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DEVELOPMENT OF MINI HYDROPOWER PROGRAMME

SI/SOI/85/802

SOLOMON ISLANDS

(R) SOLOMON ISLANDS.

Technical report: On Hydropower Projects in the Solomon Islands and Recommendations on Priorities*

Prepared for the Government of the Solomon Islands
by the United Nations Industrial Development Organization,
acting as executing agency for the United Nations Development Programme

Based on the work of Brian Glover
Expert in Hydro Electric Engineering of MHG Plants

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United Nations Industrial Development Organization
Vienna

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PREFEASIBILITY STUDIES OF HYDROPOWER PROJECTS

IN THE SOLOMON ISLANDS

AND RECOMMENDATIONS ON PRIORITIES

DRAFT FINAL REPORT, JULY 1986

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LIST OF ABBREVIATIONS

ADB - Asian Development Bank

M.a.s.l. - Metres above sea level

MNR - Ministry of Natural Resources

SIEA - Solomon Islands Electricity Authority

UNIDO - United Nations Industrial Development Organization

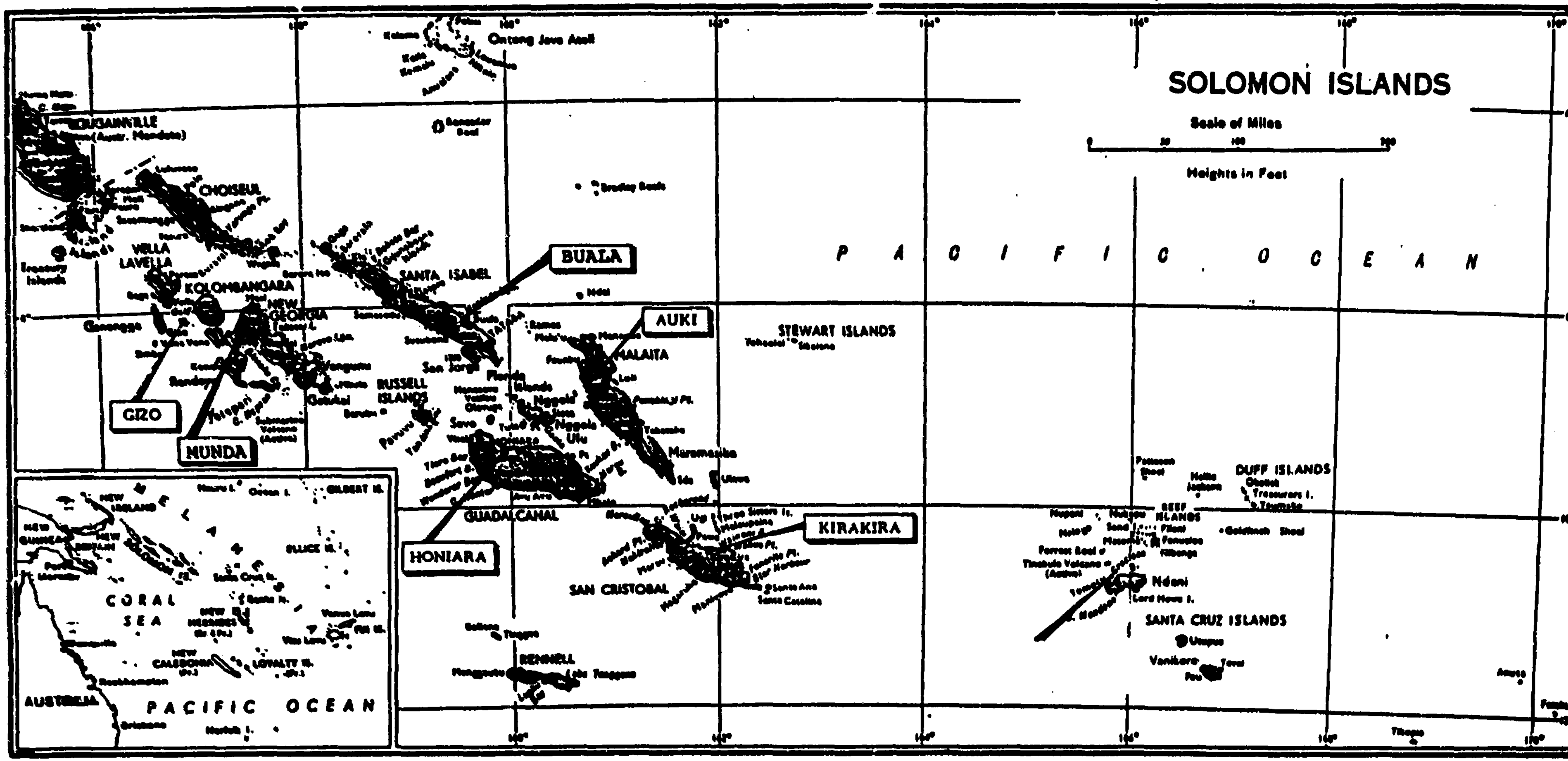


FIG. F.1 - Electricity Supply Areas in the Solomon Islands

E1 - EXECUTIVE SUMMARY

1. Hydropower development in the Solomon Islands should be divided into 3 different groups of projects according to scale.

   i) Medium and small hydro (1 - 30 MW)
   ii) Mini-hydro (100 kW - 1 MW)
   iii) Micro-hydro (less than 100 kW)

   Each type of project requires a different approach, different design philosophy and different standards for construction. Medium and small hydro require full studies, expert design and experienced contractors, whereas micro-hydro requires a maximum of local input and simplified construction techniques in order to minimise costs. Mini-hydro is often a compromise between both extremes with a leaning towards the simplified design and construction techniques of micro-hydro.

2. There is only one area where medium and small hydro need be considered at present, namely the capital, Honiara. With the present level of demand on the Honiara system of about 30 million kWh annual energy and a peak load of 5 MW, only projects larger than 1 MW will have significant benefit. A series of several smaller mini-hydro projects for Honiara would involve considerable effort, not least in land compensation, engineering and administration, and scarce resources of finance and expertise would be spread about to little effect. One project with about 5-10 MW output would be ideal for Honiara under the present circumstances.

3. Mini-hydro development is suitable for certain provincial centres and perhaps other centres where demand is expected to grow to about 100 kW in the immediate future. The first priorities must be centres where there are existing diesel generated supply systems, namely Auki, Gizo, Kira Kira, Lata (Santa Cruz), Buala and Munda (see Figure F.1). Of these Gizo and Munda lie in areas of no economic hydropower potential, and Lata lies too far from

potential hydropower sites (12 - 20 km) to justify a hydro project at the present low level of demand. The remaining 3 centres - Auki, Kira Kira and Buala have definite mini-hydro potential and these three should be developed immediately as pilot mini-hydro schemes from which to gain experience and train Solomon Islanders in hydro operation.

4. Government initiatives to electrify new rural areas by micro-hydro development should be temporarily suspended to give priority to projects for Honiara and the existing provincial supply areas. The substitution of expensive diesel running costs in existing supply areas will reduce or stabilise electricity tariffs, thus benefitting other non-hydro centres such as Gizo, Lata and Munda. On the other hand expansion of electricity supply to new areas will only increase SIEAs costs and lead to increased subsidies or higher tariffs.

Small hydro for Honiara

5. The Lungga gorge is the site of a potential large dam and power project which has been planned since 1966 and reached tender stage in 1981. The capital cost would exceed 100 million SI$ at current prices, being the result of a large and expensive dam required to generate sufficient head artificially. There is no natural fall in the river at the Lungga gorge site.

6. Lungga is too expensive a project under any conceivable scenario in the future. The cost/benefit ratio is still greater than 2 even if the entire power production can be utilised immediately on commissioning (i.e. Gold Ridge mine). Even if excessive rises in fuel costs indicate that Lungga might become economic, the adverse geological conditions at the dam site means that the project has a very high risk of cost overruns. It is therefore recommended that Lungga be dropped as an alternative development for Honiara. The existing compensation agreements to custom landowners for water rights should be renegotiated to cover the more promising Komarindi project further upstream on the Lungga River.

7. An economic analysis assuming a typical run-of-the-river hydropower project is introduced into the Honiara system after the 3 MW dendro plant in 1990 reaches the following conclusion. The hydropower project capital cost should not exceed 0.85 million SI$ for each million kWh the project produces in an average hydrological year if there is to be any economic advantage over a continued expansion of diesel units. There are various alternative hydro projects for Honiara which have been reviewed in this report - Tenaru, Mataniko, Kohove, Tinahula, Ohe and Komarindi. Only the Komarindi project is economic at present fuel prices with a cost/benefit ratio of 0.84 and a capital cost of only 0.65 million SI$ per million kWh produced annually.

8. The Komarindi Project involves a tunnel which utilises a natural head of 75 m in a run-of-the-river type of project with a low dam. Two alternative layouts are proposed and many other variations exist, all needing further study. The cost of the project is estimated to be in the range 27 - 30 million SI$ for an initial 6 MW installed capacity rising to 9 MW final. The potential production at full development is 50 - 60 million kWh annually (compare Lungga, 70 - 80 million kWh annually at three times the cost). The Komarindi project requires back-up from thermal power plant (dendro or diesel) because the reliable output is no more than 2.4 MW in the dry season. The existing diesel and dendro plant will be sufficient for this purpose until the late 1990s.

9. The Komarindi Project could come on line in early 1991 if planning work proceeds immediately. The planned 3 MW dendro plant for Honiara should proceed as soon as possible and should be on line in early 1990. The resulting mix of diesel, dendro and hydro generation plants is a very economic solution to the long-term needs of Honiara and the north of Guadalcanal, and provides an excellent diversity of fuel sources where reliability of supply is

guaranteed. Based on the predicted Honiara system demand growth of 6% p.a., the cost/benefit ratio of Komarindi against diesel generation is 0.84, and the internal rate of return is 12%. This makes the Komarindi project economically viable, and should be the next project to be commissioned after the dendro plant already planned.

10. The Tenaru project as presented in the UNDTCD mission report (reference 2) involves the transfer of the Tenaru river water over to the Lungga river. This would result in adverse effects to the population living downstream on the Tenaru, and severe environmental drawbacks such as lowering of groundwater levels on the flood plains. It would therefore be necessary to pass a minimum compensation flow along the Tenaru, thus reducing the power potential by about 30%. This makes the Tenaru project uneconomic with a cost/benefit ratio of 1.66 at 10% discount. Alternative layouts which return the water to the Tenaru itself further downstream do not significantly improve the projects viability. Nevertheless, the Tenaru River has the next highest likelihood of providing an economic hydropower project after the Lungga tributaries Komarindi and Ohe. A potential scheme (Tenaru A) with 4 MW installed would produce 15 million kWh annually at a cost of 16 - 20 million SI$ depending on rock conditions for tunnelling.

11. The Mataniko project would destroy a natural beauty spot and sacred area to the custom tribes (Mataniko Falls), and should therefore be dropped completely from future plans for hydropower developments. The Kohove and Tinahula rivers need not be investigated further, since these potential hydropower projects will most probably prove to be uneconomic under any circumstances. Further planning work should concentrate on the Komarindi and Ohe Rivers (both tributaries of the Lungga River), with the Tenaru River providing a potential worthy of further study.

Mini-hydro for the provincial centres

12. The Auki system demand is expected to reach 1 million kWh annually in 1992 with a peak of 194 kW. There is therefore good potential for mini-hydro development and Auki should be given the highest priority of the provincial centres because the existing diesel sets are very old and need replacing soon. Several possible schemes exist, 2 on the Kwaibala River and one on the larger Fiu River.

13. The lower scheme on the Kwaibala with 100 kW installed would provide about 400,000 kWh of annual production, i.e. half of Auki's present needs, at a capital cost of 510,000 SI$. This makes the scheme marginally economic with a cost/benefit ratio of about 0.9 at 10% discount rate. The other scheme on the Kwaibala is further upstream, is more costly (0.8 - 1.0 million SI$) and will take longer to design and construct, but provides 700,000 kWh of production at about the same cost/benefit ratio. The upper scheme should also be investigated at the same time, and a feasibility report produced on both schemes before deciding which to proceed with.

14. The lower Kwaibala scheme utilises 10 m of natural head in shortcutting a bend in the river, only 1.5 km upstream from the town itself. Access and all civil works construction is very simple and can be handled easily by local labour and plant. The only disadvantage is that the low head makes the turbine relatively expensive, and it is recommended that every effort be made to obtain the most competitive prices for generating equipment. The easy access and simple, easily understood civil works makes this scheme suitable as a demonstration project for training purposes. The river flow is said to be reliable, but the quantity of water available for power production is very important in determining the project benefits because all power can replace existing diesel. It is therefore vital that river flow data collection on the Kwaibala be given top priority after the Lungga and Komarindi Rivers on Guadalcanal. Design work and negotiations with landowners should proceed immediately while river flow data is being collected, and if all goes well the project could be commissioned late in 1988.

15. The Fiu River is known to run completely dry in some years at a point about 10 km upstream of Auki. The Fiu project presented by the UNDTCD mission was inspected, but the available head was measured by altimeter at 35 m instead of the 60 m quoted by UNDTCD, and the cost of the scheme will be greater than anticipated, around 2.7 million SI$ for 380 kW capacity. The Fiu project has, however, a potential of 3 - 5 million kWh annually, i.e. 3 - 5 times Aukis present needs. In effect the Fiu project is too large and too costly for Aukis short-term needs, and will not be required until the next century even assuming rapid growth in demand. Furthermore the project cannot guarantee any power during dry periods and full diesel back-up will have to be maintained. It is therefore recommended that the simple less costly lower Kwaibala projects be studied and one of them constructed immediately in order to reduce diesel consumption and heavy maintenance costs on the existing diesel sets.

16. The Kira Kira system is also experiencing difficulties with off-loading diesel in the harbour and repair of existing units. Demand is perhaps growing more rapidly than the ADB forecast (reference 1) which predicts 222,000 kWh annually with 78 kW peak in 1990. There is therefore an urgent need for an alternative mini-hydro project for Kira-Kira. Such a project was identified on the Huro river after an inspection of both the Puepue and Huro rivers, and their tributaries. The Puepue river system cuts steep gorges of up to 100 m vertical drop. The Puepue headrace project proposed in reference 2 would be impossible to construct and tunnels would be required to transfer the water resulting in excessive costs. The Puepue river is therefore not suitable for mini-hydropower development.

17. The Huro river has similar gorges, but the river emerges from these gorges at about 40 m above sea level, leaving 30 m to be utilised in a mini-hydro project. A good dam site and penstock route were identified, and the power station can be sited upstream of the existing Huro village without causing any local disturbance. The Huro project has a potential exceeding 600,000 kWh annually with 100 kW installed, at a cost of 640,000 SI$. It is therefore ideally suited to Kira Kira's short-term needs. The cost/benefit ratio is 0.92 at 10% discount making it more economic than continued diesel generation. The Huro project should therefore be designed and constructed immediately. Some additional river flow data would be useful for final design work, but there is no need to wait for flow data before going ahead with studies and financing.

18. The Buala system demand is lower than Auki and Kira Kira and it is difficult to justify a mini-hydro scheme for such low demand levels (presently estimated at 67,000 kWh annually and 22 kW peak). A diesel scheme is already in existence and functioning satisfactorly (although it is a loss-maker for SIEA). Nevertheless, the Jejevo mini-hydro project for Buala is in many ways an ideal project and if demand grows substantially it will rapidly become economic.

19. The Jejevo project utilises up to 180 m of head on the Jejevo river with an 840 m long steel penstock. River flow appears to be reliable and sufficient for present needs. As designed in reference 8 the project would cost 490,000 SI$, but this could be reduced to around 400,000 SI$ by reducing the head and the length of penstock. Although present requirements are only 20 - 30 kW, it is recommended that 100 kW be installed at little extra cost in order to standardise all electrical equipment with the Kwaibala and Huro projects. Although Buala is the lowest priority of the three mini-hydro supply areas, it is recommended that the Jejevo project be included in the set of 3 mini-hydro projects because it

meets long-term needs for a relatively small cost. A new intake site should be investigated and if possible the design adjusted to reduce the capital cost to around 400,000 SI$ while still meeting Buala's needs. Some low-flow river data is required to confirm that the flow is sufficient, and establishing a staff gauge read manually will be adequate to obtain a few months of record covering dry periods.

Micro-hydro projects

20. Micro-hydro development in the Solomons has started with 3 completed projects - Atoifi (32 kW), Maluu (30 kW) and Iriri (5 kW), all rather different in nature and in the methods they were implemented. Atoifi employs an old turbine at low capital cost and has apparently run successfully for many years although a diesel back-up is required for low flows. Maluu is situated at an ideal micro-hydro site, and was only recently commissioned after administration problems delayed construction and commissioning work. Iriri is apparently running intermittently and two villagers are presently in Australia undergoing training as operators. All 3 projects provide lessons which should be learnt before any further micro-hydro development is attempted.

21. Both Maluu and Iriri have proved to be expensive when compared with the benefits achieved. This is because they were carried out as "one-off" projects requiring a heavy financial input concentrated on the creation of electrification of a new area. In order to justify such expenditure it is necessary to have a guaranteed demand for electricity and substantial income from electricity sales in the first years after commissioning. Atoifi had a guaranteed market and it was possible to reduce initial expenditure by purchasing a second hand generating set and replacing this with new equipment after many years of running the old set. This approach results in more cost-effective use of financial resources and could be copied in other sites in the Solomons where a potential market for electricity sales exists.

E2 - INTRODUCTION

Late in 1985 the Government of the Solomon Islands requested the United Nations Industrial Development Organisation (UNIDO) to finance and recruit a technical expert mission to assist the government in assessing hydropower development in general, including existing projects, planned projects and unexplored potential of any scale.

UNIDO reacted rapidly to the request and in March 1985 appointed Dr. Brian Glover of international consulting engineers NORPLAN of Oslo, Norway to carry out the mission. After discussion with both UNIDO and the Solomon Islands Government a broad terms of reference was agreed upon in order to provide the government with a fresh independent viewpoint on all aspects of hydropower development in the Solomon Islands.

Work commenced on 1st April 1986 and concluded with presentation of this final report at the end of July 1986. The author visited the Solomon Islands for a period of two months in which data was collected, potential sites were visited, new sites identified and explored and extensive discussions were held with government authorities and the Solomon Islands Electricity Authority (SIEA). During the visit a preliminary analysis of all projects was carried out and an interim report delivered to government and UNIDO.

On return to Norway the author called upon the specialist expertise of NORPLANs consultants in hydropower engineering and coordinated a more accurate costing, analysis and optimisation of the various project alternatives which resulted in the present final report. The final report differs little from the interim report in results, conclusions and recommendations, but presents in full the data used and assumptions made, and provides drawings of project proposals.

The author wishes to extend his thanks to all authorities, private companies and individuals who assisted him greatly in all aspects of his work. Particular mention must be made of the people with whom the author worked closely during his field mission, all of whom made considerable contributions to the speedy, efficient and successful completion of the study, even in the difficult weeks after the cyclone "Namu" disaster which tragically struck the Solomon Islands on 18th and 19th May 1986 with terrible loss of life. In particular the author would like to thank Stephen Danitofea, Richard Haist, Bob Curry, Cliff Bird, Don and Tom Medynski of the Ministry of Natural Resources and Terry Leonard of SIEA whose contribution to a successful mission was very significant. Furthermore thanks must be extended to the staff of UNIDO and the UNDP regional office in Suva who enabled the mission to be completed sucessfully within the short time available.

The report is divided into 3 sections because of the different scales of project involved and the different approaches required:

- H - Projects for Honiara (the capital)
- P - Projects for the provinces
- M - Micro-hydro projects

These are preceded by an executive summary intended for non-technical readers and policy makers, while specialist technical matters are described in Appendices. A general background is given in the following chapter.

Table VI

Foreign Trade Balance 1982-85

$millions	1982	1983	1984	1985 *
Exports fob	56 6	71 2	118.6	103 9
Imports cif.	68 8	84.6	100.5	122.5
Trade surplus + deficit -	-12.2	-13.4	+ 18.1	- 18.6

* provisional

The resulting trade deficit of $18.6 million was the biggest since 1981. It completely offset 1984 s surplus. and took Solomon Islands back to the pattern of persistent deficits that has characterized the last decade Such a condition is normal for a developing country. except during commodity price booms.

Among the main exports. fish volumes were down by 18% from 1984 s record levels and up in value by 11%. This was due entirely to depreciation of the SI dollar since world prices remained weak throughout the year. Cocoa at 1528 tons recorded a volume increase of 8% and a jump in SI dollar earnings from $3.4 million to $5 million again assisted by exchange rate movements. mainly a 33% depreciation against the UK pound. Copra export volumes rose to a highest-ever 43500 tons but the world price was tumbling during the year. and export receipts were down 27% despite the 17% depreciation of the currency against the US dollar. Palm oil and kernels maintained volumes but like copra suffered a sharp fall in value yielding under $14 million 28% down from 1984.

The following table summarises export values for the last five years

Table VII
Main exports by value, 1981-85

$millions	1981	1982	1983	1984	1985
Copra	8.1	8.1	8.4	32.2	23.5
Logs and timber	16.1	22.9	20.0	30.1	24.8
Fish	22.0	14.0	29.2	28.8	31.9
Palm oil and kernels	7.5	7.3	8.8	19.1	13.7
Cocoa	0.9	0.9	2.3	3.4	5.0
Others	3.0	3.4	2.6	5.0	5.0
Total	57.6	56.6	71.3	118.6	103.9

Extract from Central Bank of Solomon Islands Annual Report 1985

E3 - BACKGROUND

The Solomon Islands is a group of six major and numerous minor islands situated to the north of Australia and east of Papua New Guinea as shown on Figure F1. The country became independent from Great Britain in 1978 and has a parliamentary democratic system of government, with decentralised provincial governments answering to the national government.

Population density is low; the entire country is estimated to have only 250,000 inhabitants mostly living in small villages scattered around the coast of the major islands, although much of the interior is also inhabited by small settlements. Population growth is rapid at over 3% p.a. despite housing shortages, and the capital Honiara is attracting an increasing population estimated at 30,000 at present.

The most populous island is Malaita followed by Guadalcanal, although most agricultural and industrial development has taken place along the flood plains on the north of Guadalcanal.

Most families live from subsistence agriculture and fishing. Paid employment is scarce, particularly outside the flood plain area of Guadalcanal. There are very few export industries because of costly transportation to major international markets, but many small industries are producing successfully for the internal market.

After unusually high copra prices in 1984 leading to a good financial year there has been a steady deterioration in the Solomons export economy, mainly due to falls in agricultural commodity prices (see Table VII from reference 20). This trend was drastically worsened after the cyclone disaster in May 1986 with extensive flooding which ruined many major agricultural crops and caused much damage to infrastructure.

The currency, the Solomon Islands Dollar, is freely interchangeable with a floating exchange rate linked to a basket of currencies from major trading partners. The value of the SI$ has recently been falling against the US dollar, yen and european currencies and in June 1986 was equal to 0.6 USD, 0.4 GBP, 4.6 NOK, 0.85 ASD and 1.06 NZD.

The islands are situated in a tropical ocean climate with near stable year-round temperatures of around 30°C in the daytime dropping to around 23°C in the early morning. Humidity is high at 80 - 100%. There are seasonal variations of wind which leads to some seasonal variations in rainfall depending on which direction the coast is facing. For example, Honiara and the north of Guadalcanal experience a dry season from April to October while the south of Guadalcanal experiences its wetter season during the same months.

The mountainous topography leads to large local variations in rainfall and there are undoubtedly many different micro-climates, although very few rainfall and meteorological records exist to substantiate this. Honiara average annual rainfall is about 2000 mm but this is the driest area of the Solomons. 3000 - 5000 mm is more common for coastal regions of other islands, rising to 8000 mm or perhaps more in the mountainous interior (see Appendix D).

The geology is also complex and variable with a mixture of young volcanic and sedimentary rocks often with poor engineering qualities and a high susceptibility to landslides. Faulting is common and the region is seismically active with frequent earthquakes. The topography is rugged with steep slopes (many unstable), deep gorges, caves, ravines and peaks of over 2000 m.

Vegetation in the interior is dense jungle with a rich variety of trees and plants. The high rainfall and soft rock types has created a dense network of streams and rivers, mostly perennial although some do dry up or dissappear underground. There are very few access tracks or paths and most sites are reached by wading up rivers during low flow periods.

There has been extensive logging activity in recent years resulting in over-exploitation of the forest resources in many places despite government efforts to ensure controlled exploitation and replanting. A moratorium on new logging licenses has recently come into effect, but logging companies continue to operate on existing licenses. Little scientific data is available on the environmental effect of logging activities, but it is probable that severe ecological changes are taking place in the interior. The authors visit to the Komarindi River shortly after the enormous cyclone flood provided evidence of this. The Komarindi river water was clear of sediment at the same time as smaller tributaries downstream and most other rivers were still flowing a muddy brown colour. The Komarindi catchment is as yet untouched by logging activities.

Apart from Guadalcanal, industrial and agricultural development on the other islands is very limited and generally restricted to small scale projects. There are plans to support small-scale industries and rural development projects in the provinces, including establishment of small-scale industrial sites at Gizo, Auki and Kira Kira as well as at Honiara. The lack of infrastructure, however, is a major impediment to any industrial initiative and the government recognises this by giving priority to development of the provincial centres. Lack of finance has hindered this work severely, particularly for the provincial governments entrusted with carrying out this work. Roads and port facilities are often inadequate. Whereever electric power supply exists, it is among the most expensive in the world at 28 SI cents/kWh (17 US cents/kWh), being almost entirely produced by small-scale diesel generation. The real cost of electricity generated in the provincial centres is much higher than Honiara (see Table H.4) due to the low level of electricity sales.

Particularly after the recent cyclone disaster the Solomon Islands Government will require considerable technical and financial assistance in rebuilding its economy. The government has long recognised the importance of energy self-sufficiency and the potential role of its hydropower resources in that respect. Lack of technical expertise and land ownership questions have been the main impediments to hydropower development hitherto, but the government is making serious efforts to resolving these and other problems and are giving hydropower development a very high priority.

E4 - METHODOLOGY FOR PROJECT IDENTIFICATION AND ANALYSIS

A simplified description of the methodology used in identifying and analysing potential hydropower projects is considered useful for future work and is given here. The procedure is considerably simplified because of lack of data, particularly flow data, but is nevertheless suitable for comparing projects with one another. More detailed analyses will be carried out in feasibility studies when more data becomes available.

Assessing potential power production

Two factors determine the project output: flow and head. In the absence of flow data estimates of flow must be made based on catchment area and rainfall. The annual average rainfall is first estimated from the nearest raingauge with reliable records. Since most raingauges are near the coast, where rainfall is likely to be less than inland, the average rainfall for inland catchments is estimated to be slightly above the coast figure.

The net evapotranspiration losses are assumed to be ralatively uniform throughout the Solomons and a figure of 1160 mm per annum is adopted from reference 2. By subtracting this from the catchment rainfall estimate the specific runoff is obtained in mm. This is converted to mean flow in million m3 per year and hence m3/s by multiplying by the catchment area. Typical values of minimum flow for a river range from 0 - 40% of the mean flow, most commonly around 20%.

If the maximum energy output is required from the project, a <u>total</u> turbine discharge of around 1.4 times the average flow is selected, even though the generating equipment may be divided into 2 or more units.

Flow data is converted to power output by multiplying by the net head, obtained from the gross head measured in the field minus about 1 - 3 m for head losses depending on penstock length. The other factor is the generating unit efficiency which is represented by a single factor between 6 and 9. The smallest micro units have the lowest efficiency (factor 6) whereas larger Francis and Pelton units are generally between 8 and 9. A sizeable crossflow unit of 200 kW would typically have a value of about 7.

Having determined the nominal installed capacity from the efficiency factor multiplied by both the net head and 1.4 x the average flow, an estimate can be made of the projects annual energy output. Normally this comes from analysis of the flow duration curve. Nothing is known of the flow duration curves of typical small rivers and streams in the Solomons, and the variation from river to river is likely to be great. In the absence of better estimates it is best to use a consistent rule of thumb for comparison of different projects.

The annual energy potential is estimated by multiplying the nominal maximum output by 4000 hours, a rule-of-thumb based on experience from regions with similar rainfall patterns and catchment conditions.

The following example illustrates the procedure:

Catchment area	= 40 km2	
Annual rainfall	= 4000 mm	(3600 mm at the coast)
Net evapotranspiration	= 1160 mm	
Specific runoff	= 4000 - 1160 = 2840 mm	
Mean flow	= 2840 mm x 40 km2 = 113.6 million m3/year	
	= 3.6 m3/s	
Minimum flow	= 17% x 3.6 m3/s = 0.6 m3/s	
Total turbine discharge	= 1.4 x average flow = 5.0 m3/s	
Gross head available	= 65 m	
Net head available	= 62.5 m	
Nominal turbine output	= 8.0 x 62.5 x 5.0 = 2500 kW = 2.5 MW	
Firm capacity	= 8.0 x 62.5 x 0.6 = 300 kW	
Estimated annual energy output	= 2500 kW x 4000 hrs. = 10×10^{6} kWh	
	= 10 GWh p.a.	

Cost/benefit analysis

The last two items, firm capacity and energy output represent the project benefits. The hydro projects firm capacity is the guaranteed contribution to the total system generating capacity and therefore represents the avoided purchase of a new diesel unit of the same capacity (300 kW in the example above). New diesel units cost 700 US$/kW (300 kW at 1170 SI$/kW costs 350,000 SI$) and must be replaced every 20 years (15 years for smaller units). Thus the hydro project results in an avoided cost of 350,000 SI$ immediately before the project commissioning date and the same amount repeated every 20 years in the future.

The annual energy benefit is calculated as the average energy output multiplied by the cost of producing the same amount of energy from existing diesel units (from Table H.4). In Honiara this is 10.64 cents/kWh at present fuel prices, and the annual benefit is therefore 10×10^6 kWh x 10.64 cents = 1,006,000 SI$. This amount is repeated every year after commissioning and together with the capacity benefits represents the total benefit stream of the hydro project as shown in Table H.9.

The project investment cost is estimated taking into account all costs including contingencies, administration etc. These costs are distributed evenly over the construction period prior to commissioning and are followed by an annual operation and maintenance cost of 2% of the investment cost (1.5% for larger projects). After 30 years it is assumed that all generating equipment must be replaced and a corresponding sum is added to the cost stream 30 years after commissioning.

Typical cost and benefit streams are set up as in Table H.9, and by discounting at 10% discount rate (recommended by Central Bank of Solomon Islands) the net present value of both the cost and benefit streams is obtained. The ratio of net present value cost to net present value benefit is an indication of the projects viability. Values less than 1.0 indicate the hydro project to be more economic than diesel generation and the project is economically viable. Different discount rates can be tested, and the particular rate at which the cost/benefit ratio is equal to 1.0 is known as the equalising discount rate, sometimes also called the internal rate of return.

The one important variation to this procedure occurs when the system energy demand is less than the potential energy output of the project calculated by the above method. In this case the full potential benefit of the project cannot be realised and the real benefit comes from only that part of the demand which can be fulfilled by hydro production. If hydro power production is limited to less than the system demand during dry flow periods, then some use of diesel generation sets will be required. If the hydro project has been correctly designed, however, the annual diesel contribution is seldom more than 10% of the annual total. It can be safely assumed that the hydropower benefits are equivalent to the system energy demand mulitplied by a factor of 90 - 100% rising assymptopically towards a limiting value equivalent to the potential energy production of the project. The Komarindi project is a good illustration and the calculation of energy benefits is tabulated in Table H.19.

TABLE H.1 - Existing Diesel Plant - Honiara Power Station

Unit	1	2	3	4	5	6
Manufacturer	Lister Blackstone	Lister Blackstone	Lister Blackstone	Ruston	Mirrlees	Mirrlee
Model	ERS8	ERDFS8	ERDFS8	VEB8		
Generator Output	428kW	440kW	440kW	332kW		
De-rated Output	300kW	300kW	300kW	280kW	900kW	900kW
Year of Manufacture	1958	1968	1968	1958		
Year Installed	1959	1974	1974	1958	1984	1984

Lungga Power Station

Unit	1	2	3	4	5
Manufacturer	English Electric	English Electric	English Electric	Mirrlees	Mirrlees
Model	6RK3C	6RK3C	6RK3C	K5 Major	K5 Major
Generator Output	776kW	776kW	776kW	1526kW	1526kW
De-rated Output	600kW	600kW	600kW	1400kW	1400kW
Year of Manufacture	1973	1973	1973	1971	1971
Year Installed	1981	1981	1981	1971	1971

PROJECTS FOR HONIARA

H 1 - Present Honiara Generating System

The present generating system for Honiara as of 1984 was described in detail in the ADB Power Development Study (reference 1). The salient features are repeated here for completeness, together with updated information to describe the situation in June 1986.

The Honiara system supplies an area from just beyond the White River in the west to just beyond the Ngalimbiu River in the east, a distance of 30 km. The distribution is at 11 kV with supply to all consumers at 415/240 V, 50 Hz. The system mainly follows the coastal development and does not extend more than a few kilometres inland.

The present system is supplied entirely by diesel generating sets situated in two power stations, the older one in the centre of Honiara and a second station beside the Lungga River located as shown on Figure F.5. The details of the existing diesel sets are given in Table H.1. The two power stations are connected by a single 33 kV line.

Supply is primarily from the larger newer sets although the older sets are still run frequently. Both Honiara and Lungga stations will continue to operate in the foreseeable future. There is some room for addition of new sets at both stations, although this would require removal of the older sets at Honiara. A larger extension of the Lungga power station would be possible by leasing adjacent land if necessary.

Diesel is imported in bulk tankers and stored in bulk in the centre of Honiara. At the time of writing discussions are in progress about the resiting of petroleum storage facilities outside the centre. Provided the new facilities are located within easy transport distance of the Lungga and Honiara power stations there will be no adverse effects on supplies to SIEA.

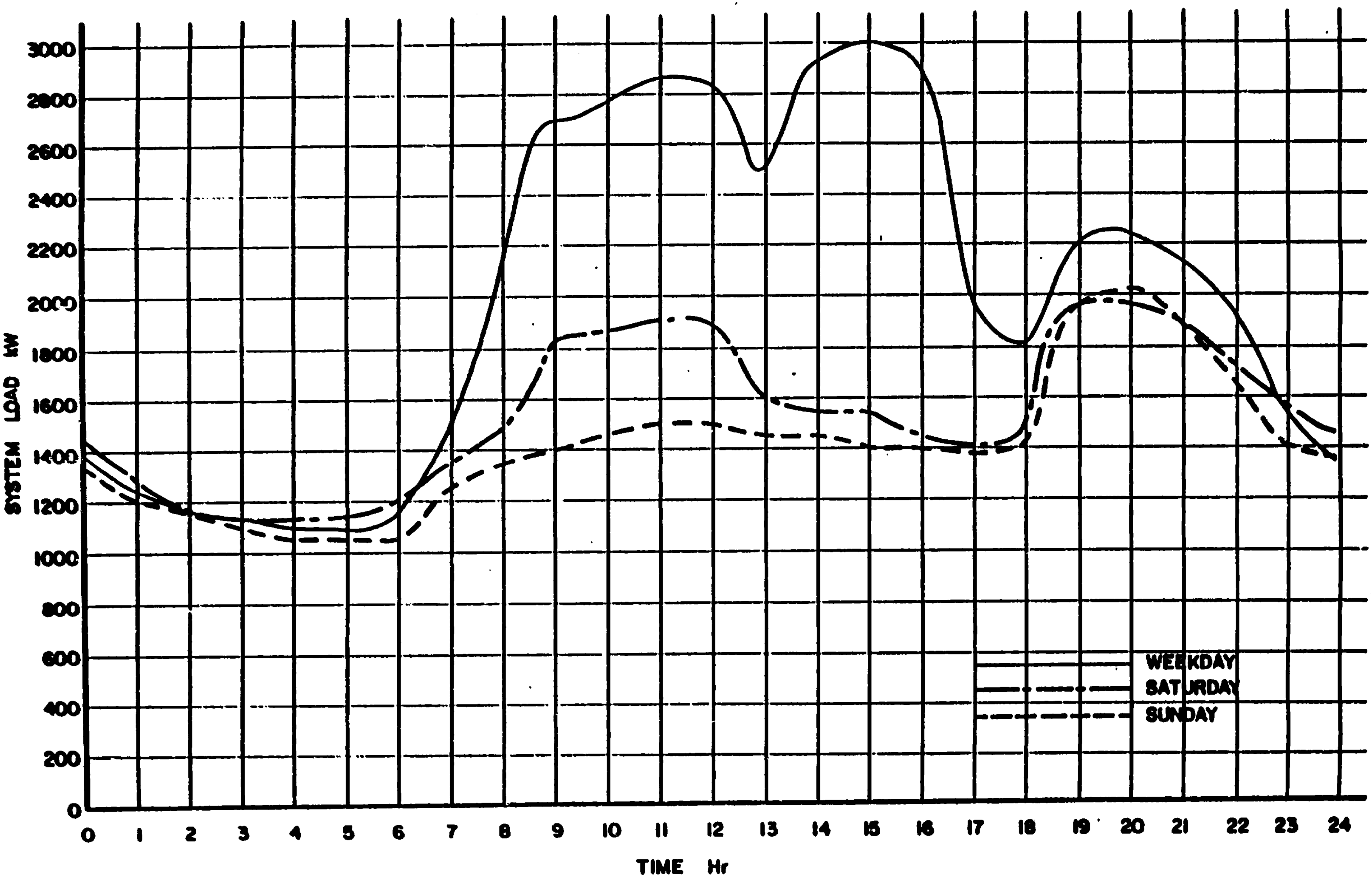


FIGURE F.2 - Guadalcanal system daily load curves 1983 (from reference 1)

Operation and maintenance of the present Honiara system is satisfactory, and the reliability of supply is reasonably good for such a small system. The stability of frequency and voltage is a little variable causing occasional problems for computers, clocks etc.

Typical daily load curves for 1983 are shown in Figure F.2 (from reference 1). The typical daytime weekday peaks reflect the predominance of office air conditioning systems and commercial users, because these peaks are noticeably absent at weekends. The load factor is 0.56 and is expected to remain around that value in the future.

H 2 - Demand Growth and New Consumers (Gold Ridge)

A thorough demand study was carried by the ADB in 1986 and is presented in reference 1, with the results summarised in Table H.2. Actual figures for 1985 and 1985 are shown in Table H.3 and the latest predictions from SIEA indicate that demand is increasing at about the predicted rate, perhaps a little faster. The growth rate of energy is assumed to be 6% after 1987 and this forms the basis for planning new generation installments.

The situation in 1986 indicates that the 6% forecast looks realistic or perhaps slightly underestimates the load growth, despite continuing high tariffs (25 - 28 SI cents/kWh in May 1986). The Energy Section of the MNR is about to undertake an energy conservation study, presumably followed-up by measures for reducing consumption, especially on air conditioning systems. There is considerable scope for savings, and these efforts are to be highly encouraged. The present rapid growth in infrastructure and private development in Honiara is likely to continue and this will outweigh any future energy conservation measures. Continued growth is therefore expected at least in the short term, and all project analysis is based on the updated forecast of 6% p.a. growth after 1987 as shown on Table H.3.

Table H.2 - Energy and Maximum Demand Forecast - Guadalcanal System : ADB forecast from reference 1 (1984)

	Res'l	Govt	Ind'l	Comm'l & Other	Total Sold	SIEA Use	Losses	Energy Generated	Load Factor	Maximum Demand
1974 (actual)	2046	2816	346	3214	8422	-	955	9377	0.57	1.88
1980 (actual)	3466	4278	2022	4637	14403	-	1297	15700	0.55	3.24
1981 (actual)	3292	4928	2345	4907	15472	-	1469	16941	0.56	3.46
1982 (actual)	3421	4848	1414	5248	14752	721	1375	17018	0.53	3.65
1983 (actual)	3657	5333	1896	5462	16348	697	1635	18881	0.56	3.79
1984	3927	5153	2146	5538	16764	754	1676	19194	0.56	3.92
1985	4197	5628	2871	5822	18518	831	1850	21199	0.56	4.32
1986	4467	6067	3571	6182	20283	901	2028	23212	0.56	4.73
1987	4737	6258	4001	6302	21298	1542	2130	24970	0.56	5.07
1988	5007	6453	4431	6422	22313	2180	2232	26725	0.56	5.45
1989	5277	6648	4711	6902	23538	2220	2354	28112	0.56	5.73
1990	5547	6843	4991	7382	24763	2410	2476	29649	0.56	6.04
1995	7423	8326	8038	8981	32768	3100	3276	39144	0.56	8.00
2000	9934	10130	12945	10927	43936	3600	4394	51930	0.56.	10.58

Growth p.a.

	Res'l	Govt	Ind'l	Comm'l & Other	Total Sold	Energy Generated
	%	%	%	%	%	%
1974-1983	6.7	7.4	20.8	6.1	7.6	8.1
1983-1990	6.1	3.6	14.8	4.4	6.1	6.7
1991-1995	6.0	4.0	10.0	4.0	5.8	5.7
1996-2000	6.0	4.0	10.0	4.0	6.0	5.8
1983-2000	6.0	3.8	12.0	4.2	6.0	6.1

Notes:

1. In 1980 and 1981 SIEA use included in the industrial category.
2. Energy in MWh and demand in MW.
3. Figures for SIEA use, losses and energy generated based on 2 x 2000kW dendrothermal station commissioned in 1987 and additional units thereafter using diesel.
4. Energy generated for specific options are developed in Appendix 4.

TABLE H.3 - UPDATED DEMAND FORECAST FOR HONIARA SYSTEM

	ENERGY (GWh)	PEAK (MW)	
1980	15.7	3.24	actual recorded figures
1981	16.9	3.46	
1982	17.0	3.65	
1983	18.9	3.79	
1984	19.6	4.05	
1985	22.0	4.50	
1986	24.4	4.90	short-term forecast (SIEA)
1987	26.4	5.28	
1988	27.5	5.60	6% predicted by ADB (ref 1)
1989	29.1	5.94	
1990	30.8	6.29	
1991	32.7	6.67	
1992	34.7	7.07	
1993	36.7	7.49	
1994	38.9	7.94	
1995	41.3	8.42	
1996	43.8	8.93	
1997	46.4	9.46	
1998	49.2	10.03	
1999	52.1	10.63	
2000	55.2	11.27	
2001	58.5	11.94	
2002	62.0	12.66	
2003	65.7	13.42	
2004	69.7	14.22	
2005	73.9	15.10	
2006	78.3	16.00	
2007	83.0	16.90	
2008	88.0	18.00	
2009	93.3	19.10	
2010	98.9	20.20	

New consumers are continually being connected, but special mention must be made of one major potential consumer, namely a future gold mine development at Gold Ridge, some 30 km south east of Honiara. Investigatory drillings have reached an advanced stage and the Government may grant a prospecting license within a year or so. There are many difficulties, however, including land ownership and compensation, and the Gold Ridge development is at present very uncertain. If the development were to go ahead it is assumed that an additional 10 MW capacity and 60 GWh annual energy would be required rapidly. This would increase the Honiara system demand to 16 MW and 90 GWh annually in 1990.

Preliminary discussions indicate that the SI Government would be responsible for supplying (and guaranteeing) adequate power at the present industrial tariff. This would have a major effect on SIEA's generation expansion plans, with new generation units being required specifically for Gold Ridge. Alternatively the mining company might provide and maintain its own power supply.

The analysis of hydropower projects for Honiara is based on the assumption that Gold Ridge mine is <u>not</u> developed. If additional power is required for Gold Ridge, it will significantly <u>improve</u> the economic feasibility of large projects such as Komarindi, but have no effect on smaller projects such as Tenaru where the potential output can already be absorbed by the present system.

	Honiara	Auki	Kira Kira	Buala	Santa Cruz
Diesel price (June 86 ex duty)	28.41	31.41	34.91	33.41	36.41 (SI cents/litre)
Consumption (l/kWh)	0.29	0.417	0.454	0.454	0.454
Fuel cost (cents/kWh)	8.24	13.10	15.85	15.17	16.53
Lubrication cost (cents/kWh)	0.4	0.5	0.5	0.5	0.5
Operation and maintenance (cents/kWh)	2.0	3.0	5.0	5.0	5.0
Marginal cost of energy (cents/kWh)	10.64	16.60	21.35	20.67	22.03
Depreciation	2.26	2.7	3.0	3.0	3.5
Other fixed costs divided by * annual sales (estimates for 1986)	9.0	13.0	25.0	30.0	35.5
TOTAL COST (SI cents/kWh sold)	21.9	32.3	49.4	53.7	61.0

* Includes admin., distribution, own generation and staff costs. (Estimated by updating SIEA figures for 1983)

TABLE H.4 - Cost of diesel generation in the Solomon Islands (1986)

H 3 - Generation Expansion Alternatives

H 3.1 Diesel

The installation of diesel generating sets will continue to be a viable expansion alternative, either combined with dendro or hydro or diesel on its own. The recent fall in oil prices will make this alternative much more favourable in the short term until oil prices rise again to levels comparable to 1984 (the date of the ADB study). At the time of writing the price of oil had sunk to around 10 USD per barrel, but the price of diesel delivered to the Solomons was falling much more slowly. Prices for diesel delivered in June 1986 ex. duty are given in Table H.4, the Honiara price being 28.41 SI cents/litre or 17 US cents/litre.

There appears to be continued pressure at present holding oil prices down, and opinions on future trends vary widely. It can be expected that after a relatively low price period, say 5 years, the pendulum will swing back again and prices will rise again rapidly as proven oil reserves begin to dwindle towards the year 2000. In the absence of reliable predictions, the June 1986 price level (Table H.4) has been assumed to apply in the future, and diesel prices are assumed to increase in par with inflation.

Future decisions based on the analyses presented in this report should bear in mind the actual price of diesel at the time of making the decision. If prices for diesel rise slower than construction costs, this will favor diesel plant compared with hydro and dendro. An economic analysis similar to the ones presented here should be repeated using current prices before major planning decisions are taken.

Diesel units have approximately constant capital investment costs per kW independent of size. The figure of SI$ 1170/kW (700 US$/kW) used here represents the complete station price and compares with the ADB report, Appendix 4.1, updated by 2.5 years inflation.

TABLE H.5 - HONIARA SYSTEM: PROBABLE DENDRO/DIESEL GENERATION EXPANSION SEQUENCE

(All figures in MW)

	HON.	LUNG.	NEW	DENDRO	TOTAL	STANDBY	FIRM	PEAK DEMAND
1986	2.98	4.60	-	-	7.58	2.30	5.28	4.90
1987	2.98	4.60	-	-	7.58	2.30	5.28	5.28
1988	2.98	4.60	1.4	-	8.98	2.80	6.18	5.60
1989	2.98	4.60	1.4	-	8.98	2.80	6.18	5.93
1990	1.80	4.60	1.4	3.0	10.80	4.40	6.40	6.29
1991	1.80	4.60	4.4*	3.0	13.80	6.00	7.80	6.67
1992	1.80	1.80	7.4*	3.0	14.00	6.00	8.00	7.07
1993	1.80	1.80	7.4	3.0	14.00	6.00	8.00	7.49
1994	1.80		10.4*	3.0	15.20	6.00	9.20	7.94
1995	1.80		10.4	3.0	15.20	6.00	9.20	8.42
1996	1.80		10.4	3.0	15.20	6.00	9.20	8.92
1997	1.80		13.4*	3.0	18.20	6.00	12.20	9.46
1998	1.80		13.4	3.0	18.20	6.00	12.20	10.03
1999	1.80		13.4	3.0	18.20	6.00	12.20	10.63
2000	1.80		13.4	3.0	18.20	6.00	12.20	11.27
2001			16.4*	3.0	19.40	6.00	13.40	11.94
2002			16.4	3.0	19.40	6.00	13.40	12.66
2003			16.4	3.0	19.40	6.00	13.40	13.42
2004			19.4*	3.0	22.40	6.00	16.40	14.22
2005			19.4	3.0	22.40	6.00	16.40	15.08
2006			19.4	3.0	22.40	6.00	16.40	16.00
2007			22.4*	3.0	25.40	6.00	19.40	16.90
2008			21.0	3.0	24.00	6.00	18.00	18.00
2009			24.0*	3.0	27.00	6.00	21.00	19.00
2010			24.0	3.0	27.00	6.00	21.00	20.20

* New 3MW unit to be commissioned by start of year

The marginal generation cost of diesel generated electricity in Honiara is calculated at SI 10.64 cents/kWh (US 6.4 cents/kWh), as calculated in Table H.4. This represents only the marginal cost of generating additional electricity using existing sets, and does not include capital depreciation or fixed components, which more than doubles the unit cost.

The Honiara system in 1986 is already running on reduced standby capacity and slight problems will arise if the two largest (1.4 MW) units are out simultaneously. SIEA are therefore considering installing a new diesel unit to be commissioned before the planned dendrothermal plant. The size of the new unit is undecided, but is assumed to be 1.4 MW for simplicity in the present analysis. The older Honiara units are due for retirement soon, and the system in 1990 is assumed to have a total of 10.8 MW installed capacity as shown in Table H.5.

In comparing the various options open to SIEA for expanding their generation facilities the following assumptions have been made.

(i) 3 MW dendrothermal capacity on line by 1990

(ii) the standby capacity must be greater than the two largest units in the system.

(iii) additional units are added of standard 3 MW size (for simplicity of analysis)

(iv) older diesel units are retired after 20 years of service

Considering the scenario or "option" where no hydro project is included, the probable sequence of diesel unit installation is set up as shown in Table H.5. This represents the basic dendro/diesel or "non-hydro" option used for comparing all hydro projects for Honiara in the cost/benefit analysis. (C.f. the ADB report, Appendix 4 with updating to include the two 900 kW second-hand diesel sets installed at Honiara power station in 1984).

To calculate the benefits from any hydro project, it is assumed that the hydro project is commissioned in early 1991. Certain costs in the "non-hydro" option can be avoided if the hydro plant is built and these are calculated in the form of

(i) avoided purchase of new diesel units equivalent to the firm capacity of the hydro plant

(ii) avoided fuel and running costs for existing diesel units equivalent to the average annual energy output of the hydro plant

It is the latter item which dominates the benefit stream of typical run-of-the-river hydro plants such as those proposed for Honiara. By multiplying by the equivalent diesel prices of 1170 SI$ per kW installed and 10.64 SI cents/kWh produced respectively, the benefit stream of the hydro project is set up. Examples of such cost/benefit analyses are given in later chapters.

H 3.2 Dendrothermal

A steam turbine generator fired by a variety of wood and plant residue fuels or "dendrothermal" plant has been proposed and is analysed and reported by the ADB mission (reference 1). This type of plant is well suited for the Solomon Islands because the running costs are low relative to diesel, and it uses indigenous fuel resources. The ADB report recommends a 2 x 2 MW dendrothermal plant but some land problems may be encountered in establishing fuelwood plantations which will be required in later years. The optimum installed capacity was therefore later reduced to 3 MW. Since the capital cost of 2 units is significantly higher than one, a single 3 MW unit is being considered and appears to be the most likely alternative at the time of writing.

The ADB have indicated their willingness to fund the design and eventual construction of the dendrothermal plant and establishment of a trial fuelwood plantation, and loans are expected to be approved later in 1986. A site has been identified and negotiations are in progress. Every indication is that a 3 MW dendrothermal plant will be commissioned in late 1989. For the purpose of further analysis, this scheme is considered to be committed and will produce power from 1990 onwards.

The possibility of further dendrothermal development (up to 8 MW) was considered by the ADB study, and found to be marginally economic compared with the option with continued diesel unit expansion after the initial dendro unit. The cost of fuel for additional dendrothermal plants will be higher than for the initial 3 MW plant, as the cheaper fuel sources are fully utilised. Furthermore, the future of fuelwood plantations on Guadalcanal is extremely uncertain due to land problems and it is probable that further dendro plants will not be a realistic alternative in the short and medium term. For these same reasons as given in reference 1, Chapter 5, and for simplicity, a development option including dendrothermal plant beyond the initial 3 MW was not considered in the present study, and the least cost alternative to hydro was assumed to be continued diesel expansion as described in the previous chapter.

The planned 3 MW dendro scheme will produce about 18 net GWh annually at an average fuel cost of about 5.5 SI cents/kWh at 1986 price levels (from ref.,1 Appendix 6.7.2 excluding the Foxwood sawmill contribution). It will be operated as the base load generator with diesel supplementing the supply as the demand varies.

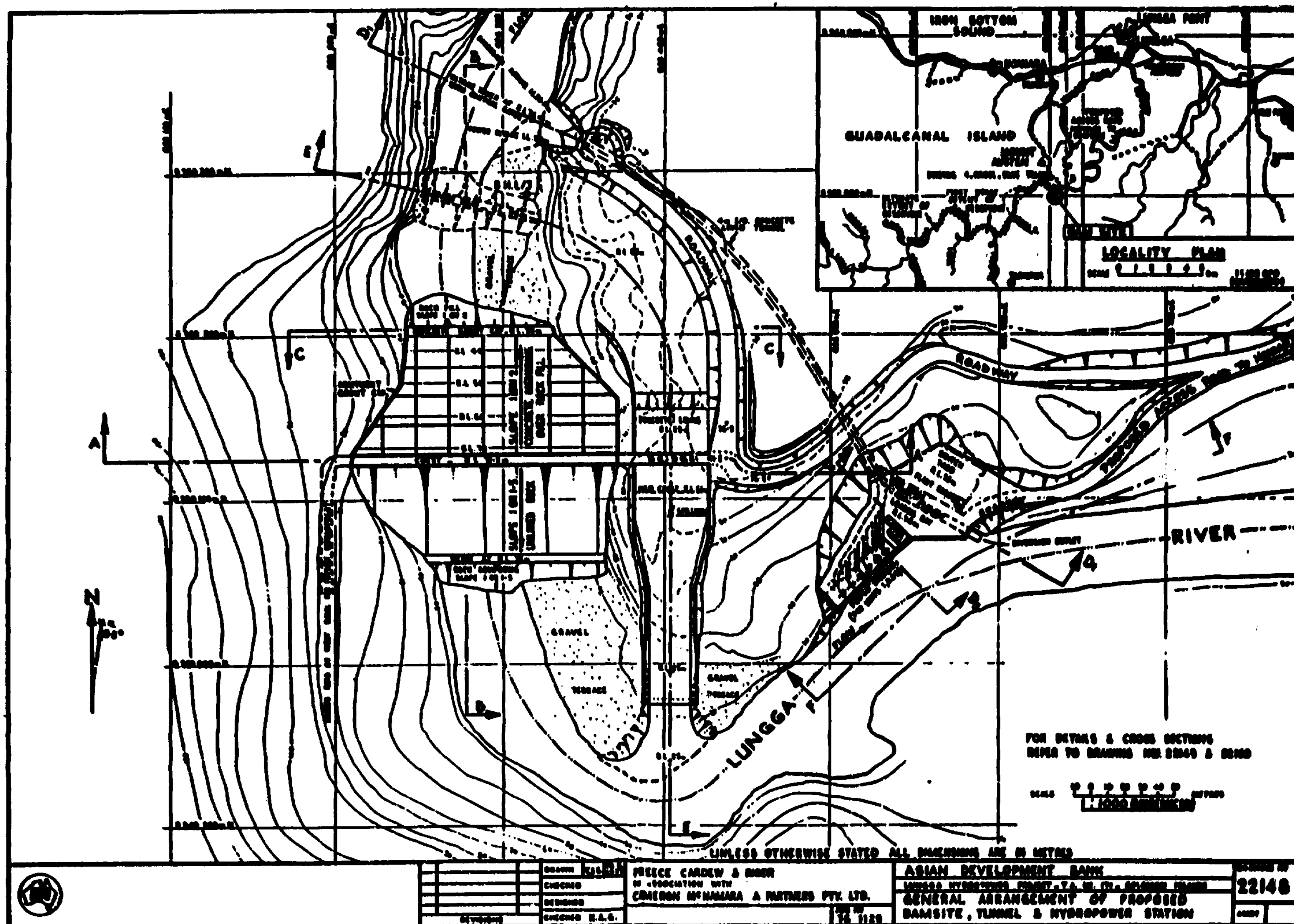


FIGURE F.3 - Lungga hydropower project - General layout (from reference 9)

H 3.3 Lungga Hydropower Project

This project is located on the Lungga River at a narrow gorge site some 9 km inland from Honiara as shown in Figure F.5. It involves the construction of a 50 m high rockfill dam and installation of a total of 21 MW generation capacity at an initial cost exceeding 100 million SI$ at 1986 price levels. The general laycut is reproduced here as Figure F.3.

The project has been planned and studied extensively since 1966, culminating in a tender competition in 1981, which showed construction costs greatly exceeding the engineers estimate. Updating of these costs to 1986 price levels results in an investment cost exceeding 100 million SI$. Repeated efforts have been made to reduce the initial investment by phasing the scheme or raising the dam in two stages, but without reducing the net present value cost significantly.

The dam was to be constructed at a site with complex and unfavourable geological conditions. The river bed alluvium is known to extend 65 m below river level and must be sealed by a bentonite slurry trench. The dam abutments include limestone shown to have karst features (large open passages in the rock) and the extent of grouting required to prevent leakage is generally unpredictable. The headraces involve concrete-lined tunnels with associated contact grouting problems in the limestone. The spillway empties directly into the river bed upstream of the power house, which will result in severe erosion of the river bed and likely deposition of alluvial material outside the power station tailrace. Maintenance costs will be high, and costly repair works may be necessary after each major flood.

According to all norms of dam engineering, the Lungga project must be considered as a high risk project, with a high likelihood of cost overruns due to unpredictable geological conditions.

TABLE H.6 - LUNGGA HYDROPOWER PROJECT

Data for cost/benefit analysis

Phase	Civil Works	Units Installed *	Year Commissioned	Annual energy (GWh)	Cost ** (million SI$)
I	Dam, power st. overflow	3 No	1991	50.0	100.0
II	-	1 No	1999	55.0	3.7
III	-	1 No	2001	60.0	3.7
IV	Spillway gate structure	uprating	2003	77.6	27.0

* Each unit is rated at 2.52 MW Phase I (FSL = 60 m)
uprated to 4.20 MW Phase IV (FSL = 70 m)

** Estimate updated to 1986 price levels

Firm capacity estimates:

2.6 MW in Phase I (guaranteed flow = 10 m3/s)
6 MW in Phase IV (guaranteed flow = 17 m3/s)

The following updated economic analysis has been carried out as part of the present study to investigate whether the Lungga project will be viable under any circumstances in the future. The analysis is a simplified one for ease of understanding and because of the amount of conjecture incorporated in many of the assumptions.

The Honiara system demand will be satisfied up to the end of 1990 by installation of a new 1.4 MW diesel unit and the proposed 3 MW dendrothermal plant. 1991 is the earliest possible commissioning date for the Lungga hydropower plant. The Lungga project data used in the present cost/benefit analysis are summarised in Table H.6. Only 3 units are required in 1991 according to the latest demand forecast with further units needed in 1999 and 2001 followed by spillway gates in 2003.

Assuming the latest demand forecast (Table H.3) it is possible to set up the cost and benefit streams of the Lungga project as presented in Table H.7. Design and construction costs totalling 100 million SI$ are spread over the years 1987 to 1990 inclusive, with Phases II, III and IV expenditure coming in years 1998, 2000 and 2002 respectively. The annual operation and maintenance cost is assumed to be 1.5% of the capital investment, amounting to 2 million SI$ after Phase IV. After operating for 30 years it is assumed that all Phase I electrical and mechanical equipment will need replacement at a cost of 11 million SI$ in 2020.

The benefits are calculated as the avoided cost of continued diesel and dendro operation up to 2020. Figures in the early years are identical to the Komarindi project analysis as set out in Table H.19, and start at 2.46 million SI$ in 1991, rising along with the hydropower contribution to demand until the total Lungga energy potential of 77.6 GWh replaces diesel in 2009, which is equivalent to 8.26 million SI$ p.a. In addition the avoided cost of installing 2.6 MW of diesel in 1990 and a further 3.4 MW in 2002 at 1170 SI$/kW are added (equivalent to Lunggas firm capacity contribution to the system).

TABLE H.7

LUNGGA HYDROPOWER PROJECT, Solomon Is. (Assumes ADB demand growth, 6% p.a.)

COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	10.00	0.00	9.09	0.00
1988	0.83	30.00	0.00	24.79	0.00
1989	0.75	30.00	0.00	22.54	0.00
1990	0.68	30.00	3.04	20.49	2.08
1991	0.62	1.50	2.46	0.93	1.53
1992	0.56	1.50	2.67	0.85	1.51
1993	0.51	1.50	2.86	0.77	1.47
1994	0.47	1.50	3.06	0.70	1.43
1995	0.42	1.50	3.29	0.64	1.40
1996	0.39	1.50	3.50	0.58	1.35
1997	0.35	1.50	3.70	0.53	1.30
1998	0.32	5.20	3.91	1.66	1.25
1999	0.29	1.50	4.12	0.43	1.19
2000	0.26	5.20	4.28	1.37	1.13
2001	0.24	1.50	4.45	0.36	1.07
2002	0.22	28.50	8.92	6.20	1.94
2003	0.20	2.00	6.05	0.40	1.20
2004	0.18	2.00	6.43	0.36	1.16
2005	0.16	2.00	6.80	0.33	1.11
2006	0.15	2.00	7.16	0.30	1.06
2007	0.14	2.00	7.53	0.27	1.02
2008	0.12	2.00	7.90	0.25	0.97
2009	0.11	2.00	8.26	0.22	0.92
2010	0.10	2.00	11.30	0.20	1.15
2011	0.09	2.00	8.26	0.18	0.76
2012	0.08	2.00	8.26	0.17	0.69
2013	0.08	2.00	8.26	0.15	0.63
2014	0.07	2.00	8.26	0.14	0.57
2015	0.06	2.00	8.26	0.13	0.52
2016	0.06	2.00	8.26	0.11	0.47
2017	0.05	2.00	8.26	0.10	0.43
2018	0.05	2.00	8.26	0.09	0.39
2019	0.04	2.00	8.26	0.09	0.36
2020	0.04	13.00	8.26	0.51	0.32
2021 onwards remainder :				0.78	3.23

NPC = 96.71 NPB = 35.59
Cost/Benefit ratio = 2.72

The results show that at 10% discount rate the cost/benefit ratio is 2.72, indicating the Lungga project to be totally uneconomic (Table H.7).

In order to test whether Lungga is uneconomic only because of the low present level og demand, it is assumed that Lungga's energy potential can be absorbed immediately, as might be the case if the Gold Ridge mine was developed. This scenario assumes the same construction sequence and hence the same cost stream as in Table H.7, but the benefits are increased as shown in Table H.8. Assuming the Phase I hydro potential of 50 GWh entirely replaces diesel at 10.64 SI cents/kWh gives an annual benefit of 5.32 million SI$ immediately after commissioning.

Even in this scenario the cost/benefit ratio is greater than 2.0, indicating the Lungga hydropower project to be totally uneconomic despite the most optimistic assumptions of power demand growth.

Furthermore, there are serious practical constraints with relying on a hydropower project to supply a mine development like Gold Ridge. Firstly, the lead time for the Lungga project is about 4 years after a firm committment is made to go ahead, and the capital repayment on the loans can run to 30 or 40 years. This is in stark contrast to the mine which will require power within 1 year of deciding to go ahead, and will only require power for its economic lifetime, estimated at 10 - 15 years for Gold Ridge. It will therefore be necessary to install provisional diesel units during the first few years of mining construction and operation while Lungga is being constructed.

Secondly the starting up of construction work on both the mine and the hydropower project simultaneously means an enormous capital drain on the economy within a short space of time. The infrastructure required in new access roads, housing, water and sanitation, port and transport facilities etc., will add even further to the capital requirement. Many large loans will be

TABLE H.8

LUNGGA HYDROPOWER PROJECT, Solomon Is. (Assumes unlimited demand)
COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	10.00	0.00	9.09	0.00
1988	0.83	30.00	0.00	24.79	0.00
1989	0.75	30.00	0.00	22.54	0.00
1990	0.68	30.00	3.04	20.49	2.08
1991	0.62	1.50	5.32	0.93	3.30
1992	0.56	1.50	5.32	0.85	3.00
1993	0.51	1.50	5.32	0.77	2.73
1994	0.47	1.50	5.32	0.70	2.48
1995	0.42	1.50	5.32	0.64	2.26
1996	0.39	1.50	5.32	0.58	2.05
1997	0.35	1.50	5.32	0.53	1.86
1998	0.32	5.20	5.32	1.66	1.70
1999	0.29	1.50	5.85	0.43	1.69
2000	0.26	5.20	5.85	1.37	1.54
2001	0.24	1.50	6.38	0.36	1.53
2002	0.22	28.50	10.35	6.20	2.25
2003	0.20	2.00	8.26	0.40	1.63
2004	0.18	2.00	8.26	0.36	1.49
2005	0.16	2.00	8.26	0.33	1.35
2006	0.15	2.00	8.26	0.30	1.23
2007	0.14	2.00	8.26	0.27	1.12
2008	0.12	2.00	8.26	0.25	1.01
2009	0.11	2.00	8.26	0.22	0.92
2010	0.10	2.00	11.30	0.20	1.15
2011	0.09	2.00	8.26	0.18	0.76
2012	0.08	2.00	8.26	0.17	0.69
2013	0.08	2.00	8.26	0.15	0.63
2014	0.07	2.00	8.26	0.14	0.57
2015	0.06	2.00	8.26	0.13	0.52
2016	0.06	2.00	8.26	0.11	0.47
2017	0.05	2.00	8.26	0.10	0.43
2018	0.05	2.00	8.26	0.09	0.39
2019	0.04	2.00	8.26	0.09	0.36
2020	0.04	13.00	8.26	0.51	0.32
2021 onwards remainder :				0.78	3.23

NPC = 96.71 NPB = 46.76
Cost/Benefit ratio = 2.07

required and most donors will not be prepared to take such high risks for a small economy like the Solomon Islands. On the other hand, the low investment cost of diesel generation sets is much more suitable for short-term use as foreseen at Gold Ridge.

It is evident from this simple but realistic analysis that the Lungga hydropower project is of the order of 2 - 3 times too costly to warrant further consideration. Even if the entire firm energy output of 77.6 GWh p.a. could be consumed by some future large consumer like Gold Ridge, the cost of power from Lungga would be double the present rate from diesel.

It is concluded that the Lungga hydropower project is definitely not economically viable and will not become viable under any circumstances within the foreseeable future. Smaller hydropower projects proposed in the next chapters present a more economic proposition, and it is therefore recommended that the Lungga project be discarded as a realistic alternative development.

H 3.4 Small Hydropower Projects for Honiara (1 - 10 MW)

Despite the impending construction of a dendrothermal power plant there is still scope for substituting diesel generation costs after the dendrothermal plant is commissioned in 1989. Hydropower projects of up to 10 MW producing up to 50 GWh annually and costing no more than 42 million SI$ are worthy of consideration at present fuel prices. These are commonly classified as "small hydro" projects.

These small hydro projects are typically run-of-the-river projects without seasonal reservoir storage. They utilise whatever flow is available in the river to substitute diesel (or dendro) generation. They have little or no reliable capacity because river flows in Guadalcanal drop to low levels or in some cases even dry up during the dry season.

TABLE H.9 - HYPOTHETICAL "BREAK-EVEN" PROJECT

Consider a project costing 8.5 million SI$.
Producing annually 10.0 GWh (from 2.5 MW installed)
Assume all 10 GWh can be absorbed in the Honiara system
Firm power 300 kW (q min. = 20% q avge.)
Operation and maintenance 2% of capital
Alternative cost of diesel energy 10.64 SI cents/kWh
Capital cost of diesel units 1170 SI$/kW (700 US$/kW)
Discount rate 10%.

Year	Costs (million SI$)	Benefits (million SI$)	Comments
1	0.5	-	Planning
2	1.0	-	Design/access
3	3.5	-	Construction
4	3.5	0.35	Construction
5	0.17	1.06	Commissioned
6	0.17	1.06	
7	0.17	1.06	
8	0.17	1.06	
etc.	etc.	etc.	

NPC = 8.22 NPB = 8.23 Cost/benefit ratio = 1.0

Conclusion:

Run-of-the-river projects costing 0.85 million SI$ per GWh annual production are marginally economic at present diesel prices (28.41 SI cents/litre - June 1986)

The advantage of such projects is that the cost of providing reservoir storage (i.e. dams) is considerably reduced. Only a concrete overflow structure or diversion weir is required to provide an intake pool or at the most a daily storage reservoir. The lack of firm capacity is substituted by thermal power units which can run in periods of low river flow. Since the Honiara system already has diesel (and soon dendrothermal) generation these can act as appropriate thermal back-up for such run-of-the-river hydropower projects at no additional cost.

It is relatively easy to analyse run-of-the-river projects because their benefits are equal to the annual average energy they produce multiplied by the marginal cost of generating that energy by existing diesel units (10.64 SI cents/kWh from Table H.4). A hypothetical run-of-the-river hydro project which is marginally economic has been set up and analysed in Table H.9.

The project is assumed to produce 10 GWh annually and will cost 8.5 million SI$. Such a project breaks even with diesel generation at 10% discount rate. Because the total benefits are directly proportional to the amount of energy the project produces, it is possible to conclude that 0.85 million SI$ per annual GWh produced is the "break-even" figure. Projects providing power at a capital cost of less than 0.85 million SI$ per annual GWh will prove to be economic provided their full energy potential can be used to substitute diesel generation. It is important to note that this figure applies to present diesel prices (28.41 cents/litre excl. duty) and will increase in proportion to any increase in diesel prices.

Investigations for hydropower development around Honiara have therefore centered on finding potential run-of-the-river projects of about 1 - 10 MW in size. It is conceivable that economic projects of less than 1 MW are available, but such "mini-hydro" projects still require good hydrological data, professional design by consultants, administration by government bodies, fully-trained operators and costly access roads and transmission lines without having the benefits of scale of larger alternatives. There is growing evidence internationally that mini-hydro projects of between 100 kW and 1 MW are usually among the most expensive per kWh produced when compared with small and large hydro (greater than 1 MW) and even some low-cost micro-hydro (less than 100 kW).

The author carried out a thorough search for project possibilities of any scale using the 1:50,000 topographical maps of Guadalcanal, followed by site inspection of the Mataniko, Tenaru, Tinahula, Kohove and Lungga rivers. Surprisingly very few possibilities emerged for the following reasons:

(i) The topography is not particularly suited to small hydro projects. Many rivers cut deep gorges with vertical sides or slopes which are lying at the critical stability angle of loose material (around 45^{o}). Such terrain renders canal and penstock construction very expensive and in some cases impossible.

(ii) The geology is very complex and the prevailing rocks are problematic for construction work such as tunnels and dam foundations. Limestone is frequent and usually karstic with caves, ducts and underground passages nearly impossible to seal. Other rocks are often soft, poorly cemented and easily erodible.

(iii) The variation in specific runoff from catchment to catchment is quite large, presumably due to the rapidly varying geological formations. There is a total lack of runoff data for small rivers, and it is therefore nearly impossible at this stage to predict which rivers have a high runoff suitable for hydropower projects.

(iv) Lack of access roads and even paths severely limits the area which can be investigated and will increase design and construction costs.

(v) Nearly all potential projects lie on custom owned land which makes it necessary to undergo a complex legal process, probably involving compensation payments and delays in investigation and construction work.

(vi) Honiara is among the driest areas of the Solomons, having an annual rainfall of only 2000 mm. There is a marked dry period from April to October in which the river flow becomes very low or totally dry (see Appendix D). Potential run-of-the-river schemes on small rivers cannot be relied on for firm capacity and full diesel back-up will be required for each hydro unit.

Nonetheless, it is possible to indicate from the present study which rivers have the most promising possibilities for small hydro development and which others can be discounted from further investigations. Only rivers on the north side of Guadalcanal within reasonable transmission distance of Honiara were considered. There is a large hydropower potential on the south side of Guadacanal where rainfall is much higher (8000 mm has been recorded) and the rivers fall more steeply. There is, however, no demand at present along the south coast, and transmission costs across the island are prohibitive for small projects.

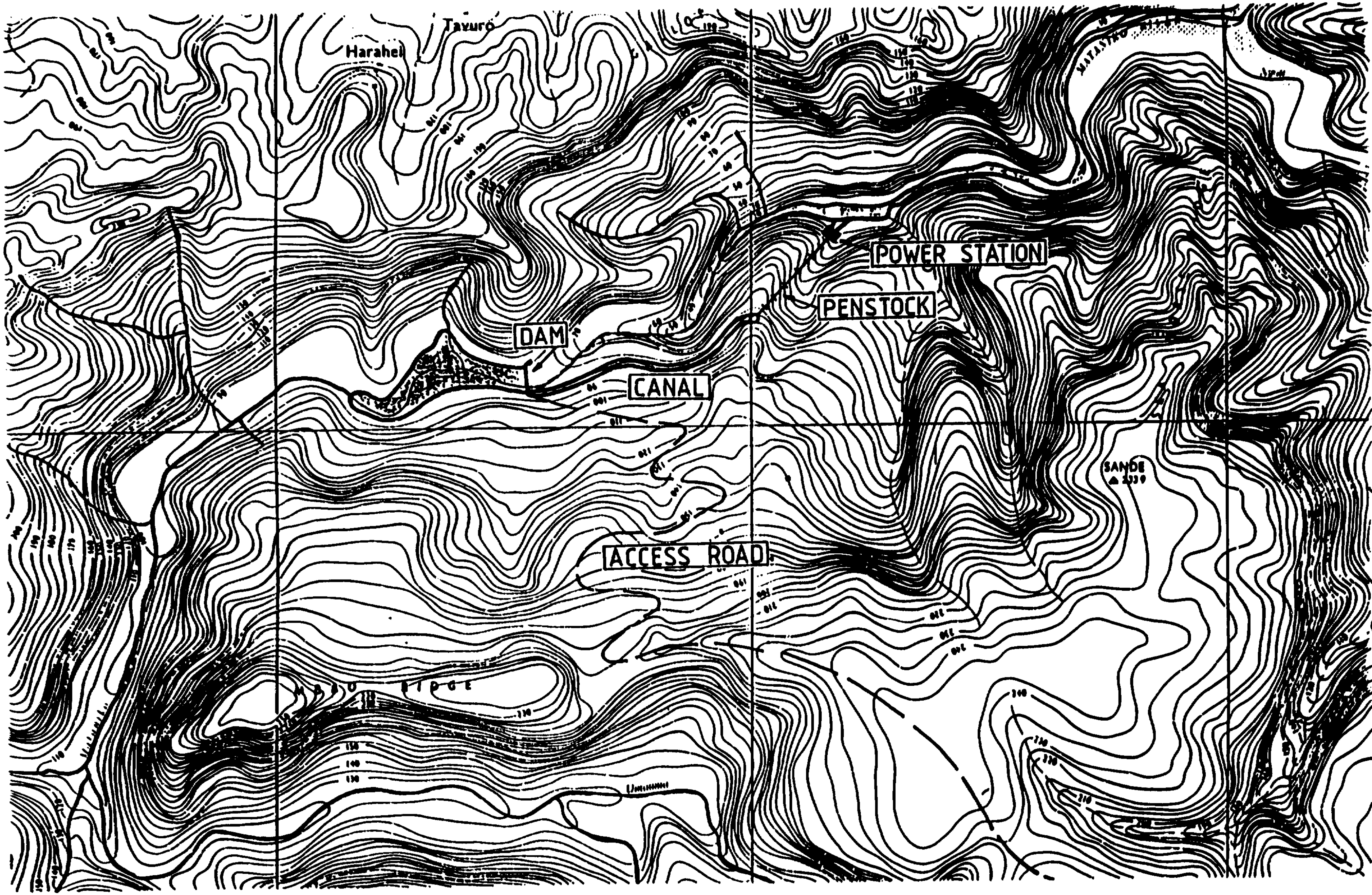


FIGURE F.4 - Matañiko hydropower project - general layout (scale 1:10,000)

Mataniko River

This is the nearest river of any size to Honiara, and has a spectacular waterfall within short walking distance known as Mataniko Falls. The project area has been mapped at 1:10,000 scale and is presented in Figure F.4.

A simple canal type of project is presented, similar to that of the UNDTCD survey (reference 2), except that the canal is considerably shortened to reduce project costs and avoid the steep slopes on which canal construction was proposed in reference 2. The revised project data are presented in Table H.10 and the cost estimates in Table H.11. The project will provide 5.0 GWh annually and cost 6.3 million SI$ to construct. Based on the break-even figure of 0.85 million SI$ per annual GWh the cost/benefit ratio is 1.48, clearly uneconomic.

The project proposal of reference 2 will be more costly at approx. 8 million SI$ at 1986 prices even assuming a headrace canal could be constructed in the steep terrain, which is very dubious.

Furthermore the project would largely destroy the Mataniko Falls as a beauty spot and as a sacred or holy place for most of the Guadalcanal people. It is therefore recommended that the Mataniko project be dropped as a viable power project. The Mataniko river may be developed as a suitable water supply source for Honiara as and when required.

Tenaru River

The Tenaru River drains a catchment area of 23 km2 adjacent to the Lungga river, and falls about 300 m in a reach of 5 km in length. At a level of 200 m above sea level it passes within 1.5 km of the Lungga River which runs at 27 m a.s.l. just below the proposed Lungga dam site (see Figure F.5). A short tunnel and penstock leading from the Tenaru to the Lungga will utilise 170 m of head to produce 11.7 GWh p.a. at a cost of 11.3 million SI$.

TABLE H.10 - MATANIKO PROJECT - KEY DATA

Catchment area	= 32.5 km2
Estimated annual runoff	= 1800 mm
Mean discharge (q)	= 1.85 m3/s (58.5 million m3 p.a.)
99% guaranteed discharge	= 0.46 m3/s (25% q)
Dam crest level	= 82 m
Normal tailwater level	= 15 m
Gross head	= 67 m
Total head losses	= 1.0 q2
Turbine discharge (1.2 MW)	= 2.4 m3/s
Annual energy potential	= 5.0 GWh
Installed capacity	= 2 x 600 kW horizontal Francis
Firm capacity	= 220 kW

TABLE H.11 - MATANIKO PROJECT - COST ESTIMATES

Civil Works	million SI$	
Land clearance	0.06	
Access roads (8 km)	0.32	
Intake weir (60 m long, 4 m high)	0.25	
Intake (2.3 m3/s max)	0.09	
Desilting basin	0.20	
Headrace tunnel (canal or pipe, 600 m long)	0.48	
Head pond	0.28	
Penstock (800 m dia, 270 m long)	0.40	
Power house	0.50	
Site establishment, preliminaries	0.38	
Sub-total		2.96
Contingencies (20%)		0.59
Electromechanical Equipment		
Generating equipment package (2 x 600 kW Francis)	1.00	
Transformers, switchgear	0.09	
Transmission line (2.5 km, 33 kW)	0.08	
Sub-total		1.17
Contingencies (15%)		0.18
Land aquisition and compensation		0.32
Engineering and administration		1.08
TOTAL INVESTMENT COST		6.30

Annual energy production = 5.0 GWh
Cost/benefit ratio = 1.48

TABLE H.12 - TENARU PROJECTS - KEY DATA

Upper dam site (Tenaru A):

Catchment area	= 17 km2	
Estimated annual runoff	= 2300 mm	
Mean discharge, q	= 1.24 m3/s	(39.1 million m3 p.a.)
99% guaranteed discharge	= 0.25 m3/s	(estimated at 20% q)
Dam crest level	= 350 m	

Lower dam site (Tenaru B):

Catchment area	= 23 km2	
Estimated annual runoff	= 2200 mm	
Mean discharge, q	= 1.60 m3/s	(50.6 million m3 p.a.)
99% guaranteed discharge	= 0.32 m3/s	(estimated at 20% q)
Dam crest level	= 200 m	

Tenaru A alternative:

Normal tailwater level	= 75 m	
Turbine axle level (Pelton)	= 80 m	
Gross head	= 270 m	
Total head losses	= 5.0 q2	
Turbine discharge (3.6 MW)	= 1.6 m3/s	(1.3 x q)
Annual energy potential	= 14.4 GWh	
Firm power	= 520 kW	

Tenaru B1 alternative (Lungga transfer):

Normal tailwater level	= 30 m	
Gross head	= 170 m	
Total head loss	= 2.0 q2	
Turbine discharge (2.5 MW)	= 1.8 m3/s	(20% q minus 0.3 m3/s)
Compensation flow	= 0.3 m3/s	constant all year
Annual energy potential	= 11.7 GWh	
Loss from compensation flow	= 3.7 GWh	
Net energy potential	= 8.0 GWh	
Firm power	= 0	

Tenaru B2 alternative:

Normal tailwater level	= 90 m	
Gross head	= 110 m	
Total head loss	= 2.0 q2	
Turbine discharge (1.8 MW)	= 2.1 m3/s	(estimated at 20% q)
Annual energy potential	= 7.5 GWh	
Firm power	= 240 kW	

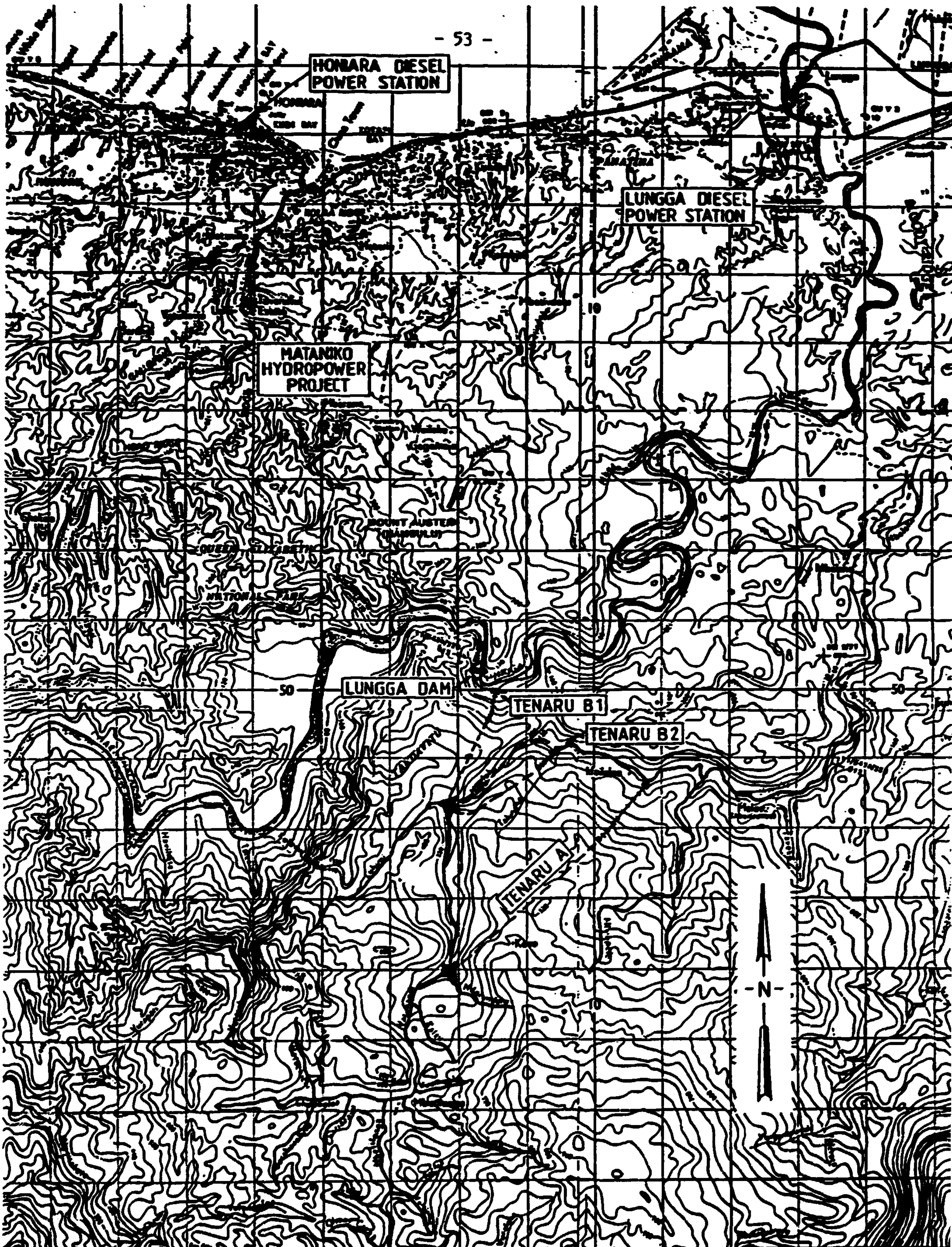


FIGURE F.5 - Tenaru project alternatives: general layout

Penstock
Tunnel

This project has one major drawback in that it transfers water from the Tenaru to the Lungga River, adversely affecting the large Tenaru river basin downstream. It will be necessary to release a compensation flow at least equivalent to the dry season flow in the river which is estimated at 20% of the mean flow or 300 l/s. This results in a lost annual power production of 3.7 GWh and complete loss of all power production during dry months. The remaining energy production is therefore 8.0 GWh p.a. mainly in the form of random power during wet weather and flood rises. This alternative is known as Tenaru B1 and is comparable with the UNDTCD proposal (reference 2).

Another alternative known as Tenaru B2 using a tunnel on the south bank and returning the water to the Tenaru River at a level of 90 m has been considered. In this case no compensation flow is required but the available head is less. Tenaru B2 would produce 7.5 GWh annually for an investment cost of 11.9 million SI$.

A third alternative has also been considered using a dam site higher up at 350 m, and a 3 km long tunnel to a power station site lower down on the Tenaru River. This is referred to as Tenaru A and would provide 14.4 GWh annually with an investment cost of 18.1 million SI$.

The Tenaru schemes are shown on Figure F.5 and key data given in Table H.12. Construction of the project will produce relatively few problems. The diversion weir can probably be founded on sound rock and the tunnel can be driven as a free surface flow headrace at a slope of 1.5 m per km. A small cross-section of excavation is adequate (6 m2) and labour intensive mining methods might be considered to keep the tunnelling cost to a minimum. A head pond and desilting basin is constructed at the tunnel exit. An 800 mm diameter steel penstock leads down to a power station either on the banks of the Lungga (Tenaru A) or on the Tenaru (B1 and B2). Flood rises on the Lungga can frequently be more than 5 m, and some head must be sacrificed in order to site the power station high enough for safety from floods.

TABLE H.13 - TENARU A - COST ESTIMATES

Civil Works	**million SI$**	
Land clearance	0.10	
Access roads and bridge (10 km)	0.60	
Diversion weir	0.15	
Intake	0.10	
Desilting basin	-	
Headrace tunnel (3 km, 6 m2 section)	6.00	
Head pond + desilting basin	0.50	
Penstock (1100 m, 800 dia)	1.10	
Power house	0.50	
Tailrace	0.05	
Site establishment, preliminaries	1.40	
Sub-total		10.50
Contingencies (20%)		2.10
Electromechanical Equipment		
Generating equipment (3.6 MW Pelton)	1.60	
Transformers, switchgear	0.12	
Transmission line (11 km, 33 kV)	0.28	
Sub-total		2.00
Contingencies (15%)		0.30
Land aquisition and compensation		0.70
Engineering and administration		2.50
TOTAL INVESTMENT COST		18.10

Annual energy production = 14.4 GWh

Cost/benefit ratio = 1.48

All the Tenaru alternatives require headrace tunnels of varying length. It is very difficult to predict the cost of such tunnels without knowledge of the geological conditions and properties of the rock encountered. The cost estimates represent typical costs for a small-section tunnel (6 m2) in medium poor quality rock with reinforced shotcrete lining and occasional concrete lining in parts with very poor rock stability.

It is very difficult to obtain access to the two dam sites, and neither one has been visited, although all power station sites were inspected. It must therefore be recognised that cost estimates are only accurate within about + 40% and - 20%. Similarly the power production estimates are also unreliable because of the total lack of runoff data. It is therefore dangerous to conclude anything on the feasibility of the Tenaru project alternatives. Preliminarily analyses indicate that they are not economic, although favourable geological conditions and favourable hydrological data could easily reverse this conclusion, as would a relative increase in diesel prices. Nevertheless, the Tenaru is the only river near Honiara on the north of Guadalcanal with interesting hydropower potential, with the exception of the Lungga River described in the next chapter.

TABLE H.14 - TENARU B1 - COST ESTIMATES

Civil Works	million SI$	
Land clearance	0.05	
Access roads (7 km)	0.30	
Diversion weir	0.15	
Intake	0.10	
Desilting basin	-	
Headrace tunnel (1.2 km 6 m2 section)	2.40	
Head pond and desilting basin	0.60	
Penstock (450 m, 800 dia)	0.50	
Power house	0.60	
Tailrace	0.10	
Site establishment, preliminaries	0.72	
Sub-total		5.52
Contingencies (20%)		1.10
Electromechanical Equipment		
Generating equipment (2x1.2 MW Francis)	1.40	
Transformers, switchgear	0.12	
Transmission line (9 km, 33 kV)	0.23	
Sub-total		1.75
Contingencies (15%)		0.26
Land aquisition and compensation		1.00
Engineering and administration		1.70
TOTAL INVESTMENT COST		11.33

Annual energy production = 8.0 GWh
Cost/benefit ratio = 1.66

TABLE H.15 - TENARU B2 - COST ESTIMATES

Civil Works	million SI$	
Land clearance	0.05	
Access roads and bridge (6 km)	0.40	
Diversion weir	0.15	
Intake	0.10	
Desilting basin	-	
Headrace tunnel (1.5 km, A = 6 m2)	3.00	
Head pond	0.50	
Penstock (250 m, 800 dia)	0.30	
Power house	0.60	
Tailrace	0.05	
Site establishment, preliminaries	0.75	
Sub-total		5.90
Contingencies (20%)		1.18
Electromechanical Equipment		
Generating equipment (2x1.5 MW Francis)	1.80	
Transformers, switchgear	0.12	
Transmission line (11 km, 33 kV)	0.28	
Sub-total		2.20
Contingencies (15%)		0.33
Land aquisition and compensation		0.49
Engineering and administration		1.80
TOTAL INVESTMENT COST		11.90

Annual energy production = 7.5 GWh
Cost/benefit ratio = 1.87

Other rivers

The Kohove River to the west of Honiara has a steep fall, but the flow at the lower level is known to dissappear regularly and be dry for several months during the dry season. It does not necessarily follow that the flow at a higher level dam site is equaly unreliable, but the chances are very slim that any viable hydropower project can be found in such conditions.

The Tina and Tinahula rivers to the east of Honiara have more reliable flows, but there is no concentrated fall shown on existing maps, and the valley sides are steep and unsuitable for canal construction. Headrace tunnels would have to run parallel to the rivers, a rather unfavourable direction for good rock stability, and the rock types found in the area are rather loose and somewhat unstable for tunnel construction. Several project configurations were investigated but none gives a cost/benefit ratio of less than 2.0. It is concluded that these rivers need not be investigated further for the time being as a source of hydropower potential.

TABLE H.16 - KOMARINDI PROJECT - KEY DATA

Catchment area, Komarindi dam = 137 km2
Estimated annual runnoff = 2600 mm +
(c.f. Lungga bridge, 377 km2 - 2300 mm from records)
Mean discharge = 11.3 m3/s (356 million m3 p.a.)
99% guaranteed discharge = 3.6 m3/s
Design flood = 2000 m3/s (estimated 1000 year return period)
Probable maximum flood = 3800 m3/s (100 mm runoff per hour)

Dam crest level	(HRWL)	=	220.0 m
Design flood level	(HFWL)	=	227.0 m
Normal tailwater level	(NTWL)	=	142.0 m
Tailwater in 1000 year flood	(HTWL)	=	147.0 m
Gross head		=	78.0 m
Total head losses		=	$0.04\ q_t^2$
Turbine discharge (q_t)	3MW	-	4.6 m3/s
	6MW	-	9.2 m3/s
	9MW	-	14.0 m3/s
Annual energy potential	3MW	-	26.0 GWh
	6MW	-	43.5 GWh
	9MW	-	52.0 GWh

Recommended phasing:

Phase A - 2 x 3 MW Horizontal Francis (1991)
Phase B - 1 x 3 MW Horizontal Francis (2002)

Firm capacity (99% guaranteed) = 2.4 MW

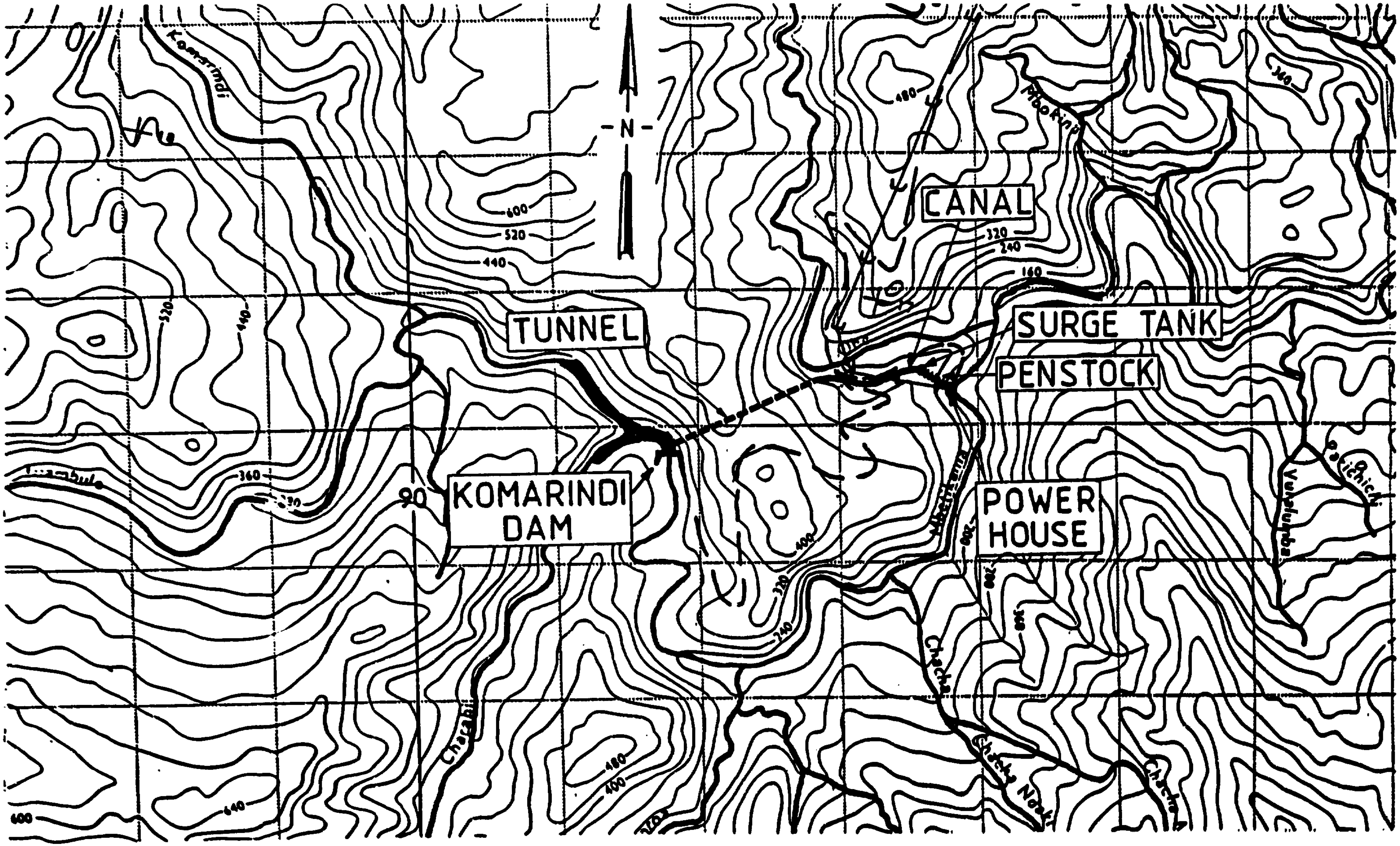
H 3.5 Komarindi Project (Lungga River)

The most suitable project for Honiara is located on the Komarindi River (a tributary of the Lungga River) some 20 km upstream of the Lungga gorge damsite. Just upstream of the Ohe River tributary the river forms a gradual bend with a fall of about 75 m. The Komarindi project short-cuts this bend with a 2 km long tunnel, thus producing 52 million kWh p.a. with 3 x 3 MW Francis turbines installed.

Komarindi is a run-of-the-river project which can guarantee 2.4 MW output even during the dry season. Only 2 x 3 MW units are to be installed initially but there is room for a third 3 MW unit when demand increases. The total output will then be 52 million kWh p.a. with apt opriate thermal back-up units to run during dry flow periods. This project alone will fulfill the hydropower requirements for Guadalcanal well into the next centruy.

The essential difference between this and the Lungga project is that Komarindi is a run-of-the-river project utilising a natural head. Thus the excessive dam costs of Lungga are avoided and the total project cost is much less (27 - 30 million SI$). The benefit from savings in fuel for the diesel and dendro plants is approximately the same as for Lungga, because the same demand is met by both projects. The only difference between Komarindi and Lungga is the lack of reservoir storage which means that power from Komarindi is mainly available in the wet season and the dendro and diesel units must run more often in the dry season.

There are many alternative layouts for the Komarindi project, and only a full feasibility study with detailed geological and topographical mapping will determine the best layout. Two alternatives are presented here as shown on Figures F.6 and F.7. The first involves a short tunnel going over to a contour headrace canal, surface penstock and power station, and is referred to as the surface alternative (Figures F.6 and F.11). The second is an



Penstock
Tunnel
Access road
Transmission line
Canal

FIG.F6:KOMARINDI PROJECT - SURFACE ALTERNATIVE
GENERAL LAYOUT

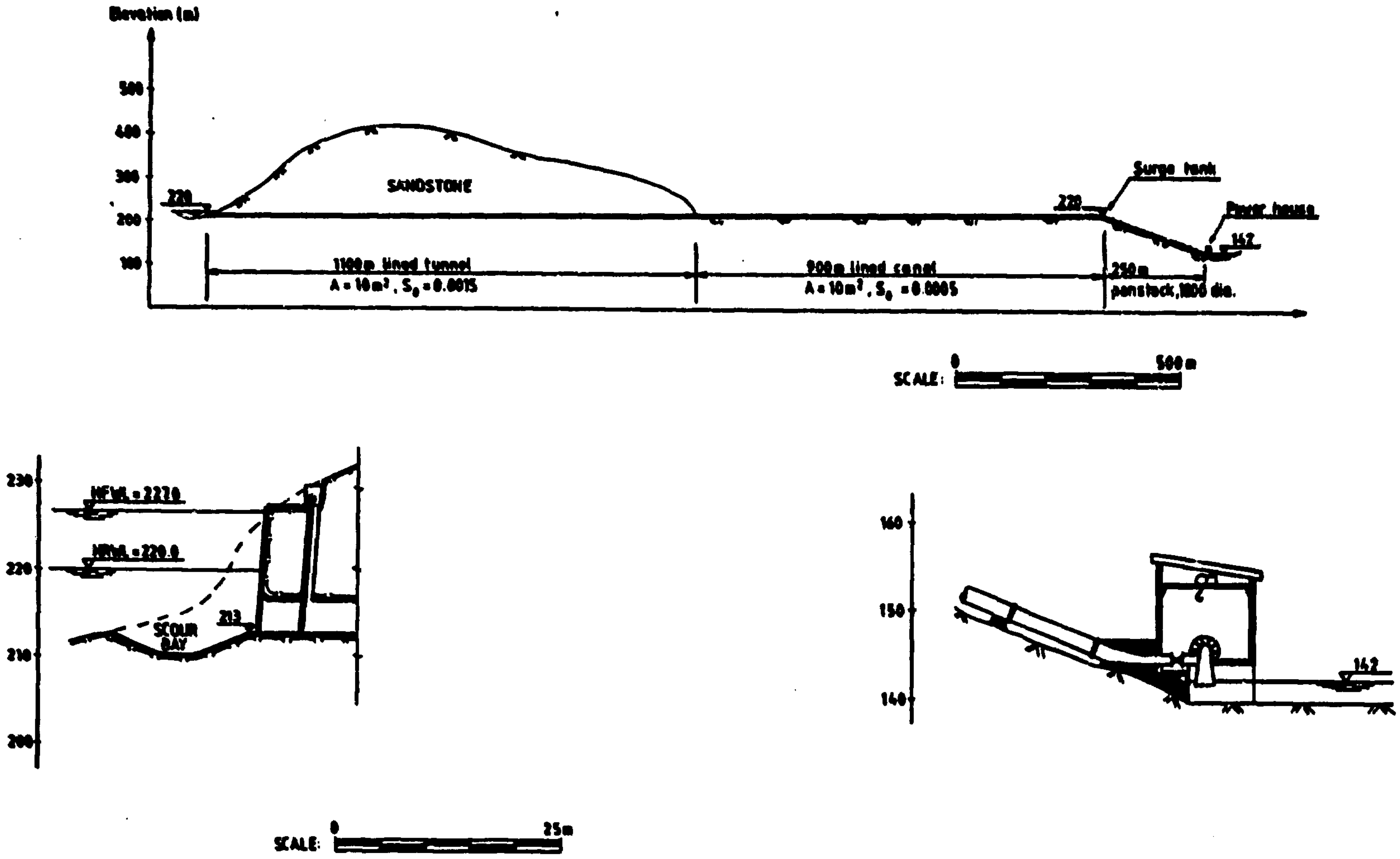
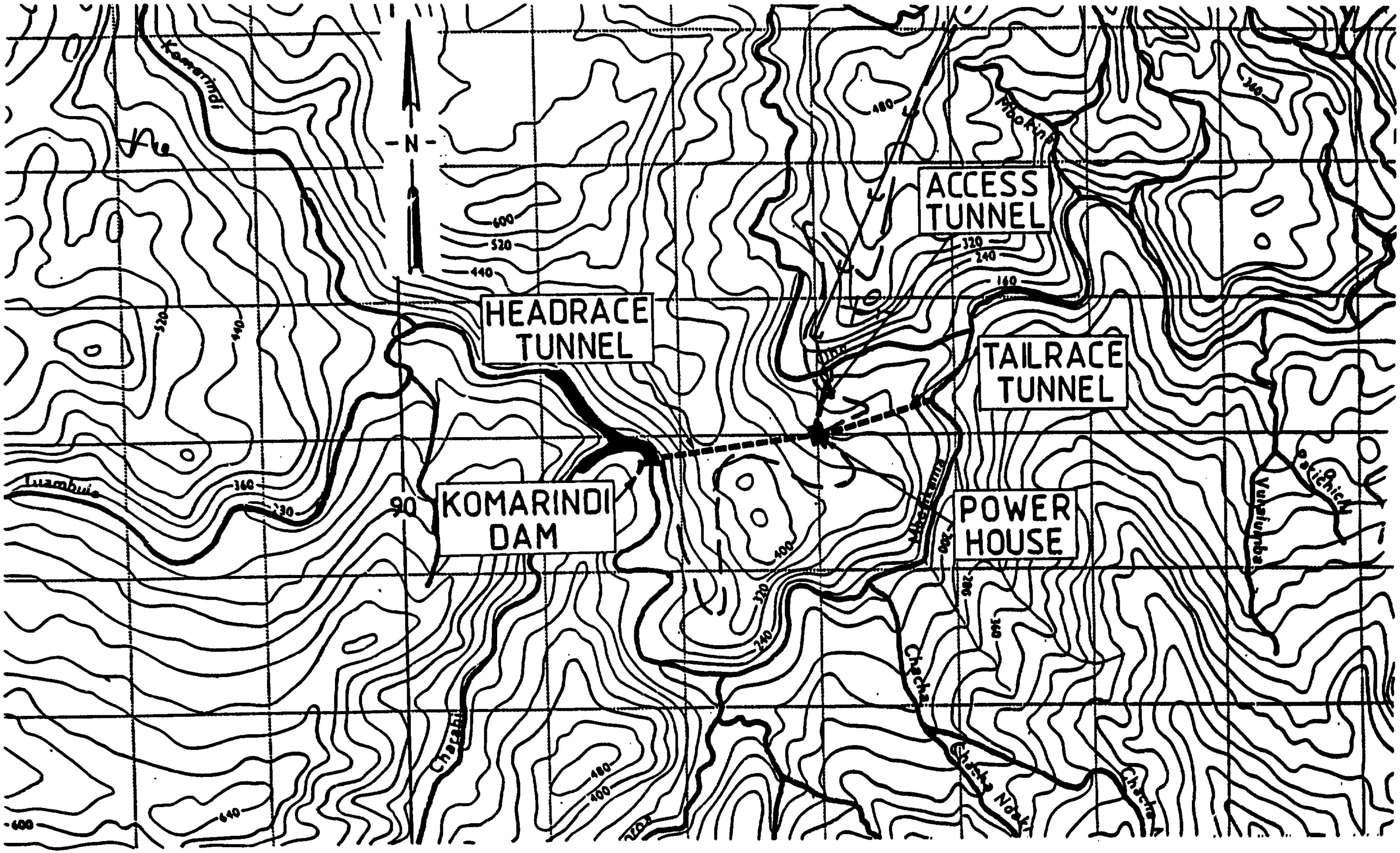


FIG. F.11 - KOMARINDI SURFACE PROJECT : SECTIONS



TRANSMISSION LINE
ACCESS ROAD

FIG. F7: KOMARINDI PROJECT - UNDERGROUND ALTERNATIVE
GENERAL LAYOUT

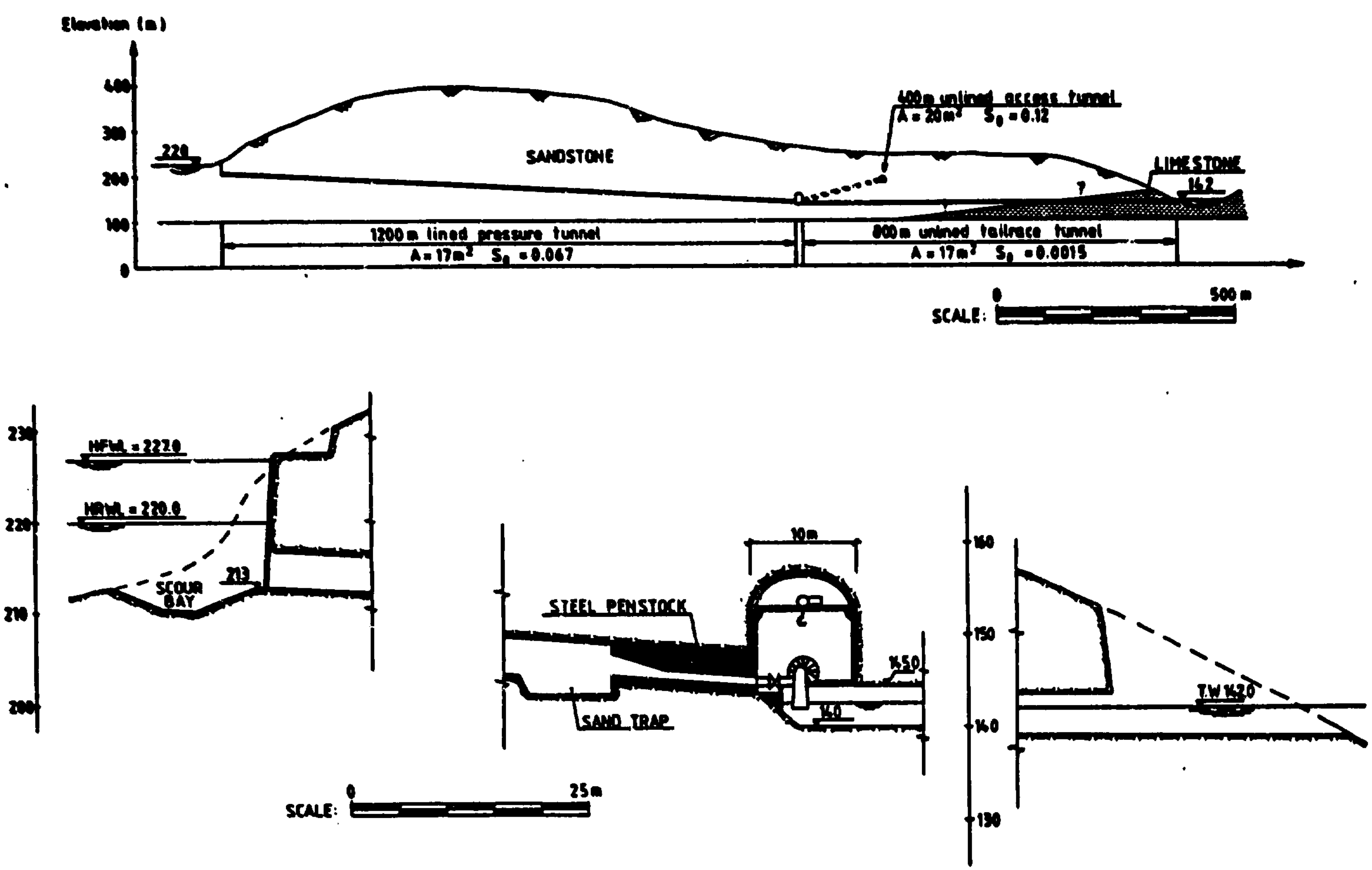


FIG. F.12 - KOMARINDI UNDERGROUND PROJECT: SECTIONS

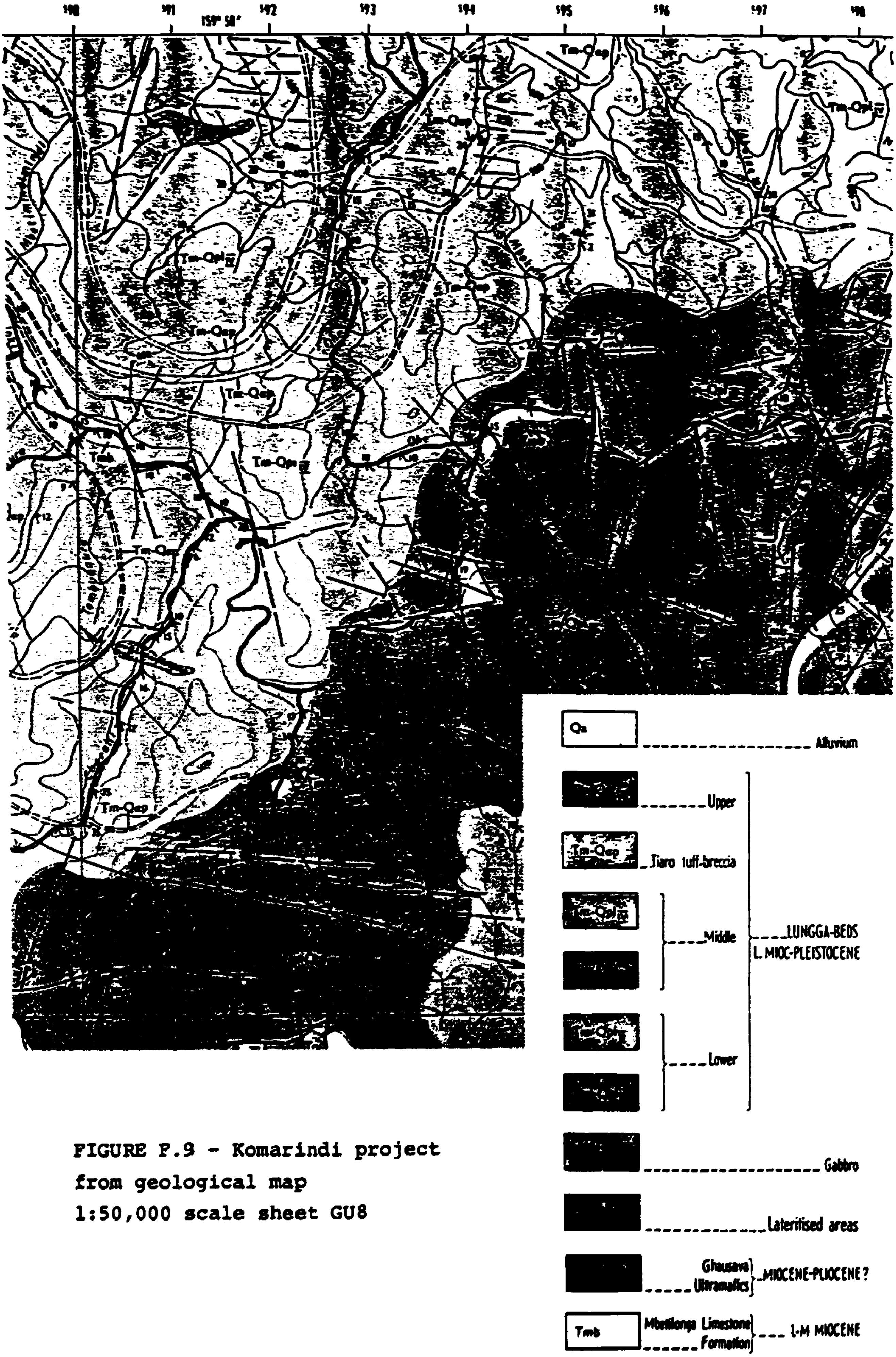


FIGURE F.9 - Komarindi project
from geological map
1:50,000 scale sheet GU8

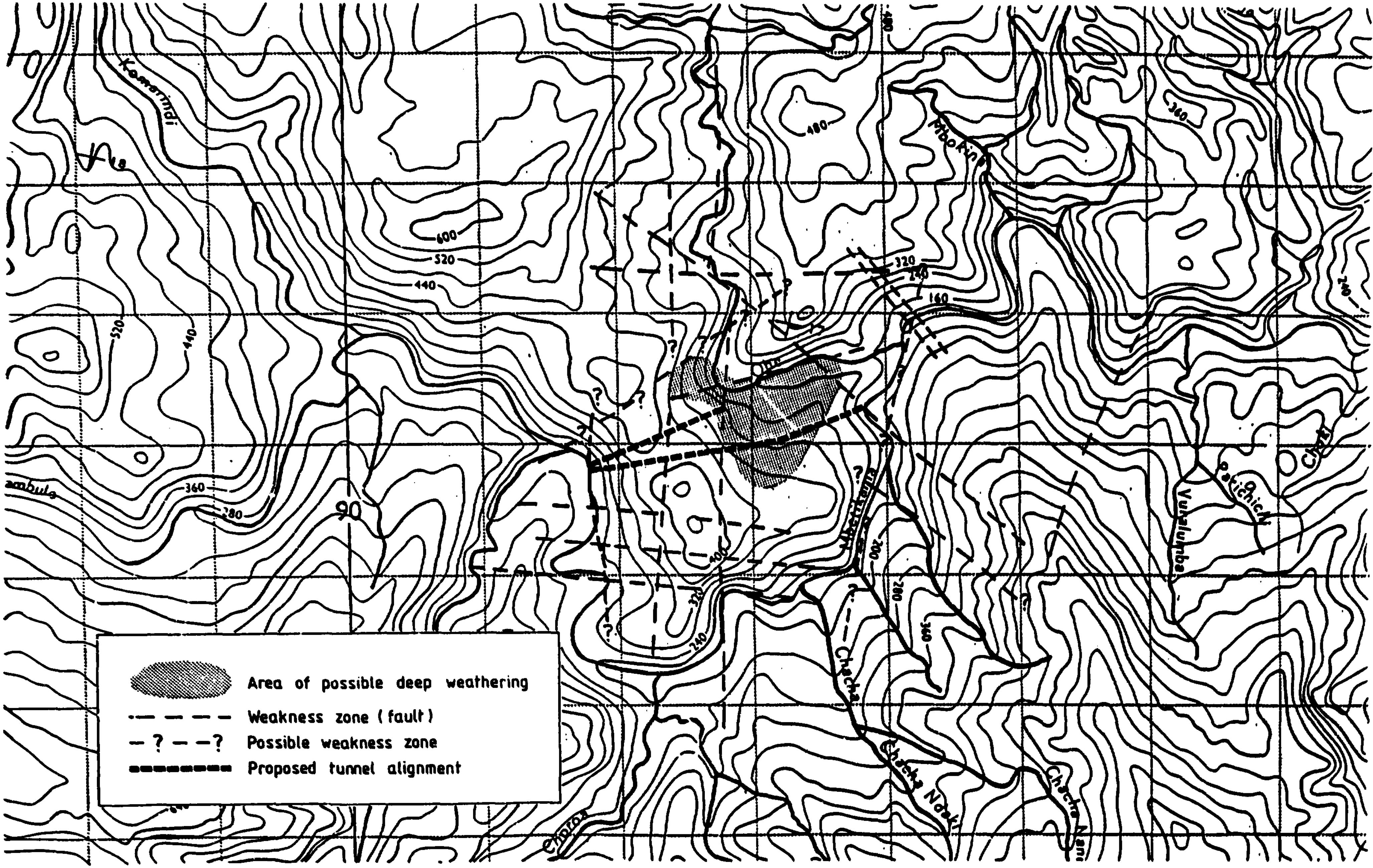


FIGURE F.10 - Komarindi project - Geological interpretation from aerial photographs underground power station and tunnel system and would be adopted in the event of unfavourable surface topography for canal construction (Figures F.7 and F.12). Both alternatives have advantages and disadvantages, and a preliminary cost comparison indicates very little difference between the two alternatives assuming medium poor rock conditions for tunnelling. Various other layouts are also possible, but they differ little in overall cost and are therefore not shown or described in this report.

Both alternatives have the same damsite and tailrace, (see Photographs 1 and 2) utilising a natural head of 75 m (+/- 5 m measured by altimeter). A concrete gravity overflow dam will be required about 10 m high to provide a small degree of storage for daily flow regulation. A useable reservoir storage of 90,000 m3 would enable 8 hours running at 6 MW followed by 16 hours at 3 MW, which corresponds to the typical weekday load variation pattern (see Figure F.2).

The dam will incorporate a large scour gate (about 4 m2 is suitable) positioned immediately below the tunnel intake in order to ensure that the intake remains free from sediment. Elsewhere the small reservoir can silt up without adversely affecting the operation of the power plant.

For the underground alternative the headrace comprises of a pressure tunnel leading down to an underground power house and a horizontal tailrace tunnel out to the river. This has the advantage of having all construction work underground and is less susceptible to damage from landslides, flooding and earthquakes.

The prevailing rock conditions will determine the best layout and the cost of this alternative, and a preliminary evaluation from aerial photographs indicates that the tunnel alignment is favourable and no unsurmountable problems are anticipated (see Figures F.9 and F.10). It is assumed that medium poor rock conditions are encountered and that the pressure headrace tunnel will require a full concrete lining. The tailrace tunnel will probably not need such a lining to prevent leakage, and reinforced shotcrete is likely to be sufficient to provide support and protection from erosion of soft rock types.

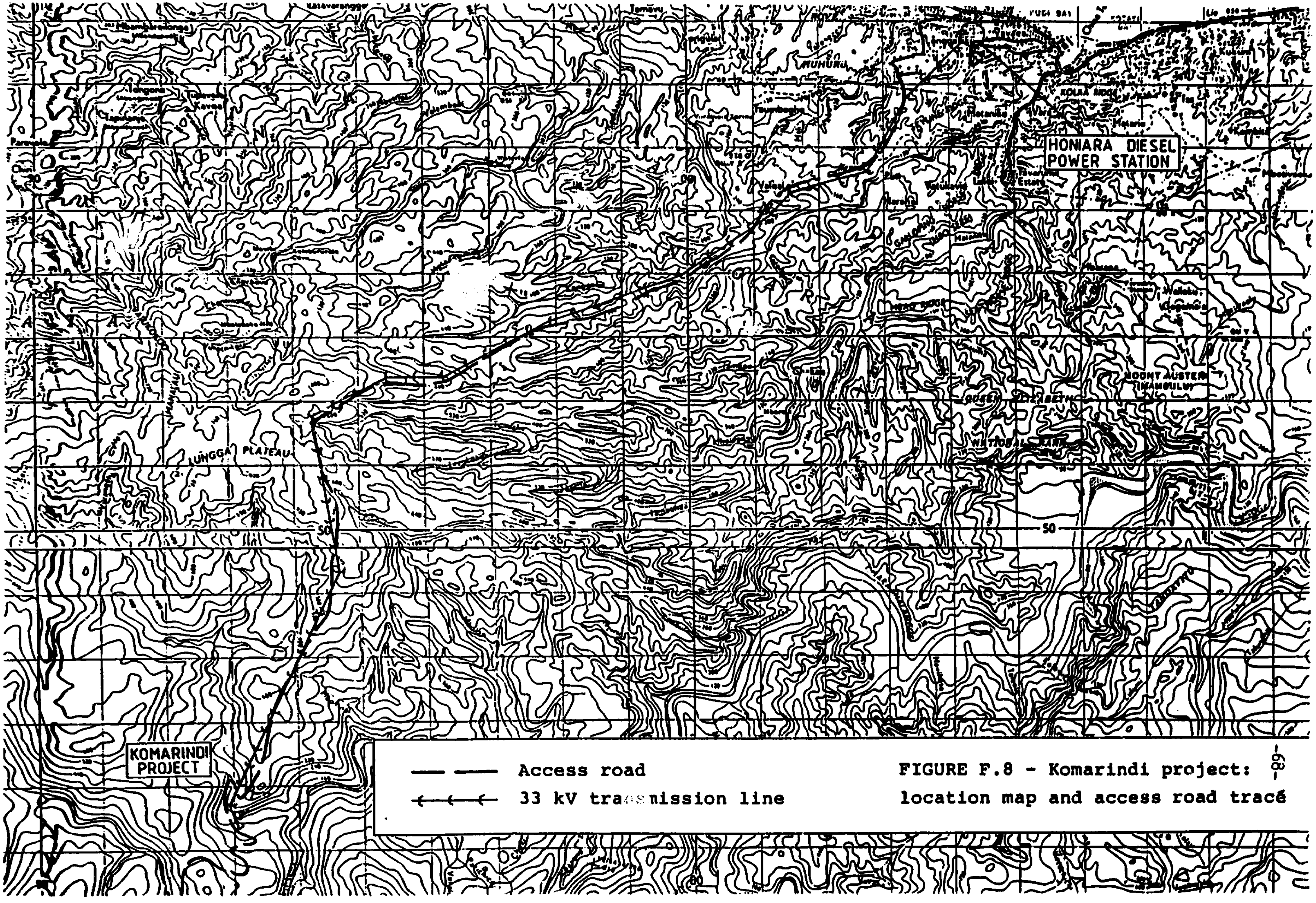


FIGURE F.8 - Komarindi project: location map and access road tracé

No headrace surge chamber is required with the proposed pressure tunnel since a flywheel and heavy generator will be sufficient to provide the required operation stability. A tailrace surge chamber may be required and can be constructed at little cost.

A 400 m long access tunnel also containing the 33 kV cables will lead up to the Ohe River where the 20 km access road and transmission lines to Honiara begin, as shown on Figure F.8.

A pump drainage system with standby generator and pump will ensure safety against flooding inside the power station at all times, even if the tailwater level is higher than the machine hall floor, which might occur during an extreme flood.

This underground power station solution is well tried and tested in many recent power plants in Norway, but is not yet well known internationally. Considerable savings can be achieved over surface alternatives if the geological conditions are well-mapped and the design is adapted to the prevailing rock conditions. Because there are no design restraints due to surface topography the designer has full flexibility to alter tunnel slopes and alignment to obtain the optimum least - cost solution.

For the surface alternative the headrace takes the form of a near horizontal tunnel from behind the scour gate leading through the ridge to a concrete-lined canal, a surge tank and penstock, as shown on Figure F.6. The power station is sited in the open (behind the helicopter in photograph 2) at a high enough level to be safe from flood rises. This layout represents a conventional solution, but necessitates good ground conditions for canal and penstock constructions.

At a later stage the flow of the Ohe River can also be utilised by constructing a diversion weir and canal or pipe leading into the headrace canal, but the extra energy is not required until well into the next century.

TABLE H.17 - KOMARINDI SURFACE ALTERNATIVE - COST ESTIMATES

Civil Works	Million SI$	
Land clearance	0.2	
Access road (26 km)	1.3	
Transfer tunnel (l=1150 m, 10 m2 section part concrete/shotcrete lined)	4.0	
Komarindi dam (l=60 m, max ht 10 m)	2.0	
Intake, scour and regulating facilities	0.6	
Headrace canal (l=900 m, 25 m2 section concrete lined)	2.7	
Desilting/Surge tank & penstock intake	0.5	
Penstock (l = 250 m, 1800 mm dia)	0.8	
Power station and tailrace	1.0	
Site establishment, contractors preliminaries	1.9	
Sub-total		15.0
Contingencies (20%)		3.0
Electromechanical equipment		
Turbines* (2 x 3.2 MW horizontal Francis)	1.4	
Generators** (2 x 4 MVA, 500 r.p.m.)	1.6	
Station ancilliary equipment, intake gate	0.6	
Transformers	0.2	
Transmission line (20 km, 33 kV)	0.7	
Sub-total		4.5
Contingencies (15%)		0.7
Land acquisition and compensation		1.0
Engineering and administrasjon		3.6
TOTAL INVESTMENT COST		27.6

* including valve, governor and associated mechanical equipment
** including associated control equipment

TABLE H.18 - KOMARINDI UNDERGROUND ALTERNATIVE - COST ESTIMATES

Civil Works	million SI$	
Land clearance	0.2	
Access road (26 km)	1.3	
Headrace tunnel (l=1200 m, 17 m2 section) concrete lined	4.8	
Tailrace tunnel (l=800 m 17 m2 section) shotcrete lined	2.4	
Access tunnel (l=400 m, 20 m2 section) shotcrete lined	1.2	
Komardindi dam (l=60 m, max ht 10 m) concrete gravity overflow	2.0	
Intake and scour facilities	0.4	
Concrete plug and penstock	0.3	
Underground power house (roof span 10 m)	1.3	
Site establishment, contractor preliminaries	2.2	
Sub-total		16.1
Contingencies (20%)		3.2
Electromechanical equipment		
Turbines * 2 x 3.2 MW horizontal Francis	1.4	
Generators** 2 x 4 MVA, 500 r.p.m.	1.6	
Station ancilliary equipment	0.4	
Transformers	0.2	
Transmission line (20 km, 33kV)	0.7	
Sub-total		4.3
Contingencies (15%)		0.7
Land acquisition and compensation		1.0
Engineering and administration		3.8
TOTAL INVESTMENT COST		29.1

* including valve, governor and associated mechanical equipment
** including associated control equipment

The additional energy would be about 8 GWh p.a. increasing the project output to 60 GWh p.a., but it is impossible to estimate the cost of the Ohe dam and headrace since the Ohe site has not been visited yet and the river bed level is not known.

The two alternatives have been costed using a conservative or pessimistic approach at this early stage of study. Both alternatives presented and other variations in layout cost between 27 and 30 million SI$ at 1986 prices for two 3 MW units. A further 3 MW unit could be installed to increase the average annual production to 52 million kWh, at a cost of an additional 3 million SI$, but this will not be required until the next century.

Environmentally the project is acceptable. A 5 - 6 km reach of the Komarindi river will be completely dry for much of the dry season, but there are no people living nearby in the dense jungle. The reservoir area is small(about 100,000 m2) and extends only a few metres up each river bank, causing no damage and submerging very little land. The use of tunnels avoids loss of land to surface structures and is much safer from the effects of cyclones, earthquakes, falling trees and landslides.

Project Analysis

The combination of Komarindi with the existing diesel and the future dendro station is a very economic way of fulfilling the Honiara system demand in the near future. In wet weather the Komarindi project will supply 3 - 6 MW depending on river flow. The dendro plant can operate at periods of high demand and during dry flow periods, with diesel on standby or used during occasional sudden peaks. The more expensive fuel resources for the dendro plant can be saved, and it may not be necessary to develop extensive plantations in order to guarantee all-year supplies to the dendro plants. Diesel consumption will drop to near zero and will only become significant around the year 2004, as shown in Table H.19.

	Energy Demand	Supply (GWh)			Savings (GWh)+		Energy Benefits (mill.SI$)		
	(GWh)	Hydro	Dendro	Diesel	Dendro	Diesel	Dendro	Diesel	Sum
1991	32.7	31.0	1.7	0	16.3	14.7	0.90	1.56	2.46
92	34.7	32.8	1.9	0	16.1	16.7	0.89	1.78	2.67
93	36.7	34.5	2.2	0	15.8	18.7	0.87	1.99	2.86
94	38.9	36.2	2.7	0	15.3	20.9	0.84	2.22	3.06
95	41.3	38.0	3.3	0	14.7	23.3	0.81	2.48	3.29
96	43.8	39.5	4.3	0	13.7	25.8	0.75	2.75	3.50
97	46.4	40.7	5.7	0	12.3	28.4	0.68	3.02	3.70
98	49.2	42.0	7.2	0	10.8	31.2	0.59	3.32	3.91
99	52.1	43.0	9.1	0	8.9	34.1	0.49	3.63	4.12
2000	55.2	43.0	12.2	0	5.8	37.2	0.32	3.96	4.28
01	58.5	43.0	15.5	0	2.5	40.5	0.14	4.31	4.45
02	62.0	49.0 *	13.0	0	5.0	44.0	0.27	4.68	4.95
03	65.7	49.8	15.9	0	2.1	47.7	0.12	5.08	5.20
04	69.7	50.6	18.0	1.1	0	50.6	0	5.38	5.38
05	73.9	51.3	18.0	5.6	0	51.3	0	5.46	5.46
06	78.3	52.0	18.0	8.3	0	52.0	0	5.53	5.53
07	83.0	52.0	18.0	13.0	0	52.0	0	5.53	5.53

* 3rd hydro unit commissioned

\+ without hydro assumes 18 GWh dendro and remainder diesel

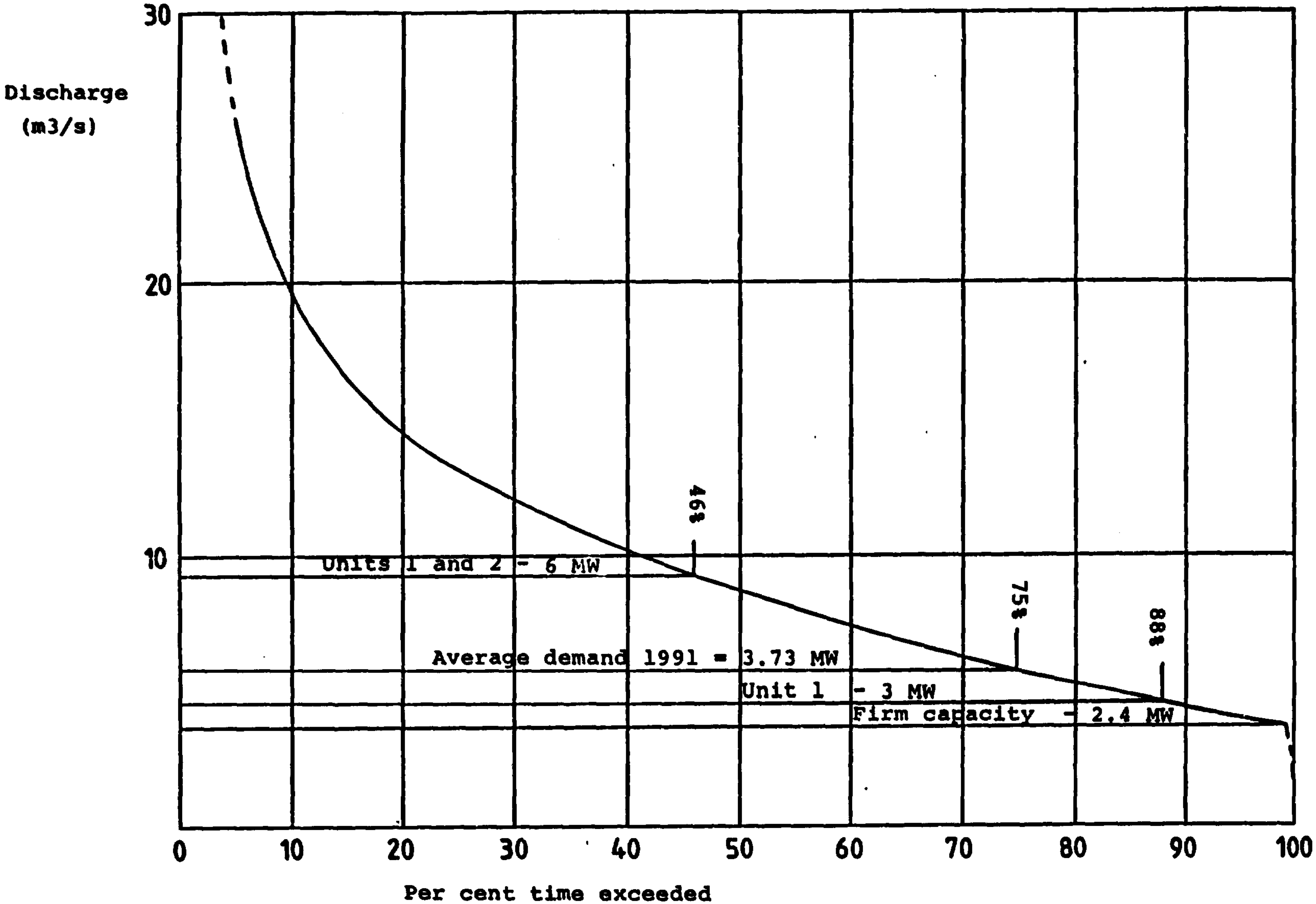
TABLE H.19 - Komarindi hydropower project option - Calculation of energy benefit

The Komarindi project is analysed by a standard economic cost/benefit technique where the benefits are equivalent to the avoided cost of diesel generation expansion if Komarindi is not constructed. This latter alternative is known as the "diesel option" and is set out in Table H.5. The system annual energy demand is assumed to be met by 18 GWh from the dendro plant and the remainder met by diesel plant (14.7 GWh in 1991 rising to 37.2 GWh in the year 2000).

For the Komarindi option it is still necessary to install new diesel units to meet the system capacity except for 2.4 MW which is the guaranteed capacity from Komarindi during the lowest river flow. The capacity benefit is therefore the avoided cost of 2.4 MW of diesel capacity or 2.76 million SI$ in 1990.

The energy benefits are much larger and more difficult to calculate. This has been done by a graphical method used for mixed hydro/thermal systems where the area under the capacity duration curve (Figure F.13) of the hydro plant is integrated and compared with the load duration curve predicted for various years in the future.

The results are presented in Table H.19 where the contribution from hydro, dendro and diesel to the system energy demand is shown for an average hydrological year. As can be seen the diesel plant is not required until about 2004 and can remain on standby. The dendro contribution is also small but increases to its full potential of 18 GWh in 2004. The hydro contribution is by far the largest and increases to the Phase 1 potential of 43 GWh in 1999. By 2002 it is economic to install the third 3 MW Komarindi unit and this increases the hydro contribution again until the full potential of 52 GWh is utilised in 2006.



* Based on data from Lungga Bridge (reference 2 figure 1])

FIGURE F.13 - Flow duration curve *
Komarindi Dam (Catchment 137 km2)

By subtracting these dendro and diesel columns from the diesel option equivalents (18 GWh dendro and the remainder diesel) the savings in energy production from the dendro and diesel plants can be calcultated, as presented in the next 2 columns in Table H.19. These are then converted to monetary terms by multiplying by the respective energy costs of 5.5 cents/kWh for dendro generation and 10.64 cents/kWh for diesel generation. The sum of these two components gives the total energy benefit of the Komarindi hydropower project.

The capacity benefit in the year 1990 is added and this forms the total benefit stream set up in Table H.20. The Komarindi cost stream is also set up by dispersing the design and construction costs from Table H.17 during the construction period 1987 - 1990, and thereafter allowing 2% p.a. for operation and maintenance.

In addition the third unit cost of 3 million $ is added in 2001, the operation and maintenance cost increases accordingly and the first two hydro units require replacement in the year 2020.

The cost and benefit streams are now complete in 1986 real cost terms, and by discounting these figures at the appropriate discount rate and comparing net present costs and benefits (NPC and NPB) a value for the cost/benefit ratio is obtained. At 10% discount this is 0.84 and at 12% discount this is 1.01 (the equalising discount rate) as shown in Tables H.20 and H.21 respectively.

TABLE H.20

KOMARINDI HYDROPOWER PROJECT, Solomon Is.
COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	1.00	0.00	0.91	0.00
1988	0.83	2.60	0.00	2.15	0.00
1989	0.75	12.00	0.00	9.02	0.00
1990	0.68	12.00	2.76	8.20	1.89
1991	0.62	0.55	2.46	0.34	1.53
1992	0.56	0.55	2.67	0.31	1.51
1993	0.51	0.55	2.86	0.28	1.47
1994	0.47	0.55	3.06	0.26	1.43
1995	0.42	0.55	3.29	0.23	1.40
1996	0.39	0.55	3.50	0.21	1.35
1997	0.35	0.55	3.70	0.19	1.30
1998	0.32	0.55	3.91	0.18	1.25
1999	0.29	0.55	4.12	0.16	1.19
2000	0.26	0.55	4.28	0.14	1.13
2001	0.24	3.55	4.45	0.85	1.07
2002	0.22	0.61	4.95	0.13	1.08
2003	0.20	0.61	5.20	0.12	1.03
2004	0.18	0.61	5.38	0.11	0.97
2005	0.16	0.61	5.46	0.10	0.89
2006	0.15	0.61	5.53	0.09	0.82
2007	0.14	0.61	5.53	0.08	0.75
2008	0.12	0.61	5.53	0.07	0.68
2009	0.11	0.61	5.53	0.07	0.62
2010	0.10	0.61	8.29	0.06	0.84
2011	0.09	0.61	5.53	0.06	0.51
2012	0.08	0.61	5.53	0.05	0.46
2013	0.08	0.61	5.53	0.05	0.42
2014	0.07	0.61	5.53	0.04	0.38
2015	0.06	0.61	5.53	0.04	0.35
2016	0.06	0.61	5.53	0.03	0.32
2017	0.05	0.61	5.53	0.03	0.29
2018	0.05	0.61	5.53	0.03	0.26
2019	0.04	0.61	5.53	0.03	0.24
2020	0.04	5.61	5.53	0.22	0.22
2021 onwards remainder :				0.24	2.16

NPC = 25.08 NPB = 29.78
Cost/Benefit ratio = 0.84

TABLE H.21

KOMARINDI HYDROPOWER PROJECT, Solomon Is.
COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 12.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.89	1.00	0.00	0.89	0.00
1988	0.80	2.60	0.00	2.07	0.00
1989	0.71	12.00	0.00	8.54	0.00
1990	0.64	12.00	2.76	7.63	1.75
1991	0.57	0.55	2.46	0.31	1.40
1992	0.51	0.55	2.67	0.28	1.35
1993	0.45	0.55	2.86	0.25	1.29
1994	0.40	0.55	3.06	0.22	1.24
1995	0.36	0.55	3.29	0.20	1.19
1996	0.32	0.55	3.50	0.18	1.13
1997	0.29	0.55	3.70	0.16	1.06
1998	0.26	0.55	3.91	0.14	1.00
1999	0.23	0.55	4.12	0.13	0.94
2000	0.20	0.55	4.28	0.11	0.88
2001	0.18	3.55	4.45	0.65	0.81
2002	0.16	0.61	4.95	0.10	0.81
2003	0.15	0.61	5.20	0.09	0.76
2004	0.13	0.61	5.38	0.08	0.70
2005	0.12	0.61	5.46	0.07	0.63
2006	0.10	0.61	5.53	0.06	0.57
2007	0.09	0.61	5.53	0.06	0.51
2008	0.08	0.61	5.53	0.05	0.46
2009	0.07	0.61	5.53	0.05	0.41
2010	0.07	0.61	8.29	0.04	0.55
2011	0.06	0.61	5.53	0.04	0.33
2012	0.05	0.61	5.53	0.03	0.29
2013	0.05	0.61	5.53	0.03	0.26
2014	0.04	0.61	5.53	0.03	0.23
2015	0.04	0.61	5.53	0.02	0.21
2016	0.03	0.61	5.53	0.02	0.18
2017	0.03	0.61	5.53	0.02	0.16
2018	0.03	0.61	5.53	0.02	0.15
2019	0.02	0.61	5.53	0.01	0.13
2020	0.02	5.61	5.53	0.12	0.12
2021 onwards remainder :				0.11	0.98

NPC = 22.79 NPB = 22.48
Cost/Benefit ratio = 1.01

Conclusion

The Komarindi project shows a cost-benefit ratio of 0.84 at 10% discount compared with a continued diesel expansion programme. This is equivalent to a 12% internal rate of return, and indicates the project to be viable even at the present low level of demand. If the dendro plant is for some reason cancelled, or if the demand growth is more rapid than predicted, or if Gold Ridge mine is developed, the Komarindi project becomes more economic, and would be more urgently needed.

It is concluded that a feasibility study of the Komarindi hydropower project is urgently required, and this should be carried out in 1987 to enable commissioning early in 1991. In preparation for the feasibility study, it is recommended that the Solomon Islands Government take the following action as soon as possible:

1. On the basis of the plans in this pre-feasibility report, negotiate with custom landowners for the right to access and free passage for surveyors, drillers, engineers etc. at least for a 2-year study and design period.

2. Cut a bush track from the nearest road access and install 2 river gauging stations, one on the Komarindi River and one on the Ohe River as near the relative dam sites as possible. Reinstate the river gauging stations at Lungga gorge and Lungga bridge to enable correlations to be made with these stations.

3. Design an access road alignment and obtain clearance from landowners in readiness to commence construction.

4. Set up ground control points and commence mapping of the site at 1:10,000 scale with 5 m contour intervals. If exact mapping proves to be too costly because of practical difficulties, an approximate map should be constructed using the existing aerial photographs. This map will enable the consultants to start immediately with preliminary design rather than carrying out this mapping themselves. More detailed mapping of local areas will be required during the feasibility study itself.

5. Negotiate with donors for funding a feasibility study to commence in early 1987. Only consultants who have up-to-date experience with tunnelling and underground power stations should be selected, because rock conditions are likely to be critical to the design, and good rock engineering is critical to the cost.

H 4 - Conclusions and Recommendations

The Honiara system demand is likely to grow at about 6% p.a. in the foreseeable future. It is necessary to plan for installation of additional generating capacity after the commissioning of the 3 MW dendro thermal plant in 1990 because several of the existing diesel units are due for retirement soon. The alternatives are diesel, dendro and hydro because other types of generating plants were not found to be competitive by the ADB (reference 1).

Because of uncertainties about the fuel resources for additional dendro thermal plants after the initial 3 MW, this alternative has been discounted and analysis of hydro power plants has been compared with a sequence of new diesel units to be installed as and when required.

Several alternative hydropower projects have been proposed utilising the Mataniko, Tenaru, Lungga and Komarindi Rivers. The most economic of these is the Komarindi River, a tributary of the Lungga. Only this project has a clearly positive economic benefit compared with the diesel option although one of the Tenaru projects might become marginally economic after further design and optimisation work.

There are many practical problems with design and construction of hydropower plants on Guadalcanal, and earlier over-optimistic cost estimates and time frames must be revised to represent the realities of the present situation. The key factors are:

1. Land ownership and compensation. All hydropower development lies on custom lands, and it will be necessary to negotiate with land owners for access to carry out studies and investigations and later to negotiate compensation payments when the project is constructed. These compensation payments must reflect the real value of damage and loss of land, and hard negotiations will be necessary.

2. Access. The access into most of the sites is at present limited to wading up river during low flows or helicopter. It will be necessary to cut bush paths for access during the feasibility study, and wider tracks or helicopter landing places to bring in drilling equipment for site investigations. All this work will also involve negotiations with custom landowners.

3. Geological conditions. The geology of Guadalcanal is very complex and variable, and the rock types are generally unsuitable for hydropower projects. Limestone is frequent and leakage paths are common. Other rock types are soft and erodible and landslides are frequent. In addition, Guadalcanal is prone to earthquakes which can also result in severe landslides.

4. Topography. Most rivers cut deep gorges with vertical or unstable rock faces on both sides. The type of projects which involve a headrace canal or penstock are very difficult to locate in the steep terrain and the risk of damage from landslides or falling trees is high.

5. Lack of runoff data and general unreliability of low flow discharge in most rivers. Only the Lungga catchment has sufficient data for detailed study and design work. Projects on any other river will require at least 1 year of good data before studies can be carried out.

For these reasons it is necessary to adopt a conservative approach to estimating project costs and plan with room for delays during planning and construction work.

TABLE P.1 - Auki system: monthly generation (figures in MWh)

	1984	1985	1986
Jan.	67	57	61
Feb.	64	57	66
Mar.	66	56	72
Apr.	63	72	
May	64	49	
Jun.	59	73	
Jul.	53	45	
Aug.	74	42	
Sep.	52	65	
Oct.	64	44	
Nov.	60	53	
Dec.	57	50	
ANNUAL	743	663	(800) estimated

Estimated Annual Growth

	Peak (kW)	Energy	Comments
1983	127	670	
1984	131	690	Actual 743
1985	138	725	Actual 663 (outages)
1986	145	761	Estimate 800 MWh, 148 kW
1987	152	799	
1988	160	839	
1989	168	881	
1990	176	925	
1995	225	1180	Prediction by ADB (ref. 1)
2000	287	1506	for extended supply area - 5% p.a.
2005	366	1922	
2010	467	2453	
2015	596	3130	
2020	761	3996	

P1 - AUKI

The Present Auki System

Although connection was previously limited to a designated central area of Auki, such limitations are now lifted so that new consumers can be connected anywhere within reasonable distance of the existing 3.3 kV network, which extends from the Kiluufi Hospital in the north to Abu in the south.

The monthly generation figures are given in Table P.1 and although a temporary fall in demand is visible in 1985, the 1986 figures are very similar to the ADB predictions (reference 1). The 1985 drop might be explained by constraints and outages prior to the new 190 kW unit being commissioned.

The present diesel station contains 2 No. 160 kW units from 1936 and 1952 respectively, one of which was undergoing a major overhaul on the day of the visit. A new 190 kW (238 kVA) unit was installed in 1985, apparently on semi-permanent loan. This unit must remain at Auki until commissioning of the first hydro project if power rationing is to be avoided.

Diesel is delivered in barrels with consequent storage and handling problems including leakage and time consuming hand-pumping. This accounts for relatively high fuel consumption and expensive operation and maintenance costs. Eleven men are employed full-time at Auki, and some additional staff have been brought in from Honiara for major repair work.

The system operates 24 hours a day and the shape of the typical load curves is given in Figure F.14 (from reference 1). Their shape is still typical for 1986, with maximum daily peaks between 100 kW and 150 kW and a load factor of about 0.6. The maximum peak recorded in April 1986 was 148 kW.

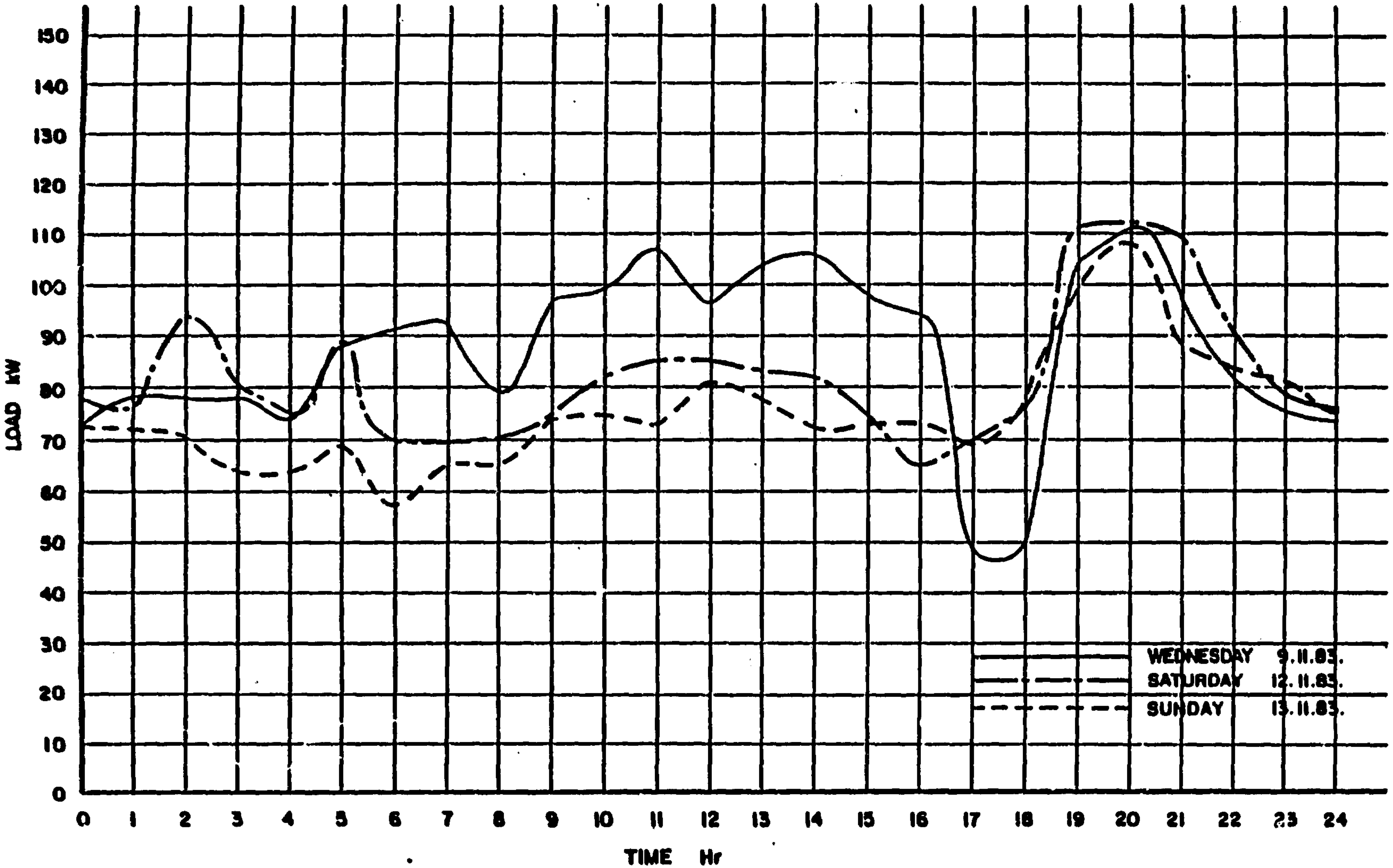


FIGURE F.14 - Auki system daily load curves

Neither of the old units is capable of 148 kW output alone, because of the poor power factor of the system (0.5 - 0.8), and the load will soon reach the capacity of the new 238 kVA unit.

The size of hydropower project which would be suitable for Auki is therefore 100 - 300 kW, matching the expected demand towards the next century. Investment cost should not exceed 2 million SI$ if the hydro project is to be more economic than continued diesel operation. There is an urgent need for new generation units at Auki, and if a hydro project is not forthcoming immediately new diesel units will be required.

As the Auki system grows, there will become a pressing need to upgrade the transmission system to 11 kV. This aspect should be reviewed in connection with any future hydropower plant.

Kwaibala River

The Kwaibala River flows to the south east of Auki, and is of the right size for mini hydro development of up to 200 kW. Two potential projects have been identified as shown on Figure F.15. The lower site has been surveyed, but the suitability of the upper site did not become apparent until after field work was completed. The upper site should also be surveyed as part of the further work.

Lower Kwaibala Project - Description

The lower project is located 2 km upstream of the estuary at Auki. The river takes a 180^{o} bend and drops 11 m in a series of steps formed by limestone ledges. The bend can be short-cut by forming a headrace canal 100 m long around the contour to an intake and a 40 m long penstock leading to a power station containing a single 100 kW turbine. A further 1 - 2 m of fall could be utilised by excavating a long tailrace in the limestone and carrying out some minor rock excavation in the riverbed to lower the tailwater level.

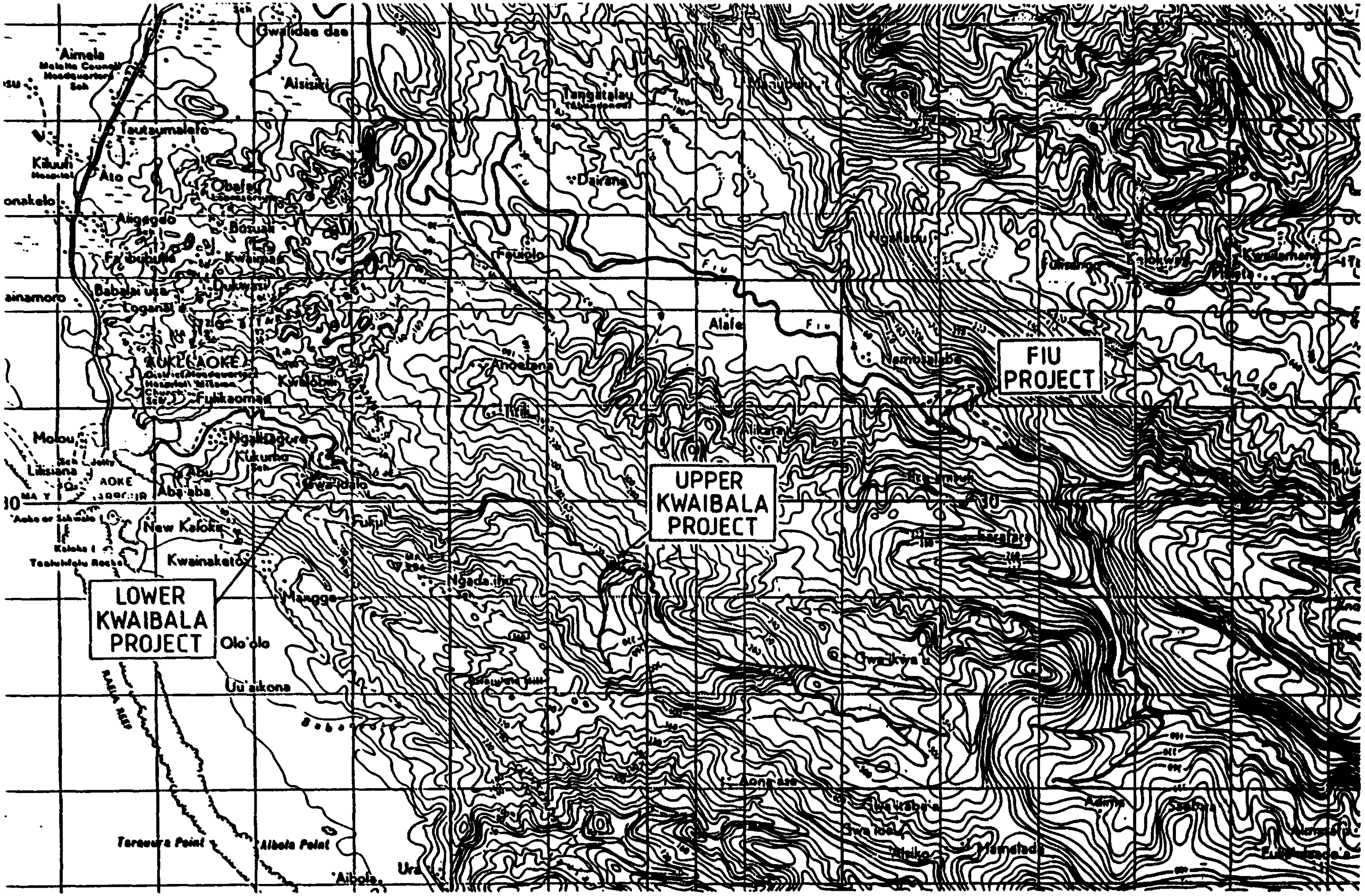


FIGURE F.15 - Location map of potential hydropower projects for Auki (scale 1:50,000)

The principle feature of the scheme is its simplicity and low cost for civil works. Access is obtained by extending the existing access road from the Auki pumping station 1 km along the Kwaibala valley in relatively flat terrain and constructing a simple ford at the power station site. The transmission line is only 1.5 km to the existing diesel power station and could therefore be completed by an extension of the existing 3.3 kV system or upgraded to 11 kV, whichever SIEA prefers. Civil works are straightforward and have a high labour content, praticularly for hand excavation of the headrace and tailrace canals in limestone.

The scheme is a suitable size for the present Auki demand of 800 MWh p.a. because the entire power potential of the hydro scheme (400 MWh) will be consumed immediately after commissioning. The plant will be a simple run-of-the-river type, generating maximum energy from the available flow, while running in parallel with the existing diesel units.

Civil Works

Civil works will include a concrete overflow weir 1.5 m high anchored into the limestone rock in the river bed. A side intake will lead into a small settling basin with scour outlet conveniently placed in a natural depression in the rock just below the weir.

The headrace canal will be excavated in limestone in relatively flat terrain, following the contour around the hill on the inside of the bend. A small intake will lead into a 750 mm diameter penstock only 40 m long and sloping at 1:4.

The power house will depend on the type of turbine chosen, and for a crossflow turbine could be similar to the power house at Maluu. For other types of turbine which utilise the full head available, a tailrace could be excavated in limestone some 100 m downstream to utilise a further 1 m of fall in the river below the power station.

Table P.2 - Cost Estimates for the Lower Kwaibala Mini-Hydro Project

		Thousand SI$
Civil Works		
Land clearance (light bush, few trees)	5	
Access road (1 km gravel/rock surface)	30	
Concrete intake weir (1.5 m high, 20 m long)	50	
Intake incl. stoplogs (max. 1.2 m3/s)	5	
Desilting basin and scour gate (200 m3 excavation)	5	
Headrace (400 m3 excavation)	10	
Penstock (750 mm dia., 40 m long)	20	
Powerhouse and tailrace	30	
Site establishment	25	
Sub-total		180
Contingencies (20%)		36
Electromechanical equipment		
Turbine generator set (crossflow or S-type, 100 kW)	150	
Transformers	10	
Transmission line (1.5 km long, 3.3 kV)	20	
Sub-total		180
Contingencies (15%)		27
Land acquisition and compensation		20
Engineering and administration (15%)		67
		510

LOWER KWAIBALA PROJECT INVESTMENT COST - SI$ 510,000

With rock clearly visible at the dam site and power station site, and good experience of hand excavation in similar limestone rock at Maluu, the civil construction works are expected to be cheap and simple. Assuming adequate supervision, the civil works could be carried out by direct labour from Malaita, and the only imported components would be the generating equipment and the 40 m long penstock.

Generating Equipment

There are a variety of turbines available for this type of low head project including S-type Kaplan and crossflow types, but prices vary widely. It will probably be most cost-effective to select a single turbine with a wide range of operating flows, rather than two micro units. A single 100 kW turbine operating over the most likely range of river flows (0.3 - 1.2 m3/s) has been chosen for the purpose of analysis.

Crossflow units must be positioned above floodwater level and are therefore not utilising the final 2 - 3 m of suction head. Their efficiency is also at least 10% lower than other types. Kaplan units would be very suitable but will be relatively expensive for such a small size. An S-type or semi-regulated standardised Kaplan unit may be a good compromise solution for this project.

Cost Estimates

It will be necessary to adopt low cost construction techniques for such a small project to be economical. Simple solutions and labour intensive techniques are envisaged, similar to those used in the Maluu micro-hydro project. Cost estimating for the generating equipment is very uncertain, and it is advisable to obtain quotes from many manufacturers including different types of turbines. The project capital cost is estimated from the experience at Maluu to be 510,000 SI$ as shown in Table P.2.

TABLE P.3

KWAIBALA HYDROPOWER PROJECT.

COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	40.00	0.00	36.36	0.00
1988	0.83	470.00	23.00	388.43	19.01
1989	0.75	10.00	67.00	7.51	50.34
1990	0.68	10.00	67.00	6.83	45.76
1991	0.62	10.00	67.00	6.21	41.60
1992	0.56	10.00	67.00	5.64	37.82
1993	0.51	10.00	67.00	5.13	34.38
1994	0.47	10.00	67.00	4.67	31.26
1995	0.42	10.00	67.00	4.24	28.41
1996	0.39	10.00	67.00	3.86	25.83
1997	0.35	10.00	67.00	3.50	23.48
1998	0.32	10.00	67.00	3.19	21.35
1999	0.29	10.00	67.00	2.90	19.41
2000	0.26	10.00	67.00	2.63	17.64
2001	0.24	10.00	67.00	2.39	16.04
2002	0.22	10.00	67.00	2.18	14.58
2003	0.20	10.00	90.00	1.98	17.81
2004	0.18	10.00	67.00	1.80	12.05
2005	0.16	10.00	67.00	1.64	10.96
2006	0.15	10.00	67.00	1.49	9.96
2007	0.14	10.00	67.00	1.35	9.05
2008	0.12	10.00	67.00	1.23	8.23
2009	0.11	10.00	67.00	1.12	7.48
2010	0.10	10.00	67.00	1.02	6.80
2011	0.09	10.00	67.00	0.92	6.18
2012	0.08	10.00	67.00	0.84	5.62
2013	0.08	10.00	67.00	0.76	5.11
2014	0.07	10.00	67.00	0.69	4.65
2015	0.06	10.00	67.00	0.63	4.22
2016	0.06	10.00	67.00	0.57	3.84
2017	0.05	10.00	67.00	0.52	3.49
2018	0.05	217.00	90.00	10.28	4.26
2019	0.04	10.00	67.00	0.43	2.88
2020	0.04	10.00	67.00	0.39	2.62
2021 onwards remainder :				3.91	26.23

NPC = 517.24 NPB = 578.37

Cost/Benefit ratio = 0.89

Economic Analysis

The scheme will substitute fuel and operation costs for the existing diesel power station at Auki, and to a small extent provide firm capacity for the combined system. The average flow at the dam site is estimated to be 0.9 m3/s from a catchment area of 12 km2, and by installing a turbine to utilise up to 1.2 m3/s, the average annual energy output is estimated at 400 MWh p.a. All this output can be absorbed in the system, therefore the energy benefits are calculated at 400 MWh multiplied by 16.6 cents/kWh (from Table H4) or 67,000 SI$ per annum.

The Kwaibala River is reported to remain flowing even in extended dry periods (although the nearby Fiu River is said to dry up completely in dry years). The 95% guaranteed flow is therefore estimated at 0.4 m3/s, providing 30 kW guaranteed capacity which is the capacity benefit of the scheme, priced at 700 US$/kW or 35,000 SI$.

Operation and maintenance costs for such micro-hydro schemes are estimated at 2% of investment cost or 10,000 SI$ p.a., which covers 1 additional hydropower operator plus occasional repair expenses. The hydropower equipment is assumed to require replacement after 30 years whereas small diesel units need replacing every 15 years.

A net present value cost-benefit analysis has been carried out by setting up cost and benefit streams based on the above parameters as in Table P.3. Discounting at 10% results in a cost/benefit ratio of 0.89. The project is therefore marginally economic, and would become more economic if fuel prices were higher than their present relatively low levels.

Upper Kwaibala Project

The upper reaches of the Kwaibala River appear to have a steep fall, but river flow at this point is likely to be reduced considerably. Analysing this project without topographical and runoff data is pure speculation, but from 1:50,000 maps it appears that about 60 m head could be obtained with a catchment area of 4.5 km2. The meand annual flow is estimated at 0.34 m3/s and installation of a 200 kW turbine would produce approximately 700 MWh annually. Such a project would cost 0.8 - 1.0 million SI$ and would appear to be marginally economic with a cost/benefit ratio of 0.8 - 1.0 at 10% discount, i.e. very similar to the Lower Kwaibala project - only a little larger. The site is therefore worthy of further investigation, and measurement of the available head and penstock length, together with some stream gaugings in dry weather would enable a better assessment of the project potential to be made.

Fiu Project - Description

This project is located on the Fiu River, 2 km upstream of the village of Namosalabe, 10 km east of Auki as shown on Figure F.15. The catchment area at the dam site is 62 km2 and the mean flow is estimated at 4.7 m3/s. The scheme was first identified in 1984 by the UNDTCD mission (reference 2), and was reported to utilise 60 m head with a 1000 m long headrace pipe in a trench, and a 200 m long penstock. The turbine discharge was 0.7 m3/s generating 300 kW.

An inspection of the site and conversations with the local people revealed that the earlier presentation of the project was rather optimistic and that construction of the 1000 m long headrace pipe was practically impossible in the steep (near vertical) terrain. Furthermore the Fiu River is reported to dry up completely in dry years although a little flow is still reported at a level of about 90 m above sea level. The available head was also measured by altimeter at 30 - 35 m instead of 60 m as presented in reference 2. The project was therefore totally redesigned and is presented here according to less optimistic assumptions.

A small-section tunnel of 6 m2 is proposed, 500 m long leading to a 400 m long penstock of 800 mm diameter.

Assuming crossflow turbines with a net head of 28 m, a turbine discharge of 2 m3/s would provide 380 kW, most suitably divided into 2 x 190 kW crossflow units. The potential of this scheme is nearly 3 GWh p.a. (or more if additional turbines are installed) which is twice the energy demand expected for Auki in the year 2000. Since the river is known to dry up, it is unlikely that the scheme can guarantee any firm capacity, and a full back-up of diesel units must be maintained.

Civil Works

The major cost item will be the tunnel which should be constructed as a least-cost working section (about 4 - 6 m2) perhaps even with hand loading and mucking out. The limestone rock is variable in quality and considerable rock support will be required probably in the form of shotcrete to prevent weathering and scaling. The tunnel cost is therefore expected to be at least of 700,000 SI$, possibly more including rock support and shotcrete lining. If a full concrete lining is required the cost will more than double and the project will become uneconomic. The tunnel intake will be placed about 1 m above normal river level in the vertical rock face upstream of the dam. After completion of the tunnel the water level in the river will be raised 2 m by a concrete diversion weir. The foundation conditions for the weir are uncertain because bedrock was not visible in the river bed. The bedrock may also be porous because river water is observed to sink into the ground at this point.

At the tunnel exit the tunnel will be widened and deepened to form a desilting chamber fitted with a scour outlet and overflow spillway. From the desilting chamber a 800 mm diameter penstock will fall gradually over a length of 400 m to the power station. The power station is sited in a flat area just upstream of a 90° bend in the river, well protected from floods. A tailrace channel will lead to the bend in the river.

Table P.4 - Cost Estimates for the Fiu Hydropower Project

Civil Works		Thousand SI$
Land clearance	40	
Access road (3 km long)	90	
Concrete overflow weir (3 m high, 40 m long)	150	
Intake with tailrace and stoplogs	20	
Tunnel (6 m2 section, 500 m long, reinforced shotcrete lining)	700	
Desilting basin and scour outlet	50	
Penstock (400 m long, 800 mm diameter)	200	
Powerhouse and tailrace (200 m long)	150	
Sub-total		1400
Contingencies (20%)		280
Electrical and Mechanical Equipment		
Generating Equipment (2 x 190 kW Crossflow)	250	
Transmission line (9 km, 11 kV overhead)	180	
Transformers	40	
Sub-total		470
Contingencies (15%)		70
Land acquistion and compensation		130
Engineering and administration (15%)		350
		2700

FIU PROJECT INVESTMENT COST 2,700,000 SI$

Access is achieved by upgrading the existing road to Alafe and extending it with a new road 3 km to the site of the power station. A 9 km long 11 kV transmission line will be required back to Auki alongside the road.

Generating Equipment

The potential of the Fiu project is much greater than present demand, and the unit size is therefore determined by the size of the existing diesel units which must act as standby (190 kW and 160 kW). Two No 190 kW units are chosen for simplicity (although room should be left for at least 2 more units allowing expansion of the total capacity to more than 1 MW). The net head available is 28 m and a crossflow turbine of 1 m3/s capacity would provide 190 kW output.

Although other types of turbine are available, the important factor with the Fiu project is low cost rather than efficiency, and crossflow turbines will probably be cheapest. A gearbox and synchronous generator will be required, with a frequency governor and full control equipment for both independent and parallel operation with Auki diesel sets.

Cost Estimate

The tunnel cost is difficult to estimate without prior experience of tunnelling in similar limestone rock. Experience of small section tunnels in other countries indicates that small tunnels can stand unsupported in very poor rock because of the narrow roof span (approximately 2.5 m). Other costs are estimated from international unit rates adjusted for the Solomon Islands and budget quotations have been obtained for generating equipment.

The total project cost is estimated at 2.7 million SI$ (Table P.4), but could be more if rock conditions are unfavourable for tunnelling. The cost of this project should therefore be seen as a minimum cost, unlike other projects not involving tunnels where costs are more predictable.

TABLE P.5

FIU HYDROPOWER PROJECT.
COST - BENEFIT ANALYSIS (mill.SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	100.00	0.00	90.91	0.00
1988	0.83	1300.00	0.00	1074.38	0.00
1989	0.75	1300.00	0.00	976.71	0.00
1990	0.68	54.00	138.00	36.88	94.26
1991	0.62	54.00	145.00	33.53	90.03
1992	0.56	54.00	152.00	30.48	85.80
1993	0.51	54.00	160.00	27.71	82.11
1994	0.47	54.00	168.00	25.19	78.37
1995	0.42	54.00	176.00	22.90	74.64
1996	0.39	54.00	185.00	20.82	71.33
1997	0.35	54.00	194.00	18.93	68.00
1998	0.32	54.00	204.00	17.21	65.00
1999	0.29	54.00	214.00	15.64	61.99
2000	0.26	54.00	225.00	14.22	59.25
2001	0.24	54.00	236.00	12.93	56.50
2002	0.22	54.00	248.00	11.75	53.97
2003	0.20	54.00	260.00	10.68	51.44
2004	0.18	54.00	273.00	9.71	49.10
2005	0.16	254.00	285.00	41.53	46.60
2006	0.15	58.00	299.00	8.62	44.44
2007	0.14	58.00	314.00	7.84	42.43
2008	0.12	58.00	330.00	7.13	40.54
2009	0.11	58.00	347.00	6.48	38.75
2010	0.10	58.00	365.00	5.89	37.06
2011	0.09	58.00	384.00	5.35	35.44
2012	0.08	58.00	403.00	4.87	33.81
2013	0.08	58.00	423.00	4.42	32.27
2014	0.07	58.00	444.00	4.02	30.79
2015	0.06	58.00	467.00	3.66	29.44
2016	0.06	58.00	490.00	3.32	28.08
2017	0.05	58.00	515.00	3.02	26.83
2018	0.05	58.00	541.00	2.75	25.62
2019	0.04	598.00	568.00	25.75	24.46
2020	0.04	58.00	596.00	2.27	23.33
2021 onwards remainder :				22.70	233.29

NPC =2610.20 NPB =1814.96
Cost/Benefit ratio = 1.44

Economic Analysis

The Fiu hydropower project will supply nearly the entire demand in Auki, but the existing 2 No 160 kW diesel units should be maintained as standby for occasional hydro shutdown and dry periods. The potential energy output with 2 x 190 kW installed is about 3 GWh rising to 5 GWh where a total of 1 MW is installed.

The Fiu project will cover the entire demand at Auki for many years to come except in dry flow periods. Energy benefits are therefore calculated from the demand predictions (minus 5% for hydro shutdowns) multiplied by the energy dependent diesel costs of 16.6 cents/kWh. This works out at 138,000 SI$ p.a. in 1990 rising to 225,000 SI$ p.a. in the year 2000. Capacity benefits are assumed to be zero.

Operation and maintenance costs are estimated at 2% p.a. of investment cost or 54,000 SI$ p.a., and a third 200 kW unit costing 200,000 SI$ is needed in 2005, followed by replacement of the first two units after 30 years (2019). The cost and benefit streams are therefore set up as in Table P.5.

At 10% discount rate the cost-benefit ratio is 1.44, i.e. not economically feasible. However, if the Fiu project is delayed 10 years while enrgy demand increases to about 1500 MWh p.a. it becomes economically feasible. Alternatively, if a new consumer causes demand to jump to 1500 MWh p.a. the project will become feasible immediately. There is little liklihood of this happening, and it is concluded that Fiu is a typical project for development in the beginning of the next century.

Conclusions and Recommendations for the Auki System

There is considerable potential for hydropower development around Auki, and the existing diesel system is in urgent need of new generating plant. The hydropower development at Auki should therefore be given top priority before Kira Kira, Buala, Manawai or any other potential mini-hydro schemes.

Of the three potential hydro schemes examined for Auki, the lower Kwaibala project (100 kW) is the best because it is easy to develop rapidly. The Fiu project (380 kW) does not become economic until demand has risen appreciably, and Fiu will require a much longer study and design period.

The runoff properties of both rivers may differ considerably, and in the case of Kwaibala the flow duration curve is critical in determining the projects viability. It is therefore unwise to decide finally which project to construct until satisfactory flow data has been collected from both rivers. It is therefore of the utmost urgency that flow measurement stations be established first on the Kwaibala at the lower dam site, but also on the Fiu at the tunnel intake site. A lot of information can be gained by instaliing a simple staff gauge which is read manually twice a day, and this should be started immediately at Kwaibala in order to obtain records while the continuous recorder is being installed.

If the lower Kwaibala site proves uneconomic because of unfavourable flow data or too costly generating equipment, then the upper Kwaibala site may be a good alternative. The upper site should therefore be investigated as soon as possible and some dry weather flow measurements taken.

The Fiu project is likely to cost around 2.7 million SI$ or more to develop, i.e. five times the cost of Kwaibala, whereas the immediate benefits are only double Kwaibala (SI$ 138,000 compared with 67,000 SI$). Fiu is therefore entirely dependent on a rapidly expanding demand growth in Auki for its economic viability. It is advisable to wait several years with the Fiu project to see if the demand growth predicted by ADB (Table P.1) actually materialises. In the meantime one of the Kwaibala projects should be developed as soon as possible.

An important question to raise in this connection is what are the productive uses of electricity in Auki and what are the real social benefits of increased electricity consumption. Government consumption is more than 50% of the total (compared with 30% in Honiara) and it is likely to be more socio-economically effective to encourage energy conservation rather than increased consumption. A slow down in the predicted sales growth could easily spell financial disaster for a comitted Fiu project where annual interest and loan repayments are likely to be more than double the annual benefits of the initial years. On the other hand the Kwaibala projects would not be effected since there is already a guaranteed market for their power potential.

Furthermore the proposed small scale industry development at Auki requires immediate prospects of reliable electricity supply at reasonable cost before private enterprise can be attracted to the site. The prospect of a costly Fiu hydropower project with a protracted construction time of 4 or more years is much less attractive than the less costly Kwaibala mini-hydro project which can be commissioned 2 years earlier.

It is therefore recommended that efforts be concentrated on the Kwaibala River. Although the Kwaibala project is marginal, there are many inherent advantages in this project compared with the Fiu:

(i) Easy access ensures that Kwaibala will be commissioned 1 or 2 years before the Fiu project could be, probably 1989. This represents a net saving of 67,000.00 SI$ for each year the commissioning date can be advanced.

(ii) Its simplicity means there is a relatively low risk of unforeseen cost increases and/or construction delays.

(iii) The construction techniques to be used are labour intensive and the local cost component is high.

(iv) It is well suited as a pilot project or demonstration scheme because of easy access and simplicity of construction and operation.

(v) The present demand is high enough to make full and efficient use of the energy potential of the project, whereas most other projects for isolated areas rely on increasing demand growth for their economic justification. (c.f. Fiu and Jejevo).

(vi) The environmental impact is minimal and the area of land or river which must be acquired is smaller than most other projects. It is more probable that compensation payments and land-ownership problems will be least for the lower Kwaibala project.

It is therefore recommended that the lower Kwaibala scheme be studied to feasibility level, and if feasible, constructed without delay. Allowing 1 year for flow data collection, feasibility study and design followed by 6 months for financing, tendering and contract negotiations and 1 year for construction, the project could be commissioned early in 1989 before any further diesel units are required.

TABLE P.6 - Forecast energy and maximum demand - Buala system

Year	5% p.a. growth		10% p.a. growth	
	Energy (MWh)	Demand (kW)	Energy (MWh)	Demand (kW)
1984	61	20		
1985	64	21		
1986	67	22		
1987	71	23		
1988	74	24		
1989	78	26	78	26
1990	82	27	86	28
1991	86	28	95	31
1992	90	30	104	34
1993	95	31	115	38
1994	99	33	127	42
1995	104	34	140	46
1996	109	36	154	51
1997	115	38	169	56
1998	121	40	186	62
1999	127	42	205	68
2000	133	44	225	75
	(from reference 1)			

P 2 - BUALA

Jejevo Hydropower Project

A 415 V electricity supply system was commissioned in Buala in 1984, powered by two 28 kW diesel generating sets. Only the centres of Buala and Jejevo are supplied at present. The potential for new consumers is reasonable with plans for a copra marketing centre, a bank, a hardware store and co-op warehouse on a planned development site at Jejevo. The government plans to build 4 - 6 new permanent houses a year. There are several large villages near Buala, but most houses are leaf houses of non-permanent consctruction. Before connections can be made to such houses, different standards of distribution and house wiring will have to be agreed on.

Present peak demand is estimated at 22 kW with sales of 67 MWh per annum, and this is expected to double by the year 2000 (see Table P.6).

Buala is ideally situated for supply from a micro- or mini-hydro project. There are several streams nearby with rapid falls, providing potential for high head projects at relatively low cost. The annual rainfall is relatively high (4200 mm) and evenly distributed throughout the year. The best streams are the Jejevo and Kerasaba which appear to have all year flow in reasonable quantities. In fact, there is a large potential for hydropower development near Buala; several schemes of more than 1 MW capacity on the Poporo and Manito river would be economic if the demand was sufficient.

An analysis of the benefit from replacing diesel generation indicates that a hydro scheme costing less than 300,000 SI$ will be necessary to have any economic advantage over diesel generation at current prices for diesel. Consequently the search for hydro alternatives has concentrated on simple low-cost mini-hydro projects near to the centres of Buala and Jejevo. Earlier studies on the Poporo River (reference 6) result in schemes which are too large and too costly for the present demand.

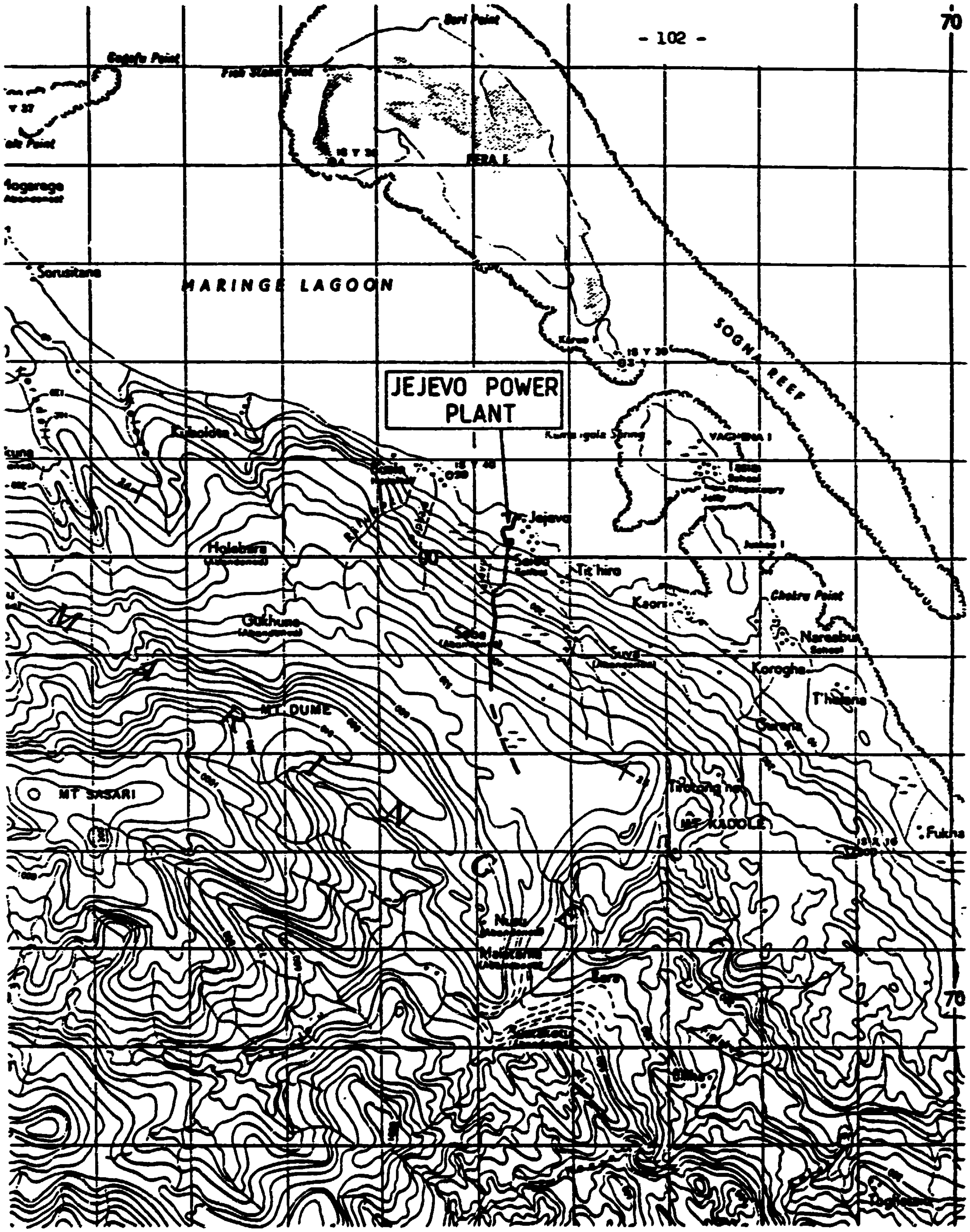


FIGURE F16 - Location map of Jejevo mini-hydro plant for Buala (scale 1:50,000)

The most suitable scheme is on the Jejevo River, which appears to have a reliable flow of 30 l/s at 200 m above sea level. The Jejevo project was first identified in 1982 and a preliminary design was carried out by consultants from New Zealand (reference 8).

The intake is from a pool at a level of about 200 m above sea level, and although there are steep waterfalls above this level it will not be necessary to place the intake higher up. Access is very difficult to the top of the falls and a good intake site will be difficult to find, and the resulting penstock too costly.

A short canal and settling basin are proposed, but would have to be constructed of wood with a correspondingly short lifetime. Alternatively it might be possible to make use of the pool itself as a settling basin. It is stones and gravel which will present the largest sediment problems and sand and silt load is expected to be relatively light. A submerged stream bed intake would be suitable for this stream.

The penstock will be about 250-300 mm in diameter, and is to be built in relatively easy terrain on the east bank, with a mean slope of 1:4. The length has been quoted at 842 m in reference 8, but efforts should be made to shorten this to reduce costs.

The power station is sited at about 20 m above sea level on the east bank, high enough to be safe from flooding (3 m above river level). The site chosen is behind the village at the foot of the slope and is only 200 m from a branch of the existing 415 V supply line.

Because the power station is so near the demand centre and the existing diesel station, it should be possible to supply directly at 415 V, thus avoiding transformers and high voltage transmission, at least for a time until the supply system needs to be extended along the coast.

Table P.7 - Cost estimates for Jejevo Mini-Hydro Project

Civil Works	Thousand SI$	
Access and preliminaries	5	
Intake	4	
Settling chamber	4	
Steel penstock	206	
Power house	11	
Sub-total		230
Contingencies (20%)		46
Equipment		
Turbine, generator, valve, governor	80	
Freight, Honiara - Buala + commisioning	10	
Control box	5	
Cabels, earthing + power house services	10	
Power lines (200 m at 415 V)	5	
Sub-total		110
Contingencies (15%)		16
Land acquisition/compensation		25
Engineering and administration (15%)		63

TOTAL INVESTMENT COST 490.000 SI$

The gross head available is 176 m, and a single jet Pelton turbine will be very suitable, using less than 100 l/s to generate 100 kW. This is higher than the anticipated peak demand of 20-40 kW, but the author agrees with the New Zealand consultants (reference 8) who recommend 100 kW installed. This has the advantage of allowing standardisation of generators and electrical equipment with the Kwaibala and Huro schemes, and provides for Bualas long-term needs at very little additional cost.

The capital cost of the scheme has been updated from reference 8 and adjusted for items not included there, particularly contigencies and engineering. An up-to-date budget quotation was obtained from Tasmania for the generating equipment. The total project cost is estimated to be 490.000 SI$ at 1986 prices, as shown on Table P.7.

The scheme is already designed, and providing finance can be found rapidly, it could be commissioned early in 1989. The first year of production is assumed to be 1989, when sales are expected to have reached 78 MWh annually, with peak demand at 26 kW.

The Jejevo River is reported to have a reliable flow and several gaugings have been made, always over 40 l/s including one on 29. May 1986 measured at 41 l/s. The reliable flow is estimated at 30 l/s which would provide 30 kW of firm power, sufficient to cover Bualas immediate needs. This avoids the need to run the hydro unit in parallel with diesel generation and a simplified operation and control system can be used for the first few years.

The project benefits are calculated as the total energy production according to the predicted growth rate from reference 1 (5% p.a.) plus the avoided cost of a new 28 kW diesel generator set in 1989. Using 10% discount rate the cost/benefit ratio is 1.84 as shown on Table P.8. This indicates that the project is not economic at 10% discount rate, and has an internal rate of return of only 6%. If, however, a more rapid growth in demand is assumed (10% p.a.) the Jejevo project becomes economic for immediate construction (see Table P.9).

TABLE P.8

JEJEVO HYDROPOWER PROJECT. (Assumes 5% p.a. growth in demand)
COST - BENEFIT ANALYSIS (mill.$Is, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	90.00	0.00	81.82	0.00
1988	0.83	400.00	35.00	330.58	28.93
1989	0.75	10.00	16.00	7.51	12.02
1990	0.68	10.00	17.00	6.83	11.61
1991	0.62	10.00	18.00	6.21	11.18
1992	0.56	10.00	19.00	5.64	10.73
1993	0.51	10.00	20.00	5.13	10.26
1994	0.47	10.00	21.00	4.67	9.80
1995	0.42	10.00	22.00	4.24	9.33
1996	0.39	10.00	23.00	3.86	8.87
1997	0.35	10.00	24.00	3.50	8.41
1998	0.32	10.00	25.00	3.19	7.97
1999	0.29	10.00	26.00	2.90	7.53
2000	0.26	10.00	27.00	2.63	7.11
2001	0.24	10.00	29.00	2.39	6.94
2002	0.22	10.00	30.00	2.18	4.53
2003	0.20	10.00	66.00	1.98	13.06
2004	0.18	10.00	33.00	1.80	5.94
2005	0.16	10.00	35.00	1.64	5.77
2006	0.15	10.00	37.00	1.49	5.50
2007	0.14	10.00	39.00	1.35	5.27
2008	0.12	10.00	41.00	1.23	5.04
2009	0.11	10.00	43.00	1.12	4.80
2010	0.10	10.00	45.00	1.02	4.57
2011	0.09	10.00	47.00	0.92	4.34
2012	0.08	10.00	49.00	0.84	4.11
2013	0.08	10.00	51.00	0.76	3.89
2014	0.07	10.00	54.00	0.69	3.74
2015	0.06	10.00	57.00	0.63	3.59
2016	0.06	10.00	60.00	0.57	3.44
2017	0.05	10.00	63.00	0.52	3.28
2018	0.05	136.00	101.00	6.44	4.78
2019	0.04	10.00	70.00	0.43	3.01
2020	0.04	10.00	73.00	0.39	2.86
2021 onwards remainder :				3.91	28.57

NPC = 501.01 NPB = 277.73
Cost/Benefit ratio = 1.84

TABLE P.9

JEJEVO HYDROPOWER PROJECT. (Assumes 10% p.a. growth in demand)
COST - BENEFIT ANALYSIS (mill.$Is, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	90.00	0.00	81.82	0.00
1988	0.83	400.00	35.00	330.58	28.93
1989	0.75	10.00	16.00	7.51	12.02
1990	0.68	10.00	18.00	6.83	12.29
1991	0.62	10.00	20.00	6.21	12.42
1992	0.56	10.00	22.00	5.64	12.42
1993	0.51	10.00	24.00	5.13	12.32
1994	0.47	10.00	24.00	4.67	12.13
1995	0.42	10.00	29.00	4.24	12.30
1996	0.39	10.00	31.00	3.86	11.95
1997	0.35	10.00	33.00	3.50	11.57
1998	0.32	10.00	35.00	3.19	11.15
1999	0.29	10.00	38.00	2.90	11.01
2000	0.26	10.00	42.00	2.63	11.06
2001	0.24	10.00	46.00	2.39	11.01
2002	0.22	10.00	51.00	2.18	11.10
2003	0.20	10.00	91.00	1.98	18.00
2004	0.18	10.00	61.00	1.80	10.97
2005	0.16	10.00	67.00	1.64	10.96
2006	0.15	10.00	74.00	1.49	11.00
2007	0.14	10.00	82.00	1.35	11.08
2008	0.12	10.00	90.00	1.23	11.06
2009	0.11	10.00	99.00	1.17	11.06
2010	0.10	10.00	109.00	1.02	11.67
2011	0.09	10.00	119.00	0.92	10.98
2012	0.08	10.00	131.00	0.84	10.99
2013	0.08	10.00	144.00	0.76	10.98
2014	0.07	10.00	158.00	0.69	10.96
2015	0.06	10.00	174.00	0.63	10.97
2016	0.06	10.00	192.00	0.57	11.00
2017	0.05	10.00	211.00	0.52	10.99
2018	0.05	136.00	267.00	6.44	12.65
2019	0.04	10.00	255.00	0.43	10.98
2020	0.04	10.00	281.00	0.39	11.08
2021 onwards remainder :				3.91	109.99

NPC = 501.01 NPB = 510.35
Cost/Benefit ratio = 0.98

The Jejevo project could be made less expensive by reducing the penstock length, while increasing the turbine discharge to keep the maximum output at 100 kW. A new intake site would have to be found at about 150 m above see level, which might reduce the project cost to approximately 400.000 SI$, while the benefits remain approximately the same.

If new development is anticipated around Jejevo, the demand might increase more rapidly than predicted in reference 1. Only one or two major new consumers can make a large difference to the demand when an electricity supply system is just developing as at Buala. When annual demand exceeds 100 MWh the hydro project will become more economic than diesel generation. In the long term the mini-hydro project has potential to generate 400-500 MWh annually.

The Jejevo mini-hydro project is inherently a very sound economic proposition once the system demand is sufficiently high to absorb more of the projects energy potential. In order to have a rational implementation schedule, it is recommended that Jejevo be planned and constructed together with Huro and Kwaibala, even if this means a few years before it becomes economic.

Furthermore the Jejevo mini-hydro scheme will have important training benefits on the island of Santa Isabel, where considerable micro-hydro potential exists. It is therefore recommended to proceed with the Jejevo mini-hydro scheme immediately, along with the Kwaibala and Huro schemes.

TABLE P.10 - Forecast energy and maximum demand - Kira Kira system

Year	Energy (MWh)	Maximum (kW)
1983	161	56
1984	167	63
1985	174	66
1986	183	68
1987	192	69
1988	202	72
1989	212	75
1990	222	78
1991	233	79
1992	245	82
1993	257	86
1994	270	89
1995	284	90
1996	298	94
1997	313	98
1998	328	99
1999	345	101
2000	362	103

Growth assumed at 5% p.a. (from reference 1)

P3 - KIRA KIRA

The Present Kira Kira System

The present supply area is limited to the Kira Kira village itself, and will remain limited as long as the present distribution system is at 415V. The power station is centrally placed but it is planned to relocate it near the Puepue River at the back of the village. Fresh consideration should be given to the new site and the introduction of a high tension system in the light of the new mini-hydro station proposed on the Huro River.

The existing station has 3 relatively modern diesel generator sets of approximately 43 kW each. One set was down for repair during the visit and the other two were required for most of the daytime running.

There were no figures readily available for the latest peak demand, but the necessity of running two units at full output seems to indicate that evening peak demand has risen appreciably from the 1983 figures quoted in the ADB report (see Table P.10 from reference 1). There are plans to install new air conditioners in the hospital and new washing machines have been delivered and are awaiting connection.

The load factor is poor, about 0.32 due to a pronounced evening peak around 1900 hrs (see Fig. F.17). The mini-hydro project will generate surplus daytime power which can be used to good effect, for instance in small-scale industries at the site proposed in Kira Kira.

For analysing mini-hydro projects for Kira Kira the predicted demand on commissioning in 1990 is 222 MWh p.a. and 78 kW peak rising at 5% p.a. thereafter (see Table P.10 from reference 1).

The optimum size of hydropower project for the Kira Kira system would be about 100 kW to cover peak demand up to the year 2000. Investment costs should not exceed 700,000.00 SI$ if the hydro project is to be more economic than continued diesel operation.

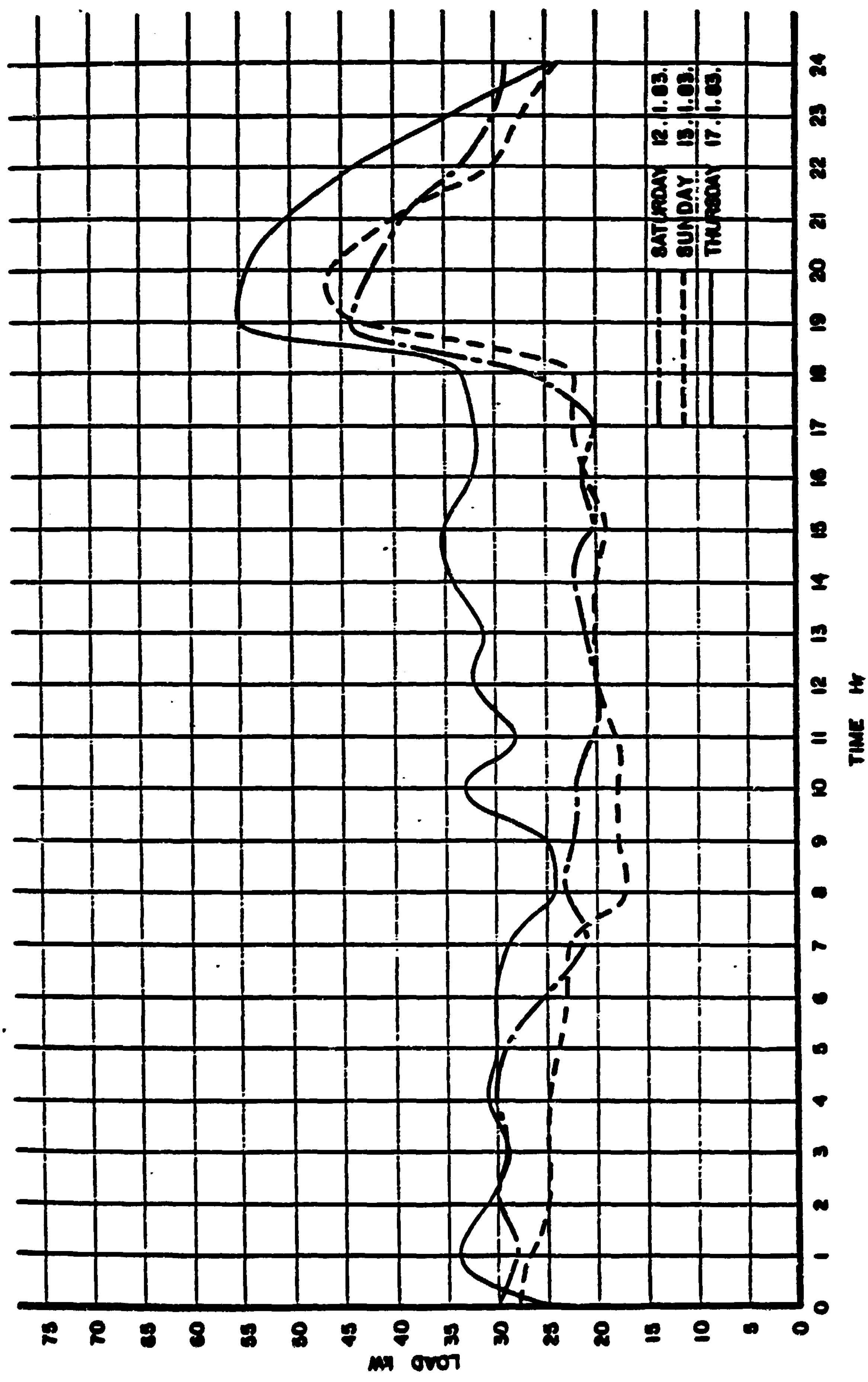


FIGURE F.17 - Kira Kira system daily load curves (from reference 1)

Huro Project - Location and Description

This project is located on the Huro River above the village of Huro some 300 m upstream of the road bridge (see Figure F.18). The lower reaches of the Huro river fall steeply over exposed rock and large boulders. The river level at the village is approximately 5 m above sea level, but at a level of about 40 m the river flows out of a dramatic gorge with vertical walls up to 50 m high. At this point, some 300 m or so below the junction of 2 major tributaries, there is a suitable site for an overflow weir 13 m wide and 2 m high. The catchment area is 6 km2 and the mean flow is estimated to be 0.6 m3/s.

The west bank of the river valley downstream is of moderate slope, and it will be possible to build a penstock without difficulty, although excavating a headrace canal might present more problems due to blocks of hard rock and uneven terrain.

The penstock length has not been measured, but is estimated at 400-600 m, the average figure being used in cost estimating. The lower part has recently been logged and there is reportedly a logging road running up the ridge above. Access is easy to the power station site, and a track for tractc_s could be excavated up to the dam site if necessary.

It is proposed to site the power station 200-300 m inland from the village just upstream of a small tributary entering on the west bank. This will avoid any adverse environmental impact since the project is constructed upstream in a rocky and inaccessible part of the river.

A single 100 kW crossflow unit would be suitable for covering demand varying from 25 kW minimum to 100 kW maximum. The estimated reliable discharge is at least 0.2 m3/s, equivalent to 40 kW output which represents satisfactory operating conditions for the single unit. Installing two units would be unnecessary and uneconomic.

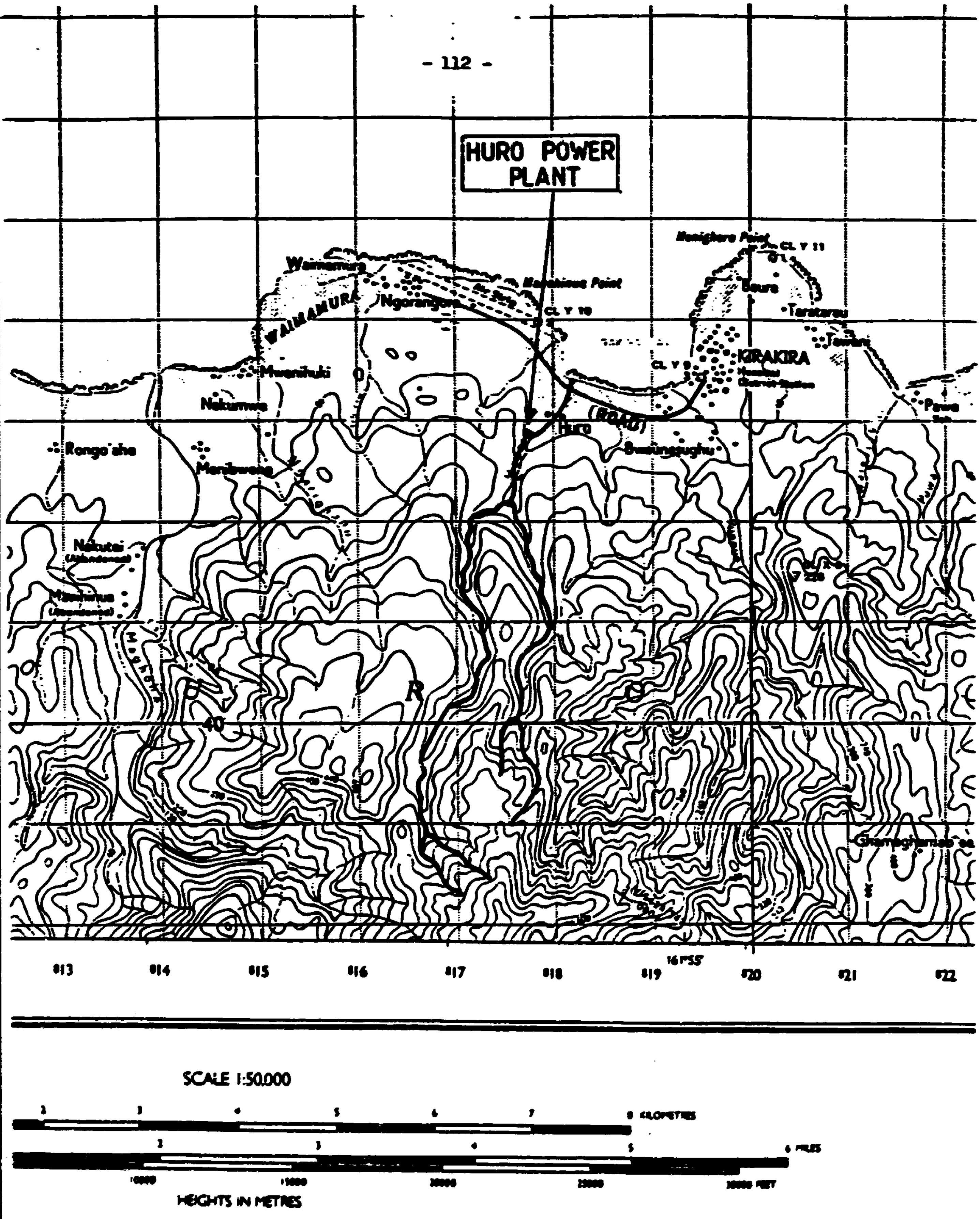


FIGURE F.18 - Location map of Huro mini-hydro plant for Kira Kira

A transmission line will run along the road 2 km into the village of Kira Kira, and the possibility arises of electrifying the airport and the village of Ngorangora 2 km to the west. Any high tension transmission voltage will be suitable, 11 kV being preferred due to SIEA's requirements for standardisation.

Civil Works

The major cost items will be the penstock and to a lesser extent the dam and intake. The dam site is very suitable with sound rock on both abutments. The river bed comprises of rock and boulders, some of more than 100 tons weight. It will be possible to build a stable diversion weir 13 m wide and 2 m high at the site chosen although some leakage may occur in cracks and fissures below the dam. Some dental concrete and natural siltation will reduce this leakage to acceptable levels. Besides there is already excess flow available for present power requirements.

An intake with trash rack and scour-gate will be constructed on the west abutment, but it will be costly to construct a settling basin of any volume at that point. This makes it important to include a large and well-sited scour gate immediately beside the intake, because the pool created upstream will act as the only settling basin. Sediment transport in the river does not appear to be high except in extreme flood conditions. Alternatively a submerged stream bed intake could be constructed.

A 450 mm diameter penstock has been chosen although smaller diameters are premissable since a high head loss is acceptable in this case. The penstock should preferably be steel since there is some risk of damage to other types due to falling rocks or trees. It will probably be necessary for steel or concrete supports to be constructed since the terrain is difficult for trench excavation.

The lower part of the penstock route runs in gentle terrain, recently logged, and the power station site can be located at any suitable place upstream of Huro village. Although there are several metres of fall in the river above the village it will probably not be necessary to utilise these because of the low demand level at present.

Generating Equipment

A crossflow turbine will almost certainly be the most economic type for the head and flow conditions of the Huro project. The size is dictated by the present demand level, and 100 kW seems appropriate. This requires a turbine dischare of 0,5 m3/s at 28 m net head. The Huro River flow was measured at 0.52 m3/s at the dam site on 1.05.86 after regular local rain showers in the preceding week. Several gaugings have been carried out previously (ref. 2) none less than 0.4 m3/s. Local people say the river never dries up, and it is reasonable to assume a reliable discharge of 0.2 m3/s. The catchment area of 6 km2 would indicate an average discharge of around 0.6 m3/s, since rainfall at Kira Kira is moderately high (3739 mm at the coast).

The reliable dischare of 0.2 m3/s would produce about 40 kW with the proposed 100 kW crossflow unit, and can therefore avoid the installation of another 43 kW diesel. There will be very few occasions when flow is insufficient to satisfy the system demand which will normally vary in the range 20-70 kW, so the hydropower project is well matched to the present Kira Kira system. It would be advisable to maintain all the existing diesel units for occasional peaking use and in the event of repairs or maintenance to the hydropower unit.

The annual energy which could be generated by the 100 kW hydropower turbine is of the order of 600 MWh, and with the diesels a total of 120 kW firm capacity can be provided. According to the ADB demand forecast, that will satisfy requirements well into the next century.

Table P.11 - Cost Estimates for Huro Mini-Hydro Project

		Thousand SI$
Civil Works		
Land clearance (forest, partly cleared already)	10	
Access road (500 m to power station)	15	
Concrete intake weir (1.5 m high, 13 m wide)	30	
Intake and scour gate	10	
Penstock (450 mm dia, 500 m long)	200	
Powerhouse	30	
Tailrace	5	
Subtotal		300
Contingencies (20%)		60
Generating Equipment:		
Generating equipment (1 x 100 kW crossflow)	100	
Transmission line (2 km, 11 kV)	40	
Transformers, switchgear	10	
Subtotal		150
Contingencies (15%)		22
Land acquisition		23
Engineering and administration (15%)		85
		640

TOTAL INVESTMENT COST SI$ 640,000

Cost Estimates

It is necessary to adopt low-cost construction techniques for small projects like Huro and Kwaibala. The project at Maluu forms the main basis for estimating civil works costs for Huro. The penstock, generating equipment, transmission lines etc. are based on international prices adjusted for the Solomon Islands. Budget quotations have been obtained for the generating equipment. A site survey is necessary before deciding if the relatively long penstock can be shortened by constructing a headrace canal part of the way. Before this can be confirmed the more expensive full-penstock solution is used in project costing as given in Table P.11.

TABLE P.12

HURO HYDROPOWER PROJECT.
COST - BENEFIT ANALYSIS (mill).SI$, 1986 price level) Discount rate = 10.0 %

YEAR	DISCOUNT FACTOR	COSTS	BENEFITS	1986 PV COSTS	1986 PV BENEFITS
1986	1.00	0.00	0.00	0.00	0.00
1987	0.91	40.00	0.00	36.36	0.00
1988	0.83	600.00	46.00	495.87	38.02
1989	0.75	13.00	45.00	9.77	33.81
1990	0.68	13.00	48.00	8.88	32.78
1991	0.62	13.00	50.00	8.07	31.05
1992	0.56	13.00	52.00	7.34	29.35
1993	0.51	13.00	55.00	6.67	28.22
1994	0.47	13.00	58.00	6.06	27.06
1995	0.42	13.00	61.00	5.51	25.87
1996	0.39	13.00	64.00	5.01	24.67
1997	0.35	13.00	67.00	4.56	23.48
1998	0.32	13.00	70.00	4.14	22.30
1999	0.29	13.00	73.00	3.77	21.15
2000	0.26	13.00	77.00	3.42	20.28
2001	0.24	13.00	81.00	3.11	19.39
2002	0.22	13.00	85.00	2.83	18.50
2003	0.20	13.00	135.00	2.57	26.71
2004	0.18	13.00	93.00	2.34	16.73
2005	0.16	13.00	98.00	2.13	16.07
2006	0.15	13.00	103.00	1.93	15.31
2007	0.14	13.00	108.00	1.76	14.59
2008	0.12	13.00	113.00	1.60	13.88
2009	0.11	13.00	119.00	1.45	13.29
2010	0.10	13.00	125.00	1.32	12.69
2011	0.09	13.00	131.00	1.20	12.09
2012	0.08	13.00	138.00	1.09	11.58
2013	0.08	13.00	145.00	0.99	11.06
2014	0.07	13.00	152.00	0.90	10.54
2015	0.06	13.00	160.00	0.82	10.09
2016	0.06	13.00	168.00	0.75	9.63
2017	0.05	13.00	176.00	0.68	9.17
2018	0.05	184.00	231.00	8.71	10.94
2019	0.04	12.00	194.00	0.52	8.35
2020	0.04	13.00	204.00	0.51	7.99
2021 onwards remainder :				5.09	79.85

NPC = 647.73 NPB = 704.44
Cost/Benefit ratio = 0.92

Economic Analysis

The Huro project would substitute almost all fuel and running costs for the existing diesel units. The existing units must remain for occasional peaking and standby. The energy benefits are therefore assumed to be 98% of the predicted energy demand multiplied by the diesel running cost of 21.35 cents/kWh (from Table H.4). This represents an annual benefit of 46,000.00 SI$ in 1990 rising to 77,000.00 SI$ in 2000 measured at current price levels. In addition there is a benefit in the avoided cost of a 40 kW diesel unit priced at 700 US$/kW or 46,000 SI$.

The operation and maintenance cost is estimated at 2% of investment cost or 13,000 SI$ p.a. and replacement of hydro generating equipment is required after 30 years (diesels replaced every 15 years).

A net present value cost-benefit analysis based on the above parameters and 10% discount rate results in a cost/benefit ratio of 0.92 as shown in Table P.12. In addition, there are three factors which would cause the project to be more economic:

(i) a higher level of demand or a more rapid growth rate. There is some evidence that this may occur in Kira Kira once the reliability of supply and the capability of the distribution system improves.

(ii) the impending construction of a new diesel station can be avoided or delayed for many years by the rapid implementation of the hydro project.

(iii) the mini-hydro project will provide a large supply of daytime energy at no additional cost. If the proper incentives are provided this can assist in the development of small-scale industries, as planned by the government at a selected site in the centre of Kira Kira.

Conclusions and Recommendations

For commissioning at the end of 1989, the Huro mini-hydro project is marginally economic at 10% discount rate. The higher the level of demand, the more economic the mini-hydro project becomes, because it has a potential several times greater than the present demand.

It is recommended that plans for building a new diesel station at Kira Kira be reconsidered pending a short feasibility study of the mini-hydro project. If the mini-hydro project is to go ahead, the new diesel station can be replaced by the mini-hydro plant while maintaining the existing station with 43 kW units on standby for occasional operation.

At the same time as the mini-hydro study, the transmission and distribution system should be reviewed. The need for a high tension transmission system and the posibility of extending the supply area should be investigated in conjunction with plans for development of small-scale industries at Kira Kira. These recommendations are very much in line with the ADB Recommended Development Plan for Kira Kira (reference 1).

It should be noted that the Puepue river was also inspected and possible hydro projects considered, including the proposal of the UNDTCD mission (reference 2). It was found that although the potential of these projects is greater than Huro, the investment costs would be too great to justify the Puepue Scheme because of the low level of demand presently prevailing in Kira Kira. The Puepue river and the tributaries cut deep gorges up to 100 m high with vertical or near vertical faces. The headrace canal type of project described in reference 2 will not be possible in such terrain and any hydropower development on the Puepue is likely to cost in excess of 2 million SI$.

P4 - OTHER PROVINCIAL CENTRES

The other provincial centres where SIEA have established an electricity supply system are Gizo, Munda and Lata (Santa Cruz) all with diesel generating sets. Gizo is on a small island which is experiencing a shortage of water resources for water supply and hydropower generation is therefore not a viable alternative to diesel. Munda is surrounded by relatively flat land without commercially viable hydropower resources, as is the nearby port at Noro where a fish processing plant is to be built. Hydropower projects serving these two places can also be discounted.

Santa Cruz is an island where considerable hydropower potential exists in the mountainous regions to the east, but the provincial capital, Lata, is situated on a penninsula on the western tip of the island. The rivers which are nearest, the Leumbalele and Leusalo, have been explored by staff from the Ministry of Natural Resources without positive results. It is therefore concluded that the nearest potential projects will probably be found in the hills to the north or east and would require transmission lines of at least 15 km to carry power to the load centre. When transmission costs alone come to 300,000 SI$ and the present load is only 50 kW, it is impossible to conceive of a mini-hydro project which is an economically viable alternative to diesel under the present circumstances.

Nevertheless, as demand grows and especially if diesel prices rise again significantly, hydropower projects will become more competitive. Once demand has doubled to about 500 MWh p.a., it is possible to justify the high transmission costs, and potential mini-hydro projects costing up to 1 million SI$ are worthy of detailed study.

It should be stressed that all the provincial supply areas will benefit from hydropower development in any existing supply area, provided such development is economic and leads to lower electricity tariffs. The policy of uniform tariffs for all the provincial centres will result in a fair distribution of benefits.

It is therefore recommended that further exploration of potential hydropower projects for Lata continues with a view to reviewing the situation in 5 - 10 years time. Priority should be given to the three centres where hydropower is already economically feasible - Auki, Kira Kira and Buala. Experience gained from design, construction and operation of these plants can then be put to use in the next phase of mini-hydro projects, including one for Lata.

Mention should also be made of certain areas where there is a potential for mini-hydro development, but where there is no electricity supply at present except for occasional privately run diesel generators. Choiseul is one such area, as is the south coast of Guadalcanal, an area with substantial mini-hydro potential, and one study of projects for the village of Avu Avu has already been carried out (reference 21). Although this study concluded that a 130 kW project at Haimatua costing over 1 million SI$ was feasible, the analysis assumes that power demand would rise at 20 - 50% p.a., which must be totally unrealistic for an isolated place like Avu Avu. More realistic growth assumptions (similar to historic growth patterns for say Kira Kira) lead to the conclusion that the Haimatua project is clearly not economic at present.

The conclusion to be drawn from such studies is that irrespective of how good the potential mini-hydro project itself may be, it is necessary to have a guaranteed income from electricity sales in the first years after commissioning if the project is to be financially viable. The introduction of a new central electricity supply and distribution system to a particular village is a costly business which almost invariably requires subsidies. It is therefore essential that the governments and SIEAs own financial resources be used on projects which reduce existing expenditure on diesel rather than increase operation, maintenance and administration costs by expanding supply into new areas. Only when the electricity supply situation is self-financing at a reasonable tariff (i.e. lower than at present) is it possible to think in terms of subsidising supply to new areas. These ideas are expanded on in the following chapters.

MICRO-HYDRO PROJECTS

M1. - Existing projects

There are 3 micro-hydro projects in operation in the Solomons. The first one at Atoifi on Malaita supplies the Seventh Day Adventist (SDA) hospital and mission and was constructed by private enterprise. Use was made of an old turbine and generator which works satisfactorily even though it was not designed specifically for the project. The nominal output is around 30 kW on 100 m head, and the unit is supplied with diesel back-up for dry flow periods.

After many years of continuous operation, SDA have recently ordered a new 32 kW turbine and generator set at a cost of 47,000 A.$ plus freight from Honiara and installation cost.

There are several important aspects of the Atoifi experience from which lessons can be learnt. Firstly, the use of used equipment was successful in minimising the initial capital cost and getting the project started without time consuming detailed study and design work. Experience was gained from many years of operation and a new unit could be designed later to fit the exact load requirements of the system. This approach is often preferable to designing new equipment at high cost for a system which is highly unpredictable because there is no previous experience of electricity use in the district. Secondly, the scheme was designed to fulfill a specific need, i.e. the hospital and mission. Electrification of rural areas where the possible uses of electricity are uncertain and unpredictable may result in costly projects when compared with the benefits achieved.

A 30 kW scheme was constructed in 1983/84 at Maluu in northern Malaita and only recently commissioned. This scheme supplies the village including a hospital and utilises what might be referred to as "the perfect micro-hydro site". The stream has a remarkably reliable flow adequate for power production at all times, and the fall is steep at a site readily accessible and near the load centre. It is unlikely that such a good site for a micro-hydro scheme will be found anywhere else in the Solomons.

The project was funded by New Zealand aid and is well designed and constructed. Administrative problems alone seem to have been the reason for the long delay in commissioning and they illustrate many of the problems which must be faced when electrifying a new rural area.

Land ownership disputes were costly and time consuming. It is important that these issues are settled in parallel with design work and prior to construction. The greatest difficulty arises if the land owners at the hydro site are not the main beneficiaries of the scheme, and in the Solomons such complications can destroy even the best projects.

Another important lesson is that experienced project management is required in all phases of design, construction and commissioning. This should be provided locally by SIEA and the designers of the scheme who have the necessary expertise to manage the project efficiently. After the recent cyclone destroyed part of the transmission line at Maluu, there was considerable delay in repairing the damage due to no spares being readily available for the non-standard equipment. If SIEA had managed the project during construction SIEAs standard equipment would have been used and repairs could have been completed within a few days.

As yet there is too little experience from running the Maluu scheme to provide information about the way in which electricity use develops after electrification and how the demand grows. Maluu is a good pilot project and the results should be monitored in coming years to provide information for other potential micro-hydro schemes proposed for village electrification. It is often the case that after national (and international) attention is diverted from the village once the scheme is commissioned, demand growth can stagnate and the financial viabililty of the project becomes dubious.

Too many micro-hydro projects base their financial and economic viability on the assumption of rapidly expanding demand which does not materialise. These difficulties are often compounded by high connection fees and high tariffs intended to recover some of the capital cost of the scheme. It is therefore important to research the potential demand thoroughly beforehand and to give priority to schemes where the demand is likely to be highest and expected to grow steadily. Areas which necessitate additional outside help in stimulating demand must be examined carefully to assess the realities of demand predictions before proceeding with electrification.

The third scheme at Iriri in Kolombangara was designed and constructed as a pilot project funded by UNIDO with Australian support. The output is nominally 7 kVA (5kW) but is used almost exclusively for village lighting. It has not been possible to substantiate the true cost of the scheme because many services have been provided free or heavily subsidised. The claim that such schemes can be repeated at a cost of 35,000 $ each (reference 14 and 15) is considered to be highly dubious under prevailing conditions in the Solomons. A proposed 25 kW follow-up project for Manawai has been quoted at 450,000 SI$ which is a more realistic figure once all hidden costs are included (e.g. training of local village operators presently undergoing instruction in Australia).

An unfortunate aspect of the Iriri scheme is that it appears to have been constructed without consultation with SIEA despite receiving international support. Although the workmanship and safety standards are probably satisfactory, the work is possibly not in accordance with national standards or safety regulations set by SIEA.

It is recommended that SIEA carry out an independent appraisal of the Iriri scheme including costs, benefits, expected lifetime, maintenance and administration issues before the government promotes any further micro-hydro schemes to be developed along the same lines. The possibility of supplying village lighting from individual household solar kits may be a simpler, less costly and safer way of achieving the objective of village lighting in remote rural areas.

M2. - Experience Gained and Recommendations

The primary lesson from Maluu and Iriri experience is that implementation of government or internationally funded rural electrification schemes should be administered or at least coordinated by SIEA. The SIEA has considerable responsibilities under the Electricity Act (licenses, safety standards etc.) but has little or no knowledge at all of the Iriri scheme, and has only recently commissioned and taken over Maluu and provided an operator. SIEA are the only organisation in the Solomons at present with expertise in repairing and maintaining high tension electrical generation systems, and should therefore be the focal point for training of all operators, technicians, linesmen and electricians and the central standardisation authority and holder of spares.

While all public micro-hydro development should be directed through SIEA, this should not discourage private enterprise from constructing micro-hydro schemes for their own consumption. Atoifi is a typical case of successful private enterprise and the government can encourage further schemes based on private initiative by assisting with technical, legal and administrative advice from their own energy section and SIEA. A precondition of such private schemes is that they do not recieve subsidies from public funds or government international aid, and that they conform to the electricity act and SIEA safety standards.

It must be recognised that substituting diesel generation in an existing electrical system can often make a micro-hydro project financially viable, but introducing a new electricity system to an undeveloped area is almost always without exception never financially viable without extensive subsidies, no matter what generation source is used, diesel, hydro, grid extension or solar. The only exception is if a sizeable enterprise can guarantee an immediate consumption and thereby guarantee a source of income from sales.

An analysis of the proposed Manawai scheme indicates that even if sales of 100 MWh per annum are achieved in the early years, the true cost of providing this power is about 70 SI cents/kWh including capital amortization of 450,000 SI$ at 10%. Comparing this figure with the national tariff of 25 - 28 SI cents/kWh and the cost of diesel stations from Table H.4, it is evident that grants or subsidies are required to start micro-hydro schemes and give them a sound financial basis.

There is ample evidence of this from many developing countries, and the reason is that the financial return from electricity sales in the early years after village electrification is so low that it often does not meet the system operation and administration costs not to mention repay the capital investment. Despite this, many governments have gone ahead by seeking grant aid or subsidising rural electrification programmes by increasing urban electricity tariffs. Fiji and Western Samoa are typical successful cases in point.

Compared to Fiji and Western Samoa the situation in the Solomons is more disadvantageous to rural electrification for several reasons. The villages are small units, widely scattered and with little industrial or commercial activity requiring electricity consumption. Any potential consumers must be artificially created by investing in development projects such as cold stores, sawmills, ice plants etc. which requires even more capital and technical input. Village lighting is more safely, cheaply and reliably provided by individual household solar kits than by a high tension distribution system, and currently it is not permitted to wire leaf houses in the Solomons which comprise 95% of all village dwellings (although wiring of leaf houses is permitted in Papua New Guinea).

For these reasons it is suggested that the Solomon Islands has not yet reached a stage where it can afford to subsidise rural electrification schemes whether these be energised by hydro, diesel or grid extension. Concentrating on electrification of new areas will only succeed in diverting scarce grant aid and scarce internal technical and administrative expertise for limited returns. Even if satisfactory returns are forthcoming they are limited to a single village area, which easily creates jealousy in other villages and starts an unfortunate precedent. If the returns are not forthcoming the authorities are left with yet another electricity system which runs at a loss and requires subsidies from other consumers (compare Buala, Munda, Santa Cruz and possibly Maluu).

The government should therefore concentrate its grant aid and technical and administrative resources on building mini-hydro plants for existing centres such as Honiara, Auki, Kira Kira and Buala where there is a definite economic return in the form of immediate savings in diesel fuel. In this way they will gain valuable expertise in hydro development and broaden their pool of experienced technicians and operators at the same time as improving SIEAs finance. This will create a cash basis from which to subsidise potential rural electrification schemes such as Manawai in 5 - 10 years from now.

During the intervening period the government can learn from the experience of Iriri, Maluu, Auki, Kira Kira and Buala and develop a sound and fair policy for systematic rural electrification based on uniform tariffs, consumer registration and cash inputs from potential consumers as used successfully in other countries. These ideas are outlined in the discussion paper enclosed as appendix A. The premature implementation of single rural electrification schemes of any type will set precedents and become a hindrance to the formation of a fair and consistent rural electrification policy in the future.

APPENDIX A

A discussion paper on micro-hydro development and rural electrification

Definition

The term micro-hydro is used to describe hydropower units of less than 100 kW. These fall into two categories:

(i) Schemes connected to the main grid, usually found in irrigation dams, water works, canals, hydraulic structures etc.

(ii) Isolated schemes for supplying a limited area such as one or two villages.

It is the latter category that is relevant for the Solomon Islands and the folowing discussion applies only to schemes isolated from the main grid.

Objectives

The objectives must be clearly defined when considering a rural electrification scheme of any sort either by grid extension, micro-hydro or diesel generation.

The overall objective will probably be socio-economic development of the village or in plain terms raising the villagers standard of living.

More specific objectives must be defined. These may include providing one or more of the following list of services:

A. Village lighting either for private or communal use.

B. Electricity for water pumping or other general usage for communal benefits.

C. Power for institutions such as missions, schools, hospitals, clinics, government buildings.

D. Commercial power supply for stores and small workshops and cottage industries, grain mills etc.

E. Power for a single industrial consumer such as a sawmill or other major power consumer.

F. Power for domestic consumption (private houses and refrigerators, fans, etc.)

G. Ice making and cold store for fish and meat, 1 kW and 3 - 4 kW).

Once the specific objectives are defined it is possible for the national or provincial government to decide which types of classification they wish to give priority to, and hence which schemes are most needed. (For instance consumers in categories E and F should have low priority).

Assistance should be given to the villagers in defining realistic objectives and presenting alternative methods of achieving these objectives relating them also to the total cost irrespective of the source of finance (not just cost to the villagers or to the government but the total monetary input whether given as grants or training packages and including hidden costs such as government administration).

Demand Survey and Registration of Potential Consumers

A survey of potential demand in the villages should be carried out by interviewing potential consumers to find out their needs and also their willingness to pay the appropriate charges. The individual consumers identified should be asked to make a nominal monetary contribution to the establishment of the scheme. This confirms the willingness of the potential consumer to pay. Successful village water supply schemes in Africa work on this basis. The aim should be to collect money to invest in a fund towards implementing the scheme. About 200 SI$ per kW demand is an affordable figure which would collect about 5000 SI$ for a 25 kW scheme or 2 - 3% of the project cost.

In addition to information of future tariffs to be charged, this test is also necessary to determine how many potential consumers are serious. If no contribution is asked for, everyone applies, irrespecitive of whether they are willing or can afford to pay the future charges.

From the list of consumers who have signed up and payed their deposit according to their expected maximum demand, the village systems daily load curve and the potential yearly sales can be estimated.

Design and Feasibililty Study

The demand survey will enable the peak capacity and energy requirements to be stipulated and the rural electrification scheme designed accordingly. It is vital to know what demand the scheme is meant to supply in order to fulfill that demand by the most economic solution.

This is often the single most important reason why some micro-hydro schemes fail to live up to financial expectations. The designer designs the scheme according to the capability of the most suitable stream or river rather than concentrating on the realistic power requirements of the village.

After the demand has been established and a reaonable margin for growth allowed, the scheme can be designed. It is important to hold open all options at this stage in order to obtain the most economic solution whether this is hydro, solar, diesel or other energy forms.

Typical costs for the various alternatives are:

SOLAR

1000 SI$ per household lighting kit (reference 5). Running costs are nominal for occasional maintenance and repair work.

DIESEL

1000 SI$ per kW capacity for installation of a complete diesel set. Running costs are dependent on fuel prices. At present levels (May 1986) fuel contributes about 16 - 25 SI cents/kWh including transport in drums to remote areas. Operation and maintenance costs are largely dependent on the manpower input whether this is in the form of village technicians or skilled mechanics. Replacement parts are not a significant proportion, and if the demand survey is properly carried out and the scheme properly managed, the running cost of diesel generation should seldom exceed 30 - 40 SI cents/kWh at present fuel prices. This figure does not include capital depreciation costs and costs for distribution, reticulation, metering and administration which are common to both diesel and hydro electrification schemes.

HYDRO (One scheme only)

If a single hydropower project is constructed in isolation, many one-off costs are disproportionately expensive such as consultants fees, mechanical equipment and shipping, administration, training etc. The proposed 25 kW Manawai scheme is a typical example and has been quoted at 265,000 US$ (1985) equivalent to nearly 500,000 SI$ or 20,000 SI$/kW (1986 prices).

Running costs are dependent on manpower input. Operation or maintenance costs are typically less than diesel, but still require a full time employee on site and occasional repairs. A reasonable estimate is 6000 $ annually which is a somewhat less than diesel to reflect less frequent repairs.

HYDRO (10 schemes implemented simultaneously as a programme)

The capital cost is considerably reduced compared with the single scheme, but seldom lower than 150 - 200,000 SI$ even for the smallest scheme. Maluu (30 kW) would perhaps have cost more than 300,000 SI$ at 1986 price level, and this scheme has many positive cost-saving features which would not be repeated at many sites.

Running costs for many micro-hydro schemes are slightly down on the "one-off" scheme because of centralised repair teams, but each scheme still requires a local operator and electrician. 5000 $ annually is estimated to be a minimum cost.

The various alternatives can be compared in Table M1 which shows the cost of various types of 25 kW scheme producing 50 MWh of sales annually. Table M2 shown how the choice is radically altered if greater energy sales can be expected (100 MWh annually).

	Capital Cost (thousand SI$)	Running Cost (thousand SI$/year)	Net Present Worth Cost (10% disc., 1986)	
DIESEL	25	15 - 20	200	TABLE M1 sales = 50 MWh p.a.
HYDRO (1 scheme)	300 - 500	6	360 - 560	
HYDRO (10 schemes)	250	5	300	
DIESEL	25	30 - 40	370	TABLE M2 sales = 100 MWh p.a.
HYDRO (1 scheme)	300 - 500	7	370 - 570	
HYDRO (10 schemes)	250	6	310	

Results and Conclusions

The above exercise demonstrates the following points:

(i) A single micro-hydro scheme is seldom if ever cost effective. Micro-hydro development is more successful if a programme is identified where 10 or more schemes are designed and constructed simultaneously.

(ii) The anticipated energy sales are critical to the choice of diesel or hydro. If substantial sales can be ensured the hydro is a good alternative, but if sales lower than 50 - 100 MWh p.a. are anticipated, it is likely that diesel will be the more economic alternative.

Implementation of Rural Electrification Schemes

The SI Government should gradually develop policies and a programme for rural electrification using solar, hydro, or diesel power generation as appropriate to each site. The following suggestions are a basis for discussions in formulating policies.

It is recommended that any rural electrification should be motivated by the real needs and wishes of each district. This can best be assessed by a registration scheme requiring a small deposit from potential consumers as a registration fee, enabling them to be considered on the rural electrification programme before any scheme is designed and constructed. Those consumers and villages who really need electric power and have the willpower to make the scheme successful will succeed in collecting say 5000 $ as a small contribution to their own scheme. If a village cannot collect such a sum, then they cannot afford either the wiring or the running cost of electrification. In such cases other basic needs should be given priority such as water, health, education, and agriculture.

Those villages who have a substantial demand and indicate this by collecting the required deposit can be assessed by electricity planners provided by either SIEA or the central or provincial government. The demand assessment will provide data on peak demand and potential energy sales from which to design the scheme. A register of interested villages and their potential demand will be an excellent basis for selecting priorties for development. An early indication of most likely types of electricity generation for each village (solar, hydro or diesel) can also be given.

Areas requiring only lighting, hot water, water pumping, refrigeration, and drying of agricultural produce may find that solar energy can fulfill their needs without the need for high voltage electricity involving complex wiring, skilled maintenance, and safety precautions.

Areas with higher power needs, (workshops, electric tools, shops, hospitals, schools, etc.) will require high voltage power and the choice is between diesel and hydro (or extension of the grid system if they lie within a few kilometers of an existing power supply).

Typical villages for hydropower development lie near a substantial stream or river with a relatively reliable dry-weather flow and a good fall. As a guideline 50 m head with 50 l/sec minimum flow within 5 km of the village would provide a viable micro-hydro scheme of 15 kW reliable output.

From the register of village electrification schemes, those with likely hydro potential can be grouped together. When about ten promising projects are found, these might be subsidised by a willing donor who will provide the remaining capital and expertise to design, construct and provide training in the operation of the micro-hydro plants.

Consideration should also be given to implementing certain schemes with diesel generation, particularly where there exists a real need and also as a comparison for the micro-hydro schemes.

Subsidising Rural Electrification Schemes

With the exception of private users such as Atoifi, there is no micro-hydro scheme which can supply cheap power in the Solomon Islands unless it is subsidised or financed by grant aid. This cannot be expected in the long run, and planning should be based on commercial finance of the type typically available to the Solomon Islands.

If an attractive package of 10 micro-hydro schemes can be presented, it may be possible to obtain soft loans or grant subsidies from a willing donor. These favourable sources of finance should be used to subsidise many schemes rather than concentrated on one or two pilot schemes which only benefit one village.

It is also imperative that many schemes are implemented in order to bring down the cost of the micro-hydro projects. The long-term aim should be to create a market for micro-hydropower equipment which is sufficiently large to justify starting local manufacture of pipes and even turbines. This will be necessary if the unit cost of micro-hydro schemes is to come down to near the economically viable levels of about 6000 SI$/kW, quoted by APACE as the repeatable cost of the Iriri scheme (reference 13) and experienced in Nepal and Thailand (reference 12).

It is the policy of subsidising rather than donating rural electrification schemes which is successful in other countries such as Fiji. Some capital contribution is always required of the beneficiaries, and the only question is how much. The registration fee and the data obtained from the village demand surveys will enable the government to gain experience and form a consistent policy.

Tariffs

The important question of tariffs must also be discussed and a policy formulated even before the registration work is started. The villagers must be given concise information as to what the power will cost, what connection charges will be made, and what restrictions will be imposed on power use (maximum demand fuses, off peak tariffs, etc.).

The earlier SIEA policy of uniform electricity charges throughout the Solomons is a simple and fair policy to be defended. This usually implies that the main supply area consumers are subsidising the more costly outstations where demand is low.

Consideration should be given to a simple fixed charge for low demand consumers, usually private houses using say less than 200 Watt maximum. Metering is too costly at these low levels, and a simple fuse is an adequate safeguard against over-use.

APPENDIX B

General geological conditions for tunnels and underground works

The Komarindi project is located in an area with sedimentary rocks of Lower Miocene-Pleistocene age, referred to as the Lungga Beds. The main components of the Lungga Beds are detrital volcaniclastic grains. Calcareous components are also present.

According to the Guadacanal Geological Map Sheet GU8 (Figure F.9) the structural geology is controlled by folding about a NW-SE-axis, and at least two sets of faults in NW-SE and NE-SW direction of which the former appears to have been the most recent.

At the dam and tunnel intake site (see photo 1), massive interbedded rudites, arenites, lutites and wackes are exposed dipping at about 15 deg. to the northwest. Individual beds vary in thickness from a few metres to a few centimetres and are mostly laterally persistent.

At the tunnel outlet site (photo 2) a thick unit (at least 20 metres) of massive calcirudite is exposed with a few minor intercalations of lutite. Steep cliffs show typical limestone karst weathering and a prominent set of vertical north-westerly trending joints have been accentuated by solution.

From a provisional interpretation of aerial photographs of the project (Figure F.10), the proposed location of the tunnels seems to be favourable. The tunnels will cross faults or fractured zones at favourable angles and this is of importance for good tunnel stability.

It is expected that rock bolts, steel netting and shotcrete will provide adequate stability during construction. For permanent stability and for reduction of leakage it is anticipated that concrete lining will be necessary across fractured zones and across karst zones.

It has been assumed that the headrace pressure tunnel will require full concrete lining whereas the tailrace tunnel will require only shortcrete and rockbolting for stability purposes. Leakage in the tailrace is unimportant.

Future investigations for the project should comprise of detailed mapping of faults and of geological strata with unfavourable properties. Assessment of the depth of weathering along the eastern part of the tunnel and the power station area is important. The weathering is expected to be deep-going in places. Seismic refraction profiling and diamond core drilling are suitable field investigation methods for this type of study.

Compared to many parts of north Guadalcanal, the geology appears to be suitable for tunnelling, although rock quality will vary considerably over short distances because of faulting and a complex bedding sequence. The only data on rock types comes from boreholes drilled in similar material at Lungga gorge site (reference 9). The geological report on the proposed tunnels at Lungga concludes that moderate rock support works will be required followed by a concrete lining. It may not be necessary with a concrete lining if the rock is competent and non-erodible, however for the purpose of cost estimating a full concrete lining has been assumed for the headrace. A detailed geological survey followed by field investigations will be necessary to clarify the suitability and hence the cost of tunnelling work.

APPENDIX C

Komarindi project: technical aspects

The dam will be a concrete overflow weir 10 m high and 60 m long with a crest level of 220 m. There will be a concrete cut off trench and a grout curtain along the upstream face, and the weir must be anchored to the foundation with a series of rock anchors. If the river bed material or rock is erodible, it will be necessary to construct an energy dissipating structure below the weir, and for preliminary costing a small flip bucket is assumed.

By the tunnel intake it will be necessary to construct a large scour outlet to remove sediment from in front of the intake, and a 2 m x 2 m submerged gate is included with automatic operation whenever the spillway begins to overflow. This gate is housed in a 17 m high concrete abutment section adjacent to the intake structure. Road access is provided onto the abutment for installing and servicing the gates. The dam must be designed for a 1000 year flood which is estimated at 2000 m3/s, equivalent to a reservoir level of 227 m, 7 m above the crest.

The tunnels can be constructed by two methods. The most economical is a minimum excavated section of 6 m2, which must be excavated at a relatively flat gradient of 1.5 m per km to enable rails and trucks to run. This section is suitable for the surface alternative and will require a minimum of rock support works. It is assumed that reinforced shotcrete combined with rockbolting is sufficient except when very fractured rock is encountered. The tunnel emerges into a trapezodial section concrete-lined canal which will be widened into a surge tank/ desilting basin just above the penstock intake. The penstock can be of steel or glassfibre , the latter being easier to erect because of its light weight. The diameter will be 1800 mm, sufficient to supply two 3 MW units comfortably and a third 3 MW unit with acceptable head loss (4 m max.).

For the underground alternative, tunnel excavation is carried out using wheeled loaders, which can work at gradients of up to 1:8. Most contractors require at least 17 m2 excavated section, but a new low-profile excavator has recently been developed to work in sections as small as 10 m2. The standard 17 m2 design is used for costing purposes.

This type of tunnel can fall at 1:20 directly down to power station level as shown in Figure F.12. The tunnel is therefore pressurised and because little is known of the rock properties, it is assumed that a full concrete lining will be necessary. Although this tunnel is more costly, it eliminates the need for a steel penstock except for the final 50 m into the underground power house.

The disadvantage of this arrangement is that it is not practical to empty the sand trap at the end of the pressure tunnel except by draining the tunnel, so more sand is passed through the turbines. There is not thought to be a high proportion of quartz or other hard rock in the river sediment, and turbine erosion due to sand transported through the turbines is expected to be acceptable.

The power house can either be constructed in the open or underground. Attention must be paid to the flood level during severe floods which may be 7 - 10 m above lowest tailwater level. The generator and electrical equipment must be placed sufficiently high and an exposed building must be positioned safe from damage from flooding. This favours the underground solution which is more protected and gives the designer greater freedom in chosing level, position and tunnel alignments.

Due to the low level of demand, only two 3 MW units are needed in the first place, using only 4.6 m3/s each as shown in Figure F.13. Preparations would be made in Phase 1 for the later extension of the power house to accomodate a further 3 MW unit. A third phase could be the collection of the Ohe river water to increase the power production by a diversion dam on the Ohe and an interconnecting tunnel, canal or pipe.

The project site will be reached from Honiara by a 20 km long access road passing over the Lungga plateau as shown on Figure F.8. The 33 kV transmission line will follow the access road alignment, and connect into the Honiara grid at the existing Honiara diesel station.

MONTHLY RAINFALL (in)

STATION 19: HONIARA **ISLAND: GUADALCANAL**

Station Type: Meteorological Station **Geographical Coordinates:** 159° 57'E 9° 26'S

Data Source: Commonwealth of Australia Bureau of Meteorology **Altitude:** 190 ft

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Mean
1949												2.73		
1950	7.42	10.11	17.32	13.88	15.02	1.03	6.14	4.79	3.16	1.97	4.36	14.41	99.61	
1951	3.26	10.15	18.85	8.36	4.93	0.03	1.63	2.14	3.28	0.97	2.59	3.88	60.07	
1952	11.07	7.88	16.50	14.06	4.06	4.67	5.35	2.22	3.30	13.72	10.56	3.88	97.27	
1953	8.25	7.56	12.94	12.45	2.74	3.15	5.68	4.38	3.22	3.23	7,21	4.84	75.65	
1954	14.42	17.72	15.86	6.08	4.92	3.08	3.27	2.64	3.76	7.46	4.64	9.69	93.54	
1955	5.01	5.23	24.08	4.58	7.06	3.09	1.64	0.27	3.03	2.87	5.41	23.15	85.42	
1956	16.10	19.53	13.05	6.01	2.05	2.92	0.62	1.07	0.45	2.85	5.07	3.62	73.34	
1957	5.64	14.74	12.50	4.49	7.45	3.47	2.16	3.47	3.18	6.85	3.87	6.34	74.16	
1958	7.41	3.87	8.01	25.60	4.91	13.54	1.19	1.83	2.60	7.41	2.15	8.15	86.67	
1959	14.83	9.63	13.49	11.74	5.18	2.35	3.78	8.76	8.39	3.89	6.45	15.79	104.28	
1960	10.65	12.29	24.25	13.11	2.96	4.05	6.10	2.43	5.32	5.46	3.74	5.18	95.54	
1961	8.69	6.94	12.63	6.96	4.26	2.52	8.51	4.92	5.69	5.89	9.79	4.85	81.65	
1962	8.76	12.41	4.68	12.75	18.90	4.50	2.41	2.72	2.56	6.69	3.91	11.46	91.75	
1963	7.24	8.23	16.21	7.47	1.62	1.46	3.79	5.67	7.58	10.98	4.85	6.56	81.66	
1964	9.53	3.24	11.93	6.27	7.43	1.68	2.56	1.88	1.50	7.65	5.29	4.36	63.32	
1965	14.98	15.49	14.93	4.53	5.99	4.33	12.22	4.81	2.70	4.65	3.53	7.70	95.86	
1966	1.28	7.88	9.89	5.63	2.27	1.91	0.64	1.91	1.03	2.16	15.67	11.40	61.67	
1967	22.59	12.15	25.41	7.21	8.59	3.50	4.52	5.53	2.67	15.06	6.78	2.54	113.55	
1968	16.92	12.72	7.91	7.70	0.93	2.59	7.04	3.89	5.62	5.17	5.49	5.50	81.48	
1969	(a) 11.56	14.47	8.86	7.25	5.41	6.18	3.82	4.00	3.09	3.92	4.47	11.48	84.51	
1970	6.57	22.42	11.03	13.27	5.26	4.78	2.08	3.26	7.24	7.86	5.64	11.39	100.80	
1971	9.57	4.42	18.20	13.61	3.84	4.59	3.57	3.28	4.27	6.30	5.20	17.87	94.72	
1972	38.23	12.07	14.36	8.18	6.30	10.69	4.13	4.67	4.15	3.04	1.54	7.14	114.50	
1973	3.27	8.73												
Mean (b)	11.30	10.92	14.47	9.62	5.74	3.92	4.04	3.50	3.82	5.91	5.57	8.75	87.56	
Mean (c)	10.97	10.83	14.47	9.62	5.74	3.92	4.04	3.50	3.82	5.91	5.57	8.68	87.07	

(a) Data Source: New Zealand Meteorological Service.

(b) Mean for all complete years.

(c) Mean for all monthly records available.

MONTHLY RAINFALL (in)

STATION 24: KONGGA **ISLAND: GUADALCANAL**

Station Type: Department of Agriculture **Geographical Coordinates: 160° 07'E 9° 30'S**

Data Source: Land Resources Division **Altitude: 300 ft**

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Mean
1967											11.68	8.09		
1968	16.73	13.30	6.81	7.57	1.04	4.18	6.76	5.83	4.52	7.70	5.88	13.02	93.34	
1969	14.35	8.67	7.94	10.54	4.14	5.06	7.14	6.74	1.99	5.36	7.69	13.42	93.04	
1970	3.43	29.25	13.72	10.13	3.32	9.17	2.18	4.10	6.74	7.51	6.75	12.65	108.95	
1971	14.85	7.68	14.67	9.70	2.33	4.17	2.95	0.29	1.58	3.26	2.82	20.05	84.35	
1972	38.82	9.43	16.71	8.55	9.28	13.40	3.75	(a)	7.90	1.08	6.02	(a)		
Mean (b)	12.34	14.72	10.78	9.48	5.21	5.64	4.76	4.24	3.71	5.96	5.78	14.78	97.40	
Mean (c)	17.64	13.67	11.97	9.30	6.02	7.02	4.56	4.24	4.55	4.98	6.81	13.45	104.39	

(a) Incomplete data for month
(b) Mean for all complete years
(c) Mean for all monthly records available

MONTHLY RAINFALL (in)

STATION 8: AUKI | **ISLAND: MALAITA**

Station Type: District Office | **Geographical Coordinates:** 160° 42'E 8° 46'S

Data Source: Commonwealth of Australia Bureau of Meteorology[(a)]
New Zealand Meteorological Service[(b)] | **Altitude:** <50 ft

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Me
(a) 1918									12.25	7.52	8.22	7.91		
(a) 1919	16.11	6.41	16.21	12.14	12.11	8.31	9.13	9.73	15.91	6.31	9.24	8.10	129.71	
(a) 1920	6.08	25.14	6.17	3.81	5.36	5.20	4.18	2.40	4.90	11.37	7.96	13.13	95.79	
(a) 1921	25.03	6.34	21.71	13.86	10.41	12.46	6.90	3.00	12.25	4.08	11.30	8.00	136.52	
(a) 1922	13.03	13.52	13.33	13.41	6.65	7.72	9.70	4.50	6.34	4.40	13.12	15.01	120.82	
(a) 1923	19.66	19.41	12.90	7.91	7.54	9.18	3.92	5.54	8.85	8.79	7.63	6.51	117.88	
(a) 1924	18.62	12.31	15.77	12.61	8.50	13.81	6.00	7.77	6.52	9.53	4.08	16.30	133.20	
(a) 1925	8.41	11.92	17.41	21.25	7.53	2.43	5.09	9.53	6.88	7.17	13.34	6.55	117.51	
(a) 1926	11.79	16.83	6.42	5.30	3.50	7.31	3.72	16.30	8.50	9.68	7.02	6.00	102.56	
(a) 1927	12.23	25.29	11.46	11.42	13.87	6.11	8.72	10.53	(d)	(d)	(d)	(d)		
(a) 1928	(d)	(d)	(d)	28.78	11.63	7.71	7.34	18.51	13.68	9.11	17.91	7.80		
(a) 1929	37.75	31.00	7.68	17.87	8.33	7.61	9.41	13.73	7.44	14.61	3.93	7.45	166.81	
(a) 1930	21.30	12.45	11.32	4.80	10.53	3.76	5.95	6.23	4.79	16.57	2.96	4.07	105.51	
(a) 1931	18.93	10.82	7.33	13.22	5.66	4.46	8.75	9.22	4.02	7.40	11.62	13.92	117.35	
(a) 1932	14.15	12.56	10.01	8.24	(c) 10.00	6.54	7.72	21.78	7.68	13.23	13.54	12.24	137.69	
(a) 1933	8.50	13.30	15.32	9.08	7.12	8.56	6.50	(d)	(d)	8.08	11.40	13.61		
(a) 1934	13.78	10.28	20.13	10.51	4.85	10.04	3.06	6.34	9.86	7.13	5.73	10.54	112.25	
(a) 1935	17.25	10.00	8.97	7.15	6.36	4.85	3.74	(d)	(d)	(d)	(d)	(d)		
(b) 1954	14.65	14.29	21.12	8.95	7.46	4.30	7.83	9.28	7.56	12.34	9.99	10.00	127.77	
(b) 1956	6.30	25.96	20.48	7.45	2.94	6.87	3.70	12.42	6.18	7.11	8.03	8.32	115.78	
(b) 1957	11.38	16.95	9.88	12.05	7.45	3.83	5.29	7.53	14.87	7.80	2.93	8.14	108.10	
(b) 1958	10.27	19.12	12.05	18.58	3.99	14.94	5.66	3.43	9.17	11.35	4.32	7.27	120.15	
(b) 1959	10.54	14.74	14.57	7.85	8.25	11.60	8.80	13.64	12.19	5.61	4.45	11.31	123.55	
(b) 1960	8.38	11.64	18.86	9.99	4.14	8.48	15.73	6.99	7.64	5.44	7.60	(e) 6.94	111.83	
(b) 1961	13.06	10.50	15.73	7.07	6.23	4.79	15.37	9.02	25.20	10.96	12.00	8.95	138.90	
(b) 1962	9.96	20.90	17.75	10.18	8.10	4.11	7.74	7.61	8.42	7.56	10.30	22.87	135.70	
(a) 1963	11.00	6.27	17.19	7.71	4.23	7.66	8.95	10.48	11.10	19.48	10.21	8.10	122.47	
(a) 1964	18.93	18.98	17.78	12.62	3.82	6.14	9.62	7.08	7.32	9.25	8.77	7.62	127.93	
(a) 1965	16.47	11.25	23.00	8.93	9.68	7.76	19.94	12.56	10.17	8.80	4.38	10.50	143.62	
(a) 1966	4.67	13.35	15.44	5.25	9.77	7.68	5.19	6.51	5.38	8.04	13.77	13.99	109.04	
(a) 1967	19.83	18.79	22.77	7.93	14.27	9.00	8.50	16.50	6.17	9.97	15.05	6.97	165.44	
(a) 1968	28.94	20.46	13.70	5.14	6.22	5.36	14.81	5.88	9.24	6.13	7.76	27.43	151.06	
(a) 1969	13.54	15.98	8.24	9.88	9.66	11.16	14.74	14.21	8.05	9.29	3.13	11.06	128.94	
(a) 1970	7.36	21.18	20.10	36.47	10.12	5.78	8.16	6.09	9.26	14.63	9.06	28.61	178.02	
(a) 1971	16.96	15.49	23.84	10.12	9.36	4.80	5.67	11.51	9.69	10.76	7.91	26.04	152.15	
(a) 1972	26.38	7.04	13.73	6.11	16.99	15.60	8.09	4.56	5.90	5.57	5.69	6.94	122.62	
(a) 1973	13.01	16.86												
Mean (f)	15.27	15.50	15.30	11.24	7.56	7.44	8.33	9.24	9.12	9.50	8.41	11.79	128.70	
Mean (g)	14.99	15.37	14.96	11.42	8.08	7.60	8.13	9.42	9.26	9.27	8.69	11.47	128.65	

(c) Commonwealth of Australia Bureau of Meteorology gives estimated figure.
(d) No record available.
(e) There is conflicting source data for this month.
(f) Mean for all complete years.
(g) Mean for all monthly records available.

MONTHLY RAINFALL (in)

STATION 22: KIRAKIRA **ISLAND: SAN CRISTOBAL**

Station Type: District Office **Geographical Coordinates: 161° 55'E 10° 27'S**

Data Source: Commonwealth of Australia Bureau of Meteorology **Altitude: <30 ft**

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Mean
1919	13.02	2.43	7.25	8.41	8.34	13.44	5.52	11.95	22.74	11.76	11.68	3.18	120.32	
1920	4.04	16.25	7.12	7.81	15.19	5.91	2.02	0.58	5.72	9.62	13.02	(a)		
1921	12.94	5.43	22.38	34.44	14.05	22.83	11.50	6.81	18.14	3.01	10.03	6.59	168.15	
1922	13.92	21.90	12.10	19.14	8.50	15.62	13.77	14.57	7.89	20.93	6.78	4.83	160.04	
1923	17.63	17.26	20.86	9.12	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)		
1924	(a)	(a)	(a)	(a)	(a)	(a)	(a)	21.47	16.19	10.75	8.24	10.49		
1925	15.24	(a)	(a)	(a)	9.10	17.55	(a)	(a)	(a)	(a)	(a)	(a)		
1926	(a)	(a)	(a)	9.97	1.24	7.52	4.12	20.35	14.41	(a)	15.10	9.22		
1927	15.74	10.39	16.69	10.63	12.81	14.56	5.34	11.87	16.80	12.37	6.98	10.06	144.24	
1928	3.02	14.49	7.38	8.39	10.45	10.13	6.96	16.97	12.04	9.18	21.96	9.27	130.24	
1929	20.51	16.75	7.40	13.25	6.36	10.02	12.59	22.92	7.75	8.09	3.71	5.78	135.13	
1930	9.23	7.46	4.89	1.97	7.85	8.27	6.93	5.31	3.79	7.02	1.59	5.84	70.15	
1931	7.38	10.52	8.20	14.51	9.90	4.93	6.86	3.55	6.53	8.42	3.85	24.10	108.75	
1932	16.56	13.80	5.98	5.82	12.14	6.38	16.87	22.20	11.90	11.20	11.11	9.60	143.52	
1964	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	3.99	(a)		
1965	16.37	13.56	15.55	8.19	15.60	19.70	29.26	20.28	12.10	16.64	5.11	23.99	196.33	
1966	6.51	17.19	10.97	12.31	14.29	6.62	0.98	6.10	6.23	5.46	15.45	19.91	121.02	
1967	19.64	11.71	26.31	8.36	14.47	14.90	7.16	27 86	8.67	20.95	S.29	15.09	184.41	
1968	28.33	14.94	7.66	22.56	6.65	4.66	13.48	6.16	11.88	11.02	8.98	11.65	147.97	
1969	20.30	15.33	17.13	16.74	10.23	17.75	19.53	18.20	12.66	12.36	4.58	9.47	174.28	
1970	6.18	7.30	10.19	10.59	14.04	16.44	22.29	27.37	8.08	13.81	7.87	8.69	152.85	
1971	17.67	11.39	30.13	23.18	6.70	9.57	7.62	13.51	14.57	6.32	9.46	16.90	167.02	
1972	16.70	10.20	16.13	13.04	18.00	10.64	10.52	5.11	3.16	3.29	5.53	8.95	123.27	
1973	4.44	4.73												
Mean (b)	14.24	13.24	14.44	13.47	10.78	12.24	11.67	14.73	11.36	11.16	8.47	11.39	147.19	
Mean (c)	14.30	13.01	14.48	12.77	10.80	11.87	10.70	14.16	11.06	10.75	8.76	11.23	143.89	

(a) No record available
(b) Mean for all complete years
(c) Mean for all monthly records available

MONTHLY RAINFALL

STATION 67: TASIA | **ISLAND: SANTA ISABEL**

Station Type: Mission | **Geographical Coordinates: 159° 37'E 8° 08'S**

Data Source: Department of Agriculture | **Altitude: <10 ft**

Year	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Mean
1957							9.62	9.90	14.83	20.25	3.94	9.68		
1958	5.87	8.96	11.99	13.50	5.55	7.79	13.45	6.73	(b)	(b)	(b)	(b)		
1959	(b)	(b)	(b)	(b)	(b)	(b)	7.45	24.05	28.20	9.10	16.64	18.17		
1960	18.18	25.80	23.28	14.37	8.54	10.90	20.31	4.34	11.84	16.42	6.85	16.48	177.38	
1961	11.67	7.22	7.20	12.46	16.31	9.28	14.92	9.26	15.39	11.49	23.60	6.33	145.13	
1962	9.77	13.18	9.89	22.85	15.78	13.66	10.95	13.88	9.04	11.22	15.11	24.48	180.81	
1963	8.02	11.15	24.26	12.33	18.15	13.03	6.33	16.49	16.38	15.85	13.99	18.55	174.53	
1964	9.28	7.35	15.57	15.59	16.12	10.47	27.86	14.65	15.18	14.05	11.69	5.57	163.36	
1965	14.49	11.39	12.53	6.14	16.54	16.19	29.00	11.18	15.71	14.77	5.79	15.83	189.56	
1966	(a)	15.50	13.99	7.28	19.36	15.58	11.95	10.61	8.03	8.78	27.12	11.2[illegible]		
1967	15.76	15.74	29.56	8.82	15.31	12.73	13.65	18.13	5.04	14.29	27.74	8.98	185.75	
1968	17.25	11.70	11.52	14.06	4.56	9.05	16.44	10.35	10.90	6.64	11.81	9.35	133.63	
1970	(b)	11.74	14.02	27.80	11.48	13.33	13.73	11.22	9.28	9.31	9.36	13.33		
Mean (c)	13.06	12.94	16.73	13.33	13.91	11.92	17.43	12.28	12.43	13.09	14.57	13.19	164.87	
Mean (d)	12.25	12.70	15.80	14.11	13.43	12.01	15.05	12.37	13.32	12.68	14.47	13.17	161.36	

(a) Incomplete data for month
(b) No record available
(c) Mean for all complete years
(d) Mean for all monthly records available

APPENDIX E - DRAFT TERMS OF REFERENCE

Technical Assistance to the Government of the Solomon Islands in Small and Mini-Hydro Development

Background

The Government of the Solomon Islands is embarking on a programme of development of small and mini-hydropower projects which substitute the use of imported diesel fuel in existing electricity supply systems. With the exception of 3 micro-hydro projects of up to 30 kW, there are no hydropower plants operating at present in the Solomons and potential schemes are generally at the very early stages of study and design.

In March 1986 UNIDO funded a mission to study potential hydropower schemes in the Solomons, discuss priorities with the government and recommended further action to be taken. A draft final report was completed in July 1986 which recommended 4 projects for immediate development:

1. Komarindi Project for Honiara (6 MW, 28 million SI$)
2. Kwaibala Project for Auki (100 kW, 0.64 million SI$)
3. Huro Project for Kira Kira (100 kW, 0.59 million SI$)
4. Jejevo Project for Buala (100 kW, 0.49 million SI$)

At the same time UNDP agreed to fund the position of hydropower projects manager in the Ministry of Natural Resources for a period of one year with possible continuation. The position is described in the annexed job description and recruiting has commenced with a view to an appointment late in 1986. At the time of writing of the hyropower managers job description, the Komarindi project had not been identified. It has since become apparent that much of the hydropower projects managers time will be occupied with preparations for this more important larger project. Consequently he will require the services of consulting engineers to carry out the design of the 3 mini-hydro projects (2 - 4 above) and provide training of Solomon Islands counterparts during the study and design of these 3 pilot projects.

The present technical assistance proposal is intended to provide training for the Solomon Islands Governments own staff in identifying, studying, designing and financing hydropower projects, starting with the 3 mini-hydro projects listed above (2 - 4). The hydropower projects manager funded by UNDP will supervise and coordinate all work on these 3 projects on behalf of the Solomon Islands Government, in addition to his duties regarding the Komarindi project. The consulting firm to be appointed under these terms of reference for technical assistance is to be responsible to the hydropower projects manager for training of Solomon Islands counterparts in various disciplines related to hydropower planning and design while undergoing the actual study, design and document preparation for the 3 afore-mentioned mini-hydro projects.

Objective

The objective is to instruct Solomon Islands counterpart staff in planning, design, report preparation and administration of mini-hydro projects by leading them through these procedures for three 100 kW pilot schemes - one each for the provincial centres of Auki, Kira Kira and Buala. During all stages of work extensive training will be given in the following:

- surveying and mapping related to mini-hydro projects
- design and preparation of construction drawings
- checking and analysis of hydrological data
- power production calculations and choice of turbine
- design and specification of generating equipment
- electrical engineering and control equipment
- project optimisation and economic analysis
- preparation of feasibility reports and applications for finance
- tendering and contract negotiation

The overall objective is to train Solomon Islands staff to continue with planning and design of further mini-hydro projects with a minimum of external assistance, while at the same time proceeding with useful pilot mini-hydro projects for demonstration purposes.

This will also prepare the Solomon Islands Government for the more demanding task of coordinating the study, design and construction of the larger Komarindi project to be carried out by international consultants and contractors.

Timing

The technical assistance period is estimated to be 1 year or more, commencing with the appointment of the hydropower projects manager and continuing until the three mini-hydro projects are financed and contracts for construction work are signed.

Requirements of the Consultant

A consulting firm with considerable experience in the design and construction of mini-hydro projects will be appointed to provide technical assistance in carrying out the work. The consultants experience must cover the full range of disciplines involved in hydropower engineering, including but not limited to the following:

- (i) surveying and mapping
- (ii) civil engineering
- (iii) hydrology and power production calculations
- (iv) hydraulics and design of river and canal structures
- (v) foundation engineering (rock and soil mechanics)
- (vi) design of mechanical and electrical equipment
- (vii) electrical engineering and control systems
- (viii) economic and financial analysis and report preparation
- (ix) tender and contract procedures

The consulting firm/contractor will be fully responsible for the technical quality of the design and document production for the three mini-hydro plants and for all work carried out under his supervision.

The consulting firm/contractor will be called upon to provide technical expertise in any discipline relevant to the three pilot projects at a suitable time as decided by the hydropower projects manager. The specific experts and rates for their services will be agreed beforehand but the timing of their visit will be determined by project progress and cannot be accurately predicted in advance.

It is intended that the consulting firm/contractor provides 2 or 3 experienced engineers as field consultants to the Solomon Islands to carry out on-the-job training of counterparts while proceeding with study and design work. These engineers should have all-round experience in mini-hydro development and might be typically from the following disciplines:

(i) hydrology and hydraulics engineer
(ii) civil engineer (low-cost construction techniques)
(iii) electrical and mechanical engineer

They could each be sent at different times according to the progress of the work and the availability of suitable counterparts, or simultaneously as a team if preferred. Each consultant may be required for about 1 - 2 months to complete the training and his part of the work on the 3 mini-hydro projects.

If the project budget allows, it might be possible for the counterparts to spend some time in the consultants home office gaining experience from design of projects in other countries and viewing actual hydropower projects under construction and in operation.

The consulting firm/contractor must also be prepared to provide back-up services for their field consultants as and when required. This may take the form of additional expertise, specialist calculations, computing and other facilities which cannot be obtained in the Solomon Islands.

Each field consultant must have full proficiency in the English language in order to provide adequate instruction for their respective counterparts.

Annex

JOB DESCRIPTION

POSITION : HYDROPOWER PROJECTS MANAGER

LOCATION : Energy Section, Geology Division, Ministry of Natural Resources, Honiara, Solomon Islands.

GENERAL : The position requires a professional engineering degree, some project management experience, familiarity with design and construction of mini-hydroelectric schemes, proven administrative skills, and willingness to work in remote and rugged parts of the country.

OVERALL OBJECTIVES:

- To review and co-ordinate hydropower development in the solomon Islands, and to design and initiate implementation of mini-hydro schemes for three provincial centres.

DUTIES:

General :

- Review previous studies and existing micro-hydro schemes.
- Identify other viable mini-hydro schemes.
- Prepare progress and end-of-job reports to Government, aid organisations and lending institutions as required.
- Prepare an outline of a training system to achieve localisation of the hydropower projects manager post by the end of 1990.
- Commence counterpart training in the planning, study, design and administration of small and mini hydropower projects.

Specific:

- Inspect potential small hydro sites (1-4 MW) on Guadalcanal suitable for supplying Honiara.
- Co-ordinate data collection for high priority sites for Honiara in preparation for a feasibility study, including preparation of

terms of reference.

- Discuss with potential donors the possibility of funding a feasibility study of promising projects for Honiara and prepare appropriate documentation/proposals for their review.

- Survey potential sites for mini-hydro schemes (100-400 kW) in the provinces, and carry out design work for the most suitable site near each of three provincial centres: Auki, Kira Kira, and Buala.

- Write a design and feasibility report for these three mini-hydro projects.

- Draw up development proposals and seek funding for the construction of approved mini-hydro schemes from various aid organisations and lending institutions.

- supervise the preparation of tender documents and specifications and oversee the awarding of contracts.

- liaise with authorities and organisations as required to facilitate successful implementation of the schemes.

TERM: One year initially (1986-1987) with possibility of extension.

RESPONSIBLE FOR:

Staff as assigned.

RESPONSIBLE TO: The Chief Geologist, Ministry of Natural Resources. Will work closely with the National Energy Planner.

FUNCTIONAL RELATIONSHIPS:

The staff member will form working relationships as required with the following:

- Solomon Islands Electricity Authority.
- Ministry of Economic Planning.
- Ministry of Finance.
- Ministry of Foreign Affairs

- Ministry of Transportation, Works and Utilities.
- Provincial Governments.
- Aid Organisations and/or Lending Institutions.
- Land Owners.
- Scheme Beneficiaries.
- Construction Contractors and private industry in the Solomon Islands.

FURTHER BACKGROUND:

The Solomon Islands, a country of 30,000 km2 and 250,000 people, has large but generally unassessed hydro potential. Hydrological investigations are now underway. External aid will be earmarked for three mini-hydro schemes (approximately 100 kW each) and later for all hydro schemes of 1-4 MW. The availability of funds will be largely dependent upon the performance of the hydro power projects manager. The job will be challenging and stimulating.

APPENDIX F

References

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20. Central Bank of Solomon Islands Annual Report, 1985.

21. Haimatua mini-hydro project - Feasibility Report, 1985. Wapcos consulting engineers, India.

PHOTO 1 - Komarindi dam site looking upstream to reservoir area

PHOTO 2 - Komarindi tailrace looking south west
(Surface power station or tunnel outlet probably sited behind helicopter)

PHOTO 3 - View of Ohe River (right) and Komarindi River (left) with power station site visible on the bend furthest from view (see photo 2)