed.

For example, when the large-scale demand which cannot be supplied in 11kV is produced by the development of the harbor in the west side of Milford S/S, there is a method for supplying up to 20 MW by constructing three circuits' "spot network", which is one type of distribution network, with cables. For the large-scale demand beyond it, there is a method of installing a 132/66kV transformer in Milford S/S to supply in 66kV.

After the T/L between Erap and Taraka S/S turns into two circuits by Ramu Transmission System Reinforcement Project, and the T/L between Taraka and Milford S/S turns into two circuits similarly, DGs currently installed in Taraka and Milford S/S will be unnecessary based on the system planning criterion. However, PPL, which has the bitter experience of transmission-tower collapse in the past, should prepare DGs for contingency in order to supply customers as much as possible with allowable cost. It is desirable to contract lease company in advance so that PPL can lease DGs when such a large-scale disaster occur, not to maintain existing DGs including leased ones. By doing so, the annual lease cost can be controlled and the present operation member can be utilized for other facility maintenance.

(3) Consideration how to supply for Madang area

a) Meiro substation

At the end time of 2014, the maximum demand of Madang areas is 12 MW. Meiro S/S which supplies power to this area is received power by the T/L of 66kV one circuit via Gusap S/S from Ramu1, and supplies power to load by one unit of 66/22kV 20MVA transformer. The conductor type of this 66 kV T/L is Tiger, and has only the transmission capacity of 37 MW. Meiro S/S can also receive a maximum of 11.6 MW through 22kV line from Madang P/S.

In 2015, new commercial facilities will be constructed, since demand of Madang area is forecasted to be 26 MW, the capacity of the transformer may be insufficient and DG at Madang P/S have to supply Madang area, which result in the increase cost of fuel.

Regarding reliability, when one 66 kV T/L malfunctions, Ramu1 power source cannot be transmitted to Madang area. As peak demand is higher than DG output, there will be an area to which electricity cannot be supplied. The same situation happens when the existing 66/11kV transformer fault occurs. It is desirable to install new 66/11 kV 20 MVA transformer immediately. According to demand forecast, demand may increase to 31 MW in 2020, 38 MW in 2025 and 48 MW in 2030. Steps of power supply for increasing demand are shown Fig. 7.6-7 and Fig. 7.6-8.

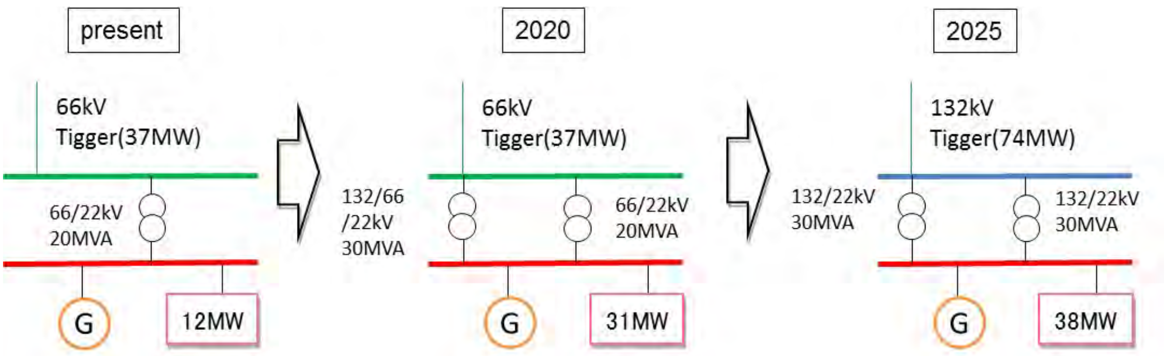


Fig. 7.6-7 Extend Step at Meiro Substation in 2014 -2025

In 2020, the demand of Madang area will increase to about 31MW. It is necessary to extend one 30 MVA transformer which can be selected to 132 kV or 66 kV for the primary voltage side.

In 2025, the demand of Madang area will increase to about 38 MW. It is necessary to upgrade the transmission from 66kV to 132 kV.

It is necessary to replace the existing transformer installed in 1974 to a transformer of 30 MVA and primary voltage of existing transformer should be upgraded to 132 kV from 66 kV.

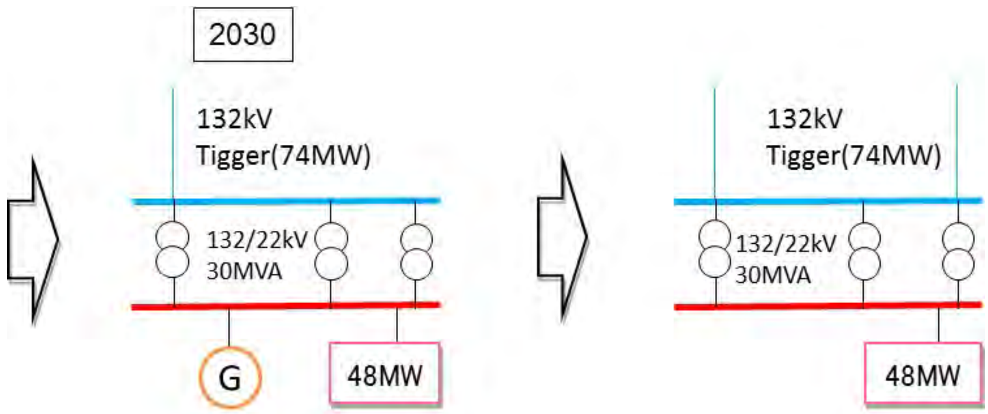


Fig. 7.6-8 Extend Step at Meiro Substation in 2025 -2030

In 2030, the demand of Madang area will increase to about 48 MW. In order to satisfy N-1 criteria at the time of transformer fault, it is necessary to increase transformer capacity to 30 MVA.

Since some of existing DG(s) are old, it may be necessary to replace. If the construction of a 132kV T/L is cheaper than replacement of DG, also in order to meet N-1 criterion, the construction of a T/L is more desirable.

The demand in 2030 of Meiro S/S is forecasted to be 48 MW, and according to the criteria, a S/S consists of three units of transformers. Therefore, the composition of Meiro S/S becomes either Plan 1) three units of transformer of 20MVA or Plan 2) three units of transformer of 30MVA. Since the operation criteria by FYPDP is 80% and the supply capacity of Plan A is 43.2 MW when a power factor is assumed to be 90%, supply capability is insufficient in Plan A. For this reason, Plan B, which can supply up to 64.8MW, is chosen as expansion step.

The conductor type of the existing T/L is Tiger, and if applied at 132kV, it can supply to until 74 MW. Moreover, if two circuits are used so that N-1 criterion can be satisfied, T/Ls can meet three transformers regarding their capacity. When the necessity for replacement of existing superannuated DG arises, it is desirable to study the optimal equipment program made by uniting the PDP and Power System Development Plan, in which the T/L is formed into two circuits and cooperation with the replacement of DG is aimed at. Comparison with plan A (one T/L + DG) and plan B (two T/Ls) is shown in Table 7.6-4.

Table 7.6-4 Compare with Each Plan

	PlanA : 132kV 1cct + DEG **Meiro S/S : 132/22kV 30MVA × 2**	**PlanB : 132kV 2cct** **Meiro S/S : 132/22kV 30MVA × 2**
currently	Meiro S/S 66kV T/L 1cct 66/22kV 20MVA × 1 22kV F×8 + Bustie × 1 Madang P/S 11.6MW	Same left
Step1 In 2020	Meiro S/S Tr extend ・132/66/22kV 30MVA×1 ・132kV F×1 + Busbar ・22kV F×1 ・switchboard + SCADA	Same left
Step2 In 2025	Meiro S/S Tr replace ・132/66/22kV 30MVA ・132kV F×1 replace ・22kV F×1 replace	Same left
Step3 In 2030	Meiro S/S 132kV step-up : zero	Same left
Step4 In 2030	DEG replace DEG operation cost when N-1 Or Gowar Hydro instead of existing Madan DEG	Meiro S/S 132kV T/L extend ・132kV T/L 70km ・132kV F×1 + Busbar ・switchboard + SCADA
Cost for 10 years	Base	▲5 mUS$ for Base

(Remark) it may calculate on the assumption that between Gusap and Walium may be constructed two 132kV T/Ls with Ramu 2 development

b) Gusap substation and Walium substation

Gusap S/S is 25 km from Singsing S/S. Walium S/S is 70 km far from the north side of Gusap S/S. The general load at Gusap S/S is less than 3 MW. As of 2014, as shown in Fig. 7.6-9 , Gusap S/S has one 132kV T/L and step-down using 132/66 kV transformer and connects to Walium and Meiro S/S. In addition, Gusap S/S has a 132/22 kV transformer which supplies surrounding demand by 22 kV distribution line. There is plantation farm of Ramu sugar as main neighborhood demand.

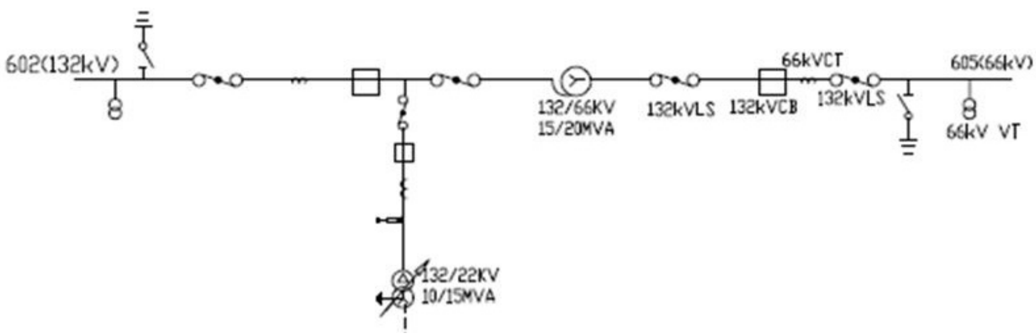


Fig. 7.6-9 Single Line Diagram for Gusap Substation in 2014

When Ramu2 P/S is developed, Ramu Nico and Yandera mines will be supplied. It is desirable from the viewpoint of stable supply, voltage and power loss to connect 132kV 2 circuit T/L. One is used as a common line and the other is used as a reserve line to supply each load. It is important for both S/Ss to take a role to supply the load of the mines. Power system is shown Fig. 7.6-10 in a configuration in which it supplies power to the mines.

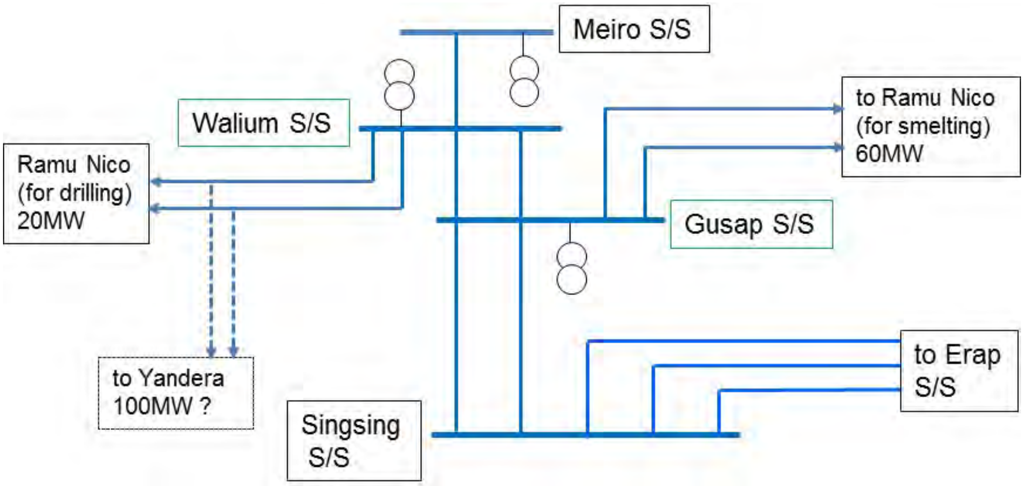


Fig. 7.6-10 Power System around Gusap and Walium in Supplying Mines

To change the power system from that in 2014 to in 2021, the construction as shown in the following steps is necessary.

About the extension step of Gusap S/S, first, one circuit of T/L between Singsing and Gusap S/Ss is constructed newly. Two S/Ss are connected by 2 circuit T/Ls. At the same time, the 132kV busbar of Gusap S/S is extended by three bays. However, it is impossible to construct switching equipment for T/Ls because existing 132/22 kV transformer has been installed.

For this reason, a 22 kV cubicle room is constructed in advance in Gusap S/S and existing outdoor 22 kV switching equipment is replaced to metal clad cubicle in the room. Singsing and Gusap S/Ss are connected by new 22 kV distribution line so that the demand of Gusap S/S can be supplied from Singsing S/S. This will contribute also to power supply when transformer at Singsing fails. Next, the existing 132/22 kV transformer is moved from second bay of Meiro side to third bay of Singsing side. By doing in this way, it becomes possible to connect two T/Ls to the first bay and the second bay of Singsing side from Singsing S/S.

Next, switching equipment is installed in the third and the fourth bay of Meiro side and T/Ls are constructed for smelting of Ramu Nico mine.

Around circumstance of Gusap S/S in 2014 is shown in Fig. 7.6-11.

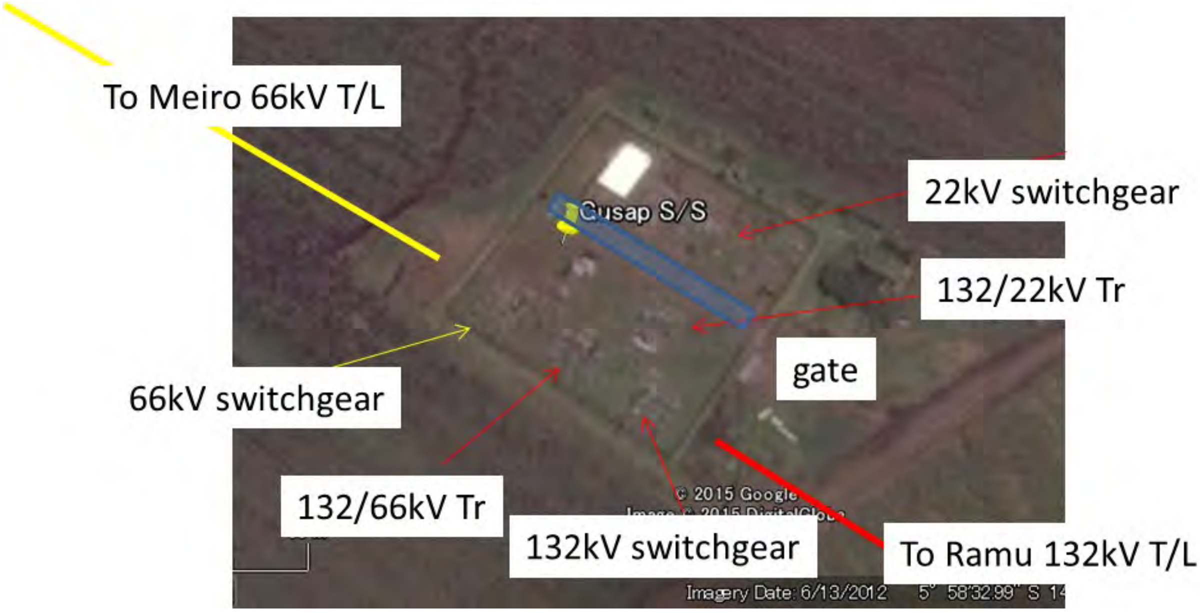


Fig. 7.6-11 Around Circumstance of Gusap Substation in 2014

Since Walium S/S is connected by 66 kV T/L via 132/66 kV transformer at Gusap S/S when Ramu2 P/S is developed, it is necessary to upgrade to 132 kV voltage. In Walium S/S, it is desirable to prepare two bays land space for switching equipment for Meiro S/S and two bays for Ramu Nico drilling and Yandera mines. Furthermore, is desirable to prepare two bays land space so that two 132kV T/Ls from P/S developed in Highland area can connect to the power system. In other words, it is necessary to secure eight bays land for Walium S/S and 2 banks of 132/22 kV transformer land in Walium S/S.

If mining demand, such as Ramu Nico and Yandera, is connected Gusap and Walium S/S respectively without using the T branch connecting, it is possible to separate the mining demand from power system by the transfer interrupting device when mining facilities malfunctions. It is possible to contract load interrupting service based on PPA contract when Ramu2 generator malfunctions. In addition, it becomes possible to construct the power system which does not have impact to general customers at the time of troubles.

(4) Consideration how for to supply for Highland area

As of 2014, peak demand of the Highland area is about 18 MW according to Part B Fig.3.1-3. Pauanda P/S and Ramu1 P/S consist of both power source for demand of those areas by connecting one 66 kV T/L. The conductor of this T/L is Dog, which is one type of British ACSR, which has a capacity of 32MW at 66 kV voltage. Therefore, in normal operational conditions, Dobel and Kudjip S/S are supplied from the Pauanda P/S, Kainantu, Himitovi and Kundiawa S/Ss are supplied from the Ramu1 P/S and the circuit breaker in Kundiawa S/S side in Kudjip S/S has been open. This power system configuration contributes to loss reduction and mitigation of voltage drop. Comparing with the case where power is supplied only from Ramu1 P/S, power loss can be reduced about 80% or more, assuming the annual load factor to be 60%. For this purpose, about 10 MW of power source in the west side including Pauanda P/S have to be enhanced. The demand of Highland area is forecasted to be about 39 MW, and the balance of power flow in this case is shown in Fig. 7.6-12.

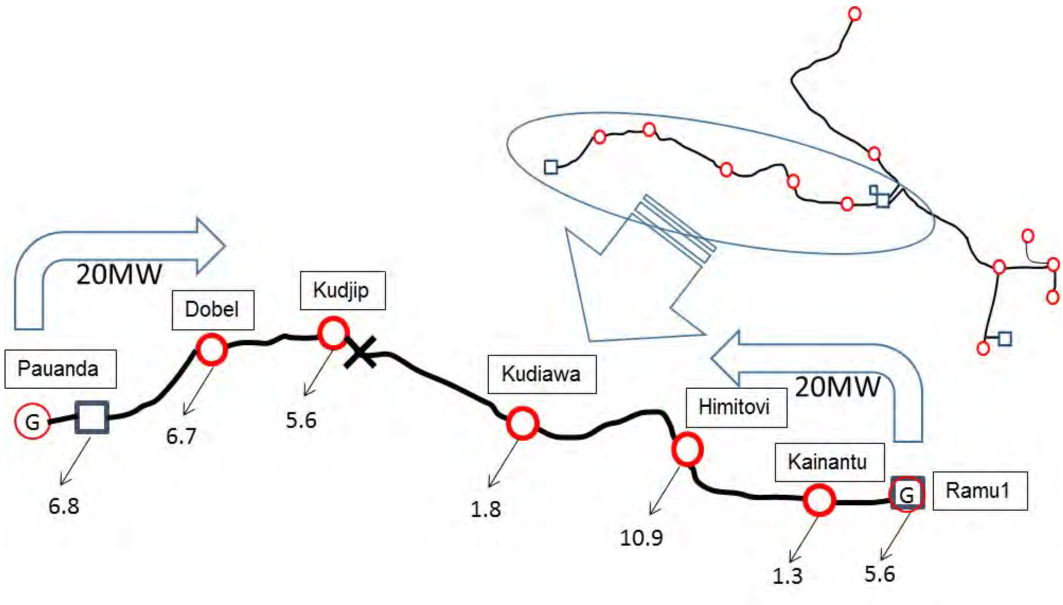


Fig. 7.6-12 Power System for Highland Area in 2030

If generators are operated at their rated outputs, and T/Ls and facilities of S/Ss are under normal condition, there is no problem. However, as described in Section 7.4 (2), there are the following issues in power system of Highland area; 1) in case of Ramu1 side T/L fault, supply trouble occurs by the shortage of supply capability of Pauanda P/S, 2) Since there is only one transformer in case of the one transformer fault of Kainantu, Kudiawa, Kudjip, and Dobel S/S, supply trouble occurs, 3) At the time of generator fault of Pauanda, a voltage-drop problem occurs for long-distance transmission of Ramu1.

It is effective to install a static condenser for power or Static Synchronous Compensator (STATCOM is a regulating device used on transmission system and based on a power electronics voltage-source converter and can act as either a source or sink of reactive AC power) at the secondary side of Himitovi and Dobel S/Ss which have a large demand in order to mitigate the voltage drop. In case of T/L failure near Ramu1, as only Pauanda P/S can supply, it is necessary to develop a power source on the west side of Pauanda or to reinforce DG up to about 40 MW. It is necessary to reinforce the transformers at Kainantu, Kundiawa, Kudjip, Dobel and Pauanda S/Ss for immediate recover when a transformer failure occurs.

7.6.2 Consideration of Power System Development Plan as Power Development Plan

(1) Ramu2 power source

According to the power development plan, Ramu2's capacity is 180 MW. However, based on FYPDP, the potential of Ramu2 hydropower is 240 MW. Here, power system development is studied using the value of 240 MW. There are three plans how to connect Ramu2 P/S to the power system. Plan A, which is based on FYPDP, is to connect Ramu2 to Singsing, Ramu1 and Gusap S/S by one T/L, respectively. Plan B is to connect Ramu2 to Singsing S/S by three routes with one T/L circuit. Plan C is to connect Ramu2 to Singsing S/S by one route with two T/Ls circuit with two Deer conductors. Comparative table is shown in Table 7.6-5.

Table 7.6-5 Comparative Table of Connecting Method for Ramu2

	PlanA : 3 S/S + 3 route	PlanB : one S/S + 3route	Plan C : one S/S + 2 route
Busbar fault	If some S/S is fault, the other S/S can supply without generation trouble	If Singsing S/S is fault, there is no influence to generation.	Same left
transient stability	Stable	Stable	stable
Cost	Ramu 2 ~ Gusap : 40km Ramu 2 ~ Singsing : 15km Ramu 2 ~ Ramu 1 : 5km 3 CB extend Total Base mUS$ + land acquisition cost A	Ramu 2 ~ Singsing : 15km × 3 route 4 CB extend Total ▲5.15 mUS$ + land acquisition cost A	Ramu 2 ~ Singsing : 15km × 2 route 2 CB extend Total ▲5.5 mUS$ + land acquisition cost 2/3A

Busbar configuration of Singsing S/S is 1.5CB system. Gusap S/S is a single busbar system. In 1.5CB system single busbar failure doesn't result in the outage of generators. Therefore, it is desirable to connect Ramu2 to Singsing S/S. Plan C will be recommended because of Plan C is cheapest with satisfying N-1 criteria. Power system grid is shown in Fig. 7.6-13 after Ramu2 development.

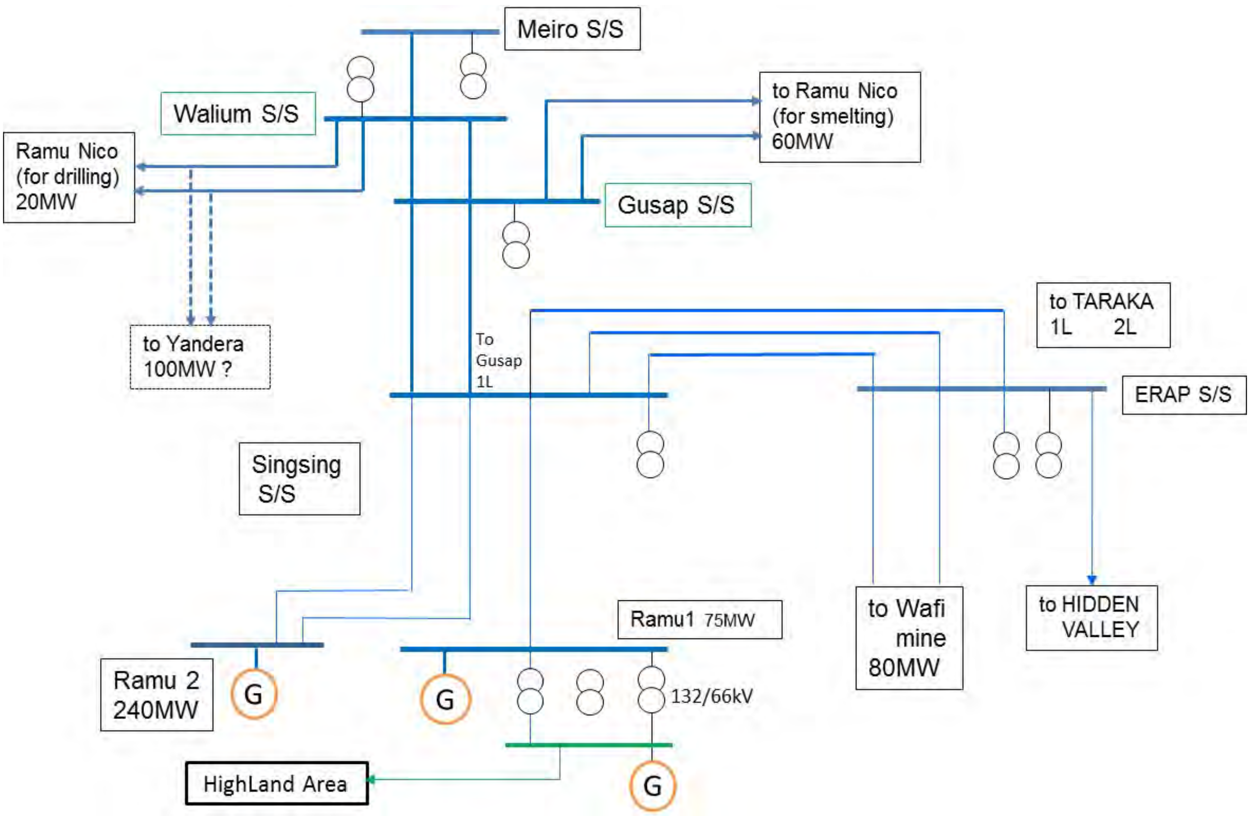


Fig. 7.6-13 Power System Grid after Ramu2 Development

(2) Mongi power source

Mongi P/S is located about 80 km northeast of Taraka S/S, and has 116 MW generating capacity. As for Mongi P/S, it is desirable to connect to Taraka S/S by two 132 kV T/Ls so that full power output can be transmitted by the other line in case of one T/L failure. As of 2014, Taraka S/S has received one T/L. By Ramu Transmission System Reinforcement Project, one bay is extended for T/L to Erap S/S in Taraka S/S and two bays for transmission will be extended in Taraka S/S by upgrading to 132 kV of Milford S/S. When Mongi P/S is connected, it is desirable to change to a double busbar configuration to upgrade power system reliability. Layout of Taraka S/S after connecting of Mongi P/S is shown Fig. 7.6-14.

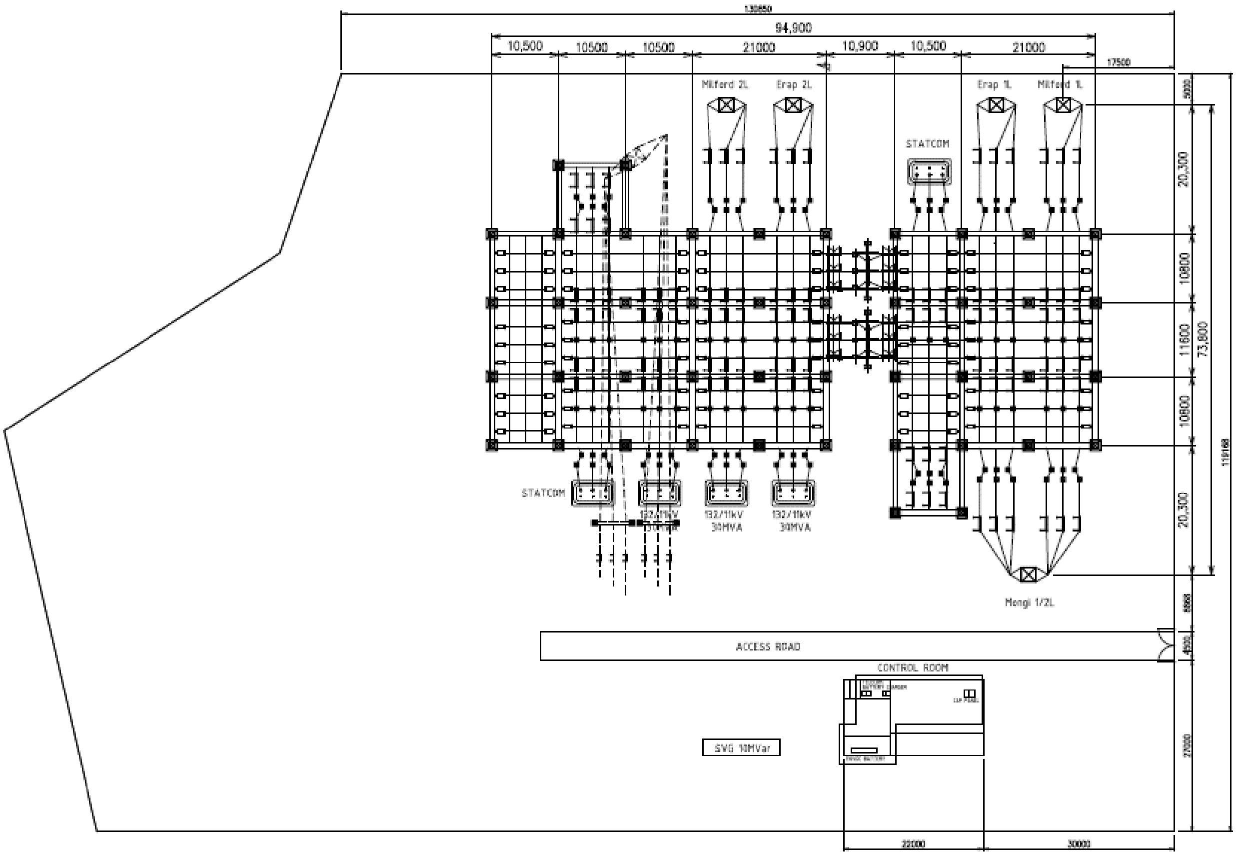


Fig. 7.6-14 Layout of Taraka Substation after Connecting Mongi Power Station

(3) Gowar power source

Gowar P/S which can generate 54MW will be located 40 km north far from Gusap S/S and located 40 km west far from Walium S/S. When Ramu2 P/S is developed, T/Ls will have already been constructed from Gusap S/S to Ramu Nico for smelting. By utilizing this T/L, Gowar P/S will be connected to two T/Ls from Gusap S/S and two T/Ls to Ramu Nico for smelting. This plan contributes to cheaper cost and supply reliability. The power system grid after connecting Gowar P/S is shown in Fig. 7.6-15.

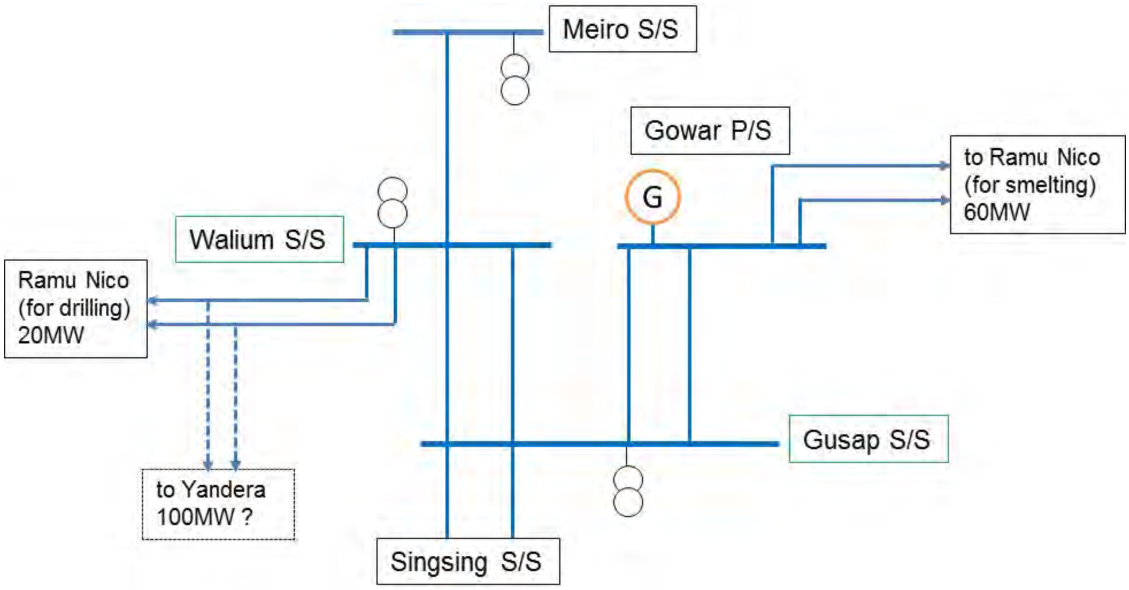


Fig. 7.6-15 Power System Grid after Connecting Gowar Power Station