CHAPTER 14 ECONOMIC AND FINANCIAL FRAMEWORK

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CHAPTER 14. ECONOMIC AND FINANCIAL FRAMEWORKS

14.1 Proposition

14.1.1 Growth and Macro Management of Economy

Turkey, with Gross National Products per capita (GNP p.c.) of about US$2,895 (1996)[1] placing it currently amongst the lower middle-income[2], and moderately indebted countries[3], is at a cross roads requiring efficient management and long-term planning of economy from the government. On the economic front, the performance had been in shape retaining real GNP growth rates of averaged over 6% Pper annum during the post World War II period of 1947 through 1977 despite no substantial development aid to the country. Economic policy during this period was mostly inward-looking import-substituting industrialization with the state actively involved in regulation, production and distribution. In the 1970's, the global economy was seriously affected by the twice of oil crisis, as such Turkey, an net-oil importer, was particularly affected by a chronic macro-disequilibrium, inter alia, external and fiscal imbalances and inflation caused by a sky-rocketing surge of oil price and associated global recession. The situation was further worsened by expantionary economic policies undertaken during 1974-77. High performance in economic growth during this period took place at the cost of an increase in short-term foreign debts, which consecutively ended in a debt-crisis by the end of 1977. Faced with this difficulty in economic management, the government took several emergency measures to alleviate the situation inclusive of debt rescheduling and increased concessional and commercial external financing.

Key Economic Indicators (1)

Population (1996, mid-year)	US$ 62.6 million
GNP (1996, estimate)	US$181.2 billion
GNP per capita (1996, estimate)	US$2,895
Annual Real Growth Rate of GDP (1995, estimate)	8.1%
Consumer Prices percent Change (1995, estimate)	93.5%

Sources: World Bank, *Trends in Developing Economies, World Tables*, 1996, International Monetary Fund, *IMF Staff Country Report No.96/122*, 1996

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[1] Turkey has recently revised its methodology for estimating national income, thereby increasing an estimated GNP by around 30%. 1996 GDP per capita is an estimate, whereas the 1995 figure was $2,670. (Refs: The Economist Intelligence Unit, *Country Report*, March 1997, p.5, World Bank. *Trends in Developing Economies 1996*, p.513)

[2] Lower middle-income economies are classified as those with a GNP per capita of more than $766 but less than $3,035 in 1995, while upper middle-income economies ranging $3,036-$9,385. Classification by income does not necessarily reflect development status. Turkey is amongst the few developing economies that are members of the Organization of Economic Cooperation and Development (OECD). (Ref: World Bank, *Ibid*., p.579)

[3] Moderately indebted means either of the two key ratios, vis-à-vis, present value of debt service to GNP and present value of debt service to exports, exceed 60% but do not reach the critical levels of 80% and 220%, respectively. (Ref: World Bank, *Ibid*., p.579)

In recent years, the Turkish economy has experienced sharp fluctuations in growth, and high and persistent inflation. A severe currency crisis, associated with the inadequate macroeconomic framework in Turkey, broke out in the early months of 1994. Faced with the devastating deterioration of the market value of the Turkish Lira against the major currencies by about 60%, the central bank intervened heavily in both foreign exchange and money markets, leading to a sharp decline in the foreign exchange reserves (about US$3 billion over the same period) and the undermined credibility of Turkey. These developments compelled the government to increase public finance through borrowings from the central bank, thereby fostering further inflationary pressures and exacerbating the depreciation of Lira.

Supported by an IMF standby arrangement in April 1994, the government embarked on a major economic stabilization program with a view to substantially reducing the internal and external deficits, curbing inflation, restoring foreign exchange reserves, and diminishing government role in economic activities, thereby strengthening Turkey's growth prospects and competitiveness in the world market.[4] Initial results turned out to be encouraging with the budget deficit substantially being reduced as borne out by the overall public sector borrowings from 12.6% of GNP in 1993 down to 7.8% in 1994. The current account registered a surplus of about US$2.5 billion in 1994 arising from a deficit of US$6.4 billion in the previous year. The accumulated external debt decreased by about 7.4% reaching US$63 billion.

With this, the country's economy rebounded in 1995 with real GDP rising by 8.1%, reversing the decline of 5.6% (-5.6%) in 1994. A strong pickup in activities in the second and third quarters of 1995 more than compensated for the continued weakness in the first quarter and a slight decline in the fourth quarter caused by uncertainty in the run-up to the election. The industry sector performed strongly with a 12.1% growth in real terms, followed by the services and agriculture sectors reaching 6.4% and 2.6%, respectively. While macroeconomic imbalances worsened and financial market uncertainty remained pronounced, an annual real GDP increased by around 10% in the first half of 1996 from its year earlier level. This outcome of "considerably above potential growth" was largely due to

[4] The fourteen-month IMF Stand-By Arrangement (SBA) approved was for SDR 509.3 million, as per 715 million in US dollar.

growth in private consumption and private investment, while net exports have subtracted from growth since 1995.

Key Economic/Social Indicators (2) (Source: World Bank, *Ibids.*, 1995)

Central Gov. Fiscal Deficit as per GDP (1994)	-1.1%
Current Account Balance as per GDP (1994)	1.4%
Debt Service Ratio (1994)	27.0%
Population Growth, (Annual Average 1990-94)	2.0%
Income Share of Richest 20% (1993)	50%

14.1.2 The Power Subsector, Policy and Issues

The energy policy emphasizes the three unifying themes, vis-à-vis, (i) the role of the government, (ii) the efficiency of supply and effective management demand, and (iii) the integration of environmental considerations with sustainable growth. With due recognition of the foregoing, and part of the official strategy to increase energy self-reliance and diversify domestic energy sources pertaining to alternative and more economic and indigenous resources, the government is in the move towards strengthening its energy strategy, managing demand more effectively, and augmenting domestic supply through appropriate policy initiatives, including energy conservation measures and investment. In this context, the policy goals are set to (i) increase energy availability by developing oil and non-oil energy sources, with natural gas, lignite and coal in particular, (ii) mobilize local energy resources to the maximum extent possible (renewable and non-renewable), and (iii) promote demand management for high energy use efficiency and energy conservation.

The basic strategy for the power subsector adopted by the government is to ensure the balanced, least-cost expansion of the system at a rate adequate to meet the country's economic growth requirements. In line with this, the Sixth Five-Year Plan called for the exploitation of domestic energy resources, particularly hydro. Consequently, the government has sought to maximize private sector investment in power generation with a view to advancing the said strategy and at the same time alleviating the fiscal burdens.

With its power demand doubling every seven to eight years, Turkey has been experiencing the faster growth in electricity in the Mediterranean and Near East region. The capital

requirements of the power development plan for the next 15 years are accordingly high standing at about US$45-55 billion in line with the highly anticipated further growth in demand at an average 7.5-8.5% per annum.[5] In view of meeting these capital requirements, the government has paid a good deal of effort to introduce the new sector development modes to mobilize domestic and external financial resources such as BOT (Build-Own and Transfer) and BOO (Build-Operate and Own) schemes. The international lending institutions did further encourage the government, through lending operations and technical assistance (TA) projects, to modernized and corporatize, at least partially, the public power utility, vis-à-vis, then Turkish Electricity Authority (TEK), and to foster private power companies.

While the advantages of hydropower as reliable and economic generation system are well recognized amongst the government officials concerned, the exploitation of hydropower resources has been constrained by the factors, vis-à-vis, (i) long gestation periods involved in construction, financial constraints, (ii) problems of land submergence, and (iii) resettlement of affected population.

Encouraged by the new economic stabilization program initiated in 1994, private-sector led growth have gained momentum emphasizing sector growth through a mobilization of the private sector resources. Among others, high capital requirements of the power development plan underlined the need to mobilize all available resources including those of the private sector. The government estimates that in the next five years around US$20 billion would be invested to the subsector, of which about 40% equivalent to US$8 billion emanate from the private sector through BOT scheme. As of 1995, two combined gas cycle power plants located in Thrace and Istanbul are under construction on this private sector-led investment scheme. In addition, four power plants comprising three lignite-thermal and one gas combined cycle power plants in Kemerkoy, Yenikoy and Soma B, and Trakya (Hamitabat) have been transferred from TEAŞ to the Privatization Administration under the Prime Minister's Office with a view to privatizing all of these by March 1997. Further, among 39 power houses enlisted for construction and operation under TEAŞ, as of November 1995, two hydropower plants combining to a total of 900 MW are scheduled to be constructed on BOT scheme[6].

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[5] The assumptive parameters for demographic and economic (as per GDP) growth over the same 15-year period are set forth by SPO as 1.5% and 6% per annum, respectively.

[6] These include Boyabat and Yedigoze power plants. (Ref: *TEAS Implementation Program 1995*)

In the meantime, the World Bank closed the loan extended to the Berke Hydropower Project[7] in March 1995, about three years before the originally scheduled closing date. This mischievous outcome is, as reported by the World Bank[8], due to a corporate takeover that took place after the Loan Agreement had been made, and the subsequent non-compliance of the new Board of Directors (BOD) with the Bank conditionalities and procurement guidelines.

Despite significant progress in system expansion, power shortages tapped as high as about 9 % of total energy and 18 % of peak capacity requirements in FY1992. The electricity elasticity for Turkey during 1980s is estimated to be extremely high at 1.53, as compared with those for the Asian Newly Industrialized Economies (NIEs) at 1.15, and Thailand at 1.43. With this, assuming all other conditions unchanged, an projected 6.0% annual growth of real GDP and 2% of annual population growth during 1995-2010 will require planning for the 8 % average annual growth of electricity consumption.

14.1.3 Least Cost Analysis

The levelized economic cost analysis would possibly be undertaken, as necessary, to confirm that the prospective hydraulic power scheme would be the least-cost means of supplying peak load and also an integral part of the power system expansion program. In line with this approach, the technically feasible alternative peak generation options to the prospective hydropower project including peak adjustment coal thermal generation and gas-turbine will be studied to determine the per unit costs. Capital cost would be levelized for discount rates ranging from 15 to 20%.

As noted by the Asian Development Bank (ADB), an important issue relating to least-cost analysis is that the analysis involves a comparison of ex-ante investment alternatives excluding current source of supply[9]. With this in view, it may not be considered appropriate to use resource cost saving associated with an existing supply source to derive the least-

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[7] Loan (3276-TU) was approved in May 1992 and made effective in October 1992 in the amount of US$270 million equivalent. The borrower was the Republic of Turkey with the beneficiary, a private-owned, regional power company, Cukurova Elektrik, A.S. (CEAS). JICA mission met the World bank project officer, Mr. Raghuveer Sharma, and exchanged views on the country's power subsector development policies and the proposed Project in the Corhu-Berta region. The mission is deeply sorry for this tragic result of the project.

[8] World Bank, *Project Completion Note* with the report No. 15619, 1996.

[9] ADB internal paper on Economic Analysis of Projects in the Power Sector, 1989

cost solution[10]. The current unit cost of the power generation alternatives in Turkey are presented herewith as indicative figures (*Table*)[11]. This information would help confirm an intuitive superiority of the project considered over other selections in terms of economic resource cost saved.

Indicative Unit Cost of Power Supply in Turkey (Construction Costs, US$/kW)

Coal-Thermal	1,173
Lignite/Geothermal	1,236
Hydropower	400-2,600
Gas-Turbine	700

(Source: EIE)

14.2 Analytical Frameworks for Economic and Financial Analyses

14.2.1 General Remarks

Electric power is essential to a nation's continued industrial growth and people's welfare. Power sector investment requires massive amounts of capital and other scare resources, accounting for 15-20% of the total development investment in many developing countries, thereby competing against other vital investment needs. it is imperative that the investment be economized and taken advantage of, to maximize financial and economic returns. In other word, essential to the proper planning is the allocation of scarce resources to its best advantage. In this light, financial and economic analyses are quantitatively undertaken, as appropriate, in preparation of the draft final report. The framework and the model configuration adopted for analysis are set forth in the subsequent section.

Transfer payment which is a shift of claims on real resources from one member or sector of society to another without any change in the national income will be excluded in the EIRR estimation. As regards the Project in concern, value added tax corresponding to 10% of the local currency cost components and another 10% of import duties on foreign cost components will be deducted. Alternatively saying, the aggregate duties and taxes levied on foreign cost portion is being assumed as 20%.

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[10] This is what micro-economists explains in price theory as "every decision is made at the margin (in addition)"
[11] Where further analysis takes place, there is a need to add costs accruable to transmission/distribution losses.

14.2.2 Benefits and Costs

In addition to economic value of an incremental supply of power as measured by LRMC, project benefits are further measured as the consumer's surplus (CS) as part of consumer's willingness to pay (WTP). In this light, the projected level of tariffs being set as per the long run marginal opportunity cost of power supply (LRMC) is used as a proxy for benefits. By estimation of TEAŞ supported by the World Bank,US$0.08/kWh was applied in the analysis. In addition, this assumptive parameter used for analysis rests in the neighborhood of the average consumer's surplus (CS) reaching US$0.009/kWh estimated by World Bank.[12] In addition, the assumptive parameter with the most likeliness of consumer surplus is considered to add by US$0.009/kWh, hence the total benefit attributable to an incremental supply of power by the newly established power plants reaches US$0.089/kWh. Of this, 10% of benefit will be deducted for distributers, as such the unit economic value associated with the project rests at US$0.0801/kWh.

The use of conversion factors will be considered to convert the market value of the Project components to its value in shadow prices expressed in terms of border currency units. Standard Conversion Factor (SCF) will be applied to the product of all non-tradable goods and services employed other than unskilled labor for the Project. To date, the SCF and conversion factors for skilled and unskilled labor in use by World Bank and the Government of Turkey are set at 0.8, 0.9, and 0.6, respectively. While keeping this in view, the SCF applied in this study worked out to 0.81, a weighted average of (i) equipment and material locally procured, (ii) skilled laborers, and (iii) unskilled laborers. Conversion factors and the cost shares of these inputs are being assumed at (0.9, 0.9, 0.9) and (0.6, 0.3, 0.1) for each of the cost components in that order. Numerical Expression of weighted average SCF is given as follows.

Cost items	CF (fi)	Cost Shares (xi)
Local Equipment and Materials	0.9	0.6
Skilled Laborers	0.9	0.3
Unskilled Laborers	0.6	0.1

[12] Consumer's surplus was computed considering a weighted price elasticity of demand of -0.42 obtained from econometric demand study for Turkey. This value was adjusted in time as a function of the consumer's income increase using an income elasticity of demand equal to 2.0 obtained from the same source. (ref: World Bank, Berke Hydropower Project, SAR, 1992, pp.125-127)

While SCF requires, in calculation, information on the ratios of border prices to market prices for a variety of commodities, it can be approximated by the use of data on foreign trade and net border taxes of general commodities. The approximation is provided by the border value formula as follows.

$$SCF \cong (M+X) / \{(M+t_m)^*(X+t_x)\}$$

M and X are the value of imports and exports in border prices, respectively, where t_m is import duties net of subsidies, and where t_x is export duties net of subsidies.

14.2.3 Measurement of Benefits

(1) Tariff[13]

The average electricity price during the latter half of the 1980's was maintained at around 6 US cents per kilowatt hour. By estimate of the World Bank, this was relatively closer to the long-run average incremental cost (LRAIC) of power system expansion, a proxy to the long-run marginal cost (LRMC) of supply, in Turkey[14]. In this respect, Turkey was among few developing countries with no subsidy for domestic electricity price during that period. Associated with the devastating inflationary pressure in the economy, LRMCs have also risen with the estimates of around US¢6.5/kWh and 7.0 for TEAŞ and TEDAŞ, respectively.[15] In 1991, electricity tariffs to residential consumers bounced back to the level of those in the early 1980's after the successive decline during the preceding decade. On the other side, tariffs to industrial and commercial consumers began declining in the same year after the steady rise in the 80's, thereby reducing the cross-subsidy from industrial/commercial to residential consumers.

The new tariff schedule became effective as of 1 January 1997 with the weighted average electricity price set at TL8,455/kWh at users' end. Deducting around 10% from this, the

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[13] Grateful acknowledgment is made of the assistance and cooperation provided to the Study Team in various forms by Mr. Raghuveer Sharma , Senior Financial Analyst. World Bank in Washington DC

[14] Ref.: World Bank, *Energy Price Increases In Developing Countries*, 1995, p. 89

[15] Source: TEDAS. and MAGE Consulting Company which undertook the tariff study for TEAS under the finance of the World Bank in 1995.

sales price of electricity by TEAŞ to distribution companies amounts to TL7,610/kWh in average.

(2) Long Run Marginal Cost (LRMC)

Further valuation of economic benefits of electricity supply would take place to assess the viability of the project more accurately. The Long-Run Marginal Cost (LRMC) will be one alternative to measure direct benefit of the project outcome which ensures the most efficient allocation of scare resources in the economy. The estimate of the LRMC of power supply will be based on the long term power development program and the weighted average per unit levelized capital costs.[16] In addition, the average value of economic benefit accruable to the energy sources saved would be considered acceptable. This estimate will be undertaken in two consecutive analysis, i.e., (i) consumption of replaced energy sources induced by electricity supply, possibly for each consumer category (energy saved due to the Project), and (ii) the economic valuation of replaced energy sources per unit by estimating the maximum willingness to pay. In line with the TEAŞ and World Bank estimation, the LRMC of supply at generation level, after transmission level, and at distribution level was assumed at US¢4.9/kWh, 5.4 and 6.0 as per 1992 real price.[17]

Microeconomic views on marginal cost pricing which was included in the previously submitted Interim Report is reiterated and given as *Attachment* in this Report in a bid to help understand part of the theoretical background of economic analysis of power development projects.

(3) Willingness to Pay (WTP) and Consumers' Surplus (CS)

In addition to economic value of an incremental supply of power as measured by LRMC, project benefits are further measured as the consumer's surplus (CS) as part of consumer's willingness to pay (WTP). Alternatively saying, consumer's WTP comprises the revenue of additional sales and the CS. CS arises when the price is fixed below the demand price, and is theoretically measured as the difference between the price that consumers are willing to pay for any given quantity and what they actually pay. When used in the current analysis, a

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[16] Ref. Guidelines for Marginal-Cost Analysis of Power Systems, WB 1984

[17] Source: TEAS World Bank Project (OMIP) Team, WB Appraisal Report, May 1992.

weighted price elasticity and an income elasticity of demand have been presumably set at respective of -0.42 and 2.0[18].

14.3 Analytical Methodology

In the light of designing the investment project under the Study to promote increased efficiency in the energy sector by providing badly needed base load capacity in the country, the following financial and economic analyses on the prospective pumped storage hydropower project would possibly be undertaken during the study period ahead:

Review of the long-run marginal cost (LRMC) of supply and Consumer's Surplus (CS),

(1) Estimation of Project Economic Internal Rate of Return (EIRR),

(2) Estimation of Benefit-Cost Ratio (B-C Ratio),

(3) Financial Internal Rate of Return (FIRR) calculation,

(4) Formation of Indicative Financial and Repayment Plans, and

(5) Financial and economic evaluation of the Project based on the numerical superiority as reflected in EIRR, B-C Ratio and FIRR.

To be noted that the analysis of project accounting could not performed due to lack of the relevant data and information.

14.4 Indices for Project Evaluation

14.4.1 Economic Internal Rate of Return (EIRR)

With due recognition of the economic viability of the Project to be analyzed from a broader national perspective, the quantitative impact represented by EIRR would be duly assessed to the extent possible. In principle, economic benefits accrued will mostly be in the form of

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[18] These elasticities had been obtained from an econometric study for Turkey. See the World Bank, *Berke Hydropower Project*, SAR, 1992, p.125

incremental electricity consumption. Some benefits may be realized through reducing supply costs during off-peak periods and through improving supply quality[19]. However, these benefits may be relatively small depending on further assumptions, and so will not be included in the analysis. Other non-quantifiable project benefits including employment opportunities during construction stage and for operation and maintenance after commissioning and avoided pollution from thermal standby generators. It would be acceptable that a minimum economic benefit be measured for incremental sales revenues using the average revenue per kWh sold as proxy for benefits. This would be justified for the currently high tariff collection rate of 75-80% as compared with the country, say for instance, India's average rate of 55-60% in 1994. Mathematical expression of EIRR is shown as follows.

$$r:\Sigma\{(B\text{-}C)_t*(1+r)^{-t}\} = 0 \quad \text{where (t denotes the year 1,2,..., and n.)}$$

14.4.2 Benefit-Cost Ratio (B-C ratio)

Electric power development requires massive amounts of capital and associated production factors thereby competing against other vital investment needs. Assuming that a number of development alternatives be prioritized in terms of degree of overriding benefits to costs, B-C ratio will be applied by discounting future benefits and costs streams to their "present worth". Numerical definition of B-C ratio is given as follows.

$$B/C = \Sigma(B_t*(1+r)^{-t}) / \Sigma C_t*(1+r)^{-t}) \quad \text{where (t denotes the year 1,2,...., and n.)}$$

In practice, it is common not to use the gross costs and gross benefits in calculation of B-C ratio. But rather, to compare the present value of the net benefits with the present value of the investment cost plus recurrent costs. Provided that the gross-based benefits and costs streams are applied, B-C ratio possibly discriminates against projects with relatively high gross operating costs even though this may be shown to have a greater wealth generating capacity than alternatives which have a higher B-C ratio.

[19] This may include improved network voltage regulation and frequency control.

14.4.3 Financial Rate of Return (FIRR)

The project in concern is subject to financial analysis that will include an analysis of the financial operations of the participating agency and estimation of financial viability of revenue-generating component (the Project). With a view to self-financing future investment costs at the maximum extent possible, revenue-earning undertakings would be expected to generate financial internal rate of return (FIRR) reasonably equivalent or close to the current opportunity cost of capital of about 9-13%. In keeping with generally accepted guidelines for financial analysis, the financial costs/benefits used in the computation of FIRR will be in constant early 1997 prices. The capital costs will be reconcilable with the base costs and physical contingencies, but with the exclusion of price contingencies and interest during construction. Numerical expression of FIRR is shown as follows.

$$r{:}\Sigma\{(B\text{-}C)_t{*}(1+r)^{-t}\} = 0 \quad \text{where (t denotes the year 1,2,..., and n.)}$$

14.5 Model Configuration and Parameters

Subject to technical and other most relevant and best available data/information at the time of final appraisal in August 1997, the numerical assumptions set for the financial analysis includes (i) Project life, (ii) Tariff, (iii) Electricity sales, (iv) Foreign exchange quotation, (v) Cost estimation (Base cost), (vi) Physical contingency factors, (vii) Price escalation factor, (viii) Financial terms, (ix) O/M cost, and (x) Interest during construction (IDC), with the parameters specific to each of the categories as follows:

14.5.1 Project Life

Duration of the Project will be set according to the prospective economic life of the proposed investment and anticipated construction/commissioning schedules. Currently the total Project life has been set at 55 years with the initiating year 2002 to commence the 5-year construction and the subsequent 50-year service periods up to the year 2056.

14.5.2 Tariff (Revenue)

The government is currency attaching an importance to set electricity prices at long-run marginal cost (LRMC) with a view to promoting an increased efficiency in consumption,

while also providing financial incentives for TEAŞ to further improve operational efficiency. The current proposition of ratesetting for power sales by TEAŞ are valued by the end of 1996 weighted average of set at TL8,455/kWh at users' end. Deducting around 10% from this, the sales price of electricity by TEAŞ to distribution companies amounts to TL7,610/kWh in average. Meanwhile, LRMC and Consumer's Surplus for Turkey are being set at US$ 0.08/kWh, and US$0.009/kWh as per 1997 price, respectively.

Other possible means of revenue such as consumers' contributions in the form of connection charge have not been included in the benefits because of no direct sales to end users by TEAŞ.

Further, there hasn't been any explicit assumptions regarding tariff development over the Project period, thus implicitly assuming that there will be no change in real tariffs as per foreign exchange over the period concerned. In other words, the nominal change in tariffs in nominal Turkish Lira term which would possibly take place during the project period will be canceled out in respect of devaluation of the Turkish Lira against the foreign exchange.

14.5.3 Sales Volume

In carrying out the analysis, sales volume of electricity would be postulated as per the following operational parameters, while taking TEAŞ's revenue projections into consideration.[20]

	Bayram Project	Bağlık Project	Total
Installed Capacity (MW)	68	59	127
Plant Factors (%)	42	44	
Annual Energy (GWh)	250.4	225.8	476.3
Effective Energy (GWh)	246.2	222.0	468.2
Transmission Loss (%)	1.4	1.4	
Auxiliary Use, (%)	0.3	0.3	

[20] Sales volume (energy at receivers' end) denoted by Q herewith is calculated with the formula stipulated by TEAS as follows.

Q = Installed capacity x 9,860 hrs x Plant factor x (1 - Transmission loss - Aux. Use)

14.5.4 Foreign Exchange Quotation

Current conversions of Turkish Lira to the US dollar, unless otherwise noted, have been made at TL100,000 to one dollar. This rate is presumably assumed to represent the maximum value that the Turkish Lira would be worth under the market conditions for the time being.

14.5.5 Financial Cost Estimation

In compliance with the generally accepted financing principlesIn estimation of financial costs, while taking into account the advise from the technical experts of the mission, the following addition and revision of the technical cost estimate as reflected in Tables 12-5 and 6 in Chapter 12.

(1) incremental investment costs for the replacement of hydraulic and electro-mecahnical equipment and materials which will subsequently take place in the 41-43rd years in the investment outlay;

(2) tax and duties, notably, value added tax (VAT) and import tariff levied on locally procured and imported goods and services. Specifically, VAT was set at 10% of factory-gate prices, and import tariff of another 10% on the CIF prices of importables; and

(3) revision of physical contingencies and interest during construction (IDC) accrued to the up-word modification of the financial cost as indicated above (1) and (2).

In view of the above, the aggregate financial cost for project implementation was estimated at US$311.9 million equivalent as per 1997 price, in lieu of the technical investment cost estimate of US$251.5 million. Of this, the foreign cost portion accounts for 42.1% (US$131.4 million) and the local cost portion residual 57.9% (US$180.5 million). Interest during construction (IDC) was estimated using 9.5% of capital cost as agreed among the study team and the counterpart team. As specified in the following paragraph, physical contingencies are being assumed to set at 15% for respective of road, camp, and civil works, 10% for hydraulic equipment, and 5% for electric equipment and transmission line,

respectively. In addition, in accordance with the internationally acceptable financing principles, physical contingency was further assumed for engineering and administration, while 10% of the aggregate of sub-construction cost and the sub-total of physical contingency accrued to each of the cost items in Tables 12-5 and 6.

Disaggregating the estimated investment outlay by sub-projects, Bayram and Baglik plants amount to US$203.1 million and US$108.8 million equivalent, while accounting for respective of 65.1% and 34.9%. While no real cost increase in any specific commodities/services associated with the project is presumably in place, the possible price-hike of any project inputs which would domestically be procured in the forthcoming years is postulated to be absorbed in a possible devaluation of the Turkish Lira against the dollar. To be reminded that price contingency is not applied to the current analysis in compliance with the Turkish practice in cost estimation.

To be noted that the financial cost for the estimation of FIRR expels interest during construction, thereby leading the "aggregate investment cost" works out US$294.4 million.

For the readers' kind reference, breakdown of the aggregate and FIRR financial costs are given as Tables 14-1, and 2.

14.5.6 Physical Contingencies

Reflecting expected increases in the base cost estimates of the Project due to changes in quantities and methods of implementation, physical contingency allowances have been set by major cost sub-components as follows.

Relocation Road/Camp Facilities/Civil Works	-	15% of each of the costs accrued
Hydraulic Equipment	-	10% of cost accrued
Electro-Mechanical Equipment/Transmission	-	5%of costs accrued
Engineering and Administration	-	10% of the aggregate of the above costs

14.5.7 Price Contingencies

In anticipation of increases in the base cost estimates of a project/projects due to changes in unit prices for the various project components/parts beyond the date of the base cost estimates, price contingency is usually considered in the estimation of financial costs. Nonetheless, as previously noted, this allowance is not included in the current analysis.

14.5.8 Recurrent (O/M) Costs

Annual O/M costs associated with the major sub-components, vis-à-vis, civil works, hydraulic equipment, and Erectro-mechanical equipment, are assumed to be 0.5%, 1.5%, and 1.5% of each of the capital investments disbursed during the initial 5 years.

14.5.9 Financial Terms

Japan's official development assistance funds assume 30 years of repayment inclusive of 10 years of grace with the concessional rate of interest at 3.5%. Annuity payments will be made twice a year, at the end of the second and fourth quarter. Interest which is payable all over the project duration will be on the diminishing balance of the outstanding principal. Consequently, interest costs will decrease proportionately as principal is amortized. External loan funds from international lending agencies assume 20 years of repayment including 5 years of grace period, at their specific standard variable interest rate currently standing at around 7% from the World Bank 's ordinary capital resource (OCR). Capital cost of domestic fund is presumably set at 9.5%.

Meanwhile, Government of Turkey (GOT), the prospective borrower, woul on-lend a loan part of the proceeds to the executing agency under the subsidiary loan agreement (SLA) with 15-20 year term including 5 years grace period. The subsidiary loan will denominated in foreign currency withdrawn and the onlending interest rate will depend on negotiation with GOT. This on-lending rate is not considered in the current analysis.

14.5.10 Interest During Construction (IDC)

While it may not be likely that loan proceeds be on-lent from the central government to TEAŞ strictly on the domestic financing scheme above, interest during construction (IDC) for

foreign and local expenditures indicatively worked out US$6.0 million and US$11.5 million, respectively, where 15 years of repayment excluding 5 years of grace period, at 3.5% and 9.5% of interest rate being assumed. To be noted that IDC does not accrue to yen-credit because of its lending policy of interest payment during construction.

14.5.11 Discount Rate

In the estimation of the financial viability and economic feasibility as reflected in those indices, discount rate was assumed to be 9.5 % while taking into account the real term capital cost as of the end of 1996 in Turkey.

14.5.12 Sensitivity Analysis

sensitivity analysis is to be carried out for the following three cases to assess the magnitude of the possible risks therein. (i) lower tariff by 10%, (ii) capital cost overrun by 10%, and (iii) one year delay in implementation.

14.6 Financial and Economic Evaluation

14.6.1 General

With the prospective project beneficiaries pertaining to the present and future industrial, commercial, residential, and other public consumers in sight, the Project is in line with the strategy adopted by the Government to achieve important social and economic policy goals by increasing the electrification ratio and developing the country's indigenous energy resources. The Project will help augment both the availability and reliability of power supply in the region, thus providing one of the basic prerequisites for further industrial production and welfare growth therein.

(1) Transfer Payment

Transfer payment which is a shift of claims on real resources from one member or sector of society to another without any change in the national income will be excluded in the EIRR estimation. As regards the Project in concern, value added tax corresponding to 10% of the local currency cost components and another 10% of import duties on foreign cost

components will be deducted. Alternatively saying, the aggregate duties and taxes levied on foreign cost portion is being assumed as 20%.

(2) Conversion Factors for Economic Costs and Benefits

As noted in 14.2.2, the SCF and conversion factors for skilled and unskilled labor in use by World Bank and the Government of Turkey are set at 0.9, 0.9, and 0.6, respectively. While keeping this in view, the SCF applied in this study worked out to 0.81, a weighted average of (I) equipment and material locally procured, (ii) skilled laborers, and (iii) unskilled laborers. Conversion factors and the cost shares of these inputs are being assumed at (0.9, 0.9, 0.9) and (0.6, 0.3, 0.1) for each of the cost components in that order.

14.6.2 Ending Remarks-Evaluation Results

(1) Financial Internal Rates of Return (FIRRs) and B-C Ratios

The FIRR has been estimated on the basis of the model configuration and numerical assumptions as specified in the section above. The cost flows comprises (i) capital investments for the generation plants to be commissioned during the years of 2002 through 2006, excluding costs incurred prior to the afore-mentioned years (sunk costs), (ii) replacement costs of hydraulic and electro-mechanical equipment scheduled over the period of 41-43rd years in project duration

The benefit comprises revenues as borne out by energy sales attributable to the investments during the aforementioned 5 year period, with the constant sales in quantity till the termination of the Project. To be reiterated that any other means of revenue, inter alia, connection charge or else, are not taken into account.

In line with the financial cost manipulation as reflected in Financial Cost Estimation in (2) and by advise extended by the engineering team of the mission, the total financial cost for FIRR worked out US$294.4 million equivalent. Of this, the first round investment costs for the respective of project as a whole worked out US$246.5 million exclusive of interest during construction (IDC), whereas the replacement costs for part of hydraulic and electro-mechanical equipment reached US$47.9 million inclusive of physical contingency and duties and taxes. In the same way, the first round investment costs for the sub-projects, vis-à-vis,

Bayram, and Baglik worked out US$167.2 million, and US$79.3 million, with the additional replacement costs in the 41-43rd years in the investment outlay of US$23.7 million, and US$24.2 million being added in that order. As such, the financial costs accrued to the sub-projects will amount to respective of US$190.9 million, and $US103.5 million for FIRR estimation. (*refer to Table 14-2*)

Disbursement schedules associated with the project as a whole is being assumed as "0%, 11%, 25%, 21%, and 43%", and "6%, 17%, 25%, 29%, and 23%" in the first through 5th years for the respective of the foreign cost and local cost portions. Operation and maintenance costs have been estimated at US$1.074 million, US$0.694 million, and US$0.380 million per year for the project as a whole, Bayram, and Bağlık, respectively. As reiterated, interest during construction (IDC) is also counted out because it is considered as "transfer payment", while causing no deterioration of real resources in the economy.

The FIRR of the investment plan with the accruable costs (base cost plus physical contingency) and benefits expressed as per 1997 price level, worked out 11.9%. With the current opportunity cost of capital standing at around 9%, the FIRRs for the Project, by and large, outnumbers the real cost of capital in view, thereby making it possible to accept the Project as financially viable. Yet, there remains somewhat the vulnerability of the project to real price-hyke.

Disaggregating the project components to Bayram and Bağlık sub-projects, FIRR came out to be 9.3% and 16.6%, respectively. This outcome reveals technical externality where the construction of the former affects favorably the cost of the latter power plant.

Benefit-Costs ratio is estimated at 1.22, with the implication that the project benefit is higher than the value of investment.

Summary net cashflow tables of FIRRs for the whole project and by sub-projects are attached as Tables 14.3 and 4, whereas the summary table of Financial Cost-Benefit ratio is given as Tabel 14.5.

(2) Economicp Internal Rates of Return (EIRRs) and B-C Ratios

Based on the financial costs associated with the conversion procedures as articulated in the preceding section, the aggregate economic costs, and hence, for the estimation of EIRR, worked out US$230.3 million, US$149.7 million, and US$80.6 million (rounded at the second decimal point) for respective of project as a whole, Bayram, and Baglik. Disaggregating the total economic investment cost, the initial investment costs as measured in economic term amount to US$199.4 million, US$131.2 million, and US468.2 million in the same order.

The EIRRs were calculated on the basis of the new and the incremental cost and benefit streams associated with the proposed investment outlays over the period of maximum 5 years with the commencement in 2000. All the costs are shadow priced, being adjusted to convert market prices to shadow prices expressed in terms of border currency unit (US$).

With the methodology and the numerical assumptions noted in the preceding, the EIRR on the Project readily estimated at 15.4%. Given the estimated real weighted average cost of capital for TEAŞ standing at around 10%, the EIRRs well outnumber the cut-off rate[21],thereby making it possible to accept that the Project with those sub-projects altogether be substantially feasible. Benefit-Cost ratio also surpassed the crucial cut-off rate of unit 1.0, with the estimated 1.65.

As considered in financial analysis, Bağlık project reveals a higher EIRR that that of Bayram project, with those at 21.4% and 12.3%, respectively. Again, economic externality worked out in favor of the Bağlık project.

Based on the financial costs associated with the conversion procedure as articulated above, breakdown of the aggregate project cost as per economic price (border price) are shown for reference as Tables 14.6. Further, summary cash-flow tables for the whole project and by sub-projects are given as Table 14.7 and 8, while that of Cost-Benefit ratio being attached as Table 14.9.

[21] Reference: ADB, *Ibid.*

(3) Sensitivity Analysis

The major financial risks associated with power project include lower growth in demand for power and front end implementation delays. Given the strong demand growth experienced in the Project area, the former risk will be considered low. In the meantime, sensitivity analysis is to be carried out for the following three cases to assess the magnitude of the possible risks therein. (i) lower tariff by 10%, (ii) capital cost overrun by 10%, and (iii) one year delay in implementation.

The results of the analysis are summarized as follows.

	Base Case	Benefits, -10%	Capital C, +10%	Implementation one- year delay
FIRR	11.9%	9.5%	10.8%	11.3%
F B-C Ratio	1.22	1.20	1.11	1.18
EIRR	15.4%	12.8%	14.2%	14.8%
E B-C Ratio	1.65	1.38	1.41	1.50

The results of the sensitivity analysis came out to be 9.5%, 10.8%, and 11.3% for FIRR, and 1.20, 1.11, and 1.18 for B-C ratio, in that order. The variants associated with the possible fluctuation in the major variables are also shown. With these, FIRRs remain somewhat satisfactory, or marginal, for these cases except tariff, indicating the resiliency against the risks as specified above.

As regards the economic evaluation, variation in the same parameters as for FIRR gives 12.8%, 14.2%, and 14.8% for EIRR, and 1.38, 1.41, and 1.50 for B-C ratio, in that order. EIRRs remain satisfactory for all these cases, while indicating the resiliency against the risks as specified above.

Table 14-1 Aggregate Financial Costs for Project Implementation-Bayram & Bağlık

	Bayram US$ ('000)			Baglik US$ ('000)			Total US$ ('000)		
	Foreign	Local	Total	Foreign	Local	Total	Foreign	Local	Total
1. Initial Investment									
Road	0.0	11,655.0	11,655.0	0.0	6,759.0	6,759.0	0.0	18,414.0	18,414.0
Camp	0.0	800.0	800.0	0.0	800.0	800.0	0.0	1,600.0	1,600.0
Civil Works and Erection	31,546.0	51,567.0	83,113.0	6,699.0	19,284.0	25,983.0	38,245.0	70,851.0	109,096.0
Hydro Equipment/Materials	1,033.0	3,697.0	4,730.0	136.0	2,487.0	2,623.0	1,169.0	6,184.0	7,353.0
Elec Equipment/Materials	11,806.0	2,083.0	13,889.0	11,943.0	2,108.0	14,051.0	23,749.0	4,191.0	27,940.0
Transmission	0.0	1,140.0	1,140.0	0.0	4,250.0	4,250.0	0.0	5,390.0	5,390.0
InitialInv DTotal	44,385.0	70,942.0	115,327.0	18,778.0	35,688.0	54,466.0	63,163.0	106,630.0	169,793.0
2. Additional Investment									
Additional Hydro Equipment/Ma	1,033.0	3,697.0	4,730.0	136.0	2,487.0	2,623.0	1,169.0	6,184.0	7,353.0
Additional Elec Equipment/Mat	11,806.0	3,223.0	15,029.0	11,943.0	6,358.0	18,301.0	23,749.0	9,581.0	33,330.0
Add DInvestment Total	12,839.0	6,920.0	19,759.0	12,079.0	8,845.0	20,924.0	24,918.0	15,765.0	40,683.0
Sub-Construction	57,224.0	77,862.0	135,086.0	30,857.0	44,533.0	75,390.0	88,081.0	122,395.0	210,476.0
3. Financial/Misc Costs									
Physical Contingency 1/	5,899.4	10,884.8	16,784.1	2,226.4	5,159.7	7,386.0	8,125.7	16,044.4	24,170.1
Eng'g & Adm 2/	6,312.3	8,874.7	15,187.0	3,308.3	4,969.3	8,277.6	9,620.7	13,843.9	23,464.6
Land Acquisition	0.0	2,242.0	2,242.0	0.0	598.0	598.0	0.0	2,840.0	2,840.0
Tax and Duties 3/	12,707.3	8,897.9	21,605.1	6,833.1	5,010.0	11,843.1	19,540.3	13,907.9	33,448.2
BaseC+PhyConti(1+2+3)	82,143.0	108,761.3	190,904.2	43,224.8	60,269.9	103,494.7	125,367.7	169,031.2	294,398.9
IDC 4/	4,251.3	7,956.6	12,207.9	1,747.0	3,517.1	5,264.1	5,998.2	11,473.7	17,472.0
Aggregate Cost	86,394.2	116,717.9	203,112.1	44,971.7	63,787.1	108,758.8	131,365.9	180,505.0	311,870.9

1/ Physical contingencies are assumed to be set at 15% for respective of Road, Camp, Civilworks, 10% for Hydraulic Equip, and 5% for Electric Equipment and Transmission, respectively.

2/ Physical contingency for Engineering and Admin is assumingly set at 10% of the aggregate of sub-construction cost and the sub-total of physical contingencies accrued to each of the cost items as shown above.

3/ No Counting in Economic Analysis because of "Transfer Payment"

4/ No counting in Economic Analysis because of "Transfer Payment"

Table 14-2 Investment Costs for FIRR-Bayram & Bağlık

	Bayram US$ ('000)			Baglik US$ ('000)			Total US$ ('000)		
	Foreign	Local	Total	Foreign	Local	Total	Foreign	Local	Total
Road	0.0	11,655.0	11,655.0	0.0	6,759.0	6,759.0	0.0	18,414.0	18,414.0
Camp	0.0	800.0	800.0	0.0	800.0	800.0	0.0	1,600.0	1,600.0
Civil Works and Erection	31,546.0	51,567.0	83,113.0	6,699.0	19,284.0	25,983.0	38,245.0	70,851.0	109,096.0
Hydro Equipment/Materials	1,033.0	3,697.0	4,730.0	136.0	2,487.0	2,623.0	1,169.0	6,184.0	7,353.0
Elec Equipment/Materials	11,806.0	2,083.0	13,889.0	11,943.0	2,108.0	14,051.0	23,749.0	4,191.0	27,940.0
Transmission	0.0	1,140.0	1,140.0	0.0	4,250.0	4,250.0	0.0	5,390.0	5,390.0
Sub-Construction	44,385.0	70,942.0	115,327.0	18,778.0	35,688.0	54,466.0	63,163.0	106,630.0	169,793.0
Physical Contingency 1/	5,899.4	9,823.1	15,722.5	2,226.4	5,159.6	7,386.0	8,125.8	14,982.7	23,108.5
Eng'g & Adm 2/	6,312.3	8,874.7	15,187.0	3,308.3	4,969.3	8,277.6	9,620.7	13,843.9	23,464.6
Land Acquisition	0.0	2,242.0	2,242.0	0.0	598.0	598.0	0.0	2,840.0	2,840.0
Tax and Duties 3/	10,139.5	8,575.6	18,715.0	4,417.3	4,125.5	8,542.8	14,556.7	12,701.1	27,257.8
BaseC+PhyConti	66,736.2	100,457.3	167,193.5	28,730.0	50,540.4	79,270.4	95,466.2	150,997.7	246,463.9
IDC 4/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aggregate Cost	66,736.2	100,457.3	167,193.5	28,730.0	50,540.4	79,270.4	95,466.2	150,997.7	246,463.9
Additional Hydro Equipment	1,238.5	4,435.8	5,674.4	162.0	2,735.6	2,897.6	1,400.5	7,171.4	8,571.9
Additional Elec Equipment	14,168.5	3,868.2	18,036.6	14,332.8	6,993.6	21,326.4	28,501.3	10,861.8	39,363.1
Total Amnt for FIRR	82,143.2	108,761.3	190,904.5	43,224.8	60,269.6	103,494.4	125,368.0	169,030.9	294,398.9

1/ physical contingencies are assumed to be set at 15% for respective of Road, Camp, Civilworks, 10% for Hydraulic Equip, and 5% for Electric Equip and Transmission, respectively.

2/ Physical contingency for Engineering and Admin is assumingly set at 10% of the aggregate of sub-construction cost and the sub-total of physical contingencies accrued to each of the above cost items.

3/ 10% of import tax and 10% of VAT are assumed for the foreign and local cost portions, respectively.

4/ No counting for FIRR estimation

Table 14-3 Summary Financial Internal Rate of Return (FIRR), Bayram & Bağlık

Year	Capital Cost ($ '000)	Fuel Costs ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET CASH FLOW ($ '000)
2002	7,976.9			7,976.9				-7,976.9
2003	34,994.7			34,994.7				-34,994.7
2004	65,480.3			65,480.3				-65,480.3
2005	66,394.6			66,394.6				-66,394.6
2006	71,617.3			71,617.3				-71,617.3
2007		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2008		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2009		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2010		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2011		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2012		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2013		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2014		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2015		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2016		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2017		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2018		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2019		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2020		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2021		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2022		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2023		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2024		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2025		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2026		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2027		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2028		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2029		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2030		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2031		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2032		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2033		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2034		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2035		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2036		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2037		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2038		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2039		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2040		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2041		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2042	4,999.2	0.0	1,074.9	6,074.1	468.2	0.076	35,565.5	29,491.4
2043	7,597.2	0.0	1,074.9	8,672.1	468.2	0.076	35,565.5	26,893.4
2044	35,338.7	0.0	1,074.9	36,413.6	468.2	0.076	35,565.5	-848.1
2045		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2046		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2047		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2048		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2049		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2050		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2051		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2052		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2053		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2054		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2055		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
2056		0.0	1,074.9	1,074.9	468.2	0.076	35,565.5	34,490.6
Total	294,398.9	0.0	53,743.8	348,142.7	23,410.7		1,778,273.3	1,430,130.6

FIRR = 11.9%

Table 14-4 Summary Financial Internal Rate of Return by Sub-Projects

SUMMARY FINANCIAL INTERNAL RATE OF RETURN (FIRR), Bayram

Year	Capital Cost ($ '000)	Fuel Cost ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET ASH FLOW ($ '000)
2002	5,267.0			5,267.0				-5,267.0
2003	23,566.9			23,566.9				-23,566.9
2004	44,864.7			44,864.7				-44,864.7
2005	45,025.3			45,025.3				-45,025.3
2006	48,469.6			48,469.6				-48,469.6
2007		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2008		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2009		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2010		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2011		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2012		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2013		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2014		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2015		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2016		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2017		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2018		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2019		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2020		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2021		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2022		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2023		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2024		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2025		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2026		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2027		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2028		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2029		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2030		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2031		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2032		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2033		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2034		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2035		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2036		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2037		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2038		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2039		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2040		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2041		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2042	2,501.0	0.0	694.9	3,195.9	245.5	0.076	18,645.6	15,449.7
2043	3,521.3	0.0	694.9	4,216.1	245.5	0.076	18,645.6	14,429.4
2044	17,888.5	0.0	694.9	18,383.4	245.5	0.076	18,645.6	262.2
2045		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2046		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2047		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2048		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2049		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2050		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2051		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2052		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2053		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2054		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2055		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
2056		0.0	694.9	694.9	245.5	0.076	18,645.6	17,950.7
Total	190,904.2	0.0	34,742.5	225,646.7	12,273.3		932,278.3	706,631.6
	FIRR =		9.3%					

SUMMARY FINANCIAL INTERNAL RATE OF RETURN (FIRR),Baglik

Year	Capital Cost ($ '000)	Fuel Cost ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET ASH FLOW ($ '000)
2002	2,709.9			2,709.9				-2,709.9
2003	11,427.9			11,427.9				-11,427.9
2004	20,615.6			20,615.6				-20,615.6
2005	21,369.3			21,369.3				-21,369.3
2006	23,147.7			23,147.7				-23,147.7
2007		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2008		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2009		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2010		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2011		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2012		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2013		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2014		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2015		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2016		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2017		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2018		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2019		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2020		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2021		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2022		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2023		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2024		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2025		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2026		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2027		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2028		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2029		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2030		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2031		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2032		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2033		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2034		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2035		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2036		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2037		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2038		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2039		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2040		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2041		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2042	2,498.2	0.0	380.0	2,878.2	222.7	0.076	16,919.9	14,041.7
2043	4,075.9	0.0	380.0	4,455.9	222.7	0.076	16,919.9	12,464.0
2044	17,650.2	0.0	380.0	18,030.2	222.7	0.076	16,919.9	-1,110.3
2045		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2046		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2047		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2048		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2049		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2050		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2051		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2052		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2053		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2054		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2055		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
2056		0.0	380.0	380.0	222.7	0.076	16,919.9	16,539.9
Total	103,494.7		19,001.3	122,495.9	11,137.4		845,995.0	723,499.0
	FIRR =		16.6%					

Table 14-5 Summary Financial Benefit-Cost Ratio, Bayram & Bağlık

Year	Capital Cost ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Discout Factor 0.095	Present Value Cost	Energy Sales (GWh)	Average Tariff ($/kWh)	Gross Benefits ($ '000)	NET Benefits ($ '000)	Present Value Benefit
1998	7,976.9		7,976.9	0.913	7,284.8					
1999	34,994.7		34,994.7	0.834	29,186.0					
2000	65,480.3		65,480.3	0.762	49,873.3					
2001	66,394.6		66,394.6	0.696	46,182.4					
2002	71,617.3		71,617.3	0.635	45,493.3					
2003		1,074.9	1,074.9	0.580	623.6	468.2	0.076	35,565.5	34,490.6	20,008.6
2004		1,074.9	1,074.9	0.530	569.5	468.2	0.076	35,565.5	34,490.6	18,272.7
2005		1,074.9	1,074.9	0.484	520.0	468.2	0.076	35,565.5	34,490.6	16,687.4
2006		1,074.9	1,074.9	0.442	474.9	468.2	0.076	35,565.5	34,490.6	15,239.6
2007		1,074.9	1,074.9	0.404	433.7	468.2	0.076	35,565.5	34,490.6	13,917.4
2008		1,074.9	1,074.9	0.369	396.1	468.2	0.076	35,565.5	34,490.6	12,710.0
2009		1,074.9	1,074.9	0.337	361.7	468.2	0.076	35,565.5	34,490.6	11,607.3
2010		1,074.9	1,074.9	0.307	330.4	468.2	0.076	35,565.5	34,490.6	10,600.3
2011		1,074.9	1,074.9	0.281	301.7	468.2	0.076	35,565.5	34,490.6	9,680.6
2012		1,074.9	1,074.9	0.256	275.5	468.2	0.076	35,565.5	34,490.6	8,840.7
2013		1,074.9	1,074.9	0.234	251.6	468.2	0.076	35,565.5	34,490.6	8,073.7
2014		1,074.9	1,074.9	0.214	229.8	468.2	0.076	35,565.5	34,490.6	7,373.3
2015		1,074.9	1,074.9	0.195	209.8	468.2	0.076	35,565.5	34,490.6	6,733.6
2016		1,074.9	1,074.9	0.178	191.6	468.2	0.076	35,565.5	34,490.6	6,149.4
2017		1,074.9	1,074.9	0.163	175.0	468.2	0.076	35,565.5	34,490.6	5,615.9
2018		1,074.9	1,074.9	0.149	159.8	468.2	0.076	35,565.5	34,490.6	5,128.7
2019		1,074.9	1,074.9	0.136	146.0	468.2	0.076	35,565.5	34,490.6	4,683.7
2020		1,074.9	1,074.9	0.124	133.3	468.2	0.076	35,565.5	34,490.6	4,277.4
2021		1,074.9	1,074.9	0.113	121.7	468.2	0.076	35,565.5	34,490.6	3,906.3
2022		1,074.9	1,074.9	0.103	111.2	468.2	0.076	35,565.5	34,490.6	3,567.4
2023		1,074.9	1,074.9	0.094	101.5	468.2	0.076	35,565.5	34,490.6	3,257.9
2024		1,074.9	1,074.9	0.086	92.7	468.2	0.076	35,565.5	34,490.6	2,975.2
2025		1,074.9	1,074.9	0.079	84.7	468.2	0.076	35,565.5	34,490.6	2,717.1
2026		1,074.9	1,074.9	0.072	77.3	468.2	0.076	35,565.5	34,490.6	2,481.4
2027		1,074.9	1,074.9	0.066	70.6	468.2	0.076	35,565.5	34,490.6	2,266.1
2028		1,074.9	1,074.9	0.060	64.5	468.2	0.076	35,565.5	34,490.6	2,069.5
2029		1,074.9	1,074.9	0.055	58.9	468.2	0.076	35,565.5	34,490.6	1,889.9
2030		1,074.9	1,074.9	0.050	53.8	468.2	0.076	35,565.5	34,490.6	1,726.0
2031		1,074.9	1,074.9	0.046	49.1	468.2	0.076	35,565.5	34,490.6	1,576.2
2032		1,074.9	1,074.9	0.042	44.9	468.2	0.076	35,565.5	34,490.6	1,439.5
2033		1,074.9	1,074.9	0.038	41.0	468.2	0.076	35,565.5	34,490.6	1,314.6
2034		1,074.9	1,074.9	0.035	37.4	468.2	0.076	35,565.5	34,490.6	1,200.5
2035		1,074.9	1,074.9	0.032	34.2	468.2	0.076	35,565.5	34,490.6	1,096.4
2036		1,074.9	1,074.9	0.029	31.2	468.2	0.076	35,565.5	34,490.6	1,001.3
2037		1,074.9	1,074.9	0.027	28.5	468.2	0.076	35,565.5	34,490.6	914.4
2038	4,999.2	1,074.9	6,074.1	0.024	147.1	468.2	0.076	35,565.5	29,491.4	714.0
2039	7,597.2	1,074.9	8,672.1	0.022	191.7	468.2	0.076	35,565.5	26,893.4	594.6
2040	35,338.7	1,074.9	36,413.6	0.020	735.3	468.2	0.076	35,565.5	-848.1	-17.1
2041		1,074.9	1,074.9	0.018	19.8	468.2	0.076	35,565.5	34,490.6	636.0
2042		1,074.9	1,074.9	0.017	18.1	468.2	0.076	35,565.5	34,490.6	580.9
2043		1,074.9	1,074.9	0.015	16.5	468.2	0.076	35,565.5	34,490.6	530.5
2044		1,074.9	1,074.9	0.014	15.1	468.2	0.076	35,565.5	34,490.6	484.4
2045		1,074.9	1,074.9	0.013	13.8	468.2	0.076	35,565.5	34,490.6	442.4
2046		1,074.9	1,074.9	0.012	12.6	468.2	0.076	35,565.5	34,490.6	404.0
2047		1,074.9	1,074.9	0.011	11.5	468.2	0.076	35,565.5	34,490.6	369.0
2048		1,074.9	1,074.9	0.010	10.5	468.2	0.076	35,565.5	34,490.6	337.0
2049		1,074.9	1,074.9	0.009	9.6	468.2	0.076	35,565.5	34,490.6	307.7
2050		1,074.9	1,074.9	0.008	8.8	468.2	0.076	35,565.5	34,490.6	281.0
2051		1,074.9	1,074.9	0.007	8.0	468.2	0.076	35,565.5	34,490.6	256.6
2052		1,074.9	1,074.9	0.007	7.3	468.2	0.076	35,565.5	34,490.6	234.4
Total	294,398.9	53,743.8	348,142.7		186,132.8	23,410.7		1,778,273.3	1,676,594.4	227,155.2

B-C Ratio 1.22

Table 14-6 Aggregate Economic Costs for Project Implementation-Bayram & Bağlık

	Bayram US$ ('000)			Bağlık US$ ('000)			Total US$ ('000)		
	Foreign	Local	Total	Foreign	Local	Total	Foreign	Local	Total
1.Initial Investment									
Road	0.0	9,440.6	9,440.6	0.0	5,474.8	5,474.8	0.0	14,915.3	14,915.3
Camp	0.0	648.0	648.0	0.0	648.0	648.0	0.0	1,296.0	1,296.0
Civil Works and Erection	31,546.0	41,769.3	73,315.3	6,699.0	15,620.0	22,319.0	38,245.0	57,389.3	95,634.3
Hydro Equipment/Materials	1,033.0	2,994.6	4,027.6	136.0	2,014.5	2,150.5	1,169.0	5,009.0	6,178.0
Elec Equipment/Materials	11,806.0	1,687.2	13,493.2	11,943.0	1,707.5	13,650.5	23,749.0	3,394.7	27,143.7
Transmission	0.0	923.4	923.4	0.0	3,442.5	3,442.5	0.0	4,365.9	4,365.9
Initial Inv Total	44,385.0	57,463.0	101,848.0	18,778.0	28,907.3	47,685.3	63,163.0	86,370.3	149,533.3
2.Additional Investment									
Additional Hydro Equipment/Materials	1,033.0	2,994.6	4,027.6	136.0	2,014.5	2,150.5	1,169.0	5,009.0	6,178.0
Additional Elec Equipment/Materials	11,806.0	2,610.6	14,416.6	11,943.0	5,150.0	17,093.0	23,749.0	7,760.6	31,509.6
Additional Inv Total	12,839.0	5,605.2	18,444.2	12,079.0	7,164.5	19,243.5	24,918.0	12,769.7	37,687.7
Sub-Construction	57,224.0	63,068.2	120,292.2	30,857.0	36,071.7	66,928.7	88,081.0	99,140.0	187,221.0
3.Financial/Misc Costs									
Physical Contingency 1/	5,899.4	8,208.7	14,108.0	2,226.4	3,720.4	5,946.7	8,125.7	11,929.0	20,054.7
Eng'g & Adm 2/	6,312.3	7,127.7	13,440.0	3,308.3	3,979.2	7,287.5	9,620.7	11,106.9	20,727.6
Land Acquisition	0.0	1,816.0	1,816.0	0.0	484.0	484.0	0.0	2,300.0	2,300.0
Tax and Duties 3/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BaseC+PhyConti (1+2+3)	69,435.7	80,220.6	149,656.3	36,391.7	44,255.3	80,647.0	105,827.4	124,475.9	230,303.3
IDC 4/	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aggregate Cost	69,435.7	80,220.6	149,656.3	36,391.7	44,255.3	80,647.0	105,827.4	124,475.9	230,303.3

1/ Physical contingencies are assumed to be set at 15% for respective of Road, Camp, Civilworks, 10% for Hydraulic Equip, and 5% for Electric Equipment and Transmission, respectively.

2/ Physical contingency for Engineering and Admin is assumingly set at 10% of the aggregate of sub-construction cost and the sub-total of physical contingencies accrued to each of the cost items as shown above.

3/ No Counting in Economic Analysis because of "Transfer Payment"

4/ No counting in Economic Analysis because of "Transfer Payment"

Table 14-7 Summary Economic Internal Rate of Return, Bayram & Bağlık

Year	Capital Cost ($ '000)	Fuel Costs ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET CASH FLOW ($ '000)
2002	5,900.8			5,900.8				-5,900.8
2003	27,026.3			27,026.3				-27,026.3
2004	51,031.2			51,031.2				-51,031.2
2005	51,201.4			51,201.4				-51,201.4
2006	57,455.9			57,455.9				-57,455.9
2007		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2008		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2009		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2010		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2011		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2012		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2013		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2014		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2015		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2016		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2017		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2018		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2019		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2020		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2021		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2022		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2023		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2024		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2025		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2026		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2027		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2028		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2029		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2030		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2031		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2032		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2033		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2034		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2035		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2036		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2037		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2038		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2039		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2040		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2041		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2042	4,072.8	0.0	978.0	5,050.8	468.2	0.0801	37,504.7	32,453.8
2043	5,485.6	0.0	978.0	6,463.6	468.2	0.0801	37,504.7	31,041.0
2044	28,129.2	0.0	978.0	29,107.2	468.2	0.0801	37,504.7	8,397.5
2045		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2046		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2047		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2048		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2049		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2050		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2051		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2052		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2053		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2054		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2055		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
2056		0.0	978.0	978.0	468.2	0.0801	37,504.7	36,526.7
Total	230,303.3	0.0	48,899.9	279,203.2	23,411.1		1,875,232.7	1,596,029.6

EIRR = 15.4%

Table 14-8 Summary Economic Rate of Return by Sub-Projects

SUMMARY ECONOMIC INTERNAL RATE OF RETURN, Bayram

Year	Capital Cost ($ '000)	Fuel Costs ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET ASH FLOW ($ '000)
2002	3,912.1			3,912.1				-3,912.1
2003	18,306.3			18,306.3				-18,306.3
2004	35,091.7			35,091.7				-35,091.7
2005	35,091.5			35,091.5				-35,091.5
2006	38,810.6			38,810.6				-38,810.6
2007		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2008		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2009		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2010		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2011		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2012		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2013		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2014		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2015		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2016		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2017		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2018		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2019		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2020		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2021		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2022		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2023		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2024		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2025		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2026		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2027		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2028		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2029		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2030		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2031		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2032		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2033		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2034		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2035		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2036		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2037		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2038		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2039		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2040		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2041		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2042	2,026.3	0.0	629.4	2,655.7	245.5	0.0801	19,661.8	17,006.1
2043	2,474.6	0.0	629.4	3,104.0	245.5	0.0801	19,661.8	16,557.8
2044	13,943.3	0.0	629.4	14,572.7	245.5	0.0801	19,661.8	5,089.1
2045		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2046		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2047		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2048		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2049		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2050		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2051		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2052		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2053		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2054		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2055		0.0	629.4	629.4	245.5	0.0801	19,661.8	19,032.4
2056		0.0	629.4	629.4	245.5	0.1	19,661.8	19,032.4
Total	149,656.3	0.0	31,469.4	181,125.7	12,273.3		983,089.7	801,964.0

EIRR = 12.3%

SUMMARY ECONOMIC INTERNAL RATE OF RETURN, Baglik

Year	Capital Cost ($ '000)	Fuel Costs ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Energy Sales (GWh)	Average Tariff ($/kWh)	Total Benefits ($ '000)	NET CASH FLOW ($ '000)
2002	1,988.8			1,988.8				-1,988.8
2003	6,720.1			6,720.1				-6,720.1
2004	15,939.5			15,939.5				-15,939.5
2005	16,109.9			16,109.9				-16,109.9
2006	18,645.3			18,645.3				-18,645.3
2007		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2008		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2009		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2010		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2011		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2012		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2013		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2014		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2015		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2016		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2017		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2018		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2019		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2020		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2021		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2022		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2023		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2024		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2025		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2026		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2027		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2028		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2029		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2030		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2031		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2032		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2033		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2034		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2035		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2036		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2037		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2038		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2039		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2040		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2041		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2042	2,048.1	0.0	348.6	2,396.7	222.8	0.0801	17,842.9	15,446.1
2043	3,010.8	0.0	348.6	3,359.4	222.8	0.0801	17,842.9	14,483.5
2044	14,184.6	0.0	348.6	14,533.2	222.8	0.0801	17,842.9	3,309.7
2045		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2046		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2047		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2048		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2049		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2050		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2051		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2052		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2053		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2054		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2055		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
2056		0.0	348.6	348.6	222.8	0.0801	17,842.9	17,494.3
Total	80,647.0	0.0	17,430.5	98,077.5	11,137.9		892,143.1	794,065.6

EIRR = 21.4%

Table 14-9 Economic B-C Ratio, Bayram and Bağlık

Year	Capital Cost ($ '000)	O/M Cost ($ '000)	Total Cost ($ '000)	Discout Factor 0.095	Present Value	Energy Sales (GWh)	Average Tariff ($/kWh)	Gross Benefits ($ '000)	NET Benefits ($ '000)	Present Value
2002	5,900.8		5,900.8	0.9132	5,388.9					
2003	27,026.3		27,026.3	0.8340	22,540.3					
2004	51,031.2		51,031.2	0.7617	38,868.1					
2005	51,201.4		51,201.4	0.6956	35,614.3					
2006	57,455.9		57,455.9	0.6352	36,497.6					
2007		978.0	978.0	0.5801	567.4	468.2	0.0801	37,504.7	36,526.7	21,189.7
2008		978.0	978.0	0.5298	518.1	468.2	0.0801	37,504.7	36,526.7	19,351.3
2009		978.0	978.0	0.4838	473.2	468.2	0.0801	37,504.7	36,526.7	17,672.5
2010		978.0	978.0	0.4418	432.1	468.2	0.0801	37,504.7	36,526.7	16,139.2
2011		978.0	978.0	0.4035	394.6	468.2	0.0801	37,504.7	36,526.7	14,739.0
2012		978.0	978.0	0.3685	360.4	468.2	0.0801	37,504.7	36,526.7	13,460.3
2013		978.0	978.0	0.3365	329.1	468.2	0.0801	37,504.7	36,526.7	12,292.5
2014		978.0	978.0	0.3073	300.6	468.2	0.0801	37,504.7	36,526.7	11,226.0
2015		978.0	978.0	0.2807	274.5	468.2	0.0801	37,504.7	36,526.7	10,252.1
2016		978.0	978.0	0.2563	250.7	468.2	0.0801	37,504.7	36,526.7	9,362.6
2017		978.0	978.0	0.2341	228.9	468.2	0.0801	37,504.7	36,526.7	8,550.4
2018		978.0	978.0	0.2138	209.1	468.2	0.0801	37,504.7	36,526.7	7,808.5
2019		978.0	978.0	0.1952	190.9	468.2	0.0801	37,504.7	36,526.7	7,131.1
2020		978.0	978.0	0.1783	174.4	468.2	0.0801	37,504.7	36,526.7	6,512.4
2021		978.0	978.0	0.1628	159.2	468.2	0.0801	37,504.7	36,526.7	5,947.4
2022		978.0	978.0	0.1487	145.4	468.2	0.0801	37,504.7	36,526.7	5,431.4
2023		978.0	978.0	0.1358	132.8	468.2	0.0801	37,504.7	36,526.7	4,960.2
2024		978.0	978.0	0.1240	121.3	468.2	0.0801	37,504.7	36,526.7	4,529.9
2025		978.0	978.0	0.1133	110.8	468.2	0.0801	37,504.7	36,526.7	4,136.9
2026		978.0	978.0	0.1034	101.2	468.2	0.0801	37,504.7	36,526.7	3,778.0
2027		978.0	978.0	0.0945	92.4	468.2	0.0801	37,504.7	36,526.7	3,450.2
2028		978.0	978.0	0.0863	84.4	468.2	0.0801	37,504.7	36,526.7	3,150.9
2029		978.0	978.0	0.0788	77.0	468.2	0.0801	37,504.7	36,526.7	2,877.5
2030		978.0	978.0	0.0719	70.4	468.2	0.0801	37,504.7	36,526.7	2,627.8
2031		978.0	978.0	0.0657	64.3	468.2	0.0801	37,504.7	36,526.7	2,399.9
2032		978.0	978.0	0.0600	58.7	468.2	0.0801	37,504.7	36,526.7	2,191.7
2033		978.0	978.0	0.0548	53.6	468.2	0.0801	37,504.7	36,526.7	2,001.5
2034		978.0	978.0	0.0500	48.9	468.2	0.0801	37,504.7	36,526.7	1,827.9
2035		978.0	978.0	0.0457	44.7	468.2	0.0801	37,504.7	36,526.7	1,669.3
2036		978.0	978.0	0.0417	40.8	468.2	0.0801	37,504.7	36,526.7	1,524.5
2037		978.0	978.0	0.0381	37.3	468.2	0.0801	37,504.7	36,526.7	1,392.2
2038		978.0	978.0	0.0348	34.0	468.2	0.0801	37,504.7	36,526.7	1,271.4
2039		978.0	978.0	0.0318	31.1	468.2	0.0801	37,504.7	36,526.7	1,161.1
2040		978.0	978.0	0.0290	28.4	468.2	0.0801	37,504.7	36,526.7	1,060.4
2041		978.0	978.0	0.0265	25.9	468.2	0.0801	37,504.7	36,526.7	968.4
2042	4,072.8	978.0	5,050.8	0.0242	122.3	468.2	0.0801	37,504.7	32,453.8	785.8
2043	5,485.6	978.0	6,463.6	0.0221	142.9	468.2	0.0801	37,504.7	31,041.0	686.3
2044	28,129.2	978.0	29,107.2	0.0202	587.8	468.2	0.0801	37,504.7	8,397.5	169.6
2045		978.0	978.0	0.0184	18.0	468.2	0.0801	37,504.7	36,526.7	673.6
2046		978.0	978.0	0.0168	16.5	468.2	0.0801	37,504.7	36,526.7	615.1
2047		978.0	978.0	0.0154	15.0	468.2	0.0801	37,504.7	36,526.7	561.8
2048		978.0	978.0	0.0140	13.7	468.2	0.0801	37,504.7	36,526.7	513.0
2049		978.0	978.0	0.0128	12.5	468.2	0.0801	37,504.7	36,526.7	468.5
2050		978.0	978.0	0.0117	11.5	468.2	0.0801	37,504.7	36,526.7	427.9
2051		978.0	978.0	0.0107	10.5	468.2	0.0801	37,504.7	36,526.7	390.8
2052		978.0	978.0	0.0098	9.6	468.2	0.0801	37,504.7	36,526.7	356.9
2053		978.0	978.0	0.0089	8.7	468.2	0.0801	37,504.7	36,526.7	325.9
2054		978.0	978.0	0.0081	8.0	468.2	0.0801	37,504.7	36,526.7	297.6
2055		978.0	978.0	0.0074	7.3	468.2	0.0801	37,504.7	36,526.7	271.8
2056		978.0	978.0	0.0068	6.6	468.2	0.0801	37,504.7	36,526.7	248.2
Total	230,303.3	48,899.9	279,203.2		146,166.6	23,411.1		1,875,232.7	1,788,645.2	240,838.7

B-C Ratio 1.65

Pricing and Tariff Structure

Inadequate pricing, investment and regulatory policies which are likely to lead the public services undertakings to relatively distressed financial performance has been a chronicle disease in the urban sanitation infrastructure sector. Among others, the current tariff policies are creating an immediate problem, as most power-supply undertakings in the country are unable to earn a sufficient rate of return to attract private debt or equity investment. The problems become increasingly difficult when rapid growth in sanitary services at a higher quality and reliability result in a larger scale demand for investible resources in the near future.

Investments in the urban sanitation sector have been financed through the public sector by general taxes, bilateral aid and concessionary loans from multilateral financing institutions. Nonetheless, with a critical lack of funds available and deteriorating public finances, which is a binding constraint to borrow external funds for the sector investment, financing through traditional sources have often been falling severely short of demand. This has led political decision makers and international aid practitioners to look for alternatives to finance investment needs. Mobilization of domestic and external resources through capital markets is now urgently called for.

Viewed in this light, associated with a number of government experiences of severe budget constraints, an appropriate framework for domestic urban sanitation sector pricing, tariffs and contracts is therefore required not only to achieve an efficient allocation of scarce resources, but also to maintain the long-term financial sustainability of utilities and sanitation service undertakings, and to attract private sector, and possibly external capital, to the sector to the extent possible. In pricing, there would be two key objectives: (i) tariffs should be sufficient to provide for the financial viability of the urban sanitation services and undertakings and generate a sufficient surplus to allow for their financing a significant part of their own investment programs in the years to come, and (ii) prices should be set at levels which encourage efficient use of service capacity and avoids wasteful consumption.

On account of the above, this section briefly reviews the microeconomics principles of pricing to achieve the policy objectives above, thus making it possible to review an allocative efficiency-oriented tariff structure for the power subsector in Turkey.

Microecoinomics Background

The purpose of an economic system is to allocate the scarce resources of an economy to the production of goods and services for the use of individuals in the society. In a mixed economy, such as that of Turkey, two primary mechanisms are relied upon to fulfill the said task, vis-à-vis, the market pricing system by which private sector business undertakings respond to prices determined by the demand and supply levels in individual markets and undertake that level of economic activities in their own self-interest, and the public sector decisions through which a significant share of the resources of the economy will be directly and indirectly allocated by government expenditures, taxes, regulations and any other measures relevant. While a rationale for public sector activities has been well recognized and stressed by a number of economists and policy decision makers, particularly after the days of the Great Depression in the United States in the early 1930's with the epoch making works in economics by J. M. Kaynes, this section will confine the discussions to the effectiveness of the market pricing mechanism in resource allocation in society.

Pareto Optimality (Allocative Efficiency Criterion)

Ever since Adam Smith's time the virtue of the competitive market system as a mechanism for the allocation of scarce resources have been perceived. In competitive markets where self-interested individuals and firms would freely buy and sell at given prices, all participants will be better off from voluntary trading and the aggregate value of outputs produced from society's resources will be maximized. Much of the fields of welfare economics has been devoted to refining these concepts of social gains from trade, comparative advantage, and welfare maximization under the general axiom of economic efficiency. Central to an understanding of this modern welfare economics is Pareto Optimality, with a *Pareto Optimum* being defined as a state of affairs such that no one can be made better off without

at the same time making at least one other person worse off.[1] This notion is depicted as follows:

Let general social welfare function be

$W=W(y_1, y_2, \ldots\ldots, y_n)$, where y_i denotes individual's welfare (well-being) in a society.

Pareto condition is that $W^A > W^B$

if $y_1^A \geq y_1^B, \ldots\ldots, y_n^A \geq y_n^B$ for $\forall i$

and $y_1^A > y_1^B, \ldots\ldots, y_n^A > y_n^B$ for $\exists i$

In the context of the economy, a Pareto Optimal allocation among uses exists if it is not possible to allocate reallocate resources so as to improve utility (well being) of one person/entity without at least reducing utility level of one other person/entity. Further, a change in resource allocation is said to constitute a *Pareto Improvement* if at least one person/entity is made better off as a result of the change and no one is worse off. With this, a change in resource allocation among arbitrary uses will be judged by economists if a situation of economy under a certain set of resource allocation be "good" or "bad"[2]. In other words, an efficient allocation of resources is defined as a Pareto-Optimum one, it is not possible to make anyone better off without at a same time making someone else worse off. Similarly, a gain in economic efficiency is equivalent to a Pareto Improvement. The underlying theorem here is that Parerto optimum is a "necessary and sufficient condition" of the equilibrium point in perfectly competitive markets, thereby providing a rational for marginal cost pricing. [3]

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[1] The concept is named after the Italian economist Vilfredo Pareto who pioneered the theory of economic welfare. See V. Pareto, *Manuel D'Economie Politique*, 1909, chap.VII, and the Mathematical Appendix para.89.

[2] As noted, the concept of Pareto Optimality is the normative basis according to which the allocation of resources is to be judged. Therefore, it shall be accepted as a basic value judgment that any Pareto-improving change constitutes an improvement in social welfare.

[3] One of the most important problems in welfare economics arises when judgment as to whether the change improves society's economic welfare involves interpersonal comparisons between the gainers and losers. That is, given that society's welfare consists of the aggregate welfare of individual members, it would be imperative to attach quantifiable weights to the gains and losses of welfare to individuals from a change in resource allocation. See, A. Bergson," A Reformulation of Certain Aspects of Welfare Economics", *Quarterly Journal of Economics*, Feb. 1938, O. Lange, *The Foundations of Welfare Economics*, *Econometrica*, July-Oct 1942, and P. Samuelson, *Foundations of Economic Analysis*, Chap. VIII, 1948. As regards the issues of economic welfare, optimum allocation of resources, interpersonal comparisons of utility, and others, see, for example, A.C. Pigou, *Wealth and Welfare*, 4th ed.,1932, L. Robbins, *An Essay on the Natural and Significance of Economic Science*, 2nd ed., 1935

Marginal Opportunity Cost Pricing

With the standard allocative efficiency considerations in view, it is useful to obtain an indication of the benchmark level at which the price should be set. A number of papers have been written on the efficient ways to set prices on different goods and services, and production factors. In this section, a bird's eye view of the concept of marginal cost pricing and the current state-of-the-art to approximate it when financial sustainability and economic viability of development projects are to be evaluated.

Meanwhile, it would be noteworthy to delineate the concepts of "marginal opportunity cost (MOC) pricing" and "marginal cost (MC) pricing" used in the Report. While MOC pricing emphasizes the cost of consuming scarce resources in the light of the opportunity foregone by that consumption. On the measurement side, MOC denotes the shadow price of supply with a good deal of distortions in most of the economies worldwide, whereas MC pricing is used in lieu of the annuitized cost accrued to an investment project, inter alia, construction costs and recurrent costs. I this context, MOC pricing is most relevant to the economic analysis of development projects whereas MC pricing to the financial analysis therein.

A crucial distinction here is between marginal cost within a given capacity of the system, and that allowing for capacity expansion. For small additions of supply in a certain period requiring no additional capital investment, the marginal cost is defined as short-run marginal (opportunity) cost (SRMOC), while a large amount of capital investment takes place intermittently over the long period, say 30 to 50 years, it is circumscribed as long run marginal (opportunity) cost (LRMOC). In practice, a smoothing of short-run fluctuation of incremental investments can be obtained by calculating LRMOCs and averaging them over time. This average can be defined as the incremental cost of all adjustments in the system expansion plan and operations, attributable to an incremental increase in demand.

When looked more closely,

LRMOC = MC of construction + Recurrent Cost (Fuel, and Operation and Maintenance costs)

The origins of marginal cost pricing theory date back as far as the works of P. Dupuit and subsequently H. Hotelling, in the 1930's[4]. N. Ruggles provided a comprehensive review of work in this area up to the next decade, and the theory developed, especially for the application of in the electric power sector, with contributions from the works of M. Boiteux, P. Steiner and others from the 1950's onwards[5]. More recently, the academic interest has led to more sophisticated investment models which permit determination of marginal costs, consideration of uncertainty, developments in peak load pricing, and so forth. On the practitioner's side, a number of contribution has been made by the economists of the international lending agencies, namely, M. Munasinghe, J. Warford, Y. Albouy, and others[6]. Backed up with these and others, the rationale for setting price equal to marginal cost to consequently attain the maximum economic welfare level will be clarified in this section.[7]

The rational for setting price equal to marginal cost may be clarified in mathematical terms as follows:

Net Benefit (NB) = Total Revenue (TR) - Total Cost (TC)

The necessary first order condition for maximizing net social benefits is to set the derivative of the net benefit function at zero, that is numerically such as:

$$NB(Q)=TR(Q)-TC(Q)$$
$$=p(Q) * Q - TC(Q)$$
$$(d/dQ)NB = (\partial p/\partial Q * Q/p + p) - \partial TC/\partial Q = 0$$
$$1/(\partial Q/\partial p) * p + p = \partial TC/\partial Q$$

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[4] P. Dupuit, "De l'Utilite et de sa Mesure", *La Reforma Soziale*, Turin, 1932, H. Hotelling, "The General Welfare in Relation to Problems of Railway and Utility Rates", Econometrica vol 6, 1938, pp. 242-269

[5] N. Ruggles, "The Welfare basis of the Marginal Cost Pricing Principle", *Review of Economic Studies* vol.17 (1949/50), pp. 29-46, and "Recent Developments in the Theory of Marginal Cost Pricing", *Review of Economic Studies*, vol.27(1949-50), pp.107-126. See for example: M. Boiteux, "La Tariffication of des Demandes en Pointe, Revenue Generale de l'Electricite", vol. 58, 1949, P. Steiner, "Peak Loads and Efficient Pricing", *Quarterly Journal of Economics*, 1957, R. Turvey and D. Anderson, *Electricity Economics*, Johns Hopkins University Press, 1977

[6] For example, see M. Munasinghe, *Guidelines for Marginal-Cost Analysis of Power System*, WB, 1984, M. Munasinghe and J. Warford, *Shadow Pricing and Power Tariff Policy*, WB, 1978, J. Warford, *Marginal Opportunity Cost Pricing: Municipal Water Supply* (Early Draft), 1994, Y. Albouy, *Marginal Cost Analysis and Pricing of Water and Electric Power*, Inter-American Development Bank, 1983, and many others.

[7] In economics, LRMOC is defined as the amount by which aggregate costs are changed if the volume of output is increased or decreased by one unit. Frequently in accounting, marginal cost is used when strictly one should refer to average variable cost, which are not incurred if production does not take place. Ref: W. Hingley *Accounting*, Made Simple Book, 1989, p. 302

$$p(1+1/\varepsilon) = \partial TC/\partial Q$$

where p, Q and ε denote the price (the equation of demand schedule), quantity of supply (the equation of supply schedule) and price elasticity of supply which is mathematically depicted as $\partial Q/\partial p * p/Q$, respectively.

Provided that $\varepsilon = \infty$ under the assumption of perfectly competitive market,

$$p = \partial TC/\partial Q$$
$$= \text{Marginal Cost}$$

It is one of the basic axioms of economics that at the price p and supply (demand) Q, the total net benefit of consumption attributed to society is maximized with the optimum market clearing point (p,Q).

In a simple and static model of pricing, an economically efficient equilibrium price has the three invariable characteristics as such that (i) it will clear the market in terms of demand and supply, (ii) it will encourage additional production or exploitation whenever the expected costs are less than the expected value of incremental supplies, and (iii) it discourages "wasteful" consumption on the demand side.[8]

Estimation of Marginal Opportunity Costs

The model presented so far has been deliberately idealized and simplified to clarify the basic principles involved. While the marginal cost is an important pricing guidepost subject to a certain range of conditions, it is highly conceptual and there would be no data readily available for the estimation of future supply and demand schedules, thereby making it difficult to readily estimate in practice yet maintaining theoretical rigidity. Thus, a seek for

[8] In theory, after having computed the basic shadow priced marginal costs as the benchmark for tariff setting, decision would be made to deviate from such "strict LRMC values" while reflecting decision makers' value judgment concerning other policy objectives, vis-à-vis, equity, financial sustainability, and preferential deployment of resources to specific sectors/regions. In addition, a "second best" departure from the "first best" LRMC pricing policy would be required where prices elsewhere in the economy do not reflect marginal social opportunity costs. Nonetheless, the discussions on this "optimal departures from marginal cost pricing" specifically for the Project has not been included largely due to the hypothetical nature of the issue, and the lack of information and time.

proxy for the strict LRMOC, though indicative, has been initiated and sorted out mainly by power economists, as previously noted, since the 1950's.

In welfare economics and its applied segment of investment decision theory, in particular, the most commonly used variant of this theoretical concept is a levelized annuity cost plus recurrent cost over a fixed period of time. Specifically for the Project under the current study, it is defined that the required long-run marginal opportunity cost of supply of the sanitation subsector services in question is the cost of advancing one unit of services (sewerage treatment and solid waste management), which may be estimated in terms of the cost per cubic meter treated/managed, annuitized over the expected project period. Further in estimation, capital recovery factor (CRF) which is a function of the opportunity cost of capital (denoted by i) and project life (n) to estimate the levelized annuity cost.[9]

Thus, a numerical expression will be:

$$\text{LRMOC} = \text{TC} * \text{CRF}(i, n) + \text{annual recurrent cost}$$

where TC denotes the total capital investment cost, while CRF is depicted as:

$$\text{CRF}^{10} \equiv \frac{i(1+i)^n}{(1+i)^n - 1}$$

With this, objective of efficient pricing of goods and services is that prices should reflect the true economic opportunity costs of using scarce resources.

Average Cost Pricing

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[9] Another variant of MC widely used is the Long Run Average Incremental Cost (LRAIC) with its short accessibility to the relevant information and data. In theoretical terms it may not be correct nonetheless it is useful as an approximation. Mathematically it is expressed as LRAIC = $[(\sum I_t/(1+i)^t)/(\sum Q_t/(1+i)^t)]$ where t is a year in a project period (t=1,2,....,n), whereas i, I and Q denote a discount rate,an incremental investment and an incremental supply, respectively.

[10] CRF is defined as a summation of depreciation (represented by a sinking fund factor) and opportunity cost of capital (or inflation rate), which is mathematically depicted as follows:

$$\frac{i(1+i)^n}{(1+i)^n - 1} = \frac{i(1+i)^n + i - i}{(1+i)^n - 1} = \frac{i\{(1+i)^n - 1\} + i}{(1+i)^n - 1} = \frac{i}{(1+i)^n - 1} + i$$

There would be a discussion regarding the overall rationale for the use of average cost pricing in lieu of marginal cost pricing where public utility prices be made everywhere equal to marginal cost. By far the most important considerations that conflict with the strict application of marginal cost pricing is the need for revenues where average cost decreases as output increases R. Coase, a Nobel-prize laureate at economics in 1990 and a partial advocate of average cost pricing, once discussed the issue in the context of general welfare loss and tax incidence in a society in such a way that "average cost pricing may sometimes prevent something being done which ought to be done, but it is also a means of avoiding errors which would certainly made if a policy of marginal cost pricing were adopted, and there is the redistribution of income which would occur and which could not be rectified without producing the same disadvantages which it is the aim of marginal cost pricing to avoid."[11]

Notwithstanding, in line with the generally accepted methodological frameworks and guidelines for economic appraisal of projects, Long Run Marginal Opportunity Cost (LRMOC) pricing reflects the practitioners' major concern with the amount of future resources used by consumer decisions, whereas Average Cost pricing represents the traditional accounting approach which is the recovery of sunk costs.

Shadow Pricing

In the idealized world of perfect competition, the interaction of atomoistic profit maximizing producers and atomoistic utility maximizing consumers gives rise to a situation where, for a given income distribution, no one can be better off without making someone else worse off,

[11] R. Coase, "The Theory of Public Utility Pricing and Its Application", *Bell Journal of Economics and Management Science*, Sep. 1970 pp.113- 128. Citing the advocating article of marginal cost pricing by Hotelling (op cit.,1938), Coase pointed out the possible weakness attributable to marginal cost pricing as follows: (i) this policy proposal does not take into account the stimulus to correct forecasting of having a subsequent market test whether consumers are willing to pay the total cost, (ii) it ignores the probable effects on the administrative structure, with state enterprise superseding private enterprise and centralized operations superseding decentralized operations, (iii) it involves a redistribution of income in favor of consumers of products produced in conditions of decreasing costs, and (iv) it failed to take into account the misallocation of resources resulting from the additional taxation necessitated by the subsidies (p.113). To articulate, Coace discussed that while "marginal cost pricing certainly allows a better choice at the margin than average cost pricing", but "this disadvantage of average cost pricing would be reduced and might be offset if marginal cost involved increased income taxes (p.120). Further, it would be interesting to note that "the argument for marginal cost pricing, like many propositions in modern welfare economics, is more concerned with diagrams on a blackboard than with the real effects of such policies on the working of economic system" while Coase refers to this type of economics as "blackboard economics" (p.119).

vis-à-vis, Pareto Optimal. In this state, prices reflect the true marginal social costs, scarce resources are efficiently allocated to maximize the total output in a society. Nonetheless, conditions are likely to be far from that hypothetical and idealistic model of perfectly competitive market due to a good deal of prevalent distortions in the economy[12], thus making it inevitable to substantially diverge from market (or financial) prices for goods and services. Hence, the use of appropriate shadow pricing will be necessitated in designing and evaluating the economic feasibility of the optimal investment programs.

While avoiding mingled procedures to estimate conversion factors for each of the goods and services, and production factors, shadow pricing will take place in a way that: transfer payment which is a shift of claims on real resources from one member or sector of society to another without any change in the national income will be excluded. The use of standard conversion factor (SCF) is considered to convert the market value of the Project components to its value in shadow prices expressed in terms of border currency units. Specifically in this Project, value added tax (VAT) corresponding to 10 percent of the local currency cost components will be deducted, and subsequently the SCF of 0.81 will be applied. [13]

[12] Distortions are largely due to monopoly practices, external economies and diseconomies (which are not internalized in the private market), interventions in the market process through taxes, import duties and subsidies, and so forth.

[13] 0.9 is the estimate of SCF currently in use by the World Bank.

CHAPTER 15 FINANCING PLAN

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CHAPTER 15. FINANCING PLAN

The indicative financing plan and repayment plan are forwarded herewith as a kind of financial benchmarks. No breakdown of prospective fund allocation or equity investment from the government and private sector are included in the analysis, as such the Turkish counterpart and the mission would discuss further detailed plans, as appropriate, if the occasion arises in due course of project processing to come.

15.1 Financing Plan

Of the total "financial costs" for the project of US$311.9 million as reflected in the preceding section of financial cost estimation, the initial investment for the foreign and local cost portions, exclusive of replacement cost in the 41-43rd years in the investment outlay worked out respective of US$95.5 million and US$150.9 million, thereby leading to US$246.5 million in aggregate (refer to Table 14-2). Replacement cost accrued in the far later years during the project period is being excluded due to very low probability of credit extended by international or bi-lateral financing institutions. With the highly hypothetical assumption that 100 percent of these foreign and local cost (base cost plus physical contingencies) are presumably covered by multi, and bi-lateral aid agencies, notably, the World Bank and the Overseas Economic Cooperation Fund, Japan, differences in financial terms and conditions between the two agencies are reiterated herewith in a bid to articulate the basic assumptions.

	Foreign Cost Portion		Local Cost Portion	
	Multi-Lateral	Bi-Lateral	Multi-Lateral	Bi-Lateral
Financing Coverage (%)	100	100	100	100
Loan Period (years)	20	30	20	30
Grace Period (years)	5	10	5	10
Loan Repayment Period (yrs)	15	20	15	20
Interest Rate (%)	3.5	3.5	9.5	9.5

15.2 Repayment Plan

In compliance with the hypothetical parameters associated with the two financing sources as above, annuity payments are calculated as follows.

	Foreign Cost Portion		Local Cost Portion	
	Multi-Lateral	Bi-Lateral	Multi-Lateral	Bi-Lateral
Disbursement (US$million)	95.5	95.5	150.9	150.9
Principal (US$million)	101.5	95.5	184.5	150.9
Cumulative Repayment (US$million)	132.2	157.0	353.5	445.1
Annual Payment (US$million)	8.8	6.7	23.6	17.1
Present value of Repayments (S$milion)	85.5	85.5	117.2	116.8

In a bid to simplify the model, annuity payments are assumed to be made once a year, at the end of the fourth quarter. Commitment charge of 0.75% which is payable to the agreed amount of loan is not included either in discussion for the same reason. Amortization is on a levelized basis, and interest which is payable all over the project duration will be on the diminishing balance of the outstanding principal, as such interest costs will decrease proportionately as principal is amortized.

The schematic presentation of repayment schedules payable to international lending institutions and bi-lateral aid agencies for the foreign and local cost portions are attached as Tables 15-1 and 2, respectively.

Table 15-1 Indicative Repayment Schedule for Foreign Currency Portion of $95.5 Million

Alt 1. Multi-Lateral Agency

Principle $		95.5	$ '000									
	Share	0	0.11079	0.25131	0.20366	0.43424	1					
	Disb't	0.0	10.6	24.0	19.5	41.5	95.5					
	Interest	3.5%										
	Repayme	20										
	Grace	5										
	Yrs/Perio	15										
	Level Pa	-8.8127										
	CommitC											
	IDC (int 1998-2002)			5.999								
	Balance Beginning	Disburse	IDC	Outstandi	Interest Payment	Principal Repayme	Commit't Charge	Balance End	Amortizn	Accumulated Payment		
1998	0.0	0.0	0.0					0.0		0.0		
1999	0.0	10.6	0.2					10.8		0.0		
2000	10.8	24.0	0.8					35.6		0.0		
2001	35.6	19.5	1.6					56.6		0.0		
2002	56.6	41.5	3.4					101.5		0.0		
2003				132.2	3.6	5.3	0.0		8.8	8.8		
2004				123.4	3.4	5.4	0.0		8.8	17.6		
2005				114.6	3.2	5.6	0.0		8.8	26.4		
2006				105.8	3.0	5.8	0.0		8.8	35.3		
2007				96.9	2.8	6.0	0.0		8.8	44.1		
2008				88.1	2.6	6.2	0.0		8.8	52.9		
2009				79.3	2.3	6.5	0.0		8.8	61.7		
2010				70.5	2.1	6.7	0.0		8.8	70.5		
2011				61.7	1.9	6.9	0.0		8.8	79.3		
2012				52.9	1.6	7.2	0.0		8.8	88.1		
2013				44.1	1.4	7.4	0.0		8.8	96.9		
2014				35.3	1.1	7.7	0.0		8.8	105.8		
2015				26.4	0.9	7.9	0.0		8.8	114.6		
2016				17.6	0.6	8.2	0.0		8.8	123.4		
2017				8.8	0.3	8.5	0.0		8.8	132.2		
				0.0			0.0		0.0			
Total		95.5	6.0		30.7	101.5				132.2		

Alt 2. Bi-Lateral Agency

Principle $		95.5	$ '000										
	Share	0	0.10995	0.25026	0.20314	0.43665	1						
	Disb't	0.0	10.6	24.0	19.5	41.5	95.5						
	Interest	3.5%											
	Repayme	20											
	Grace	5											
	Yrs/Perio	15											
	Level Pa	-6.7195											
	CommitC												
	IDC (int 1998-2002)					5.87							
	Balance Beginning	Disburse	IDC		Outatandi	Interest Payment	Principal Repayme	Commit't Charge	Balance End		Amortizn	Accumulated Payment	
1	1998	0.0	0.0	0.0		0.0			0.0			0.0	
2	1999	0.0	10.6	0.2		0.2			10.6		0.2	0.2	
3	2000	10.6	24.0	0.8		0.8			34.6		0.8	1.0	
4	2001	34.6	19.5	1.6		1.6			54.0		1.6	2.5	
5	2002	54.0	41.5	3.3		3.3			95.5		3.3	5.9	
6	2003					3.3			95.5		3.3	9.2	
7	2004					3.3			95.5		3.3	12.6	
8	2005					3.3			95.5		3.3	15.9	
9	2006					3.3			95.5		3.3	19.2	
10	2007					3.3			95.5		3.3	22.6	
11	2008				134.4	3.3	3.4	0.0			6.7	29.3	
12	2009				127.7	3.2	3.5	0.0			6.7	36.0	
13	2010				121.0	3.1	3.6	0.0			6.7	42.7	
14	2011				114.2	3.0	3.7	0.0			6.7	49.5	
15	2012				107.5	2.8	3.9	0.0			6.7	56.2	
16	2013				100.8	2.7	4.0	0.0			6.7	62.9	
17	2014				94.1	2.6	4.2	0.0			6.7	69.6	
18	2015				87.4	2.4	4.3	0.0			6.7	76.3	
19	2016				80.6	2.3	4.4	0.0			6.7	83.1	
20	2017				73.9	2.1	4.6	0.0			6.7	89.8	
21	2018				67.2	2.0	4.8	0.0			6.7	96.5	
22	2019				60.5	1.8	4.9	0.0			6.7	103.2	
23	2020				53.8	1.6	5.1	0.0			6.7	109.9	
24	2021				47.0	1.4	5.3	0.0			6.7	116.7	
25	2022				40.3	1.3	5.5	0.0			6.7	123.4	
26	2023				33.6	1.1	5.7	0.0			6.7	130.1	
27	2024				26.9	0.9	5.9	0.0			6.7	136.8	
28	2025				20.2	0.7	6.1	0.0			6.7	143.5	
29	2026				13.4	0.4	6.3	0.0			6.7	150.3	
30	2027				6.7	0.2	6.5	0.0			6.7	157.0	
31	2028				0.0			0.0					
	Total		95.5	5.9		55.6	95.5					157.0	

Table 15-2 Indicative Repayment Schedules for Local Borrowing of $150.9 Million From Multi and Bi-Lateral Aid Agencies

Alt 1. Multi-Lateral Agency

Principle $	150.9 $ '000						
Share	0.0528562	0.1617628	0.274884	0.3110471	0.19945	1	
Disb't	8.0	24.4	41.5	46.9	30.1	150.9	
Interest	9.5%						
Repayment	20						
Grace	5						
Yrs/Periods	15						
Level Payt	-23.6						
CommitC							
IDC (int 1998-2002)			33.6				

	Balance Beginning	Isburseme	IDC	Outstandin	Interest Payment	Principal Repayment	Committ Charge	Balance End	Amortizn	ccumulated Payment
1998	0.0	8.0	0.4					8.4		0.0
1999	8.4	24.4	2.0					34.7		0.0
2000	34.7	41.5	5.3					81.5		0.0
2001	81.5	46.9	10.0					138.4		0.0
2002	138.4	30.1	16.0					184.5		0.0
2003				353.5	17.5	6.0	0.0		23.6	23.6
2004				329.9	17.0	6.6	0.0		23.6	47.1
2005				306.4	16.3	7.2	0.0		23.6	70.7
2006				282.8	15.6	7.9	0.0		23.6	94.3
2007				259.2	14.9	8.7	0.0		23.6	117.8
2008				235.7	14.1	9.5	0.0		23.6	141.4
2009				212.1	13.2	10.4	0.0		23.6	165.0
2010				188.5	12.2	11.4	0.0		23.6	188.5
2011				165.0	11.1	12.5	0.0		23.6	212.1
2012				141.4	9.9	13.7	0.0		23.6	235.7
2013				117.8	8.6	15.0	0.0		23.6	259.2
2014				94.3	7.2	16.4	0.0		23.6	282.8
2015				70.7	5.6	17.9	0.0		23.6	306.4
2016				47.1	3.9	19.7	0.0		23.6	329.9
2017				23.6	2.0	21.5	0.0		23.6	353.5
				0.0			0.0		0.0	
Total		150.9	33.6		169.0	184.5				353.5

Alt 2. Bi-Lateral Agency

Principle $	150.9 $ '000						
Share	0.0528562	0.1617628	0.274884	0.3110471	0.19945	1	
Disb't	8.0	24.4	41.5	46.9	30.1	150.9	
Interest	9.5%						
Repayment	20						
Grace	5						
Yrs/Periods	15						
Level Payt	-17.12363						
CommitC							
IDC (int 1998-2002)			30.9				

	Balance Beginning	Isburseme	IDC	Outstandin	Interest Payment	Principal Repayment	Committ Charge	Balance End	Amortizn	ccumulated Payment
1998	0.0	8.0	0.4		0.4			8.0		0.4
1999	8.0	24.4	1.9		1.9			32.4	1.9	2.3
2000	32.4	41.5	5.0		5.0			73.9	5.0	7.3
2001	73.9	46.9	9.2		9.2			120.8	9.2	16.6
2002	120.8	30.1	14.3		14.3			150.9	14.3	30.9
2003					14.3			150.9	14.3	45.3
2004					14.3			150.9	14.3	59.6
2005					14.3			150.9	14.3	73.9
2006					14.3			150.9	14.3	88.3
2007					14.3			150.9	14.3	102.6
2008				342.5	14.3	2.8	0.0		17.1	119.7
2009				325.3	14.1	3.1	0.0		17.1	136.9
2010				308.2	13.8	3.3	0.0		17.1	154.0
2011				291.1	13.5	3.7	0.0		17.1	171.1
2012				274.0	13.1	4.0	0.0		17.1	188.2
2013				256.9	12.7	4.4	0.0		17.1	205.3
2014				239.7	12.3	4.8	0.0		17.1	222.5
2015				222.6	11.9	5.3	0.0		17.1	239.6
2016				205.5	11.4	5.8	0.0		17.1	256.7
2017				188.4	10.8	6.3	0.0		17.1	273.8
2018				171.2	10.2	6.9	0.0		17.1	291.0
2019				154.1	9.6	7.6	0.0		17.1	308.1
2020				137.0	8.8	8.3	0.0		17.1	325.2
2021				119.9	8.1	9.1	0.0		17.1	342.3
2022				102.7	7.2	9.9	0.0		17.1	359.5
2023				85.6	6.2	10.9	0.0		17.1	376.6
2024				68.5	5.2	11.9	0.0		17.1	393.7
2025				51.4	4.1	13.0	0.0		17.1	410.8
2026				34.2	2.8	14.3	0.0		17.1	428.0
2027				17.1	1.5	15.6	0.0		17.1	445.1
2028				0.0			0.0			
Total		150.9	30.9		263.3	150.9				445.1

Chapter 16 FURTHER INVESTIGATION

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16.1 Geological Investigation for Bayram Project

Drilling investigations as shown below at Table 16-1 will be required to be conducted for grasp of the geological properties at the dam site, underground powerhouse site and tailrace tunnel route for Bayram project. (see Figure 16-1)

Table 16-1 Further Drilling Investigation for Bayram Project

No. of Hole	Length (m)	Location	Water Level Measurement	Lugeon Test
Y-1	120	Dam site	required	required
Y-2	110	Spillway site	required	required
Y-3	50	Spillway site	required	required
Y-4	100	Intake site	required	not required
Y-5	300	Underground powerhouse site	required	required
Y-6	160	Tailrace tunnel route	required	required

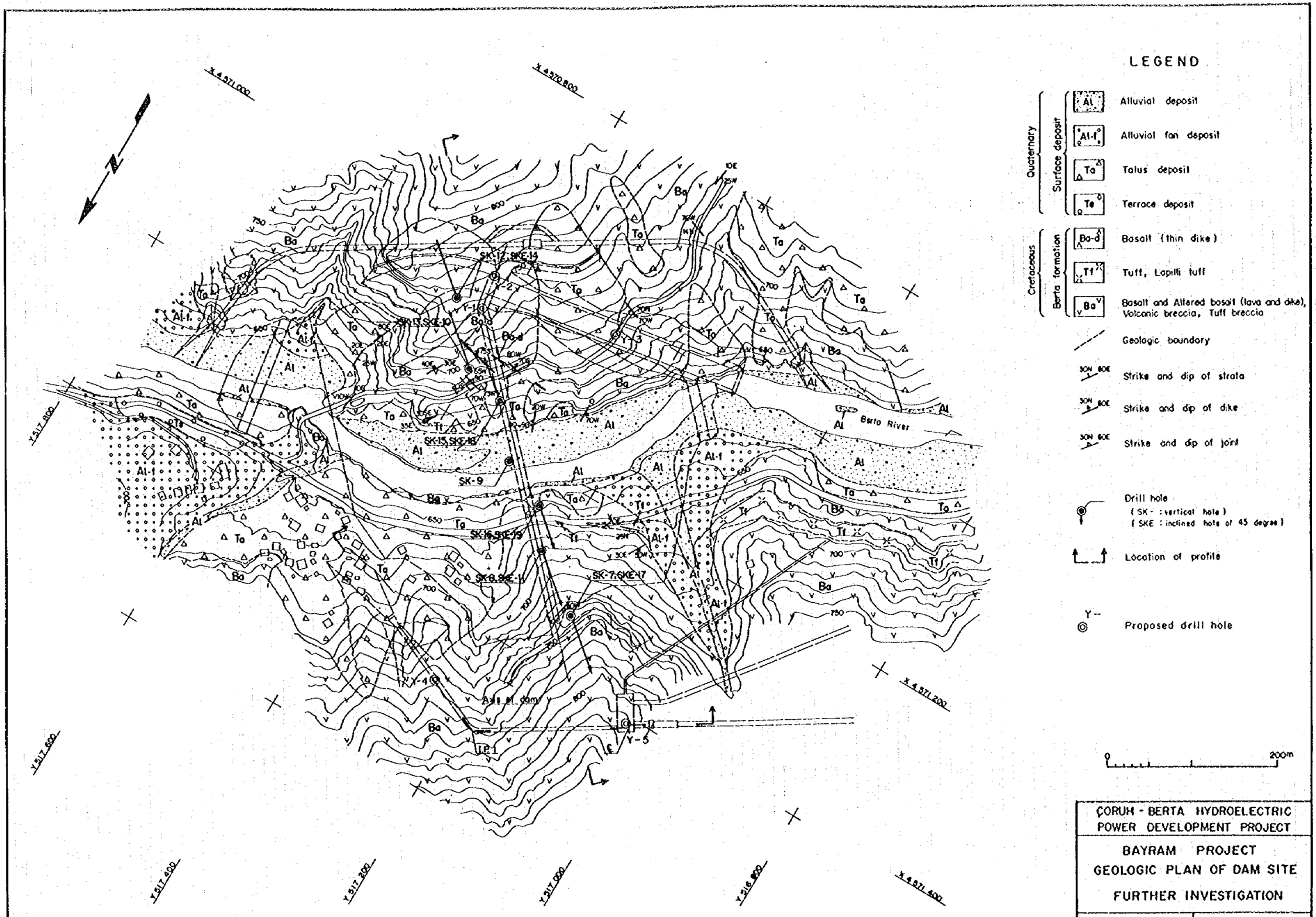
16.2 Geological Investigation for Bağlık Project

Drilling investigations as shown below at Table 16-2 will be required to be conducted for grasp of geological properties at the dam site and tailrace tunnel route. (see Figure 16-2)

Table 16-2 Further Drilling Investigation for Bağlık Project

No. of Hole	Length (m)	Location	Water Level Measurement	Lugeon Test
G-1	75	Dam site	required	required
G-2	75	Dam site	required	required
G-3	80	Dam site	required	required
G-4	80	Dam site	required	required
G-5	75	Dam site	required	required
G-6	75	Dam site	required	required
G-7	70	Dam site	required	required
G-8	70	Dam site	required	required
G-9	70	Dam site	required	required
G-10	70	Dam site	required	required
G-11	50	Dam site	required	required
G-12	200	Tailrace tunnel route	required	required

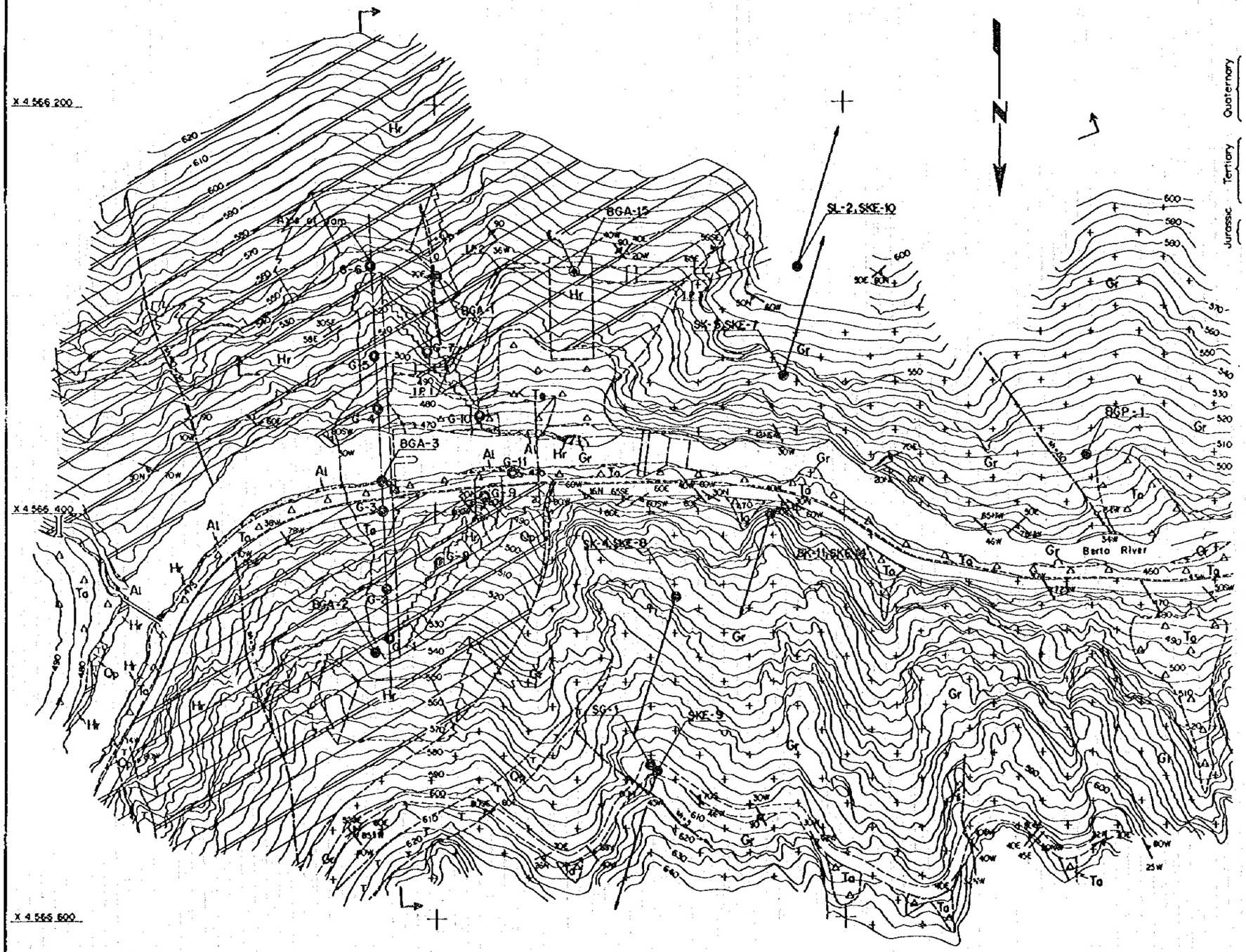
Exploratory adits should be carried out at the Bağlık dam site to grasp in-situ mechanical properties of the bedrock. However the definite investigation program including locations and quantities for the exploratory adits will be formulated after studying the results of the drilling investigations.



ÇORUH - BERTA HYDROELECTRIC POWER DEVELOPMENT PROJECT

BAYRAM PROJECT
GEOLOGIC PLAN OF DAM SITE
FURTHER INVESTIGATION

Figure 16-1



LEGEND

Quaternary	Surface deposit	Al	Alluvial deposit
		To	Talus deposit
Tertiary	Ikizdere granitic rocks	Qp	Quartz porphyry
		Gr	Granite
Jurassic	Yusufeli formation	Hr	Hornfels (with Meta-diabase and Meta-basalt)

Geologic boundary

Strike and dip of fault (sh : width of shear zone, cm)

Strike and dip of strata

Strike and dip of dike

Strike and dip of joint

Drill hole
(SK- : verticol hole)
(SKE- : inclined hole of 45 degrees)

Location of profile

G-
Proposed drill hole

0 100m

ÇORUH - BERTA HYDROELECTRIC POWER DEVELOPMENT PROJECT

BAĞLIK PROJECT
GEOLOGIC PLAN OF DAM SITE
FURTHER INVESTIGATION

Figure 16 - 2