Metering and billing are contracted to a company, which in turn charges the costs to the Government. The charge is not a fixed rate, and it is not subject to the number of accounts, but to the total amount of the bills collected. For this reason, it may be appropriate to classify metering and billing costs as energy costs rather than as customer costs.

It must be clearly noted that the prices of the Project's outputs will cover the investment costs for generation/production and transmission facilities as well as the costs for the operation of generation/production facilities.[4] This conversely means that the prices are those at the end of "the transmission lines" that the Project plans to build, and are not prices at the consumer-end.

16.3.2 Marginal Capacity and Energy Costs for Electricity

The Project (Alternative 2) envisions the installments of twelve 96 MW gas turbine units and six 100 MW steam turbine units in the form of a combined cycle, and one 96 MW gas turbine in the form of an open cycle, in four stages. During the thirteen years between 1998 and 2010, a total capacity of 1,848 MW will be installed by the Project.

(a) Marginal capacity costs for generation

The LRMC of generating capacity ($LRMC_{G.C.}$) is defined as the additional cost required (to the long-run total cost), when one more kilowatt power is generated. It, to be more specific, is the investment cost required to meet a kilowatt increment in peak load demand at the busbars. The cost must also cover reserve margin and loss at the power station. $LRMC_{G.C.}$ is calculated by the following formula:

$LRMC_{G.C.}$ = (annuitized cost per kilowatt) (1+RM%)/(1-Lsu%)

where

RM: Reserve margin
Lsu: Loss due to station use

4 Chiefly because data and information concerning the operating costs of transmission facilities are not sufficient or complete, those costs are not included in the Project inputs' costs or outputs' prices.

Annuitized cost is defined as the annual payment by installments over the life of the property invested. In computing the annuitized cost, an annuity factor is applied which is designed to convert a present lump-sum amount into a series of future cash flows (installments). The computation of the factor is made by the following formula:

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

where

i:: annual discount rate

n: year (life expectancy)

Investments for generation capacity include gas turbines, steam turbines, and civil-work improvements, for each of which the annuitized cost needs to be computed. We assume the life expectancies of both gas turbines and steam turbines at 20 years. The investment costs of each gas turbine unit (96 MW) and steam turbine unit (100 MW) are estimated at 19,656 thousand R.O., 32,637 thousand R.O., respectively.[5] With an assumed opportunity cost of capital (or discount rate) of 8%, the annuitized costs are calculated at:[6]

Gas turbine:		20.4 million R.O. x 0.101852
	=	2.08 million R.O. per year (for 20 years)
Steam turbine:		36.65 million R.O. x 0.101852
	=	3.73 million R.O. per year (for 20 years)

The costs for civil works need to be apportioned to the power and water divisions as their additional generation/production capacity costs. We allocate the costs based firstly on the purposes of the inputs (i.e., whether they are for power generation or for water production) and secondly on the comparative size of the total capacity costs of the two divisions. As shown in Chapter 15 in this report, it is determined that the power division takes 20.15 million R.O. (including 6.13 million R.O. for foreign currency costs and 13.92 million R.O. for local currency costs), and the water division 19.94 million R.O. (including 6.35 million R.O. for foreign and 13.59 million for local currency costs).[7]

5 The costs for foundations and power houses are distributed evenly over the nineteen generators and are included in the unit costs.

6 Since local currency costs are not significant, all the costs are treated as foreign currency costs.

7 The share of the water division does not cover foundations of desalination equipment, which will be included in the desalination unit.

We assume that the average life expectancy of the improvements of civil works is 30 years. The annuitized costs allocated to the power and water divisions are thus as follows:

Power division;

Foreign currency costs (FC)		6.13 million R.O. x 0.0888
	=	0.54 million R.O. per year (for 30 years)
Local currency costs (LC)		13.92 million R.O. x 0.0888
	=	1.24 million R.O. per year (for 30 years)

Water division:

FC		6.35 million R.O. x 0.0888
	=	0.56 million R.O. per year (for 30 years)
LC		13.59 million R.O. x 0.0888
	=	1.21 million R.O. per year (for 30 years)

Since two type of generators with different annuitized costs are involved, we compute the average annuitized cost per installed capacity as shown below (the annuitized cost of the civil works components is also included):

Not shadow priced:

(2.08 million R.O. x 13 units + 3.73 million R.O. x 6 units + 1.78 million R.O.)/1,848 MW = 27.70 R.O./KW (per year)

Shadow priced:

(2.08 million R.O. x 13 units + 3.73 million R.O. x 6 units + 1.66 million R.O.)/1,848 MW = 27.63 R.O./KW (per year)

For the calculation of $LRMC_{G.C.}$, we make the following two assumptions.

1. The reserve margin needs to be discussed from the viewpoint of the system as a whole. While at the present time the system has no reserve margin, we assume that at least 150 MW of reserve margin will be required for the entire system by 2010. The figure is equivalent to approximately 8 % of the total capacity scheduled at the Barka Station in 2010, and thus this ratio is applied for the calculation of $LRMC_{G.C.}$

2. The station use is basically proportional to the total power generated at the station. For the computation of $LRMC_{G.C.}$, we assume that 2 % of the power generated will be consumed at the station. (Consumption by the desalination plant is not included.)

With these assumptions and the annuitized cost per kilowatt calculated, $LRMC_{G.C.}$ is computed as shown below.

$LRMC_{G.C.}$ (not shadow-priced)	=	27.70 R.O./KW x (1 + 8%)/(1 - 2%)
	=	30.53 R.O./KW per year
$LRMC_{G.C.}$ (shadow-priced)	=	27.63 R.O./KW x (1 + 8%)/(1 - 2%)
	=	30.45 R.O./KW per year

(b) Marginal capacity costs for transmission

The Project covers the transmission lines (and related facilities) which will interconnect the proposed Barka Station with the substation in Madinat Qaboos. Usually, in calculating the marginal costs for transmission capacity, all the investment costs in the transmission facilities are allocated to incremental capacity, as the designs of those facilities are determined by the peak kilowatts they carry, rather than the kilowatt-hours. In the case of the Project, investments in transmission facilities are limited only to those scheduled to be built at the end of 1997. Therefore, we simply annuitize the total investment cost for the facilities over an estimated life expectancy of 40 years at an assumed discount rate of 8%, and then divide the resulting figure by the peak kilowatts that the facilities are expected to carry in the year 2010. The average capacity cost for transmission obtained by this method is thus:

FC:		45.79 million R.O. x 0.0839 ÷ 1,559 MW
	=	2.46 R.O./KW per year (for 40 years)
LC:		12.95 million R.O. x 0.0839 ÷ 1,559 MW
	=	0.70 R.O./KW per year (for 40 years)

Note: 1,559 MW = 1,640 MW (peak load at generation) x [1 - 2% (station loss)] x [1 - 3% (transmission loss)]

The capacity-related price of the power generated and transmitted (at the high voltage level to the substation in Madinat Qaboos) by the Project will reflect the investment cost required to meet a kilowatt increment in peak demand at the end of the HV transmission line concerned. In other words, the price will be the

LRMC for capacity at the high voltage level ($LRMC_{HVC.}$), which is expressed by the following function:

$$LRMC_{HVC.} = LRMC_{G.C.}/(1 - L_{HV}\%) + \Delta LRMC_{HV}$$

where,

$L_{HV}\%$: HV transmission loss factor (i.e., power loss during the transmission from the Barka Station to the Madinat Qaboos substation)

$\Delta LRMC_{HV}$: Incremental (or average annual) HV capacity costs (i.e., annuitized cost of the transmission facilities covered by the Project)

With the assumption of the transmission loss at 3%, the $LRMC_{HVC.}$ is computed at:

$LRMC_{HVC.}$ (not shadow-priced)	=	30.53 R.O./(1 - 3%) + 3.16 R.O.
	=	34.63 R.O./KW per year
$LRMC_{HVC.}$ (shadow-priced)	=	30.45 R.O./(1 - 3%) + 3.09 R.O.
	=	34.48 R.O./KW per year

Note: 3.18 = 2.48 + 0.70
3.11 = 2.48 + 0.70 x 0.9 (conversion factor)

(c) Marginal energy costs

The marginal cost of energy is defined as the operating or running cost to provide additional energy. The marginal cost of energy, in general, differs as to whether it is during the peak hours or off-peak hours. The reason for this is that a utility system usually consists of a number of generators with different fuel inputs and different heat rates, and that the operation of the various generators of the system is programmed in such a way that the cost of the operation can be minimized. In order to provide additional energy during the peak period, machines that are the least cost efficient will be used to meet the incremental peak kilowatt-hours. The marginal cost of peak energy, thus, is the operating cost of those machines. Similarly, in order to provide additional energy during off-peak hours, base-load machines that are last in terms of operating cost efficiency for the use of base load will be employed. The marginal cost of off-peak energy is the running cost of those machines.

The proposed Barka Station is expected to be more efficient than any of the existing plants. Because all the existing plants of the Muscat and Wadi Jizzi Systems are equipped prodominantly with gas turbines, their per-KWH energy costs are basically the same. We, therefore, simply apply for the marginal energy cost, the average cost of operating the plants of the Muscat and Wadi Jizzi Systems, which is higher than the estimated cost at the Barka station. The cost was 10.88 bz/KWH (including 0.67 bz for foreign currency costs and 11.20 bz for local ones) in 1993.

The marginal cost of energy at the sending-end must include the loss at the station, and similarly that at the end of the transmission line must reflect the transmission loss of energy. The marginal cost of energy is thus calculated as follows:

(BZ/KWH)

	Not shadow priced	Shadow priced
Marginal energy cost	10.88	9.85
At sending-end (loss factor at 2%)	11.10	10.05
At transmission-end (loss factor at 3%)	11.45	10.36

(d) Summary of marginal costs

The marginal costs for generation capacity and transmission capacity, and the marginal energy costs are summarized as follows:

(R.O.)

	Not shadow priced	Shadow priced
LRMC for generation capacity (per KW, yearly)	30.53	30.48
LRMC for capacity at high voltage level (per KW, yearly)	34.63	34.48
(Project's capacity cost)		
Marginal cost of energy		
At generation (per KWH)	10.88×10^{-3}	9.85×10^{-3}
At sending-end	11.10×10^{-3}	10.05×10^{-3}
At transmission-end	11.45×10^{-3}	10.36×10^{-3}

16.3.3 Marginal capacity and production costs for water

The marginal capacity costs and the marginal energy costs required to supply an additional unit of water can be estimated in a similar manner.

(a) Marginal capacity costs for production

The Project contemplates the installation of eight desalination units with a capacity of 31,820 m^3/d each. The implementation will be made in four stages with two units installed at each stage.

Capital investments will consist of civil-work improvements, desalination units, and transmission facilities. The annuitized total cost of the civil improvements has already been calculated at 1.77 million R.O. (per year) including 0.56 million R.O. for foreign currency costs and 1.21 million R.O. for local ones. The annuitized cost per cubic meter a day of installed capacity is calculated at 6.95 R.O. [1.77 million R.O. ÷ (31,820 m^3/d x 8)], including 2.20 R.O. for foreign currency costs and 4.75 R.O. for local currency costs.

The estimated cost of the desalination unit including its foundation is 47.66 million R.O., a total of 38.18 million R.O. for foreign components and 9.48 million R.O. for local components. At a life expectancy of 20 years and at a discount rate at 8%, the annuitized cost of each unit is calculated at:

FC:	38.18 million R.O. x 0.10185 = 3.89 million R.O.(annually)
LC:	9.48 million R.O. x 0.10185 = 0.97 million R.O. (annually)

Each desalination unit has a capacity of 31,820 m^3/d. Therefore, the annuitized cost per unit (m^3/d) of installed capacity is calculated at:

FC:	3.89 million R.O. ÷ 31,820 m^3/d = 122.25 R.O./m^3/d (annually)
LC:	0.97 million R.O. ÷ 31,820 m^3/d = 30.48 R.O./m^3/d (annually)

To these figures, we add the corresponding figures for civil improvements as shown below, to obtained the total annuitized capacity costs for the production of a unit of water.

FC:	2.20 R.O. + 122.25 R.O. = 124.45 R.O.
LC:	4.75 R.O. + 30.48 R.O. = 35.23 R.O.

Although no reserve margin is taken, the installed capacity will be set at 120% for the peak demand. The station use is expected to be at 2%. Therefore, the not-shadow-priced LRMC for production capacity ($LRMC_{P.C.}$) is calculated at 195.53 R.O./m^3 [= (124.45 + 35.23) x 120% ÷ (1 - 2%)], and the shadow-priced $LRMC_{P.}$ at 191.21 R.O./m^3 [= (124.45 + 35.23 x 0.09) x 120% ÷ (1 - 2 %)] a year. These costs are the capacity costs at the sending-end.

(b) Marginal capacity costs for transmission

Transmission facilities include pipes connecting existing reservoirs of the Muscat Water System, and related facilities, as well as pipes extending to six walayats in South Batinah and related facilities including reservoirs and pump stations. For the sake of simplicity, we assume that all the planned transmission facilities will be built by 1999, when the Project is scheduled to begin producing water.

The total cost of the transmission facilities is 51.45 million R.O. including 36.55 million R.O. for foreign components and $14.90 million R.O. for local ones. With an assumption of the discount factor at 8% and the average life span of the facilities at 50 years, the annuitized cost is computed at:

FC:	36.55 million R.O. x 0.0817 = 2,987,000 R.O.(per year)
LC:	14.90 million R.O. x 0.0817 = 1,217,000 R.O. (per year)

To estimate the marginal capacity cost for transmission, we divide the annuitized cost by the volume of water the transmission facilities are expected to carry in 2010. With assumed station loss and transmission loss factors at 2 % and 0 % respectively, the marginal capacity cost for transmission we can estimate at:

FC:	2,987,000 R.O. ÷ 176,520 m^3/d = 16.92 R.O. per year (for 50 years)
LC:	1,217,000 R.O. ÷ 176,520 m^3/d = 6.89 R.O. per year (for 50 years)

Note: 176,520 m3/d = 180,122 m3/d (demand at production) x [1 - 2% (station loss)] x [1 - 0% (transmission loss)]

The marginal capacity cost for both production and transmission at the transmission-end ($LRMC_{T.C.}$) is thus estimated as follows:

$LRMC_{T.C.}$ = $LRMC_{P.C.}$/(1-transmission loss factor) +

average capacity cost for transmission per m^3/d of demand

= 195.53 R.O./m^3/d /(1 - 0%) + (16.92 R.O. + 6.89 R.O.) = 219.34 R.O./m^3/d

When the local currency inputs are shadow-priced, the corresponding cost will decrease to 214.33 R.O./m^3/d.

(c) Marginal production costs

For the marginal production cost, we simply assume the unit production cost at the Ghubrah desalination plant, the operation of which is less cost efficient than the proposed Barka plant, and which is the only plant that can produce an additional supply of water in the Muscat-South Batinah area. The production cost (excluding the depreciation cost) in 1993 was 0.434 R.O./m^3, including 0.026 R.O./m^3 for foreign components and 0.408 R.O./m^3 for local ones. When local currency costs are shadow-priced, the product cost will decrease to 0.393 R.O./m^3.

With the expected station use of water at 2% of the total production, the marginal production cost is computed as follows: (no transmission loss expected)

(R.O./m^3)

	Not shadow priced	Shadow priced
Marginal production cost	0.434	0.393
At sending-end (loss factor at 2%)	0.443	0.401
At transmission-end (loss factor at 0%)	0.443	0.401

(d) Summary of marginal costs

The marginal cost for the production and transmission capacities, and the marginal production cost are summarized as follows:

(R.O.)

	Not shadow priced	Shadow priced
LRMC for production capacity (per m^3/d, yearly)	195.53	191.21
LRMC for capacity at transmission-end (per m^3/d, yearly)	219.34	214.33
Marginal of production (per m^3)		
At sending-end	0.443	0.401
At transmission-end	0.443	0.401

16.4 Financial Analysis

The primary objective of financial analysis is to measure the financial viability of the project concerned by projecting the cash in- and out-flows of the project. In the analysis we first calculate the financial rate of return of the Project. In this procedure, in order to evaluate the project's fundamental soundness, specific financing considerations will not be made (i.e., no interest charges assumed), and prices will be expressed in constant or real terms (i.e., no inflationary impacts assumed). Then, we calculate the rate of return on equity invested, for the first stage of the Project. In this step, cash flows will be prepared in nominal prices, taking also into account the debt financing elements, so that the financial performance of the Project can be evaluated from the lenders' view point as well.

16.4.1 Financial Rate of Return (FRR)

In previous sections, we estimated the costs of all the project inputs including capital costs and operating costs, and also determined, based on the concept of LRMC, the cost and therefore the prices of the project outputs. By using those study results, we now analyze the financial rate of return of the Project[8]. Not-shadow-priced costs are used, as it is not necessary to shadow price the costs of the project inputs for financial analysis, which are concerned with actual costs the Project will pay.

Table 16.8 exhibits annual cost and benefit streams expressed in constant 1994

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8 Technically speaking, the application of the LRMC for the financial analysis may not be appropriate. The existing tariffs (which do not specifically impose capacity costs) do not cover the full cost to supply electricity/water. The government has no immediate plan to raise them. However, when the current electricity/water services are privatized in the near future, the charges for those services set by the newly established entity will fully reflect the cost and sufficient return, and will be higher than the current tariffs (regardless of whether any part of the charges is subsidized by the government or not). This study assumes that those charges will be determined based on the LRMC concept. And thus the LRMC-based charges will be used for the financial analysis (as well as for the economic analysis). As far as the electricity is concerned, the average tariff level in 1993 was estimated at 16.67×10^{-3} R.O. per KWH consumed (the total revenue of 65.42 million R.O. divided by the total billed consumption of 3,924,159 KWH). The charge determined based on the LRMC concept consists of the capacity charge of 34.65 R.O./KW and the energy charge of 11.45×10^{-3} R.O./KWH. At the current load factor of 52%, the capacity charge is equivalent to a KWH charge of 7.61×10^{-3} R.O.; therefore making a total KWH charge of 19.06×10^{-3} R.O. Assuming that the capacity charge for distribution facilities and consumer costs jointly account for 12% of the total charge to supply electricity, the overall per-KWH charge will be 21.66×10^{-3} R.O. This charge, which is expressed in 1994 price, is 30% higher than the average tariff level of 1993. As for the water, the average tariff in 1993 was estimated at somewhere around 2.3×10^{-3}R. O. per gallon. The capacity charge and the production charge determined by the LRMC concept are 219.34 R.O./m^3/day (or 0.6326 R.O./m^3 at the load factor of 95%) and 0.443 R.O./m^3, respectively. With an assumption that the capacity cost for distribution facilities and consumer costs jointly represent 12% of the total charge, the overall charge for a cubic meter of water supplied will be 1.222 R.O (i.e., 2.688×10^{-3} R.O. per gallon). This charge is 17% higher than the average tariff level of 1993. The disparities between the average tariffs and the assumed new charges for electricity and water are similar to the government's current subsidy level for these utilities services, and therefore the assumed charges are considered to be appropriate.

prices. Benefits are derived from the generation of electricity and the production of water. In the capital costs, no price contingencies, or interest during the implementation periods are included. Also, no considerations were made regarding financing costs, working capital requirements, or taxes during the project life, which, similar to inflation, could distort the underlying viability of the Project and make it difficult to compare the attractiveness of the Project with that of other urgent projects.

Key assumptions used in our financial rate of return analysis include:

1. No replacement is made when the equipment (generators and desalination units) finishes its life expectancy. The project life extends until 2029 when the useful life of the last generator is expected to be finished.

2. Demand forecasting has been made up to the year 2010. After 2010, the power demand increases by an average annual increment expected during 1993 and 2010, until it leaves only 150 MW for the reserve margin.[9] The energy demand increases at the load factor of 52%, which is the current level. The water capacity demand (m^3/d) also increases at the same rate that is expected during the period between 1993 and 2010, until it leaves 20% of the installed capacity for the peak demand. Similarly, the total water production demand (m^3) rises until it reaches 95% of the plant's available capacity.[10]

The financial rate of return is computed at 13% for the entire project (10% for the power division and 17 % for the water division). This rate of return exceeds the discount rate (opportunity cost of capital) of 8 %.[11] The Project's net present value (at the discount factor of 8 %) is also calculated for net present value analysis. The value is approximately 339 million R.O.

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9 For the projection of power demand after 2010, the following formula was used, which is based on the changes in the demand during the period between 1993 and 2010:
Power demand (MW) = -263635.89 + 131.945 x X (Year), $r^2 = 0.996$.

10 The water capacity demand (m^3/d) and the production demand (m^3) after 2010 were estimated by the following formulae:
Water capacity demand (m^3/d) = -31,374,686.711 + 15,705.752 x X (Year), $r^2 = 0.999$
Water production demand (m^3) = -11,451,782,763.348 + 5,732,610.455 x X (Year), $r^2 = 0.999$

11 Discount factor is synonymous with the opportunity cost of capital. An appropriate discount rate for a project can be estimated by looking into rates of returns on investments in comparable projects with similar levels of risk involved. In some cases, if not most, however, the discount rates are estimated, referring to rates of return available in international capital markets.

Table 16.8 Financial rate of return analysis

Thousand R.O.

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1. Electricity																		
A. Benefit (Revenue)																		
(a) Capacity																		
1 Power requirement at generation (MW)			106	202	304	413	529	652	783	921	1,050	1,185	1,329	1,480	1,640	1,700	1,700	1,700
2 Power requirement at sending-end (2% loss)			103	198	298	405	518	639	767	903	1,029	1,162	1,302	1,451	1,607	1,666	1,666	1,666
3 Power requirement at transmission-end (3% loss)			100	192	289	392	503	620	744	876	998	1,127	1,263	1,407	1,559	1,616	1,616	1,616
4 Total benefit at transmission-end @34.63 R.O./KW			3,475	6,643	9,999	13,589	17,404	21,458	25,767	30,325	34,553	39,019	43,738	48,724	53,993	55,968	55,968	55,968
(b) Energy																		
1 Energy requirement at generation (MWH)			475,898	913,345	1,376,776	1,872,470	2,399,234	2,959,055	3,554,049	4,183,412	4,767,198	5,383,898	6,035,450	6,723,916	7,451,482	7,744,569	7,744,569	7,744,569
2 Energy requirement at sending-end (2% loss)			466,380	895,078	1,349,240	1,835,021	2,351,249	2,899,873	3,482,968	4,099,744	4,671,854	5,276,220	5,914,741	6,589,438	7,302,452	7,589,677	7,589,677	7,589,677
3 Energy requirement at transmission-end (3% loss)			452,388	868,226	1,308,763	1,779,970	2,280,712	2,812,877	3,378,479	3,976,752	4,531,699	5,117,933	5,737,299	6,391,755	7,083,379	7,361,987	7,361,987	7,361,987
4 Total benefit at transmission-end @0.01145 R.O./KWH			5,180	9,941	14,985	20,381	26,114	32,207	38,684	45,534	51,888	58,600	65,692	73,186	81,105	84,295	84,295	84,295
Sub-total			8,654	16,584	24,984	33,970	43,518	53,666	64,451	75,859	86,441	97,620	109,430	121,910	135,098	140,263	140,263	140,263
B. Cost																		
(a) Capital cost																		
Foreign	15,160	114,110	19,540	23,650	42,350	12,570	44,460	27,190	23,230	44,870	30,310	48,570	51,950	24,660	0	0	0	0
Local	2,950	12,890	13,800	1,650	300	360	470	1,890	340	1,780	640	2,000	2,080	410	0	0	0	0
Total	18,110	127,000	33,340	25,300	42,650	12,930	44,930	29,080	23,570	46,650	30,950	50,570	54,030	25,070	0	0	0	0
(b) Operating cost																		
Foreign			138	265	399	543	696	858	1,031	1,213	1,382	1,561	1,750	1,950	2,161	2,246	2,246	2,246
Local			3,493	6,704	10,106	13,744	17,610	21,719	26,087	30,706	34,991	39,518	44,300	49,354	54,694	56,845	56,845	56,845
Total			3,631	6,969	10,505	14,287	18,306	22,578	27,117	31,919	36,374	41,079	46,050	51,303	56,855	59,091	59,091	59,091
Sub-total	18,110	127,000	36,971	32,269	53,155	27,217	63,236	51,658	50,687	78,569	67,324	91,649	100,080	76,373	56,855	59,091	59,091	59,091
C. Net benefit (A - B)	-18,110	-127,000	-28,317	-15,685	-28,171	6,753	-19,718	2,008	13,763	-2,710	19,117	5,971	9,350	45,536	78,243	81,172	81,172	81,172
D. Net present value	-18,110	-117,593	-24,277	-12,451	-20,706	4,596	-12,426	1,172	7,436	-1,356	8,855	2,561	3,713	16,744	26,639	25,589	23,693	21,938
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-18,110	-135,703	-159,980	-172,431	-193,137	-188,541	-200,967	-199,796	-192,360	-193,715	-184,860	-182,300	-178,587	-161,843	-135,204	-109,616	-85,922	-63,984

F. FRR 10%

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
1. Electricity																	
A. Benefit (Revenue)																	
(a) Capacity																	
1 Power requirement at generation (MW)	1,700	1,700	1,700	1,700	1,524	1,343	1,255	1,167	1,075	986	806	718	629	449	361	180	32,985
2 Power requirement at sending-end (2% loss)	1,666	1,666	1,666	1,666	1,493	1,316	1,230	1,143	1,053	967	790	703	617	440	353	177	32,325
3 Power requirement at transmission-end (3% loss)	1,616	1,616	1,616	1,616	1,448	1,277	1,193	1,109	1,021	938	766	682	598	427	343	171	31,356
4 Total benefit at transmission-end @34.63 R.O./KW	55,968	55,968	55,968	55,968	50,153	44,217	41,310	38,402	35,374	32,466	26,530	23,623	20,715	14,779	11,872	5,936	1,085,843
(b) Energy																	
1 Energy requirement at generation (MWH)	7,744,569	7,744,569	7,744,569	7,744,569	6,939,938	6,118,545	5,716,229	5,313,914	4,894,836	4,492,520	3,671,127	3,268,812	2,866,496	2,045,103	1,642,787	821,394	150,099,866
2 Energy requirement at sending-end (2% loss)	7,589,677	7,589,677	7,589,677	7,589,677	6,801,140	5,996,174	5,601,905	5,207,636	4,796,939	4,402,670	3,597,704	3,203,435	2,809,166	2,004,201	1,609,932	804,966	147,097,869
3 Energy requirement at transmission-end (3% loss)	7,361,987	7,361,987	7,361,987	7,361,987	6,597,105	5,816,289	5,433,848	5,051,407	4,653,031	4,270,590	3,489,773	3,107,332	2,724,891	1,944,075	1,561,634	780,817	142,684,933
4 Total benefit at transmission-end @0.01145 R.O./KWH	84,295	84,295	84,295	84,295	75,537	66,597	62,218	57,839	53,277	48,898	39,958	35,579	31,200	22,260	17,881	8,940	1,633,742
Sub-total	140,263	140,263	140,263	140,263	125,690	110,814	103,527	96,241	88,651	81,365	66,488	59,202	51,915	37,039	29,753	14,876	2,719,585
B. Cost																	
(a) Capital cost																	
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	522,620
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41,560
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	564,180
(b) Operating cost																	
Foreign	2,246	2,246	2,246	2,246	2,013	1,774	1,658	1,541	1,420	1,303	1,065	948	831	593	476	238	43,529
Local	56,845	56,845	56,845	56,845	50,939	44,910	41,957	39,004	35,928	32,975	26,946	23,993	21,040	15,011	12,058	6,029	1,101,733
Total	59,091	59,091	59,091	59,091	52,952	46,684	43,615	40,545	37,348	34,278	28,011	24,941	21,871	15,604	12,534	6,267	1,145,262
Sub-total	59,091	59,091	59,091	59,091	52,952	46,684	43,615	40,545	37,348	34,278	28,011	24,941	21,871	15,604	12,534	6,267	1,709,442
C. Net benefit (A - B)	81,172	81,172	81,172	81,172	72,738	64,129	59,912	55,696	51,303	47,087	38,478	34,261	30,044	21,435	17,218	8,609	1,010,143
D. Net present value	20,313	18,808	17,415	16,125	13,380	10,922	9,448	8,133	6,936	5,895	4,460	3,677	2,986	1,972	1,467	679	78,633
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08	
E. Cumulative NPV	-43,671	-24,863	-7,447	8,678	22,057	32,980	42,428	50,560	57,497	63,391	67,851	71,529	74,514	76,487	77,954	78,633	

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2. Water																		
A. Benefit (Revenue)																		
(a) Capacity																		
1. Production requirement (m3/d)				10,131	20,224	34,999	50,500	66,764	83,829	100,525	115,089	130,298	146,183	162,779	180,122	180,122	180,122	180,122
2. Capacity requirement (20% for peak demand)				12,157	24,269	41,999	60,600	80,117	100,595	120,630	138,107	156,357	175,420	195,335	216,147	216,147	216,147	216,147
3. Capacity requirement at sending-end (2% loss)				11,914	23,784	41,159	59,388	78,515	98,583	118,217	135,345	153,230	171,912	191,429	211,824	211,824	211,824	211,824
4. Capacity requirement at transmission-end (0% loss)				11,914	23,784	41,159	59,388	78,515	98,583	118,217	135,345	153,230	171,912	191,429	211,824	211,824	211,824	211,824
5. Total benefit at transmission-end @219.34 R.O./m3/d				2,613	5,217	9,028	13,026	17,221	21,623	25,930	29,687	33,610	37,707	41,988	46,461	46,461	46,461	46,461
(b) Production																		
1. Production requirement (m3)				3,697,646	7,381,897	12,774,673	18,432,633	24,368,973	30,597,635	36,691,625	42,007,505	47,558,693	53,356,893	59,414,511	65,744,704	74,948,972	74,948,972	74,948,972
2. Production requirement at sending-end (-2%)				3,623,693	7,234,259	12,519,179	18,063,981	23,881,593	29,985,682	35,957,793	41,167,355	46,607,519	52,289,755	58,226,221	64,429,809	73,449,993	73,449,993	73,449,993
3. Production requirement at transmission-end (-0%)				3,623,693	7,234,259	12,519,179	18,063,981	23,881,593	29,985,682	35,957,793	41,167,355	46,607,519	52,289,755	58,226,221	64,429,809	73,449,993	73,449,993	73,449,993
4. Total benefit at transmission-end @0.443 R.O./m3				1,605	3,205	5,546	8,002	10,580	13,284	15,929	18,237	20,647	23,164	25,794	28,542	32,538	32,538	32,538
Sub-total				4,218	8,422	14,574	21,029	27,801	34,907	41,859	47,924	54,257	60,871	67,782	75,004	79,000	79,000	79,000
B. Cost																		
(a) Capital cost																		
Foreign	930	12,750	65,980	0	5,560	33,030	0	0	5,560	33,030	0	5,560	33,030	0	0	0	0	0
Local	1,140	8,630	23,750	0	1,110	9,920	0	0	1,110	9,920	0	1,110	9,920	0	0	0	0	0
Total	2,070	21,380	89,730	0	6,670	42,950	0	0	6,670	42,950	0	6,670	42,950	0	0	0	0	0
(b) Operating cost																		
Foreign				422	843	1,459	2,105	2,783	3,494	4,190	4,797	5,431	6,093	6,785	7,507	8,558	8,558	8,558
Local				372	742	1,285	1,854	2,451	3,078	3,690	4,225	4,783	5,367	5,976	6,613	7,538	7,538	7,538
Total				794	1,585	2,744	3,959	5,234	6,571	7,880	9,022	10,214	11,459	12,760	14,120	16,097	16,097	16,097
Sub-total	2,070	21,380	89,730	794	8,255	45,694	3,959	5,234	13,241	50,830	9,022	16,884	54,409	12,760	14,120	16,097	16,097	16,097
C. Net benefit (A - B)	-2,070	-21,380	-89,730	3,424	166	-31,120	17,070	22,567	21,665	-8,971	38,902	37,372	6,462	55,022	60,884	62,903	62,903	62,903
D. Net present value	-2,070	-19,796	-76,929	2,718	122	-21,180	10,757	13,168	11,705	-4,488	18,019	16,028	2,566	20,231	20,729	19,830	18,361	17,001
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-2,070	-21,866	-98,795	-96,077	-95,955	-117,135	-106,378	-93,210	-81,505	-85,993	-67,974	-51,945	-49,379	-29,148	-8,419	11,411	29,771	46,772
F. FRR 17%																		

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
2. Water																	
A. Benefit (Revenue)																	
(a) Capacity																	
1. Production requirement (m3/d)	180,122	180,122	180,122	180,122	180,122	183,283	183,283	183,283	1,221,892	1,221,892	1,221,892	61,094	61,094	61,094	61,094	0	7,002,327
2. Capacity requirement (20% for peak demand)	216,147	216,147	216,147	216,147	216,147	152,736	152,736	152,736	1,018,243	1,018,243	1,018,243	50,912	50,912	50,912	50,912	0	6,767,495
3. Capacity requirement at sending-end (2% loss)	211,824	211,824	211,824	211,824	211,824	149,681	149,681	149,681	997,878	997,878	997,878	49,894	49,894	49,894	49,894	0	6,632,145
4. Capacity requirement at transmission-end (0% loss)	211,824	211,824	211,824	211,824	211,824	149,681	149,681	149,681	997,878	997,878	997,878	49,894	49,894	49,894	49,894	0	6,632,145
5. Total benefit at transmission-end @219.34 R.O./m3/d	46,461	46,461	46,461	46,461	46,461	32,831	32,831	32,831	218,875	218,875	218,875	10,944	10,944	10,944	10,944	0	1,454,695
(b) Production																	
1. Production requirement (m3)	74,948,972	74,948,972	74,948,972	74,948,972	74,948,972	63,553,450	63,553,450	63,553,450	423,690,912	423,690,912	423,690,912	21,184,483	21,184,483	21,184,483	21,184,483	0	2,548,090,183
2. Production requirement at sending-end (-2%)	73,449,993	73,449,993	73,449,993	73,449,993	73,449,993	62,282,381	62,282,381	62,282,381	415,217,094	415,217,094	415,217,094	20,760,794	20,760,794	20,760,794	20,760,794	0	2,497,128,379
3. Production requirement at transmission-end (-0%)	73,449,993	73,449,993	73,449,993	73,449,993	73,449,993	62,282,381	62,282,381	62,282,381	415,217,094	415,217,094	415,217,094	20,760,794	20,760,794	20,760,794	20,760,794	0	2,497,128,379
4. Total benefit at transmission-end @0.443 R.O./m3	32,538	32,538	32,538	32,538	32,538	27,591	27,591	27,591	183,941	183,941	183,941	9,197	9,197	9,197	9,197	0	1,106,228
Sub-total	79,000	79,000	79,000	79,000	79,000	60,422	60,422	60,422	402,816	402,816	402,816	20,141	20,141	20,141	20,141	0	2,560,923
B. Cost																	
(a) Capital cost																	
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	195,430
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	66,610
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262,040
(b) Operating cost																	
Foreign	8,558	8,558	8,558	8,558	8,558	7,257	7,257	7,257	48,381	48,381	48,381	2,419	2,419	2,419	2,419	0	290,966
Local	7,538	7,538	7,538	7,538	7,538	6,392	6,392	6,392	42,615	42,615	42,615	2,131	2,131	2,131	2,131	0	256,287
Total	16,097	16,097	16,097	16,097	16,097	13,649	13,649	13,649	90,996	90,996	90,996	4,550	4,550	4,550	4,550	0	547,253
Sub-total	16,097	16,097	16,097	16,097	16,097	13,649	13,649	13,649	90,996	90,996	90,996	4,550	4,550	4,550	4,550	0	809,293
C. Net benefit (A - B)	62,903	62,903	62,903	62,903	62,903	46,773	46,773	46,773	311,820	311,820	311,820	15,591	15,591	15,591	15,591	0	1,751,629
D. Net present value	15,741	14,575	13,496	12,496	11,570	7,966	7,376	6,830	42,159	39,036	36,144	1,673	1,549	1,435	1,328	0	260,147
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08	
E. Cumulative NPV	62,514	77,089	90,585	103,081	114,651	122,617	129,993	136,823	178,982	218,017	254,162	255,835	257,384	258,819	260,147	260,147	

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
3. Total (Electricity and Water)																		
A. Total benefit	0	0	8.654	20,802	33,406	48,543	64,547	81,467	99,358	117,718	134,365	151,876	170,302	189,692	210,102	219,263	219,263	219,263
B. Total cost																		
(a) Capital cost																		
Foreign	16,090	126,860	85,520	23,650	47,910	45,600	44,460	27,190	28,790	77,900	30,310	54,130	84,980	24,660	0	0	0	0
Local	4,090	21,520	37,550	1,650	1,410	10,280	470	1,890	1,450	11,700	640	3,110	12,000	410	0	0	0	0
Total	20,180	148,380	123,070	25,300	49,320	55,880	44,930	29,080	30,240	89,600	30,950	57,240	96,980	25,070	0	0	0	0
(b) Operating cost																		
Foreign	0	0	138	687	1,242	2,002	2,801	3,641	4,525	5,403	6,179	6,992	7,843	8,734	9,668	10,804	10,804	10,804
Local	0	0	3,493	7,076	10,848	15,029	19,464	24,170	29,164	34,397	39,216	44,301	49,667	55,329	61,306	64,384	64,384	64,384
Total	0	0	3,631	7,763	12,090	17,031	22,265	27,811	33,689	39,800	45,396	51,293	57,510	64,064	70,975	75,188	75,188	75,188
Sub-total	20,180	148,380	126,701	33,063	61,410	72,911	67,195	56,891	63,929	129,400	76,346	108,533	154,490	89,134	70,975	75,188	75,188	75,188
C. Net benefit (A - B)	-20,180	-148,380	-118,047	-12,261	-28,004	-24,367	-2,648	24,575	35,429	-11,682	58,019	43,343	15,812	100,558	139,127	144,075	144,075	144,075
D. Net present value	-20,180	-137,389	-101,206	-9,733	-20,584	-16,584	-1,669	14,339	19,141	-5,844	26,874	18,589	6,279	36,975	47,367	45,418	42,054	38,939
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-20,180	-157,569	-258,775	-268,508	-289,092	-305,676	-307,345	-293,005	-273,864	-279,708	-252,834	-234,245	-227,966	-190,991	-143,623	-98,205	-56,151	-17,212
F. FRR 13%																		

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
3. Total (Electricity and Water)																	
A. Total benefit	219,263	219,263	219,263	219,263	204,690	171,236	163,949	156,663	491,467	484,180	469,304	79,343	72,056	57,180	49,893	14,876	5,280,508
B. Total cost																	
(a) Capital cost																	
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	718,050
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	108,170
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	826,220
(b) Operating cost																	
Foreign	10,804	10,804	10,804	10,804	10,571	9,032	8,915	8,798	49,801	49,684	49,446	3,367	3,250	3,012	2,895	238	334,495
Local	64,384	64,384	64,384	64,384	58,478	51,302	48,349	45,396	78,543	75,590	69,561	26,124	23,171	17,142	14,189	6,029	1,358,020
Total	75,188	75,188	75,188	75,188	69,049	60,334	57,264	54,195	128,344	125,274	119,007	29,491	26,421	20,154	17,084	6,267	1,692,515
Sub-total	75,188	75,188	75,188	75,188	69,049	60,334	57,264	54,195	128,344	125,274	119,007	29,491	26,421	20,154	17,084	6,267	2,518,735
C. Net benefit (A - B)	144,075	144,075	144,075	144,075	135,641	110,902	106,685	102,469	363,123	358,906	350,297	49,852	45,635	37,026	32,809	8,609	2,761,772
D. Net present value	36,055	33,384	30,911	28,621	24,950	18,888	16,824	14,962	49,095	44,930	40,604	5,350	4,535	3,407	2,795	679	338,780
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08	
E. Cumulative NPV	18,843	52,226	83,137	111,759	136,709	155,597	172,421	187,383	236,478	281,409	322,013	327,363	331,898	335,305	338,101	338,780	

Note: The salvage value at the end of the economic life is minimum, and therefore is disregarded.

16.4.2 Sensitivity to the Financial Rate of Return

The primary objective of sensitivity analysis is to test how the profitability of an investment is affected by modifications in the assumptions used on key variables. This analysis essentially allows a judgment as to the riskiness of the project under alternative assumptions. We test the sensitivity to the financial rate of return of the Project obtained in the preceding section.

Usually, in the sensitivity analysis, modifications are made for such variables that may significantly change the projected costs or benefits of the Project and that involve high levels of uncertainty. Because of an underlying attribute of the concept of LRMC, the prices of the Project's outputs are completely linked with the costs of the Project's inputs and hence, sensitivity analysis will not be required for those variables concerning outputs' prices and inputs' costs. In determining the outputs' prices, we assumed a discount factor at 8%. This discount factor is a critical variable that needs to be tested for sensitivity.

Table 16.9 shows how variations in the discount rate affect the rate of return for the Project. A project is acceptable, if its FRR equals or exceeds the opportunity cost of capital, which is a common criterion for assessing a project. The Project evidently fulfills this criterion.

Table 16.9 Sensitivity Analysis for FRR

	Discount rate		
	7%	9%	10%
Power (R.O.)			
LRMC at generation	28.27	32.74	35.25
LRMC at transmission-end	31.97	37.26	40.19
Water (R.O.)			
LRMC at production	180.86	210.62	205.98
LRMC at transmission-end	201.99	237.2	255.35
Net benefit (Thousand R.O.)			
Electricity	926,737	1,092,608	1,184,480
Water	1,636,561	1,870,079	1,990,453
Total	2,563,299	2,962,688	3,174,933
FRR			
Electricity	10%	11%	11%
Water	16%	17%	18%
Total	13%	13%	14%

16.4.3 Rate of Return on the Equity Invested

There has recently been a strong drive in government policy towards the privatization of public corporations. An announce was made for example in June 1994 of the plan to offer public shares in the Oman Cement Company, which is one of the largest state-owned corporations. In line with this privatization movement of key public enterprises, discussions have been going on concerning a plan to create a private power and water industry by privatizing a part or all of MEW. Regardless of the future procedure and development of this plan, it has become a policy of MEW to finance the Project through a method commonly called BOOT (Build, Own, Operate, and Transfer), or BOO (Build, Own, and Operate).

The proposed Manah Station is also financed by a BOOT package. A general agreement for this BOOT project has been signed between the Government and investors, while its details have not yet been made public.

For the Project's BOO(T) financing, no details have been fixed in such critical areas as project structure, and government concessions and supports. With reference to recent BOO(T) packages for comparable projects, we make the following key assumptions for the financial analysis of the first phase of the Project.

Assumptions:

1. Equity-loan ratio: 1 : 1

   (Some portion of the equity capital may be raised by the sale of the shares of the project company.)

2. Loan (non-recourse commercial bank loan):

   Interest rate: 8%
   Amortization: Approximately 10 years
   (Assume a fixed rate, while the rate actually adopted will be a floating rate.)

3. Concessions

   (1) Tax: Exempted from all the applicable taxes including income tax during the entire project period.

(2) Power (and water) purchase on a "Take or Pay" basis.

(Operation at 70% available capacity of the power plant, and at 95% available capacity of the desalination plant)

(3) Concession period: Life expectancies (20 years) of all the generation/ production equipment

(4) Guaranteed supply of natural gas during the entire concession period, at the price of US$0.0283 per cubic meter.

(There will be no problem concerning the availability of natural gas. See relevant discussion in Appendix 3.)

Prices are comparatively stable in Oman, and the foreign exchange of the Rial Omani is relatively constant. However, in the long run, there are small elements of uncertainty in these, as the same speculation can be said of most countries. Our financial projections, therefore, are expressed in a foreign currency, namely US dollars. And we adopt an estimated international rate of inflation of 3%, and assume that the exchange rate of the Omani Rial will adjust itself to the difference between the international inflation level and domestic price increases.

Based on the assumptions discussed above, tables were prepared, as shown below, concerning the total initial costs, the cash flow during the operation period, financing, and the rate of return on equity.

Table 16.10 indicates the construction costs for Stage 1, and Tables 16.11 and 16.12 exhibit the disbursement of the initial investment costs and the flow of the financial resources (consisting of equity capital and commercial bank loans), for the power plant and for the desalination plant respectively. The financial requirement totals 505 million US dollars, or 194 million R.O., which includes price contingencies and interest on loans during the implementation period.

Table 16.10 Construction costs (Stage 1)

Million R.O.

Item	1996 FC	1996 LC	1996 TC	1997 FC	1997 LC	1997 TC	1998 FC	1998 LC	1998 TC	Total FC	Total LC	Total TC
A Power Plant												
1. Civil Work--Stage 1 share	0.21	0.29	0.51	0.85	1.46	2.31	0.24	1.18	1.42	1.30	2.94	4.23
(excluding foundations and powei	(0.56)	(0.76)	(1.32)	(2.21)	(3.79)	5.99	(0.61)	(3.08)	(3.69)	(3.37)	(7.63)	(11.01)
2. Foundation and power house	0.15	0.17	0.32	0.58	1.47	2.05				0.73	1.64	2.37
	(0.39)	(0.44)	0.83	(1.51)	(3.82)	(5.33)				(1.90)	(4.27)	(6.16)
3. Equipment & erection	9.40	0.08	9.48	77.52	0.52	78.04	7.07	0.30	7.37	93.99	0.90	94.89
	(24.45)	(0.20)	(24.64)	(201.61)	(1.36)	(202.98)	(18.39)	(0.78)	(19.17)	(244.45)	(2.34)	(246.79)
4. Transmission facilities--Stage 1 sh	0.96	0.27	1.24	6.71	0.83	7.55	1.94	1.62	3.55	9.61	2.72	12.34
	(2.50)	(0.71)	(3.21)	(17.46)	(2.17)	(19.63)	(5.04)	(4.20)	(9.24)	(25.00)	(7.08)	(32.08)
5. Total cost for Stage 1	10.73	0.81	11.54	85.66	4.29	89.95	9.24	3.10	12.34	105.63	8.20	113.83
	(27.90)	(2.11)	(30.01)	(222.79)	(11.14)	(233.93)	(24.04)	(8.06)	(32.10)	(274.72)	(21.32)	(296.04)
B Desalination Plant												
1. Civil work stage--1 share	0.23	0.28	0.51	0.93	1.67	2.60	0.39	1.50	1.89	1.55	3.45	5.00
(excluding foundations)	(0.60)	(0.73)	(1.33)	(2.42)	(4.34)	(6.76)	(1.01)	(3.90)	(4.92)	(4.03)	(8.97)	(13.00)
2. Foundation				0.20	0.44	0.64	1.79	4.02	5.81	1.99	4.46	6.45
				(0.52)	(1.14)	(1.66)	(4.66)	(10.46)	(15.11)	(5.18)	(11.60)	(16.78)
3. Equipment and erection				5.33	0.51	5.84	30.87	4.50	35.37	36.20	5.01	41.21
				(13.86)	(1.33)	(15.19)	(80.29)	(11.70)	(91.99)	(94.15)	(13.03)	(107.18)
4. Transmission facilities--Stage 1 share				0.92	0.37	1.29	8.23	3.35	11.58	9.15	3.72	12.87
				(2.39)	(0.96)	(3.36)	(21.40)	(8.71)	(30.12)	(23.80)	(9.67)	(33.47)
5. Total cost for Stage 1	0.23	0.28	0.51	7.38	2.99	10.37	41.28	13.37	54.65	48.89	16.64	65.53
	(0.60)	(0.73)	(1.33)	(19.19)	(7.78)	(26.97)	(107.36)	(34.77)	(142.13)	(127.15)	(43.28)	(170.43)
C Total construction cost	10.96	1.09	12.05	93.04	7.28	100.32	50.52	16.47	66.99	154.52	24.84	**179.36**
	(28.49)	(2.84)	(31.33)	(241.98)	(18.92)	260.90	(131.40)	(42.83)	(174.23)	(401.88)	(64.59)	(466.47)

Note: 1 ( ) Million US$

US$= 0.3845 O.R.

2 Costs include physical contingencies, engineering fees and administration expenses.

Table 16.11 Investment costs disbursement and flow of financial resources--power plant

Million US$

Project year	0			1			2			Total		
Year	1996			1997			1998					
	FC	LC	TC	FC	LC	TC	FC	LC	TC	FC	LC	TC
A Fixed assets												
(1) Construction costs (including physical contingencies, engineering fees and administration costs)	27.90	2.11	30.01	222.79	11.14	233.93	24.04	8.06	32.10	274.72	21.32	296.04
(2) Interest on loan accrued 8%	0.59	0.04	0.63	5.88	0.32	6.21	11.32	0.74	12.06	17.79	1.11	18.90
Sub-total	28.48	2.16	30.64	228.67	11.47	240.14	35.36	8.80	44.16	292.51	22.43	314.94
B Net working capital	0	0	0	0	0	0	0	0	0	0	0	0
C Total initial investment (A + B)	28.48	2.16	30.64	228.67	11.47	240.14	35.36	8.80	44.16	292.51	22.43	314.94
D Total price contingencies 3%	0.85	0.06	0.92	6.86	0.34	7.20	1.06	0.26	1.32	8.78	0.67	9.45
E Total finance required (C + D)	29.34	2.22	31.56	235.53	11.81	247.34	36.42	9.07	45.48	301.28	23.10	**324.39**
(Financial resources)												
F Equity capital	14.67	1.11	15.78	117.76	5.91	123.67	18.21	4.53	22.74	150.64	11.55	**162.19**
Cumulative	14.67	1.11	15.78	132.43	7.02	139.45	150.64	11.55	162.19			
G Commercial bank loan	14.67	1.11	15.78	117.76	5.91	123.67	18.21	4.53	22.74	150.64	11.55	**162.19**
Interest 8%												
Cumulative	14.67	1.11	15.78	132.43	7.02	139.45	150.64	11.55	162.19			
H Total finance	29.34	2.22	31.56	235.53	11.81	247.34	36.42	9.07	45.48	301.28	23.10	324.39
Cumulative	29.34	2.22	31.56	264.87	14.03	278.90	301.28	23.10	324.39			

Note: 1 Equity-loan ratio

Equity: 50%

Loan: 50%

2 Computation of interest

Cumulative debt x 8% + new debt x 4%

3 No working capital nor pre-operation expenditures assumed.

Table 16.12 Investment costs disbursement and flow of financial resources--desalination plant

Million US$

Project year	0			1			2			Total		
Year	1996			1997			1998					
	FC	LC	TC	FC	LC	TC	FC	LC	TC	FC	LC	TC
A Fixed assets												
(1) Construction costs (including physical contingencies, engineering fees and administration costs)	0.60	0.73	1.33	19.19	7.78	26.97	107.36	34.77	142.13	127.15	43.28	170.43
(2) Interest on loan accrued 8%	0.01	0.02	0.03	0.43	0.19	0.62	3.11	1.10	4.21	3.55	1.31	4.86
Sub-total	0.61	0.74	1.35	19.62	7.97	27.59	110.47	35.87	146.34	130.70	44.58	175.29
B Net working capital	0	0	0	0	0	0	0	0	0	0	0	0
C Total initial investment (A + B)	0.61	0.74	1.35	19.62	7.97	27.59	110.47	35.87	146.34	130.70	44.58	175.29
D Total price contingencies 3%	0.02	0.02	0.04	0.59	0.24	0.83	3.31	1.08	4.39	3.92	1.34	5.26
E Total finance required (C + D)	0.63	0.77	1.39	20.21	8.21	28.42	113.78	36.95	150.73	134.62	45.92	180.55
(Financial resources)												
F Equity capital	0.31	0.38	0.70	10.11	4.11	14.21	56.89	18.47	75.36	67.31	22.96	90.27
Cumulative	0.31	0.38	0.70	10.42	4.49	14.91	67.31	22.96	90.27			
G Commercial bank loan	0.31	0.38	0.70	10.11	4.11	14.21	56.89	18.47	75.36	67.31	22.96	90.27
Interest 8%												
Cumulative	0.31	0.38	0.70	10.42	4.49	14.91	67.31	22.96	90.27			
H Total finance	0.63	0.77	1.39	20.21	8.21	28.42	113.78	36.95	150.73	134.62	45.92	180.55
Cumulative	0.63	0.77	1.39	20.84	8.98	29.82	134.62	45.92	180.55			

Note: 1 Equity-loan ratio

Equity: 50%

Loan: 50%

2 Computation of interest

Cumulative debt x 8% + new debt x 4%

3 No working capital nor pre-operation expenditures assumed.

Table 16.13 exhibits projected cash flow during the operation period which extends from 1998 to 2018. Because of the higher cost efficiency of its operation, the Project is expected to have priority over the other plants. We assume that the proposed Barka phase-one power plant will be operated at an average load factor of 70%, as it will be serving for the year-round baseload. The plant will have a reserve margin of 8%, as planned for the entire system. Similarly, the proposed desalination plant will be operated at 95% of its available capacity. We expect that the Project will generate a total net operating income of approximately 2,206 million US dollars or 848 thousand R.O. by 2018, when the Project is expected to complete its economic life. (The residual of the Project will be minimal.)

Table 16.14 shows the projected cash flow including debt service. The commercial loan amounting to approximately $252 million is expected to be amortized in 10 years. The debt service coverage is expected to be at 1.12 for the first year of the loan repayment. The ratio will be improved steadily and quickly, to 1.51 for the fifth year. Table 16.15 summarizes the cash in- and out-flows. The net income over the project's life years reaches more than $1,800 million in nominal terms. The internal rate of return on the equity invested is calculated at 22%.

A sensitivity test regarding the power load factor suggests that the rate of return will be little affected at lower load factors, as indicated below.

Load factor	55%	60%	65%	(70%)
Net operating income (Thousand R.O.)	976,756	1,001,668	1,026,580	(1,051,492)
FRR on equity	21%	22%	22%	(22%)

Table 16.13 Projected cash flow before debt service (operation period) 1998-2018

Thousand US$

Project year			0	1	2	3	4	5	6	7	8	9
Year	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
1. Electricity												
Installed capacity (MW)					192	292	292	292	292	292	292	292
Available capacity (92%)					177	269	269	269	269	269	269	269
A. Operating income												
(a) Capacity												
1 Power requirement at generation (MW)					177	269	269	269	269	269	269	269
2 Power requirement at sending-end (2% loss)					173	263	263	263	263	263	263	263
3 Power requirement at transmission-end (3% loss)					168	255	255	255	255	255	255	255
4 Unit charge ($/KW)	90.07	92.77	95.55	98.42	101.37	104.41	107.54	110.77	114.09	117.51	121.04	124.67
90.07 in 1994												
5 Total charge at transmission-end					17,021	26,663	27,463	28,287	29,135	30,010	30,910	31,837
(b) Energy												
1 Energy requirement at generation (MWH)					1,083,156	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300
2 Energy requirement at sending-end (2% loss)					1,061,493	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354
3 Energy requirement at transmission-end (3% loss)					1,029,649	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924
4 Unit charge ($/KWH)	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
0.02978 in 1994												
5 Total charge at transmission-end					34,510	54,059	55,680	57,351	59,071	60,844	62,669	64,549
Total income					51,531	80,722	83,144	85,638	88,207	90,853	93,579	96,386
B. Operating expenditure												
Foreign					1,807	2,831	2,916	3,003	3,093	3,186	3,282	3,380
Local					24,255	37,995	39,135	40,309	41,518	42,763	44,046	45,368
Total expenditure					26,062	40,826	42,051	43,312	44,611	45,950	47,328	48,748
C. Net operating income (A - B)					25,469	39,896	41,093	42,326	43,596	44,903	46,250	47,638
	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
2. Water												
Installed capacity (MW)						63,640	63,640	63,640	63,640	63,640	63,640	63,640
Capacity requirement for average demand (less 20% for peak demand)						50,912	50,912	50,912	50,912	50,912	50,912	50,912
Available capacity (95%)						48,366	48,366	48,366	48,366	48,366	48,366	48,366
A. Operating income												
(a) Capacity												
1. Capacity requirement (m3/d)						48,366	48,366	48,366	48,366	48,366	48,366	48,366
2. Capacity requirement at sending-end (2% loss)						47,399	47,399	47,399	47,399	47,399	47,399	47,399
3. Capacity requirement at transmission-end (0% loss)						47,399	47,399	47,399	47,399	47,399	47,399	47,399
4. Unit charge ($/m3/d)	570.46	587.57	605.20	623.36	642.06	661.32	681.16	701.59	722.64	744.32	766.65	789.65
570.46 in 1994												
5. Total charge at transmission-end						31,346	32,286	33,255	34,253	35,280	36,339	37,429
(b) Production												
1. Production requirement (m3)						17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736
2. Production requirement at sending-end (2% loss)						17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661
3. Production requirement at transmission-end (0% loss)						17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661
4. Unit charge ($/m3)	1.15	1.18	1.22	1.26	1.29	1.33	1.37	1.41	1.46	1.50	1.55	1.59
1.15 in 1994												
5. Total charge at transmission-end						23,065	23,757	24,469	25,203	25,959	26,738	27,540
Total income						54,411	56,043	57,724	59,456	61,240	63,077	64,969
B. Operating expenditure												
Foreign						6,078	6,260	6,448	6,641	6,841	7,046	7,257
Local						5,354	5,514	5,680	5,850	6,025	6,206	6,392
Total expenditure						11,431	11,774	12,128	12,491	12,866	13,252	13,650
C. Net operating incomet (A - B)						42,979	44,269	45,597	46,964	48,373	49,825	51,319
	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
3. Total (Electricity and Water)												
A. Operating income					51,531	135,132	139,186	143,362	147,663	152,093	156,656	161,355
B. Operating expenditure												
Foreign					1,807	8,909	9,176	9,451	9,735	10,027	10,328	10,638
Local					24,255	43,348	44,649	45,988	47,368	48,789	50,253	51,760
Total					26,062	52,257	53,825	55,440	57,103	58,816	60,580	62,398
C. Net operating income (A - B)					25,469	82,875	85,361	87,922	90,560	93,277	96,075	98,957

Project year	10	11	12	13	14	15	16	17	18	19	20	21	22	
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
1. Electricity														
Installed capacity (MW)	292	292	292	292	292	292	292	292	292	292	292	292	100	
Available capacity (92%)	269	269	269	269	269	269	269	269	269	269	269	269	92	
A. Operating income														
(a) Capacity														
1 Power requirement at generation (MW)	269	269	269	269	269	269	269	269	269	269	269	269	92	
2 Power requirement at sending-end (2% loss)	263	263	263	263	263	263	263	263	263	263	263	263	90	
3 Power requirement at transmission-end (3% loss)	255	255	255	255	255	255	255	255	255	255	255	255	87	
4 Unit charge ($/KW)	128.41	132.26	136.23	140.32	144.53	148.86	153.33	157.93	162.67	167.55	172.57	177.75	183.08	
5 Total charge at transmission-end	32,792	33,776	34,789	35,833	36,908	38,015	39,156	40,330	41,540	42,786	44,070	45,392	16,012	702,727
(b) Energy														
1 Energy requirement at generation (MWH)	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	1,647,300	564,144	32,946,010
2 Energy requirement at sending-end (2% loss)	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	1,614,354	552,861	32,287,089
3 Energy requirement at transmission-end (3% loss)	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	1,565,924	536,275	31,318,477
4 Unit charge ($/KWH)	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	
5 Total charge at transmission-end	66,485	68,480	70,534	72,650	74,830	77,075	79,387	81,769	84,222	86,748	89,351	92,031	32,463	1,424,759
Total income	99,278	102,256	105,324	108,483	111,738	115,090	118,543	122,099	125,762	129,535	133,421	137,424	48,475	2,127,486
B. Operating expenditure														
Foreign	3,482	3,586	3,694	3,805	3,919	4,036	4,157	4,282	4,411	4,543	4,679	4,820	1,700	74,613
Local	46,729	48,131	49,575	51,062	52,594	54,171	55,797	57,471	59,195	60,970	62,800	64,684	22,816	1,001,382
Total expenditure	50,211	51,717	53,268	54,866	56,512	58,208	59,954	61,753	63,605	65,513	67,479	69,503	24,517	1,075,995
C. Net operating income (A - B)	49,067	50,539	52,055	53,617	55,325	56,882	58,589	60,346	62,157	64,021	65,942	67,920	23,958	1,051,492
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
2. Water														
Installed capacity (MW)	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	63,640	1,272,800
Capacity requirement for average demand (less 20% for peak demand)	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	50,912	1,018,240
Available capacity (95%)	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	967,328
A. Operating income														
(a) Capacity														
1. Capacity requirement (m3/d)	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	48,366	967,328
2. Capacity requirement at sending-end (2% loss)	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	947,981
3. Capacity requirement at transmission-end (0% loss)	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	47,399	947,981
4. Unit charge ($/m3/d)	813.34	837.74	862.87	888.76	915.42	942.88	971.17	1,000.31	1,030.31	1,061.22	1,093.06	1,125.85	1,159.63	
5. Total charge at transmission-end	38,552	39,708	40,899	42,126	43,390	44,692	46,033	47,414	48,836	50,301	51,810	53,364	54,965	842,277
(b) Production														
1. Production requirement (m3)	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	17,653,736	353,074,720
2. Production requirement at sending-end (2% loss)	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	346,013,226
3. Production requirement at transmission-end (0% loss)	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	17,300,661	346,013,226
4. Unit charge ($/m3)	1.64	1.69	1.74	1.79	1.85	1.90	1.96	2.02	2.08	2.14	2.20	2.27	2.34	
5. Total charge at transmission-end	28,367	29,218	30,094	30,997	31,927	32,885	33,871	34,887	35,934	37,012	38,122	39,266	40,444	619,755
Total income	66,918	68,926	70,993	73,123	75,317	77,576	79,904	82,301	84,770	87,313	89,932	92,630	95,409	1,462,032
B. Operating expenditure														
Foreign	7,475	7,699	7,930	8,168	8,415	8,666	8,926	9,193	9,469	9,753	10,046	10,347	10,658	163,316
Local	6,584	6,782	6,985	7,195	7,410	7,633	7,862	8,098	8,341	8,591	8,849	9,114	9,387	143,851
Total expenditure	14,059	14,481	14,915	15,363	15,824	16,298	16,787	17,291	17,810	18,344	18,894	19,461	20,045	307,166
C. Net operating incomet (A - B)	52,859	54,445	56,078	57,760	59,493	61,278	63,116	65,010	66,960	68,969	71,038	73,169	75,364	1,154,866
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
3. Total (Electricity and Water)														
A. Operating income	166,196	171,182	176,317	181,607	187,055	192,667	198,447	204,400	210,532	216,848	223,353	230,054	143,884	3,589,519
B. Operating expenditure														
Foreign	10,957	11,286	11,624	11,973	12,332	12,702	13,083	13,476	13,880	14,296	14,725	15,167	12,358	237,929
Local	53,313	54,912	56,560	58,256	60,004	61,804	63,658	65,568	67,535	69,561	71,648	73,798	32,204	1,145,232
Total	64,270	66,198	68,184	70,229	72,336	74,506	76,741	79,044	81,415	83,857	86,373	88,964	44,562	1,383,161
C. Net operating income (A - B)	101,926	104,984	108,133	111,377	114,719	118,160	121,705	125,356	129,117	132,990	136,980	141,090	99,322	2,206,358

Note: Annual price increase (in charges and expenditures) 3%

Table 16.14 Cash flow table for financial planning (operation period)--Stage 1

Thousand US$

Project year	2	3	4	5	6	7	8	9	10	11	12
Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1. Net cash flow from operatio	25,469	82,875	85,361	87,922	90,560	93,277	96,075	98,957	101,926	104,984	108,133
2. Interest earned 3%	382	1,243	1,280	1,319	1,358	1,399	1,441	1,484	1,529	1,575	1,622
3. Working capital (net increas	4,344	4,366	261	269	277	286	294	303	312	321	331
4. Interest paid on debt 8%	347	20,197	18,803	17,297	15,671	13,915	12,018	9,970	7,757	5,368	2,787
5. Net income before tax	21,160	59,555	67,578	71,675	75,970	80,476	85,204	90,169	95,386	100,870	106,637
6. Income tax paid 0%	0	0	0	0	0	0	0	0	0	0	0
7. After-tax cash flow	21,160	59,555	67,578	71,675	75,970	80,476	85,204	90,169	95,386	100,870	106,637
8. Loan repayments		17,427	18,822	20,327	21,954	23,710	25,607	27,655	29,868	32,257	34,839
Outstanding principal	252,465	235,038	216,216	195,889	173,935	150,225	124,619	96,964	67,096	34,839	0
9. After-debt service cash flow	21,160	42,128	48,756	51,347	54,017	56,766	59,598	62,514	65,518	68,613	71,798
Cummulative	21,160	63,288	112,044	163,391	217,408	274,173	333,771	396,285	461,803	530,416	602,214
10. Debt service coverage Item 9 / (items 4 & 8)		1.12	1.30	1.36	1.44	1.51	1.58	1.66	1.74	1.82	1.91

Project year	13	14	15	16	17	18	19	20	21	22	
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
1. Net cash flow from operatio	111,377	114,719	118,160	121,705	125,356	129,117	132,990	136,980	141,090	99,322	2,206,358
2. Interest earned 3%	1,671	1,721	1,772	1,826	1,880	1,937	1,995	2,055	2,116	1,490	33,095
3. Working capital (net increas	341	351	362	373	384	395	407	419	432	-14,827	0
4. Interest paid on debt 8%	0	0	0	0	0	0	0	0	0	0	124,130
5. Net income before tax	112,707	116,088	119,571	123,158	126,853	130,658	134,578	138,616	142,774	115,640	2,115,322
6. Income tax paid 0%	0	0	0	0	0	0	0	0	0	0	0
7. After-tax cash flow	112,707	116,088	119,571	123,158	126,853	130,658	134,578	138,616	142,774	115,640	2,115,322
8. Loan repayments											252,465
Outstanding principal											
9. After-debt service cash flow	112,707	116,088	119,571	123,158	126,853	130,658	134,578	138,616	142,774	115,640	1,862,857
Cummulative	714,921	831,009	950,580	1,073,739	1,200,591	1,331,250	1,465,828	1,604,444	1,747,218	1,862,857	
10. Debt service coverage Item 9 / (items 4 & 8)											

Note: 1. Assumptions on loan

1 Principal	252.47	million US dollars
2 Interest	8%	
3 Duration	10	years
4 PRF	0.149029	
5 Loan ratio	70%	

2. Interest earned: Interest on a half of the net operating income of the year
3. Working capital: 2-month operating expenditure
4. Beginning of year (BOY) basis
5. Interest paid in 1996 is on the working capital of that year.
   Interest on the loan in1996 is included in the initial investment.

Table 16.15 Discounted return on equity invested

Thousand US$

		0	1	2	3	4	5	6	7	8	9	10	11
	Project year	0	1	2	3	4	5	6	7	8	9	10	11
	Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
A. Cash inflow				51,913	136,376	140,467	144,681	149,021	153,492	158,097	162,840	167,725	172,756
a. Operation				51,531	135,132	139,186	143,362	147,663	152,093	156,656	161,355	166,196	171,182
b. Interest earned				382	1,243	1,280	1,319	1,358	1,399	1,441	1,484	1,529	1,575
B. Cash outflow		16,476	137,883	128,860	94,248	91,711	93,333	95,005	96,726	98,499	100,325	102,206	104,144
a. Equity capital paid-in		16,476	137,883	98,106									
b. Operation				26,062	52,257	53,825	55,440	57,103	58,816	60,580	62,398	64,270	66,198
c. Net working capital				4,344	4,366	261	269	277	286	294	303	312	321
d. Interest paid on debt				347	20,197	18,803	17,297	15,671	13,915	12,018	9,970	7,757	5,368
e. Income (corporate) tax paid				0	0	0	0	0	0	0	0	0	0
f. Loan repayments				0	17,427	18,822	20,327	21,954	23,710	25,607	27,655	29,868	32,257
C. Net cash flow (A - B)		-16,476	-137,883	-76,947	42,128	48,756	51,347	54,017	56,766	59,598	62,514	65,518	68,613
D. Cumulative net CF		-16,476	-154,359	-231,305	-189,178	-140,422	-89,074	-35,058	21,708	81,306	143,820	209,338	277,951
E. Net present value		-16,476	-142,925	-198,307	-150,175	-103,214	-60,622	-22,092	12,667	43,927	71,946	96,964	119,208
	8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43
F. Cumulative NPV		-16,476	-159,401	-357,708	-507,884	-611,098	-671,720	-693,812	-681,146	-637,219	-565,273	-468,309	-349,101
G. Internal rate of return on equity (IRR)	22%												

		12	13	14	15	16	17	18	19	20	21	22	
	Project year	12	13	14	15	16	17	18	19	20	21	22	
	Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
A. Cash inflow		177,939	183,277	188,776	194,439	200,272	206,280	212,469	218,843	225,408	232,170	145,374	3,622,614
a. Operation		176,317	181,607	187,055	192,667	198,447	204,400	210,532	216,848	223,353	230,054	143,884	3,589,519
b. Interest earned		1,622	1,671	1,721	1,772	1,826	1,880	1,937	1,995	2,055	2,116	1,490	33,095
B. Cash outflow		106,141	70,570	72,687	74,868	77,114	79,427	81,810	84,265	86,792	89,396	29,734	2,012,222
a. Equity capital paid-in													252,465
b. Operation		68,184	70,229	72,336	74,506	76,741	79,044	81,415	83,857	86,373	88,964	44,562	1,383,161
c. Net working capital		331	341	351	362	373	384	395	407	419	432	-14,827	0
d. Interest paid on debt		2,787	0	0	0	0	0	0	0	0	0	0	124,130
e. Income (corporate) tax paid		0	0	0	0	0	0	0	0	0	0	0	
f. Loan repayments		34,839	0	0	0	0	0	0	0	0	0	0	252,465
C. Net cash flow (A - B)		71,798	112,707	116,088	119,571	123,158	126,853	130,658	134,578	138,616	142,774	115,640	1,610,392
D. Cumulative net CF		349,749	462,456	578,544	698,115	821,273	948,126	1,078,785	1,213,363	1,351,978	1,494,752	1,610,392	
E. Net present value		138,890	170,044	196,972	220,075	239,722	256,249	269,965	281,151	290,065	296,941	296,216	2,307,189
	8% discount rate	0.40	0.37	0.34	0.32	0.29	0.27	0.25	0.23	0.21	0.20	0.18	
F. Cumulative NPV		-210,210	-40,166	156,805	376,880	616,602	872,851	1,142,816	1,423,967	1,714,032	2,010,973	2,307,189	

16.5 Economic Analysis

The economic analysis is concerned primarily with whether or not the Project will generate adequate economic benefits to the country to justify its costs. We make this analysis by two approaches: a revenue-based approach and an approach (or a method) where the cost of an alternative to the Project is compared with the cost of the Project.

16.5.1 Revenue Approach

The revenue-based economic analysis is straightforward. We simply compute the economic rate of return (ERR) of the Project, by using the shadow-priced cost and benefit of the Project we estimated earlier.

Table 16.16 exhibits projected streams of the economic benefit and cost of the Project. Because the local currency costs are shadow-priced, the Project's economic cost is lower than its financial cost. The economic benefit is also lower than the financial benefit, because the benefit is determined so as to reflect fully the cost on the principle upon which the concept of the long-run marginal cost is based. Consequentially, the economic rates of return (ERR) indicated in the table are almost the same as the financial internal rates of return computed earlier. The ERRs are higher than the assumed discount rate of 8%.

Table 16.17 shows the results of the sensitivity analysis for the ERR. The analysis employed the same modified assumptions that were used earlier for the sensitivity test for the FRR. Because the prices or the values of the Project's outputs are linked with the discount rate assumed, the selection of a higher discount rate results in a higher level of income and thus a higher ERR.

Table 16.16 Economic rate of return analysis--revenue-based approach

Thousand R.O.

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
I. Electricity																		
A. Benefit																		
(a) Capacity																		
1 Power requirement at generation (MW)			106	202	304	413	529	652	783	921	1,050	1,185	1,329	1,480	1,640	1,698	1,698	1,698
2 Power requirement at sending-end (2% loss)			103	198	298	405	518	639	767	903	1,029	1,162	1,302	1,451	1,607	1,664	1,664	1,664
3 Power requirement at transmission-end (3% loss)			100	192	289	392	503	620	744	876	998	1,127	1,263	1,407	1,559	1,614	1,614	1,614
4 Total benefit at transmission-end @34.48 R.O./KW			3,459	6,614	9,956	13,530	17,328	21,365	25,656	30,194	34,404	38,850	43,549	48,513	53,760	55,655	55,655	55,655
(b) Energy																		
1 Energy requirement at generation (MWH)			475,898	913,345	1,376,776	1,872,470	2,399,234	2,959,055	3,554,049	4,183,412	4,767,198	5,383,898	6,035,450	6,723,916	7,451,482	7,744,569	7,744,569	7,744,569
2 Energy requirement at sending-end (2% loss)			466,380	895,078	1,349,240	1,835,021	2,351,249	2,899,873	3,482,968	4,099,744	4,671,854	5,276,220	5,914,741	6,589,438	7,302,452	7,589,677	7,589,677	7,589,677
3 Energy requirement at transmission-end (3% loss)			452,388	868,226	1,308,763	1,779,970	2,280,712	2,812,877	3,378,479	3,976,752	4,531,699	5,117,933	5,737,299	6,391,755	7,083,379	7,361,987	7,361,987	7,361,987
4 Total benefit at transmission-end @0.01036 R.O./KWH			4,687	8,995	13,559	18,440	23,628	29,141	35,001	41,199	46,948	53,022	59,438	66,219	73,384	76,270	76,270	76,270
Sub-total			8,146	15,609	23,514	31,970	40,957	50,507	60,657	71,393	81,352	91,872	102,987	114,732	127,143	131,925	131,925	131,925
B. Cost																		
(a) Capital cost																		
Foreign	15,160	114,110	19,540	23,650	42,350	12,570	44,460	27,190	23,230	44,870	30,310	48,570	51,950	24,660	0	0	0	0
Local	2,655	11,601	12,420	1,485	270	324	423	1,701	306	1,602	576	1,800	1,872	369	0	0	0	0
Total	17,815	125,711	31,960	25,135	42,620	12,894	44,883	28,891	23,536	46,472	30,886	50,370	53,822	25,029	0	0	0	0
(b) Operating cost																		
Foreign			136	260	392	534	684	843	1,013	1,192	1,359	1,534	1,720	1,916	2,124	2,207	2,207	2,207
Local			3,144	6,034	9,095	12,370	15,849	19,548	23,478	27,636	31,492	35,566	39,870	44,418	49,224	51,161	51,161	51,161
Total			3,279	6,294	9,487	12,903	16,533	20,391	24,491	28,828	32,851	37,100	41,590	46,335	51,348	53,368	53,368	53,368
Sub-total	17,815	125,711	35,239	31,429	52,107	25,797	61,416	49,282	48,027	75,300	63,737	87,470	95,412	71,364	51,348	53,368	53,368	53,368
C. Net benefit (A - B)	-17,815	-125,711	-27,093	-15,820	-28,593	6,173	-20,460	1,225	12,630	-3,907	17,615	4,402	7,575	43,368	75,795	78,557	78,557	78,557
D. Net present value	-17,815	-116,399	-23,228	-12,559	-21,017	4,201	-12,893	715	6,823	-1,954	8,159	1,888	3,008	15,946	25,805	24,764	22,930	21,232
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-17,815	-134,214	-157,442	-170,001	-191,017	-186,816	-199,709	-198,994	-192,171	-194,125	-185,966	-184,078	-181,070	-165,124	-139,318	-114,554	-91,624	-70,392

F. FRR: 10%

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
I. Electricity																	
A. Benefit																	
(a) Capacity																	
1 Power requirement at generation (MW)	1,698	1,698	1,698	1,698	1,522	1,430	1,341	1,161	1,073	985	897	717	628	537	360	268	33,398
2 Power requirement at sending-end (2% loss)	1,664	1,664	1,664	1,664	1,491	1,401	1,315	1,138	1,052	965	879	702	616	526	353	263	32,730
3 Power requirement at transmission-end (3% loss)	1,614	1,614	1,614	1,614	1,446	1,359	1,275	1,104	1,020	936	852	681	597	510	342	255	31,748
4 Total benefit at transmission-end @34.48 R.O./KW	55,655	55,655	55,655	55,655	49,872	46,861	43,970	38,067	35,176	32,285	29,393	23,491	20,600	17,588	11,806	8,794	1,094,663
(b) Energy																	
1 Energy requirement at generation (MWH)	7,744,569	7,744,569	7,744,569	7,744,569	6,939,938	6,118,545	5,716,229	5,313,914	4,894,836	4,492,520	3,671,127	3,268,812	2,866,496	2,045,103	1,642,787	821,394	150,099,866
2 Energy requirement at sending-end (2% loss)	7,589,677	7,589,677	7,589,677	7,589,677	6,801,140	5,996,174	5,601,905	5,207,636	4,796,939	4,402,670	3,597,704	3,203,435	2,809,166	2,004,201	1,609,932	804,966	147,097,869
3 Energy requirement at transmission-end (3% loss)	7,361,987	7,361,987	7,361,987	7,361,987	6,597,105	5,816,289	5,433,848	5,051,407	4,653,031	4,270,590	3,489,773	3,107,332	2,724,891	1,944,075	1,561,634	780,817	142,684,933
4 Total benefit at transmission-end @0.01036 R.O./KWH	76,270	76,270	76,270	76,270	68,346	60,257	56,295	52,333	48,205	44,243	36,154	32,192	28,230	20,141	16,179	8,089	1,478,216
Sub-total	131,925	131,925	131,925	131,925	118,219	107,118	100,264	90,400	83,381	76,528	65,548	55,683	48,829	37,728	27,984	16,883	2,572,879
B. Cost																	
(a) Capital cost																	
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	522,620
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37,404
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	560,024
(b) Operating cost																	
Foreign	2,207	2,207	2,207	2,207	1,978	1,744	1,629	1,514	1,395	1,280	1,046	932	817	583	468	234	42,778
Local	51,161	51,161	51,161	51,161	45,845	40,419	37,761	35,104	32,335	29,678	24,251	21,594	18,936	13,510	10,852	5,426	991,560
Total	53,368	53,368	53,368	53,368	47,823	42,163	39,391	36,618	33,730	30,958	25,298	22,525	19,753	14,093	11,320	5,660	1,034,338
Sub-total	53,368	53,368	53,368	53,368	47,823	42,163	39,391	36,618	33,730	30,958	25,298	22,525	19,753	14,093	11,320	5,660	1,594,362
C. Net benefit (A - B)	78,557	78,557	78,557	78,557	70,395	64,955	60,874	53,781	49,651	45,570	40,250	33,157	29,076	23,636	16,664	11,223	978,516
D. Net present value	19,659	18,203	16,854	15,606	12,949	11,063	9,600	7,853	6,713	5,705	4,666	3,559	2,890	2,175	1,420	885	69,405
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08	
E. Cumulative NPV	-50,733	-32,531	-15,676	-70	12,878	23,941	33,541	41,394	48,107	53,811	58,477	62,035	64,925	67,100	68,520	69,405	

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2. Water																		
A. Benefit																		
(a) Capacity																		
1. Production requirement (m3/d)				10,131	20,224	34,999	50,500	66,764	83,829	100,525	115,089	130,298	146,183	162,779	180,122	180,122	180,122	180,122
2. Capacity requirement (20% for peak demand)				12,157	24,269	41,999	60,600	80,117	100,595	120,630	138,107	156,357	175,420	195,335	216,147	216,147	216,147	216,147
3. Capacity requirement at sending-end (2% loss)				11,914	23,784	41,159	59,388	78,515	98,583	118,217	135,345	153,230	171,912	191,429	211,824	211,824	211,824	211,824
4. Capacity requirement at transmission-end (0% loss)				11,914	23,784	41,159	59,388	78,515	98,583	118,217	135,345	153,230	171,912	191,429	211,824	211,824	211,824	211,824
5. Total benefit at transmission-end @214.33 R.O./m3/d				2,553	5,098	8,822	12,729	16,828	21,129	25,338	29,008	32,842	36,846	41,029	45,400	45,400	45,400	45,400
(b) Production																		
1. Production requirement (m3)				3,697,646	7,381,897	12,774,673	18,432,633	24,368,973	30,597,635	36,691,625	42,007,505	47,558,693	53,356,893	59,414,511	65,744,704	74,948,972	74,948,972	74,948,972
2. Production requirement at sending-end (-2%)				3,623,693	7,234,259	12,519,179	18,063,981	23,881,593	29,985,682	35,957,793	41,167,355	46,607,519	52,289,755	58,226,221	64,429,809	73,449,993	73,449,993	73,449,993
3. Production requirement at transmission-end (-0%)				3,623,693	7,234,259	12,519,179	18,063,981	23,881,593	29,985,682	35,957,793	41,167,355	46,607,519	52,289,755	58,226,221	64,429,809	73,449,993	73,449,993	73,449,993
4. Total benefit at transmission-end @0.401 R.O./m3				1,453	2,901	5,020	7,244	9,577	12,024	14,419	16,508	18,690	20,968	23,349	25,836	29,453	29,453	29,453
Sub-total				4,007	7,999	13,842	19,972	26,405	33,154	39,757	45,517	51,531	57,814	64,378	71,237	74,854	74,854	74,854
B. Cost																		
(a) Capital cost																		
Foreign	930	12,750	65,980	0	5,560	33,030	0	0	5,560	33,030	0	5,560	33,030	0	0	0	0	0
Local	1,026	7,767	21,375	0	999	8,928	0	0	999	8,928	0	999	8,928	0	0	0	0	0
Total	2,070	21,380	89,730	0	6,670	42,950	0	0	6,670	42,950	0	6,670	42,950	0	0	0	0	0
(b) Operating cost																		
Foreign				422	843	1,459	2,105	2,783	3,494	4,190	4,797	5,431	6,093	6,785	7,507	8,558	8,558	8,558
Local				335	668	1,156	1,669	2,206	2,770	3,321	3,803	4,305	4,830	5,378	5,951	6,785	6,785	6,785
Total				757	1,511	2,615	3,773	4,989	6,264	7,511	8,599	9,736	10,923	12,163	13,459	15,343	15,343	15,343
Sub-total	2,070	21,380	89,730	757	8,181	45,565	3,773	4,989	12,934	50,461	8,599	16,406	53,873	12,163	13,459	15,343	15,343	15,343
C. Net benefit (A - B)	-2,070	-21,380	-89,730	3,250	-183	-31,723	16,199	21,416	20,220	-10,705	36,917	35,126	3,941	52,215	57,778	59,511	59,511	59,511
D. Net present value	-2,070	-19,796	-76,929	2,580	-134	-21,590	10,208	12,496	10,924	-5,355	17,100	15,065	1,565	19,199	19,671	18,760	17,371	16,084
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-2,070	-21,866	-98,795	-96,216	-96,350	-117,940	-107,732	-95,236	-84,312	-89,667	-72,567	-57,502	-55,937	-36,738	-17,067	1,693	19,064	35,148
F. FRR 16%																		

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
2. Water																
A. Benefit																
(a) Capacity																
1. Production requirement (m3/d)	180,122	180,122	180,122	180,122	180,122	183,283	183,283	183,283	1,221,892	1,221,892	1,221,892	61,094	61,094	61,094	61,094	7,002,327
2. Capacity requirement (20% for peak demand)	216,147	216,147	216,147	216,147	216,147	152,736	152,736	152,736	1,018,243	1,018,243	1,018,243	50,912	50,912	50,912	50,912	6,767,495
3. Capacity requirement at sending-end (2% loss)	211,824	211,824	211,824	211,824	211,824	149,681	149,681	149,681	997,878	997,878	997,878	49,894	49,894	49,894	49,894	6,632,145
4. Capacity requirement at transmission-end (0% loss)	211,824	211,824	211,824	211,824	211,824	149,681	149,681	149,681	997,878	997,878	997,878	49,894	49,894	49,894	49,894	6,632,145
5. Total benefit at transmission-end @214.33 R.O./m3/d	45,400	45,400	45,400	45,400	45,400	32,081	32,081	32,081	213,875	213,875	213,875	10,694	10,694	10,694	10,694	1,421,468
(b) Production																
1. Production requirement (m3)	74,948,972	74,948,972	74,948,972	74,948,972	74,948,972	63,553,450	63,553,450	63,553,450	423,690,912	423,690,912	423,690,912	21,184,483	21,184,483	21,184,483	21,184,483	2,548,090,183
2. Production requirement at sending-end (-2%)	73,449,993	73,449,993	73,449,993	73,449,993	73,449,993	62,282,381	62,282,381	62,282,381	415,217,094	415,217,094	415,217,094	20,760,794	20,760,794	20,760,794	20,760,794	2,497,128,379
3. Production requirement at transmission-end (-0%)	73,449,993	73,449,993	73,449,993	73,449,993	73,449,993	62,282,381	62,282,381	62,282,381	415,217,094	415,217,094	415,217,094	20,760,794	20,760,794	20,760,794	20,760,794	2,497,128,379
4. Total benefit at transmission-end @0.401 R.O./m3	29,453	29,453	29,453	29,453	29,453	24,975	24,975	24,975	166,502	166,502	166,502	8,325	8,325	8,325	8,325	1,001,348
Sub-total	74,854	74,854	74,854	74,854	74,854	57,056	57,056	57,056	380,377	380,377	380,377	19,019	19,019	19,019	19,019	2,422,816
B. Cost																
(a) Capital cost																
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	195,430
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	59,949
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262,040
(b) Operating cost																
Foreign	8,558	8,558	8,558	8,558	8,558	7,257	7,257	7,257	48,381	48,381	48,381	2,419	2,419	2,419	2,419	290,966
Local	6,785	6,785	6,785	6,785	6,785	5,753	5,753	5,753	38,353	38,353	38,353	1,918	1,918	1,918	1,918	230,658
Total	15,343	15,343	15,343	15,343	15,343	13,010	13,010	13,010	86,735	86,735	86,735	4,337	4,337	4,337	4,337	521,625
Sub-total	15,343	15,343	15,343	15,343	15,343	13,010	13,010	13,010	86,735	86,735	86,735	4,337	4,337	4,337	4,337	783,665
C. Net benefit (A - B)	59,511	59,511	59,511	59,511	59,511	44,046	44,046	44,046	293,643	293,643	293,643	14,682	14,682	14,682	14,682	1,639,151
D. Net present value	14,893	13,789	12,768	11,822	10,946	7,502	6,946	6,432	39,701	36,760	34,037	1,576	1,459	1,351	1,251	236,381
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	
E. Cumulative NPV	50,040	63,830	76,598	88,420	99,366	106,868	113,814	120,246	159,947	196,707	230,744	232,320	233,779	235,130	236,381	

Project year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
3. Total (Electricity and Water)																		
A. Total benefit	0	0	8,146	19,615	31,513	45,812	60,929	76,911	93,810	111,150	126,868	143,404	160,801	179,109	198,380	206,779	206,779	206,779
B. Total cost																		
(a) Capital cost																		
Foreign	16,090	126,860	85,520	23,650	47,910	45,600	44,460	27,190	28,790	77,900	30,310	54,130	84,980	24,660	0	0	0	0
Local	3,681	19,368	33,795	1,485	1,269	9,252	423	1,701	1,305	10,530	576	2,799	10,800	369	0	0	0	0
Total	19,771	146,228	119,315	25,135	49,179	54,852	44,883	28,891	30,095	88,430	30,886	56,929	95,780	25,029	0	0	0	0
(b) Operating cost																		
Foreign	0	0	136	683	1,235	1,992	2,789	3,626	4,507	5,382	6,155	6,965	7,813	8,701	9,631	10,766	10,766	10,766
Local	0	0	3,144	6,368	9,763	13,526	17,518	21,753	26,248	30,957	35,295	39,871	44,700	49,797	55,176	57,945	57,945	57,945
Total	0	0	3,279	7,051	10,999	15,518	20,307	25,379	30,755	36,339	41,450	46,836	52,513	58,497	64,807	68,711	68,711	68,711
Sub-total	19,771	146,228	122,594	32,186	60,178	70,370	65,190	54,270	60,850	124,769	72,336	103,765	148,293	83,526	64,807	68,711	68,711	68,711
C. Net benefit (A - B)	-19,771	-146,228	-114,448	-12,571	-28,665	-24,558	-4,261	22,641	32,961	-13,619	54,532	39,638	12,508	95,583	133,573	138,068	138,068	138,068
D. Net present value	-19,771	-135,396	-98,121	-9,979	-21,069	-16,714	-2,685	13,211	17,808	-6,813	25,259	17,000	4,967	35,146	45,476	43,525	40,301	37,315
8% discount rate	1.00	0.93	0.86	0.79	0.74	0.68	0.63	0.58	0.54	0.50	0.46	0.43	0.40	0.37	0.34	0.32	0.29	0.27
E. Cumulative NPV	-19,771	-155,167	-253,288	-263,267	-284,336	-301,050	-303,735	-290,524	-272,717	-279,530	-254,271	-237,271	-232,304	-197,158	-151,682	-108,157	-67,856	-30,541
F. FRR 15%																		

Project year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
3. Total (Electricity and Water)																	
A. Total benefit	206,779	206,779	206,779	206,779	193,072	164,174	157,321	147,456	463,758	456,905	445,925	74,701	67,848	56,747	47,003	16,883	4,995,695
B. Total cost																	
(a) Capital cost																	
Foreign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	718,050
Local	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	97,353
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	815,403
(b) Operating cost																	
Foreign	10,766	10,766	10,766	10,766	10,536	9,001	8,886	8,772	49,776	49,662	49,428	3,351	3,236	3,002	2,887	234	333,745
Local	57,945	57,945	57,945	57,945	52,630	46,172	43,514	40,857	70,689	68,031	62,605	23,511	20,854	15,428	12,770	5,426	1,222,218
Total	68,711	68,711	68,711	68,711	63,166	55,173	52,401	49,628	120,465	117,693	112,032	26,862	24,090	18,430	15,657	5,660	1,555,963
Sub-total	68,711	68,711	68,711	68,711	63,166	55,173	52,401	49,628	120,465	117,693	112,032	26,862	24,090	18,430	15,657	5,660	2,371,366
C. Net benefit (A - B)	138,068	138,068	138,068	138,068	129,906	109,001	104,920	97,828	343,294	339,213	333,892	47,839	43,758	38,318	31,346	11,223	2,624,329
D. Net present value	34,551	31,992	29,622	27,428	23,895	18,565	16,546	14,285	46,414	42,465	38,703	5,134	4,349	3,526	2,671	885	310,489
8% discount rate	0.25	0.23	0.21	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11	0.10	0.09	0.09	0.08	
E. Cumulative NPV	4,011	36,003	65,625	93,053	116,948	135,513	152,058	166,343	212,757	255,222	293,925	299,059	303,408	306,933	309,604	310,489	

Table 16.17 Sensitivity Analysis for ERR

	Discount rate		
	7%	9%	10%
Power (R.O.)			
LRMC at generation	28.21	32.74	35.13
LRMC at transmission-end	31.84	37.18	39.99
Water (R.O.)			
LRMC at generation	176.88	205.98	220.96
LRMC at transmission-end	197.40	231.79	249.51
Net benefit (Thousand R.O.)			
Electricity	988,874	1,158,407	1,247,619
Water	1,526,869	1,754,949	1,872,470
Total	2,515,744	2,913,356	3,120,089
ERR			
Electricity	10%	11%	12%
Water	15%	17%	17%
Total	13%	13%	14%

16.5.2 Comparative Method

The net benefit resulting form a project can be identical to the cost saved by not adopting an alternative to the project. The so-called "comparative method" is based on that conception.

16.5.2.1 Alternative to the Project--Electricity

There are 16 diesel engine stations for rural electrification in the Northern Sector, whereas about 90% of the power generation in the sector is on natural gas. When the proposed Manah Power Station, which will run on natural gas, is completed, some of the diesel plants will retire. A shift of power energy source from diesel gas to natural gas is already a course of action in this country.

Nevertheless, the Barka project will contribute to the nation, by allowing the Muscat and Wadi Jizzi Systems to expand into the inner regions, and as a result, supplying electricity generated on natural gas at a lower cost than on diesel gas to areas presently served with power generated on diesel gas, and to towns developed in the future which otherwise would have to have diesel plants. Thus, the economic benefit of the Project can be approximated by calculating the cost which would be saved by not building and not operating oil-fired thermal plants. For the scheme with this alternative type of power plant, and for the cost comparison with the Project, we make the following assumptions and computations. The capital costs and the operating costs of the alternative scheme can be translated as, respectively, the KW capacity value and the KWH energy value of the benefit that the Project will generate.

(1) Alternative scheme:

Plant type	:	oil-fired thermal plant
Capital cost (shadow-priced)	:	346.05 R.O./KW (900 US$/KW)
Life expectancy	:	20 years
Discount factor (opportunity cost of capital)	:	8%

(2) KW capacity value:[12]

Annuitized value	:	346.05 R.O./KW x 0.101852 = 35.246 R.O./KW (annually)

(3) KWH energy value:

Price of fuel (oil)	:	0.2 $/l
Heat value	:	10,000 kcal/l
Thermal efficiency	:	31%
Heat rate[13]	:	2,774 kcal/KWH
Fuel cost[14]	:	5.55×10^{-2} $/KWH ($2.13 \times 10^{-2}$ R.O./KWH)
Operating costs excluding fuel	:	8.77×10^{-3} R.O./KWH
Total operating costs	:	3.01×10^{-2} R.O./KWH

The annuitized capacity value has to be adjusted in the same manner as the LRMC for capacity cost for the Project was computed. Assuming the station use at the diesel plant concerned at 6%, the transmission-end KWH value is calculated as follows:

Transmission-end KW value =

35.246 R.O./KW x (1 + 8%) ÷ (1 - 6%) ÷ (1 - 3%) = 41.75 R.O./KW

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12 In this report, operation and maintenance costs are not included in the capacity cost, but in the energy (or operating) cost.

13 1 KW = 1,000 joul/sec.
1 kcal = 4,185.5 joul
1 KWH = 1,000 x 3,600 ÷ 4,185.5 = 860 (kcal/hr)
Heat rate = 860 ÷ 31% = 2,774 (kcal/KWH)

14 5.55×10^{-2} $/KWH = 0.2 $/l x 2,774 kcal/KWH ÷ 10,000 kcal/l

The generation cost of rural stations in the MEW's Northern Sector, excluding fuel and equipment depreciation, was 8.77 bz/KWH in 1993 (5.7 bz for foreign currency costs, and 3.07 bz for shadow-priced, local currency costs). We assume the same cost for the subject diesel plant. As indicated earlier, the operating costs including fuel total to 10.90 bz/KWH.

With an assumption of the station loss at 6% and the transmission loss at 3%, the transmission-end KWH value is computed as follows:

Transmission-end KWH value =

$$3.01 \times 10^{-2} \text{ R.O./KWH} \div (1 - 6\%) \div (1 - 3\%) = 3.30 \times 10^{-2} \text{ R.O./KWH}$$

Table 16.18 shows the projected cost streams of the alternative to the Project. Those projected costs are entered in the column labeled "operating benefit" in Table 16.19, whereas the capital cost and the operating cost appearing in the table are those of the Project. The net benefit in the table is the cost saved by the Project, by not taking the alternative scheme. The economic internal rate of return obtained by this method is 29%.

The ERR obtained by the comparative method and that by the revenue-based approach are significantly different, while both of them exceed the assumed discount factor of 8%. One may question whether or not the alternative scheme discussed is a realistic or appropriate one. The scheme, however, may represent best the society's willingness-to-pay for power, as, in some areas of the country, the power is still supplied through that scheme.

16.5.2.2 Alternative to the Project--water

Alternatives to the Project to meet the future water demand include (1) exploitation of natural spring water or purchase of water from neighboring countries, and (2) water production by small-scale desalination plants at different locations. There is a rock-hill dam in Muscat, called Muscat Dam, which was built in November 1993. The dam is intended to hold water and, at the same time, to prevent flood, while it has not yet served for those purposes. There is another dam behind it, in the reservoir of which people reportedly used to swim. It is said that the area does not have much rain in recent years, and that dams are not a possible answer to the water needs.

Table 16.18 Economic cost of alternative scheme--electricity

Thousand R.O.

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(a) Capacity																		
1 Power requirement at generation (MW)			106	202	304	413	529	652	783	921	1,050	1,185	1,329	1,480	1,640	1,698	1,698	1,698
2 Power requirement at sending-end (2% loss)			103	198	298	405	518	639	767	903	1,029	1,162	1,302	1,451	1,607	1,664	1,664	1,664
3 Power requirement at transmission-end (3% loss)			100	192	289	392	503	620	744	876	998	1,127	1,263	1,407	1,559	1,614	1,614	1,614
4 Cost at transmission-end @41.75 R.O./KW			4,189	8,008	12,055	16,383	20,982	25,870	31,065	36,560	41,657	47,042	52,731	58,742	65,095	67,389	67,389	67,389
(b) Energy																		
1 Energy requirement at generation (MWH)			475,898	913,345	1,376,776	1,872,470	2,399,234	2,959,055	3,554,049	4,183,412	4,767,198	5,383,898	6,035,450	6,723,916	7,451,482	7,753,591	8,353,461	8,953,331
2 Energy requirement at sending-end (2% loss)			466,380	895,078	1,349,240	1,835,021	2,351,249	2,899,873	3,482,968	4,099,744	4,671,854	5,276,220	5,914,741	6,589,438	7,302,452	7,598,519	8,186,392	8,774,264
3 Energy requirement at transmission-end (3% loss)			452,388	868,226	1,308,763	1,779,970	2,280,712	2,812,877	3,378,479	3,976,752	4,531,699	5,117,933	5,737,299	6,391,755	7,083,379	7,370,564	7,940,800	8,511,036
4 Cost at transmission-end @0.0330 R.O./KWH			14,929	28,651	43,189	58,739	75,263	92,825	111,490	131,233	149,546	168,892	189,331	210,928	233,751	243,229	262,046	280,864
Total cost			19,118	36,660	55,244	75,122	96,246	118,695	142,555	167,793	191,203	215,934	242,062	269,670	298,846	310,618	329,436	348,254

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
(a) Capacity																	
1 Power requirement at generation (MW)	1,698	1,698	1,698	1,698	1,522	1,430	1,341	1,161	1,073	985	897	717	628	537	360	268	33,398
2 Power requirement at sending-end (2% loss)	1,664	1,664	1,664	1,664	1,491	1,401	1,315	1,138	1,052	965	879	702	616	526	353	263	32,730
3 Power requirement at transmission-end (3% loss)	1,614	1,614	1,614	1,614	1,446	1,359	1,275	1,104	1,020	936	852	681	597	510	342	255	31,748
4 Cost at transmission-end @41.75 R.O./KW	67,389	67,389	67,389	67,389	60,388	56,741	53,241	46,093	42,592	39,092	35,591	28,444	24,943	21,296	14,295	10,648	1,325,469
(b) Energy																	
1 Energy requirement at generation (MWH)	9,553,201	10,412,136	10,412,136	10,412,136	9,330,356	8,766,928	8,226,038	7,121,721	6,580,831	6,039,940	5,499,050	4,394,733	3,853,843	3,290,415	2,208,635	1,645,208	180,903,872
2 Energy requirement at sending-end (2% loss)	9,362,137	10,203,893	10,203,893	10,203,893	9,143,749	8,591,590	8,061,517	6,979,286	6,449,214	5,919,142	5,389,069	4,306,838	3,776,766	3,224,607	2,164,462	1,612,303	177,285,794
3 Energy requirement at transmission-end (3% loss)	9,081,272	9,897,776	9,897,776	9,897,776	8,869,436	8,333,842	7,819,672	6,769,908	6,255,738	5,741,567	5,227,397	4,177,633	3,663,463	3,127,869	2,099,528	1,563,934	171,967,220
4 Cost at transmission-end @0.0330 R.O./KWH	299,682	326,627	326,627	326,627	292,691	275,017	258,049	223,407	206,439	189,472	172,504	137,862	120,894	103,220	69,284	51,610	5,674,918
Total cost	367,071	394,016	394,016	394,016	353,079	331,758	311,290	269,500	249,032	228,563	208,095	166,305	145,837	124,516	83,579	62,258	7,000,387

Table 16.19 Economic rate of return analysis (electricity)--compartive method

million R.O.

Year	Project year	Capital cost (1)	Operating cost (2)	Operating benefit (3)	Net benefit (4)=(3)-(1)-(2)	Discount factor 8% (5)	Net present value (6)=(4)x(5)	Cumulative NPV (7)
1996	0	17,815			-17,815	1.00	-17,815	-15,856
1997	1	125,711			-125,711	0.93	-116,399	-132,255
1998	2	31,960	3,279	19,118	-16,122	0.86	-13,822	-146,077
1999	3	25,135	6,294	36,660	5,231	0.79	4,153	-141,924
2000	4	42,620	9,487	55,244	3,137	0.74	2,305	-139,619
2001	5	12,894	12,903	75,122	49,325	0.68	33,569	-106,049
2002	6	44,883	16,533	96,246	34,829	0.63	21,948	-84,101
2003	7	28,891	20,391	118,695	69,413	0.58	40,502	-43,599
2004	8	23,536	24,491	142,555	94,528	0.54	51,070	7,471
2005	9	46,472	28,828	167,793	92,493	0.50	46,270	53,741
2006	10	30,886	32,851	191,203	127,467	0.46	59,042	112,783
2007	11	50,370	37,100	215,934	128,463	0.43	55,096	167,879
2008	12	53,822	41,590	242,062	146,649	0.40	58,236	226,115
2009	13	25,029	46,335	269,670	198,306	0.37	72,917	299,032
2010	14	0	51,348	298,846	247,498	0.34	84,263	383,295
2011	15	0	53,368	310,618	257,250	0.32	81,096	464,391
2012	16	0	53,368	329,436	276,068	0.29	80,582	544,973
2013	17	0	53,368	348,254	294,886	0.27	79,698	624,671
2014	18	0	53,368	367,071	313,704	0.25	78,504	703,175
2015	19	0	53,368	394,016	340,648	0.23	78,932	782,108
2016	20	0	53,368	394,016	340,648	0.21	73,085	855,193
2017	21	0	53,368	394,016	340,648	0.20	67,672	922,865
2018	22	0	47,823	353,079	305,256	0.18	56,149	979,014
2019	23	0	42,163	331,758	289,595	0.17	49,322	1,028,336
2020	24	0	39,391	311,290	271,899	0.16	42,878	1,071,215
2021	25	0	36,618	269,500	232,882	0.15	34,005	1,105,220
2022	26	0	33,730	249,032	215,301	0.14	29,109	1,134,329
2023	27	0	30,958	228,563	197,605	0.13	24,738	1,159,066
2024	28	0	25,298	208,095	182,797	0.12	21,189	1,180,255
2025	29	0	22,525	166,305	143,780	0.11	15,432	1,195,687
2026	30	0	19,753	145,837	126,084	0.10	12,530	1,208,217
2027	31	0	14,093	124,516	110,423	0.09	10,161	1,218,377
2028	32	0	11,320	83,579	72,259	0.09	6,156	1,224,534
2029	33	0	5,660	62,258	56,598	0.08	4,465	1,228,999
Total		560,024	1,034,338	7,000,387	5,406,025		1,227,040	

Economic rate of return (ERR): 29%

Bottled spring water is available at 1 R.O. for 4 gallons. This price is the lowest at the retail level, and its wholesale price is reported to go down to 400 bz. Bottled water can be imported as well, and therefore, presumably any level of demand can be satisfied. However, this alternative, because of the high cost, can not be a realistic solution. (The MEW water is sold at 2 bz a gallon to households, and its production cost is estimated at 2.7 bz.)

In November 1993, a small desalination plant with an installed capacity of 4,550 m^3/d was built in Sur. Water is pumped up from wells at the coast and thus no intake facility is required. The capital cost of this alternative plant was approximately $12,000,000 in 1993. This type of small desalination plants can be a realistic alternative to the Project, while many plants would have to be built along the coast by the year 2010.

The operation and maintenance of the Sur plant is contracted to a private company at an annual fee of approximately 300,000 R.O. The plant requires other operating costs, of which data is not available. For simplicity, we assume that the operating costs to produce one unit of water at the alternative plant are the same as those at the proposed Barka desalination plant. Hence, the economic rate of return of the Project can be estimated by comparing only the initial investment costs for the Project and those for this alternative scheme.

The estimated capital costs of the alternative scheme appear in the "Benefit" column in Table 16.20. To meet the demand, 48 plants would be required by the year 2010. The economic rate of return is calculated at 46.01%. The Project, owing to the economies of scale, is economically superior to its alternative, while it requires a substantial investment in early years.

Table 16.20 Economic rate of return analysis (water)--compartive method

million R.O.

Year	Demand (m3/d) (1)	Capacity requirement (m3/d) (2)=(1)x120% for peak demand	Capacity installed (m3/d) (3)	Number of new plants (4)	Cumulative total installed capacity (m3/d) (5)	Benefit Capital cost (6)=(3)x@12 million R.O.	Cost (7)	Net benefit (8)=(6)-(7)	Discount factor 8% (9)	Net present value (10)=(8)x(9)	Cumulative NPV (11)
1996							1.86	-2	1.00	-2	0
1997							19.24	-19	0.93	-18	-18
1998						36	80.76	-45	0.86	-38	-56
1999	10,131	12,157	13,650	3	13,650	36	0.00	36	0.79	29	-28
2000	20,224	24,269	13,650	3	27,300	48	6.00	42	0.74	31	3
2001	34,999	41,999	18,200	4	45,500	48	38.66	9	0.68	6	10
2002	50,500	60,600	18,200	4	63,700	48	0.00	48	0.63	30	40
2003	66,764	80,117	18,200	4	81,900	60	0.00	60	0.58	35	75
2004	83,829	100,595	22,750	5	104,650	48	6.00	42	0.54	23	98
2005	100,525	120,630	18,200	4	122,850	48	38.66	9	0.50	5	102
2006	115,089	138,107	18,200	4	141,050	48	0.00	48	0.46	22	124
2007	130,298	156,357	18,200	4	159,250	48	6.00	42	0.43	18	142
2008	146,183	175,420	18,200	4	177,450	48	38.66	9	0.40	4	146
2009	162,779	195,335	18,200	4	195,650	60	0.00	60	0.37	22	168
2010	180,122	216,147	22,750	5	218,400	0	0.00	0	0.34	0	168
Total	1,101,445	1,321,734	218,400	48	1,351,350	576	236	340	9	166	975

Economic internal rate of return (EIRR): 46.01%

Note: Assume that the disbursement of the capital cost is made one year earlier, as the construction of plants is completed one year earlier.

16.5 Conclusion

We assessed the viability of the Project from both financial and economic points of view. For the financial assessment, the FRR of the Project was computed, to find that the rate is 13%, which is sufficiently higher than the assumed discount factor of 8%. The Project's first stage, which requires a total initial investment of approximately US$505 million (or 194 million R.O.), is expected to generate a total net profit of US$1,863 million over 21 years from 1998 to 2018, if it is given priority over other plants regarding operating hours (i.e. high load factor). The rate of return on the equity of approximately US$129 million is expected at 22%.

The revenue-based ERR of the Project was also computed at 13%. The ERRs calculated by the so-called comparative method, which measured the cost saved by not adopting an alternative scheme, were 29% for power and 41% for water. All the rates of return estimated by our assessment suggest that the Project is feasible.