APPRAISAL OF EL-KUREIMAT COMBINED CYCLE POWER PLANT

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Abstract

The proposed El Kureimat Plant (module II) project is one of 19 new generation plants that the public electrical utility of Egypt plans to setup over its current planning horizon of 2005-2012. This paper reports on an integrated investment appraisal of the project. The project involves the construction of a 750 MW (2x250 MW gas turbine and 1x250 MW steam turbine) combine cycle power plant in the premises of the existing El Kureimat Power Station. The estimated total cost of the investment is € 271.1 million in nominal prices. The project, when completed, will provide 750 MW of additional capacity to the unified power system (UPS) in 2009. The proposed project is expected to save a substantial amount of natural gas for the state-controlled gas utility, which will be able to export the gas and earn foreign exchange for the Government.

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APPRAISAL OF EL-KUREIMAT COMBINED CYCLE POWER PLANT (MODULE II)

PROJECT FEASIBILITY STUDY

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ABBREVIATIONS

ADSCR	=	Annual debt service coverage ratio
AfDB	=	African Development Bank, also “Bank”
BOOT	=	Build, own, operate and transfer
CC	=	Combined cycle
DSCR	=	Debt service coverage ratio
EEAA	=	Egyptian Environmental Affairs Agency
EEHC	=	Egyptian Electricity Holding Company
EEUCPRA	=	Egyptian Electricity Utilities Consumer Protection Regulatory Agency
EGPC	=	Egyptian General Petroleum Corporation
EIRR	=	Economic Internal Rate of Return
EOCK	=	Economic cost of capital
EOCL	=	Economic cost of labor
FEP	=	Foreign exchange premium
FIRR	=	Financial internal rate of return
FY	=	Financial year
GEP	=	Generation expansion plan
GDP	=	Gross domestic product
GOE	=	Government of Egypt
HRSG	=	Heat Recovery Steam Generator
HV	=	High voltage
IPP	=	Independent power producer
ISO	=	International Standards Organization
LC	=	Local cost
LRMC	=	Long run marginal cost
LV	=	Low voltage
MEE	=	Ministry of Electricity and Energy
kV	=	Kilo volt
MOP	=	Ministry of Petroleum
MOSEA	=	Ministry of State for Environmental Affairs
MOT	=	Ministry of Transport
MV	=	Medium voltage
MVA	=	Mega volt ampere
NMA	=	Nuclear Material Authority
NPV	=	Net present value
OEP	=	Organization for Energy Planning
O&M	=	Operation and maintenance
p.a.	=	Per annum
REA	=	Rural Electrification Authority
SMEs	=	Small and Medium Size Enterprises
UEEPC	=	Upper Egypt Electricity Production Company
UPS	=	Unified Power System
VHV	=	Very high voltage

APPRAISAL OF EL-KUREIMAT COMBINED CYCLE POWER PLANT (MODULE II)

Project Feasibility Study

1. INTRODUCTION

The abundance of fossil fuels in Egypt and subventional policies of the Government over past decades have created a strong energy sector, delivering electric power to 99% of the population. This ever growing sector has been managed and operated by a single electricity utility, the Egyptian Electricity Holding Company (EEHC). This holding company integrates a total of 15 companies engaged in the generation, transmission and distribution of electricity. To keep up with the growing number of connections and electricity demand by its consumers the EEHC has been expanding its generation and transmission capacity.

The proposed El Kureimat Plant (module II) project is one of 19 new generation plants that the company plans to setup over its current planning horizon of 2005-2012. The project involves the construction of 750 MW (2x250 MW gas turbine and 1x250 MW steam turbine) combine cycle power plant in the premises of the existing El Kureimat Power Station. The estimated total cost of investment is € 271.1 million in nominal prices. The project, when completed, will provide 750 MW of additional capacity to the unified power system (UPS) in 2009.

The Government of Egypt (GOE) has strongly backed the project and submitted a request to the African Development Bank (AfDB) for financing of the proposed project, seeking an affordable source of finance for the foreign currency costs of the proposed project. The Government has agreed to be the direct borrower of loan. The present report presents the assessment of the proposed investment using an integrated approach that covers the evaluation of the financial, economic, stakeholder and risk aspects of the project in a single consistent model.

The evaluation of a generation plant within an electric utility that does not allow for power shortages has a unique feature regarding the incrementality of the project. The incremental impact that a new efficient combine cycle plant brings to the system is basically substitution of older units that have higher running costs during the base load and the provision of additional generation capacity at the peak times.

As such, the proposed investment must be evaluated in the context of its parent utility's operations, rather than on a stand-alone basis, since the new plant does not actually increase the total sales of the utility. The utility-wide approach allows us to examine the cost savings alone to the electricity system. A stand-alone evaluation where the benefits are measured in terms of additional revenue is unrealistic in this case just the same as in cases of system improvements such as interconnection, transmission/distribution, reliability improvements as they do not actually generate significant energy but have a tremendous impact on the quality of service provided.

As a result, the financial analysis of the proposed plant is focused on the assessment of the role of the new plant in the system, and its impact on the utility's cost savings. In addition, the financial model includes a projection of the electric utility cashflows in order to examine its ability to service the debt repayments. Within the integrated appraisal framework, the economic analysis is built directly on the financial cashflows of the project and the economic treatment of project benefits is measured by the cost savings expressed in economic terms, consistent with the financial valuation of system cost savings by the EEHC. This case-study report presents the analysis of the proposed project. Six specific questions need to be asked about the proposed El Kureimat (Module II) plant:

1) Does the project ensure the least-cost way of meeting the power demand by the EEHC?
2) What is the magnitude of financial benefits realized by the electric utility?
3) What are the cashflow implications for the utility in terms of servicing the debt obligations of the proposed project?
4) To what extent does this project contribute to the Egyptian economy?
5) Who are the stakeholders and by how much do they benefit, or lose, as a consequence of this project?
6) What are the risk factors that affect the project and how can the uncertainty and risk exposure be mitigated?

2. EEHC UTILITY

2.1 Energy Sector in Egypt

Over past 5 years, the economy of Egypt has been steadily growing at an average of 3.9% a year. Unlike a number of other countries, the Government places a high priority on having a well-managed electricity system that supports virtually every sector of the economy. The growth in electricity demand, that mirrors the economic development of the country, averaged 6.2% p.a. over period of 1999-2004. No power shortages have been experienced in Egypt during the last decade.

The macroeconomic projections of the country's development over the period of 2005-2012 indicate that the annual growth rate of GDP should be in the range 5-6%. The forecast of electricity demand predicts that if the past trend continues, the average rate of growth of power consumption over the same period will be 7.5% per annum in the base scenario. To keep up with the pace of country development, the Egyptian Electricity Holding Company (EEHC) has developed a Generation Expansion Plan (GEP) to meet the increased demand and to maintain system reliability in the Unified Power System (UPS) in the short-to-medium term.

The Government's goal for the energy sector is to make available sufficient energy at minimum cost to the various economic sectors for the efficient operation and sustainable growth of the economy. It also targets providing sufficient and reliable commercial energy to the household sector in order to improve the living conditions of the population. To attain the sector goal, the country will secure energy supply through an appropriate diversity of economically competitive and reliable sources, with emphasis on the development of its indigenous energy resources both for domestic market and exports.

Egypt's energy sector falls under two key Ministries, namely (i) the Ministry of Petroleum (MOP), and (ii) Ministry of Electricity and Energy (MEE). The MOP is responsible for the exploration, production, refining, transportation and marketing of oil and natural gas. The MEE is concerned with electricity generation, transmission and distribution. Decision-making by these Ministries is supported by three central organizations. The Cabinet of Ministers is the main forum for coordination in the sector. It operates through specific Ministerial committees and is responsible for the pricing of petroleum products and electricity.

2.2 Organizational Structure of EEHC

2.2.1 Generation: The EEHC is an integrated utility that is responsible for generation, transmission and distribution of electric power in Egypt. Internally, the holding company consists of 15 companies, organized by function and geographical area. Currently, there are 5 generation, 1 transmission and 9 distribution companies.

On the generation side, the total installed capacity of the EEHC at the end of 2004 was 14,091 MW comprising of 2,100 MW of hydro, 11,914 MW of thermal and 77 MW of wind. The thermal units include 1,056 MW of gas turbines, 8,789 MW of steam turbines, and 2,069 MW of combine cycle units. The available capacity of hydro plants is constrained by need to discharge water for irrigation purposes at times that are not ideal for generating electricity.

Private sector participation in the sub-sector was introduced in the mid 1990s. In 1996, the government approved plans to open the industry to IPPs and three projects were subsequently tendered in 1997 and have already been implemented under BOOT financing with foreign partners. The energy purchased by the EEHC from IPPs and BOOTs in 2004 was 13,578 GWh. Under on-going reforms, the Government anticipates that the private sector will eventually be allowed to hold up to 49% equity stake in the generation and distribution companies currently owned by the EEHC, while transmission assets will remain in government ownership. At present, the addition of a new independent power producer to the sector is not feasible as the electricity tariffs are too low and the Government is not willing to provide subsidies to private ventures.

2.2.2 Transmission and Distribution: The electricity network in Egypt has developed into a complex interconnected system, commonly referred as the UPS, serving all major load centers countrywide. In 2003/2004, the transmission system had a network of 38,204 km of lines including 4,263 km of 500 kV, 33 km of 400 kV, 13, 711 km of 220 kV, 4,466 km of 132 kV and 15,731 km of 66 kV overhead lines. The substation capacities for 500 kV, 220 kV and 132 kV networks were 10,155 MVA, 29,208 MVA and 4,641 MVA, respectively. In 2004 the distribution system consisted 126,921 km medium voltage lines, 211,445 km low voltage lines and 118,776 transformers with aggregate capacity of 39, 24 MVA, supporting 19,768,016 consumers. It should be noted that the transmission and distribution losses are about 13% including 3% in transmission and 10% in distribution of electricity, respectively.

2.3 Energy Balance

Demand for power is dependent on a number of factors, which have been long analyzed by the EEHC and a number of scenarios have been prepared during the forecasting of the future electricity consumption. While it is admitted that a range of possible scenarios exist, the electric utility has adopted the following base-case scenario. Starting from 2005, the average annual demand growth rate is expected to be 7.5% until year 2012. For the purpose of analysis, it is assumed that thereafter the power demand growth rate is 5.0% per annum.[1]

Despite the low tariffs, the EEHC has managed to match the demand for electricity with sufficient generation over the past decade. This remarkable balance has been achieved through a continuous expansion of the system capacity. For its current planning horizon, the EEHC carried out a study to compare various generation options, including thermal, hydropower, solar-thermal power and power imports from neighboring countries. Given that (i) the country has no future hydropower potential sites available for exploitation and has no nuclear energy resources; (ii)

[1] No official demand projections exist beyond 2012, and an assumption has to be made.

generation of power of such magnitude from solar and wind energy was found non-competitive compared to conventional thermal generation; and (iii) importing electricity from the neighboring countries was not possible. Hence, power generation through expansion of thermal power plants was found to be the best option for meeting the forecast demand in the UPS.

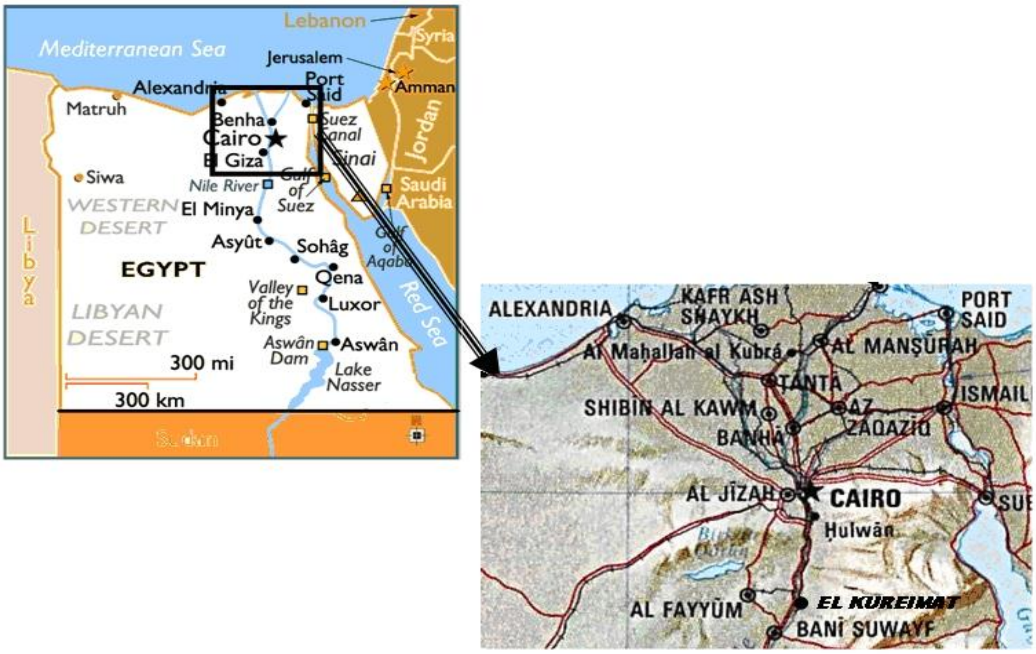
A system planning study carried out by the EEHC identified locations for 19 new power stations, with aggregate installed capacity of 13,009 MW, to be commissioned in the period 2004-2012. Of the additional generation capacity, 12,464 MW will be from thermal power plants and the remainder from Zafarana wind turbine (565 MW) and Nag Hammadi hydro (64 MW). The proposed El Kureimat Power Plant (Module II) is one of the plants that are conveniently located for easy connection to the grid, with to the existing gas distribution system and close to supply of cooling water.

3. PROPOSED EL KUREIMAT (MODULE II) PLANT

3.1 Project Area

The site of the proposed El Kureimat Combined Cycle Power Project is about 90 km south of Cairo and has the main River Nile running adjacent to it, as shown on Figure 1. The proposed plant will be installed inside the existing El Kureimat Power Station located on the east bank of River Nile in the Giza Governorate. The proposed plant will be located alongside the existing units while adequate space has been set aside to accommodate the proposed plant. While the project is located within the El Kureimat area, it will not share any facilities with the existing plant. Power generated by the proposed El Kureimat power plant will be sent to the UPS to contribute to meeting the overall system demand.

Figure 1: El Kureimat (Module II) Project, Egypt[2]



2 This map has been drawn by the African Development Bank Group exclusively for the use of readers of this report. The names used and borders shown do not imply on the part of the Bank and its members any judgment concerning the legal status of a territory nor any approval or acceptance of those borders.

3.2 Investment Costs

The project involves construction of a 750 MW (2x250 MW gas turbine and 1x250 MW steam turbine) combine cycle power plant. Table 1 shows the detailed expenditure plan by component.

Table 1: Investment Costs by Component, Current Prices (€ million)*

Components	2005		2006		2007		2008		2009		Total Costs	
	Foreign	Local**	Foreign	Local	Foreign	Local	Foreign	Local	Foreign	Local	Foreign	Local
A. Civil works	0.0	0.0	2.1	5.7	3.4	9.3	3.1	8.3	0.0	0.0	**8.6**	**23.3**
B. Gas turbine generator	8.3	0.5	33.9	2.1	43.3	2.7	0.0	0.0	0.0	0.0	**85.5**	**5.4**
C. Steam turbine generator	4.3	0.4	8.7	0.7	13.4	1.1	13.6	1.1	4.6	0.4	**44.7**	**3.7**
D. Heat recovery steam generator	0.0	0.0	7.1	2.0	11.7	3.3	7.4	2.1	3.0	0.9	**29.3**	**8.3**
E. Switchyard	1.3	0.0	8.1	0.2	4.1	0.1	0.0	0.0	0.0	0.0	**13.5**	**0.3**
F. Environmental monitoring	0.0	0.0	0.4	0.3	0.1	0.1	0.1	0.0	0.0	0.0	**0.6**	**0.4**
G. Wrap-up insurance	0.0	0.0	0.3	0.1	0.3	0.1	0.3	0.1	0.7	0.1	**1.7**	**0.4**
H. Project management	1.6	1.3	2.5	2.0	2.1	1.7	1.7	1.4	0.4	0.3	**8.5**	**6.6**
I. Customs and taxes	0.0	1.8	0.0	7.4	0.0	9.3	0.0	3.8	0.0	1.0	**0.0**	**23.3**
Sub-total	**15.6**		**63.3**		**78.5**		**26.3**		**8.8**		**192.4**	
Sub-total		**3.9**		**20.5**		**27.6**		**16.8**		**2.8**		**71.7**
Loan Financing	**13.9**		**58.3**		**72.5**		**21.1**		**7.7**		**173.6**	
Equity Financing	**1.6**	**0.0**	**5.0**	**0.0**	**5.9**	**0.0**	**5.2**	**0.0**	**1.2**	**0.0**		

* Sources: EEHC, Techno – Economic Feasibility Study for El-Kureimat Combine Cycle Power Plant Project (750MW), (December 2004); and Revision of El Kureimat Construction Costs, (April 2005).

** The exchange rate between the EURO and Egyptian pound is 8.1936 EGP/€.

4. FINANCIAL ANALYSIS OF PROJECT

4.1 Incrementality of Project

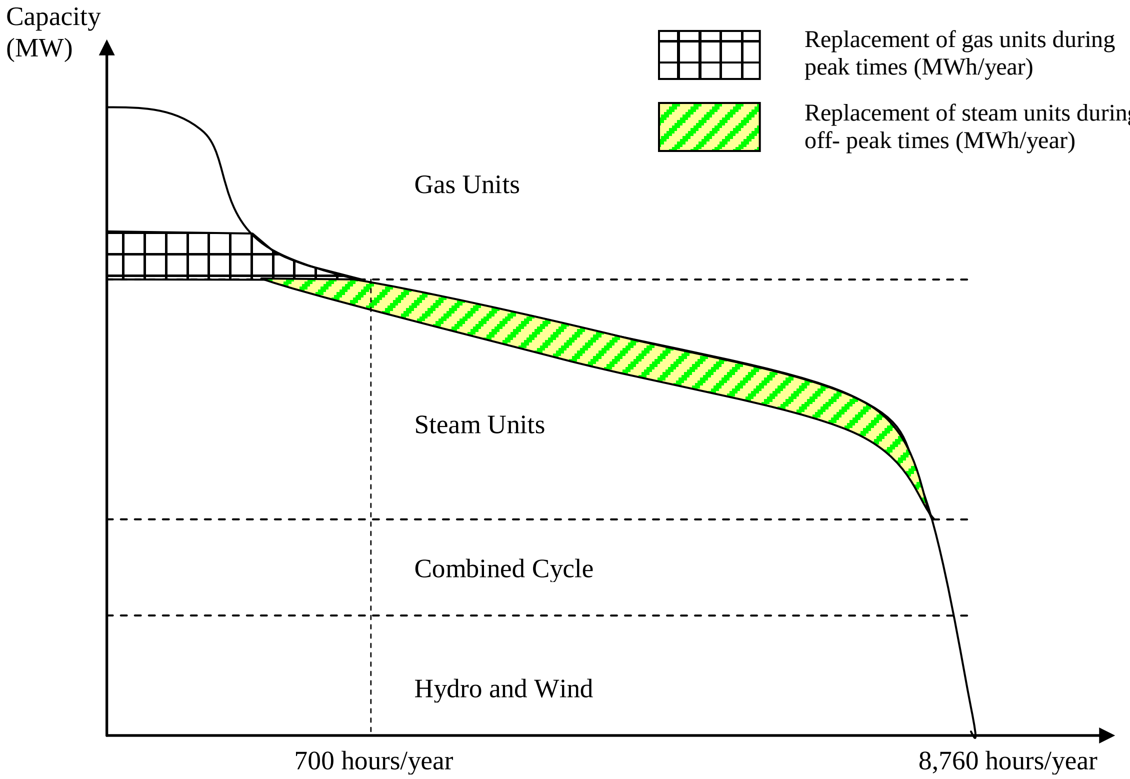
The Egyptian authorities realized some decades ago that it is worthwhile to maintain a modern power system requiring a continuous improvement and expansion in order to have an affordable and reliable energy supply. The system supplies all the power demanded by consumers and the EEHC is determined to continue its policy of timely capacity expansion.

Given such circumstances, under the “without” project scenario the EEHC will supply sufficient electricity to meet the demand it faces, regardless where additional power might come from: own generation or purchases from private BOOT plants. No single user will be left without electricity even if the proposed plant is not built as planned, because the EEHC has the mandate to provide a reliable supply of electricity to all its customers. The “without” scenario would also include the other elements of the proposed system expansion plan, which will enhance the reliability and generation capacity of the utility until 2014/15.

The specific feature of the “with” scenario of this project is that with the implementation of this new efficient combine cycle plant, the projected demand will be met at a lower generation cost to the EEHC. Since the system planners foresee the growing demand and new sales of energy, the EEHC has been already expanding its capacity to meet that demand in the “without” case. If the proposed plant does not come online, the electric utility will meet the demand by running other plants more.

The incremental change introduced by the plant is the change in the mix of plants that the EEHC would operate. Currently, during the off-peak the company uses a number of steam plants in the base load together with a few existing combine cycle plants and its limited hydro potential. At the peak time, additional capacity is provided by gas turbines. Figure 2 illustrates the impact of the project on system dispatch of the EEHC. The new, efficient combine cycle plant substitutes for some steam plants during the off-peak periods and for gas turbines during the peak times.

Figure 2: Impact of Project on System Dispatch (MWh/year)



Since both the steam and gas units operate with a substantially higher fuel and O&M costs, the proposed plant will enable the utility to reduce the use of its most inefficient units whenever the plant's capacity allows. The utility will be able to save cash on fuel and operating costs on other plants in the system. Therefore, the financial benefits from the proposed plant are the savings of the running costs of steam plants during the off-peak regime, and savings on the operation and capital cost of gas plants at the system peak. No additional energy sales should be credited as financial benefits.

4.2 Assumptions and Parameters

A comprehensive financial model of the proposed project has been developed, based on the following assumptions.

Investment Costs

- Total investment costs, including price and physical contingency as well as customs and taxes, are € 264.1 million with a 72.9% share of foreign costs.
- Project operational life is 40 years from 2008.
- Analysis is conducted in constant 2005 prices and liquidation value for the gas turbine is included.
- Rated plant capacity is 750MW and availability factor at 80%.[3] The annual plant utilization is reduced at the rate of 0.50% per year, starting from 2010.

[3] Since the plant will be operating in the base load of the system, the plant availability factor is mainly a function of technical availability of its units.

- Plant net generation capacity is 691 MW after deducting the ISO factor (5%) and auxiliary consumption (3%).
- Replacement for the gas turbines after 25 operational years is assumed.

Financing

- The AfDB provides a loan of the amount of € 173.6 million to finance most of the foreign cost of capital investment.[4]
- Floating base interest rate of 2.451% real p.a. is assumed with a repayment period of 20 years, including a 5-year grace period. The resulting nominal interest rate is 4.5% p.a.
- There is a commitment fee of 0.25% p.a. on the undisbursed amount.

Operating Costs

- Fuel cost: estimates are based on annual net plant heat rate of 6,190 Btu/kWh, natural gas consumption rate of 0.16081 m^3/kWh (with degradation factor built in), at EGP 0.141/m3.[5]
- Diesel fuel is used for starting up the turbines, and it is 4% of generation time. The consumption rate is 163.27 gram/kWh at 182 EGP/ton.[6]
- Operations and Maintenance (O&M) costs: fixed generation O&M is estimated at US$ 15.769 million p.a. and variable O&M at 1.57 US$/MWh.[7]
- Labor costs are part of the fixed generation O&M; the project is expected to hire additional 350 employees.
- In addition to the annual O&M, there is a major periodic maintenance of the gas turbines every five years estimated at a cost of 10% of the gas turbine.
- Incremental working capital: accounts payable at 6 weeks of the fuel, labor and variable costs; cash balances at 5 weeks based on the fuel, labor and variable costs; and a carried-over stock of 83,000 tons of diesel fuel.

Cost Savings

- System Off-Peak Savings: based on the fuel savings and O&M savings on steam plants during 8,060 off-peak hours/year.[8] The average system fuel consumption on steam plants is 205.34 gram/kWh.[9]
- System Peak Savings: includes the fuel savings, O&M savings and capital savings on gas plants during 700 peak hours/year. The average system fuel consumption on peaking gas plants is 381.00 gram/kWh.[10] In addition, the system does not need to install additional gas peaking capacity that would come at a cost of EGP 31.4 Piaster/kWh.[11]

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4 The loan covers all the foreign costs of the following components: (B) gas turbine generator, (C) steam turbine generator, (D) heat recovery steam generator, (E) switchyard, (F) environmental monitoring. The EEHC will pay for the local costs of these components, and also will cover both foreign and local costs of components (A) civil works, (G) wrap-up insurance and (H) project management. The loan does not cover any customs or taxes on the project components. Any cost overruns beyond the physical and price contingencies are to borne by the borrower.

5 Per-unit consumption is equal to the heat rate of 6,190 Btu/kWh divided by the calorific value of natural gas of 38,493 Btu/m3. Over time, the per-unit consumption of natural gas by plant's turbines increases according to the heat degradation factor specified by the engineers.

6 The diesel gross calorific value is of 40,000,000,000 Joules/ton. Since one Btu is equal to 1,055.056 Joule, one ton of diesel translates into a calorific value of 37,912,685 Btu. Taking the plant's heat rate of 6,190 Btu/kWh and dividing it by the calorific value of natural gas of 37,912,685 Btu/ton, yields the diesel requirement as 0.00016327 ton/kWh.

7 O&M estimates are provided by the EEHC.

8 The average duration of peak and off-peak hours is obtained from EEHC annual reports 2002/03 and 2003/04.

9 An average fuel consumption rate by all steam units in 2004, weighted by the amount of energy generated by each unit.

10 An average fuel consumption rate by all gas turbines in 2004, weighted by the amount of energy generated by each unit.

11 See Section 4. This cost expressed in the US currency is US$ 5.22 cent/kWh.

- The average O&M costs on all existing thermal plants are EGP 4.0 Piaster/kWh and the project will have average O&M costs of EGP 3.4 Piaster/kWh.[12]

Macro-economic Variables

- Inflation rate at 3.5% p.a. is assumed for Egypt, 2.0% for EU, and 2.5% for USA.
- The exchange rates in 2005 are 8.1936 EGP/€ and 6.0154 EGP/US$.

4.3 Financial Benefits of Project

The financial benefits of the project depend upon cost savings during the peak and off-peak times of the system. The existing pattern of daily power consumption in the country suggests that about 700 hours a year, the maximum running time for gas units is the system peak time. The remaining time, about 8,060 hours/year, is the off-peak load on the system.

System Off-Peak Savings: The off-peak savings include the off-peak fuel savings and off-peak O&M savings. The off-peak savings are the amount of cash saved by the electric utility on the operation of steam plants, which is the largest component of the savings. In 2005 the average system fuel consumption on steam plants is 0.2022 m3/kWh of natural gas, while the initial fuel consumption by the proposed combine cycle plant is only 0.16081 m3/kWh.[13]

System Peak Savings: At the peak times, gas turbines have to be deployed in order to meet the peak demand by the users. As the running costs of gas units are expensive in comparison to steam and combine cycle costs, the electric utility uses the gas units only 700 hours/year, or 8% of the time.[14] The system must be equipped with enough gas turbine capacity in order to meet the peak load, and any system improvement that reduces the need for additional gas turbine capacity is therefore capital-saving in its nature. In short, the peak savings are a summation of the peak fuel savings, peak O&M savings and capital costs associated with the installation of gas turbines for reserve capacity.

The average system fuel consumption on gas plants is 0.3752 m3/kWh of natural gas, which is significantly higher than 0.16081 m3/kWh fuel requirement by the combine cycle plant. The capital savings on the installation of gas turbine capacity can be estimated as follows. If the current cost of gas turbine installed is US$ 400 per kW, and if it is expected to serve 25 years, while generating a weighted average cost of capital (WACC) for project of 5.1% p.a., then the annual depreciation charge is US$ 16.00 p.a., and the required return on capital is US$ 20.51 p.a. The total capital or capacity charge per annum will be US$ 36.51 per kW of installed capacity. This charge must be amortized over the amount of energy generated during the year. Since the gas turbine is operated 700 hours/year then the corresponding capital charge on energy amounts to US$ 5.22 cent/kWh.[15] In other words, the value of capital savings during the peak times from the proposed plant, on per-kWh basis, is equal to how much it would cost the electric utility to have that gas turbine capacity in place in order to meet the system peak load.

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12 The figure of average O&M costs on all existing thermal plants of EGP 4.0 Piaster/kWh is estimated from the financial statements provided by the EEHC. The plant's O&M cost of EGP 3.4 Piaster/kWh is the levelized cost of operation and maintenance costs over the duration of the project, defined as the present value of all O&M costs over the present value of energy sent out of the plant.

13 Figures provided by the EEHC.

14 While the peaking plants may run, on the average, for only 700 hours a year, they will need to be available as spinning reserve for substantially longer periods of time. Hence, the estimate of 700 hours of system peak load will lead to under-valuation of the cost savings. Accordingly, the contribution of the plant to off-peak savings is limited by the time when the capacity of EL Kureimat plant will not be needed at the peak times.

15 This is obtained as annual capital charge on installed capacity divided by the running time of gas turbine: (36.51 US$/kW) / (700 hours) = 0.0522 US$/kWh, or US$ 5.22 cent/kWh.

4.4 Financial Viability from EEHC Perspective

Net Financial Benefit: As the proposed project is a part of the electricity utility, the EEHC can be considered as the sole equity holder of the El Kureimat (module II) plant. What this appraisal aims to address is whether the stream of financial benefits from the proposed plant is big enough to offset the capital and operating costs. The amount of savings from steam and gas plants should compensate the electric utility for installation of this additional capacity to its existing generation system. As the owner of the project, the electric utility will be expecting to receive a rate of return on the project no less than its target real (net of inflation) rate of return on equity.

In other words, the present value of the discounted net financial cashflow over the life of the project should not be less than zero. Table 2 shows that the financial NPV of the project is EGP 740.1 million, using a real discount rate of 6.0%.[16] This represents an incremental contribution to the amount of the initial investment costs of EGP 2,013.2 million recovered by the equity holder. Clearly, the discounted net cash savings of the electric utility cover not only the investment and operating costs of the plant but also interest and loan repayment. The high financial internal rate of return (FIRR) of 12.3% also indicates a sufficient contribution to the equity.

Cost Savings and Project Debt Repayment: Another question that the AfDB is quite justified in asking is whether the cash savings from the project, accrued to the EEHC, are sufficient to cover the scheduled loan repayments. This can also be seen in Table 2 where all annual and cumulative debt service indicators of the project are well above 1.2, implying that the project's net cash savings are, at least, 20% greater than the scheduled loan obligations. In addition, the present value of the project's net cash savings over the whole loan repayment period is, at least, 191% of the present value of the scheduled debt repayments.

While the cash savings from the project are sufficient to ensure a timely repayment of the proposed loan, it does not mean that the parent EEHC Company will be actually able to service the project debt comfortably because it may have many other conflicting obligations. Section 5.4 examines the ability of the EEHC, as a borrowing entity, to service all its debt including the loan for the project in question.

Cost of Electric Energy: It is also important to assess whether the proposed plant is able to generate energy at a reasonable cost. The levelized cost of electricity from the proposed plant is estimated US$ 1.71 cent/kWh, a highly competitive figure by regional and international standards.[17] It is clear that the project is not only the least-cost way of supporting the utility expansion, but also because of its greater efficiency, results in substantial savings of fuel and operating costs over the existing steam and gas plants.

4.5 Financial Sensitivity Analysis of Project

A number of sensitivity tests are carried out to identify critical parameters affecting the project's performance. This section lists the most important parameters identified during the analysis.

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[16] The required rate of return for a public electricity utility is generally regarded as a positive rate that allows the company to manage its cashflows without a loss. Setting a high rate of return on equity, equivalent to private operators, would imply that pricing of the services provided by the public utility will have to be adjusted upward, thus hurting the consumers. Some countries regard excessive profits that may be generated by public utilities as unnecessary, for example public-sector electricity utilities in the UK use a preferential discount rate of 6.0%. For comparison, the official weighted cost of capital for the EEHC in 2004 was stated as 3.0%.

[17] The levelized cost of energy is estimated as the present value of all investment and operating costs over the present value of energy sent out from the plant over its life.

Table 2: Cash Flow Statement for Project: Total Investment Perspective, 2005 prices (million EGP)

INFLOWS	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2033**	**2035**	**2040**	**2045**	**2047**	**2048**
System off-peak cost savings	0	0	0	111	275	324	323	322	322	321	316	315	313	312	311	306	297	285	188	275	265	256	0	0
System peak cost savings	0	0	0	53	134	159	158	157	159	158	157	156	155	154	153	152	146	141	92	136	131	126	0	0
Other revenues	0	0	0	22	55	65	66	66	64	65	64	64	65	62	63	62	61	59	37	56	54	52	290	0
Total Inflows	**0**	**0**	**0**	**186**	**463**	**548**	**547**	**545**	**545**	**544**	**536**	**535**	**533**	**529**	**527**	**520**	**504**	**485**	**317**	**467**	**450**	**434**	**290**	**0**
OUTFLOWS																								
Investment Costs	160	673	836	333	88	0	0	0	0	0	0	0	0	0	0	0	0	0	644	0	0	0	0	160
Operating Costs																								
Fuel costs	0	0	0	60	152	181	182	182	178	179	178	179	179	172	174	173	168	164	103	155	150	145	0	0
O&M	0	0	0	47	101	109	109	108	169	108	108	107	107	167	106	106	105	103	48	102	100	99	0	0
Labor	0	0	0	19	33	33	33	33	33	34	34	34	34	34	34	34	35	36	36	37	38	38	0	0
Change in working capital	0	0	0	24	-2	0	1	1	1	1	1	1	1	1	1	1	1	1	2	1	1	1	5	0
Total Outflows	**160**	**673**	**836**	**482**	**372**	**323**	**324**	**324**	**381**	**321**	**320**	**320**	**320**	**375**	**315**	**314**	**309**	**304**	**834**	**294**	**288**	**283**	**5**	**160**
NET CASH FLOW BEFORE FINANCING	**-160**	**-673**	**-836**	**-297**	**92**	**225**	**223**	**221**	**165**	**222**	**216**	**215**	**212**	**154**	**212**	**206**	**195**	**182**	**-517**	**172**	**162**	**151**	**285**	**-160**
Loan disbursement	114	468	571	163	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	114
Debt repayment	3	7	26	50	57	58	141	135	128	122	116	111	105	100	94	89	67	0	0	0	0	0	0	3
NET CASH FLOW AFTER FINANCING	**-49**	**-211**	**-290**	**-184**	**93**	**167**	**82**	**86**	**36**	**100**	**100**	**105**	**107**	**54**	**117**	**117**	**129**	**182**	**-517**	**172**	**162**	**151**	**285**	**-49**

Annual Net System Savings over Project Debt Service	**1.58**	**1.64**	**1.28**	**1.82**	**1.86**	**1.95**	**2.02**	**1.54**	**2.24**	**2.30**	**2.93**
PV Net System Savings over PV Project Debt Service	**1.91**	**1.95**	**2.00**	**2.10**	**2.14**	**2.19**	**2.23**	**2.27**	**2.42**	**2.46**	**2.93**

NPV @ ROE: 6% real	**EGP 740.1 million**
Financial Internal Rate of Return, real	**FIRR: 12.3%**
Levelized Energy Cost, real	**US 1.71 cent/kWh**

Plant's Utilization: The technical availability of the plant's facilities to generate power depends on the proper exploitation of the turbines and regular maintenance of all mechanisms. The average annual availability of the plant is 80% of the time, and it is expected to decline by 0.5% per annum as the plant ages. Taking that trend as 100% expected utilization, a sensitivity test is carried out in Table 3 in order to examine the performance of the project under situation when the management of the plant achieves a utilization rate beyond or below the expectations. The plant utilization factor is of major concern as a 10% reduction in the this factor over the life of the project would result in a reduction in the NPV of EGP 381.3 million, which is equivalent to a loss of 13.9% of the initial investment value. As the utilization rate declines, the resulting cost of power generated by the plant rises.

Table 3: Sensitivity Test of Plant Availability

Utilization Factor	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
85.0%	168.0	7.4%	1.87
90.0%	358.7	9.1%	1.81
95.0%	549.4	10.7%	1.76
100.0%	740.1	12.3%	1.71
105.0%	930.7	13.9%	1.67
110.0%	1,121.3	15.4%	1.63
115.0%	1,311.8	16.9%	1.59

Investment Costs Overrun: A 10% escalation of investment cost leads to a reduction in the NPV of EGP 159.5 million, which is equivalent to a loss of 5.8% of the initial investment value. Table 4 shows the resulting financial outcomes under a range of possible cost overruns. The cost of electric energy supplied by the plant is influenced by cost overruns, which make power more expensive.

Table 4: Sensitivity Test of Investment Costs Overrun

Costs Overrun	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
-10%	899.6	15.6%	1.66
-5%	819.8	13.7%	1.68
0%	740.1	12.3%	1.71
5%	660.3	11.1%	1.73
10%	580.6	10.1%	1.76
15%	500.9	9.3%	1.78
20%	421.1	8.6%	1.80
25%	341.4	8.0%	1.83
30%	261.6	7.4%	1.85

Growth Rate of Electricity Demand: The amount of power generated by the EEHC will depend on the size of electricity demand by the ultimate users. Table 5 presents the results of a sensitivity test on the rate of annual demand growth over 2005-12. A reduction of 1.5% in the annual demand growth rate lowers the financial NPV of the project by only EGP 26.3 million. That is to say that the equity holder would suffer a loss of 1.0% of the initial investment value of the project. The financial cost of electricity generation from the plant is essentially unaffected by the demand that the electric utility faces.

Table 5: Sensitivity Test of Growth Rate of Electricity Demand 2005-2012

Demand Growth Rate	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
1.0%	385.3	8.8%	1.71
2.0%	557.1	10.3%	1.71
4.0%	667.9	11.5%	1.71
6.0%	713.8	12.0%	1.71
7.5%	740.1	12.3%	1.71
8.0%	750.5	12.4%	1.71
10.0%	754.3	12.5%	1.71

Domestic Inflation: If the rate of domestic inflation in Egypt is raised from expected 3.5% to 7.0% p.a. the financial NPV would decline by EGP 5.4 million as shown in Table 6. This is equivalent to a 0.2% share of the initial investment value of the whole project. The unit cost of power generation would also gradually rise with a higher rate of domestic inflation.

Table 6: Sensitivity Test of Domestic Inflation

EGP Inflation	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
0.0%	748.5	12.3%	1.706
1.0%	746.0	12.3%	1.707
2.0%	743.6	12.3%	1.707
3.0%	741.2	12.3%	1.708
3.5%	740.1	12.3%	1.708
4.0%	739.0	12.3%	1.709
6.0%	734.7	12.2%	1.710
8.0%	730.7	12.2%	1.711
10.0%	726.9	12.2%	1.712
12.0%	723.4	12.1%	1.713

Foreign Inflation: The importance of the project as a least-cost generation unit, resulting in system savings is also demonstrated by an analysis of the impact of foreign inflation in Table 7. An additional 1.0% escalation in the EU inflation rate would reduce the NPV by EGP 18.3 million, which is equivalent to 0.7% of the initial investment value. This is due to the fact that the financing of the investment costs is highly leveraged with debt, and inflation of the EURO will erode the purchasing power of the foreign funds in comparison to the local currency.

Table 7: Sensitivity Test of Foreign Inflation

EU Inflation	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
0.0%	771.6	13.2%	1.70
1.0%	755.1	12.7%	1.70
2.0%	740.1	12.3%	1.71
2.5%	730.7	12.0%	1.71
3.0%	721.8	11.8%	1.71
4.0%	705.2	11.4%	1.72
6.0%	676.1	10.8%	1.73
8.0%	651.7	10.3%	1.73

Loan Interest Rate: Table 8 presents the results of a sensitivity test on the real rate of the AfDB loan. With the base "real" rate of 2.451% and expected EU inflation 2.0%, the nominal borrowing rate is 4.50% p.a. If the base lending rate is raised to 4.0%, implying a nominal rate of 6.08% p.a., the financial NPV will decline by about EGP 136.6 million, or 5.0% of the initial investment value of the whole project.

Table 8: Sensitivity Test of Real Interest Rate

Real Interest Rate	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
0.0%	956.2	15.1%	1.65
1.0%	868.1	13.9%	1.67
2.0%	779.9	12.8%	1.70
2.5%	735.8	12.2%	1.71
2.451%	740.1	12.3%	1.71
3.0%	691.7	11.7%	1.72
4.0%	603.5	10.7%	1.75
5.0%	515.3	9.9%	1.77
6.0%	427.1	9.1%	1.80

Price of Natural Gas: The project is very sensitive to the price of natural gas, a 13.5% increase in the price of natural gas from 0.141 to 0.16 EGP/m3 makes the project more attractive to the utility as the financial NPV rises by EGP 86.9. This is equivalent to 3.2% of the initial investment value of the whole project. Table 9 illustrates this relationship because the higher the price of natural gas the more savings can be gained by using this plant instead of other generation units of the EEHC. While the Government provides a subsidy for a certain portion of the fuel costs, any rise in these costs will push the resulting electricity costs per-kWh upward.

Table 9: Sensitivity Test of Price of Natural Gas

Natural Gas Price (EGP/m3)	FNPV (EGP million)	FIRR	Financial Unit Cost (US$ cent/kWh)
0.12	644.1	11.5%	1.65
0.141	740.1	12.3%	1.71
0.16	826.9	13.0%	1.76
0.18	918.4	13.7%	1.81
0.20	1,009.8	14.5%	1.87
0.22	1,110.3	15.3%	1.93
0.26	1,284.0	16.7%	2.03
0.30	1,466.9	18.2%	2.14
0.35	1,695.4	19.9%	2.28
0.40	1,924.0	21.7%	2.42

5. FINANCIAL ANALYSIS OF ELECTRIC UTILITY

5.1 EEHC Sales and Accounts Receivable

5.1.1 Tariffs and Sales: The EEHC classifies its consumers into several categories according to their power requirements and institutional arrangement. Industrial users, utilities and interconnection are mostly wired through ultra-high voltage (UHV) and high voltage (HV) connection, while all other users are in the medium voltage (MV) and low voltage (LV) schemes. The tariff structure is devised according to the cost of supplying the necessary voltage level and development considerations. Table 10 presents the effective tariff rates, price demand elasticity and amount of energy sold for each consumer group.[18]

Table 10: Effective Tariffs, Price Elasticity and Electricity Sales

Consumer	Effective Tariff, 2005		Price	Energy Sales, 2004	
	(EGPiaster/kWh)	(US cent/kWh)	Elasticity	Share	GWh
Industries	8.90	1.48	-0.07	20.0%	16,131
Agriculture	19.00	3.16	-0.23	4.0%	3,226
Government / Utilities	16.00	2.66	-0.31	12.0%	9,679
Housing	11.40	1.90	-0.30	0.1%	81
Residential	10.95	1.82	-0.30	47.8%	38,554
Commercial	21.00	3.49	-0.32	3.0%	2,420
Others	20.45	3.40	-0.32	3.5%	2,823
Street lighting	34.00	5.65	-0.08	8.5%	6,856
Interconnection	24.00	3.99	-0.50	1.1%	887
Total:	**14.22**	**2.36**		**100%**	**80,656**

The Cabinet of Ministers has allowed the EEHC to raise the electricity tariffs by not more than 5% a year over the period 2005-10. This adjustment is approved in nominal terms, notwithstanding the actual inflation rate that can be materialized during the period. It can be reasonably assumed that the relative proportion of energy demand among the consumer groups will remain following the pattern seen in 2004.

5.1.2 Billing Cycle and Accounts Receivable: Billing and collection is the responsibility of marketing centers at the distribution companies. Currently, all customers are metered and the billing cycle of EEHC's affiliated companies is about 2 months. For most customers, cash is collected upon presentation of the bill and delivered to the marketing centers where collections are banked at the end of each day. A second notice is made if payment is not received within two weeks. Disconnection is invoked for residential and commercial customers failing the customer's settlement of the bill within two weeks after the second notice.

The EEHC is currently burdened with a large accounts receivable, mostly owed by government and public sector institutions. The Government has approved a number of measures in an effort to tackle the weak financial performance of the electricity sector. These include the approval of 5% annual tariff adjustments up to 2010. Secondly, the Government has authorized EEHC henceforth to disconnect public sector consumers who fail to pay their bills; at the same time the Government has stepped up the payment of outstanding accounts receivables.

5.2 System Expansion Plan

5.2.1 Planning Horizon: To meet the projected load and energy demand, EEHC has developed a plan that aims at expanding the generation capacity over 2005-12. This expansion plan is based on the projected demand growth. The main aim is to meet the demand increase and to maintain system reliability to 2012. Details of the program, excluding the El Kureimat plant, are presented in the Table 11.

[18] Parameters provided by the EEHC.

Table 11: System Expansion Plan excluding El Kureimat II Plant, 2005 prices, 2005-12

	2005	2006	2007	2008	2009	2010	2011	2012
Generation Plants								
Additional Capacity Installed (MW)	**2,182**	**835**	**1,434**	**1,370**	**1,450**	**1,650**	**1,650**	**1,575**
Foreign cost, real (US$ million)	395.7	371.0	416.7	494.3	564.7	518.0	442.0	348.0
Local cost, real (EGP million)	804.7	771.9	999.8	1,334.4	1,777.9	1,434.0	1,044.0	828.0
Transmission Networks								
Foreign cost, real (US$ million)	62.0	24.0	109.0	38.0	28.0	35.0	100.0	128.0
Local cost, real (EGP million)	972.0	798.0	690.0	846.0	876.0	960.0	1,020.0	1,248.0
Distribution Networks								
Foreign cost, real (US$ million)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local cost, real (EGP million)	546.0	600.0	660.0	726.0	798.0	876.0	966.0	1,062.0

5.2.2 Financing: The EEHC has relied heavily on debt financing in the past. The explicit government guarantees for its borrowing and timely servicing of the debt have been very helpful to uphold the credit status of the company. For the planned system expansion, it is also clear that the Government will use all possible means to tap international donor's funds available for infrastructure projects. Egypt is also eligible to access financial resources of various Arab development institutions.

While the actual loan arrangements for the projects in the expansion plan have not gained momentum, it is clear that the EEHC will be able to secure funds on concessional terms. For the purpose of this analysis, the assumption is that all loans financing during 2005-12 will come at the same terms, covering 100% of foreign costs and 60% of local costs.

5.3 Assumptions of EEHC Projection Financial

Since the proposed plant is an integral part of a bigger entity, the EEHC, the financial analysis needs to look at the utility's ability to service its debt in the future. The projection of the EEHC cashflows and analysis of cash flow implications for the company's debt servicing over period 2005-25 are built on the following assumptions and parameters.

Energy Balance[19]

- Energy demand forecast expects a 7.5% average annual growth rate during 2005-2012 and 5.0% p.a. thereafter.
- There are 13% system energy losses, comprising of 3% in transmission and 10% during distribution.

Expansion Program[20]

- The 2005-12 expansion programs that install an additional 12,896 MW generation and transmission capacity to the system are part of the financial cashflows of the EEHC.
- Physical and price contingencies will amount to additional 12% of the base costs.
- The financing of 80% of the costs of expansion program assumes a US-dollar denominated development loan.
- Floating base interest rate of 2.70% real p.a. is assumed with a repayment period of 20 years, including a 5-year grace period. The resulting nominal interest rate is 5.23% p.a. There is a commitment fee of 0.25% p.a. on the undisbursed amount.

[19] Figures provided by the EEHC. The annual rate of demand growth beyond 2012 has been assumed.
[20] Refer to Section 5.2 for detailed discussion.

Tariffs and Collection

- Average system tariff in 2005 is EGP 14.22 Piaster/kWh.
- The nominal tariff is assumed to increase at the rate of 5% p.a. up to 2010, and to increase in line with local inflation thereafter.
- Receivables: the average receivables of 327 days in 2004, gradually reducing to 190 days in 2007, 167 days in 2008, 152 days in 2009, and then assuming to be 90 days for government/industries and 60 days for all other customers.[21]

Operation Costs and Working Capital[22]

- Fuel requirements by the system are based on the per-kWh consumption by plants: 0.3752 m3/kWh for gas units, 0.2022 m3/kWh for steam units, and 0.1608 m3/kWh for new combined cycle units.[23]
- Salaries and wages cost the EEHC, on the average, EGP 3.6 Piaster/kWh.
- Material and service input is EGP 2.2 Piaster/kWh.
- Net energy purchased from BOOTs and IPPs is caped at current level of 13,578 GWh/year and cost of EGP 12.72 Piaster/kWh.
- Net interest expense of the EEHC is EGP 2,049 million in 2004, it is assumed to remain constant in nominal terms.
- EEHC's accounts payable are 90 days, cash balances held are 120 days, and inventories are 150 days. The base for A/P, C/B and inventories is the sum of the fuel, salaries & wages, and materials & services inputs expenditures.

5.4 Electric Utility Cashflows and Project's Debt Obligation

5.4.1 No Additional Tariff Increases after 2010: In the electric utility's cashflows, the benefits include the sales of energy to consumers, changes in the stock of receivables, sales of assets, subsidies, any other revenues, including El Kureimat (module II) plant. These inflows are compared with the expenditures on fuel, operation and maintenance, labor, purchases of energy for re-sale, existing and new interest payments on all projects run by the EEHC. In conducting this analysis the entire system expansion plan between 2005-12 must be taken into consideration. The resulting net cash flow should be examined in terms of its capacity to service all the debt obligations of the EEHC, including these from the project.

For the AfDB, it is important to assess the ability of the EEHC to service the scheduled debt repayments of this new project. At the projected levels of investment and operating costs, the net cash flow of the company is a function of the revenues collected from customers. In turn, the revenues of the EEHC are entirely dependent on the electricity tariffs set by the Cabinet of Ministers. An approval has been granted to the EEHC to raise the nominal tariff by a maximum of 5% p.a. over a period from 2005 to 2010, but no decision has been taken about the further tariff adjustment. Given that the average rate of inflation over that past 5 years has been 3.1%, it would appear that this 5.0% nominal raise will yield a real increase in electricity tariffs of only about 1.45% a year.[24]

The net cashflows of the EEHC in Table 13 indicate that in a situation where only this 5% nominal adjustment is undertaken until 2010 and the tariff is inflation-adjusted on annual basis thereafter, the company may have some liquidity gaps and will not be able to pay off all its debt obligations without an external injection of funds in 2013-14. The annual debt service coverage

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[21] The figures are taken from the proposed plan for reduction of receivables from the public sector.

[22] The parameters presented in this section are obtained from the EEHC financial statements.

[23] An average fuel consumption rate by respective types of generation plants in 2004, weighted by the amount of energy generated by each unit. The fuel consumption for new combine cycle plants is the sane as the projects.

[24] The relationship between the nominal and real rates follows identity: $i = r + (1 + r) * gP^e$, where i am nominal rate, r is real rate, and gP^e is expected rate of inflation.

ratios (ADSCR) are the ratios of the net cashflow of the company over the amount of scheduled debt repayment in the current year. As Table 13 shows, all annual debt service ratios are above one, except in 2013 and 2014. The debt service coverage ratios (DSCR) are defined as the present value of the net cashflow during the loan repayment period over the present value of the remaining debt obligations. The cashflow projection indicates that all cumulative debt ratios are well above one, with the lowest ratios in 2012 and 2013.

Note that the debt service ratios are estimated excluding the capital costs of the 2005-12 expansion programs. The EEHC has the ability to borrow for the capital costs and it is unrealistic to expect the company to finance the system expansion from operating margins. Due to this exception of the capital costs from the projection of debt service ratios, the annual ratios are high in the first two years of project debt service, and then in 2013 when the repayment of other loans taken by the EEHC is due the annual ratios decline below one. In the following year and thereafter, the annual debt ratios gradually recover and rise to acceptable levels.

5.4.2 One-Time Real Increase of Tariffs by 6.0% in 2011: In order to bring net cashflows of the utility to a level where the repayments on the debt for all the future elements of the expansion program is just covered (i.e., ADSCR = 1.0 in the worst period of loan repayment, year 2013), the average electricity tariff would need to be raised on a once-for-all basis by at least 6.0% above the rate of inflation in 2011. This adjustment is in addition to the already committed 5% p.a. nominal tariff increases over the period 2005-10 under the assumption of a 3.5% annual rate of inflation. On top of that, the utility would have to adjust the tariffs for inflation in the following years. Table 14 shows the resulting debt service ratios for the EEHC.

Table 13: EEHC Cash Flow Projection and Debt Service, Current Prices (billion EGP)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
REVENUES																						
Sales of Energy	12.3	13.9	15.7	17.7	20.0	22.6	25.1	27.9	30.3	31.4	32.5	33.6	34.8	36.0	37.3	38.6	40.0	41.4	42.8	44.4	45.9	47.5
Change in A/R	0.2	0.3	0.6	0.1	0.0	0.0	-0.5	-0.6	-0.5	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Other revenues	0.8	0.9	1.0	1.1	1.2	1.4	1.5	1.7	1.8	1.9	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.8
Total Inflows	**13.4**	**15.1**	**17.3**	**18.9**	**21.2**	**24.0**	**26.1**	**29.0**	**31.7**	**33.1**	**34.2**	**35.4**	**36.7**	**38.0**	**39.3**	**40.7**	**42.1**	**43.6**	**45.1**	**46.7**	**48.4**	**50.1**
EXPENDITURES																						
Investment Costs	5.8	6.0	7.5	8.0	9.1	8.8	8.7	8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs																						
Fuel costs	3.4	3.9	4.4	4.8	5.3	5.9	6.7	7.5	8.6	8.9	9.1	9.5	9.9	10.3	10.7	10.9	11.4	11.8	12.3	12.8	13.1	13.7
Purchases for sale	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.4	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.6
Salaries and wages	3.2	3.6	4.1	4.7	5.2	5.9	6.7	7.6	8.4	8.4	8.9	9.3	9.7	10.2	10.4	10.9	11.4	11.9	12.5	12.7	13.4	14.0
Materials & services input	1.9	2.2	2.4	2.8	3.2	3.6	4.0	4.5	5.0	5.2	5.2	5.5	5.7	6.0	6.2	6.2	6.5	6.8	7.2	7.4	7.4	7.8
Net interest expenses	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Change in WC	1.0	0.6	0.6	0.6	0.6	0.8	1.0	1.1	1.1	0.3	0.3	0.5	0.5	0.6	0.4	0.4	0.6	0.6	0.7	0.5	0.5	0.8
Total Outflows	**19.1**	**20.1**	**22.9**	**24.8**	**27.5**	**29.0**	**31.2**	**33.5**	**27.4**	**27.3**	**28.0**	**29.3**	**30.4**	**31.8**	**32.4**	**33.4**	**35.0**	**36.3**	**37.9**	**38.7**	**40.0**	**41.8**
NET CASH FLOW BEFORE FINANCING	**-5.7**	**-4.9**	**-5.5**	**-5.9**	**-6.3**	**-5.1**	**-5.1**	**-4.5**	**4.2**	**5.8**	**6.2**	**6.1**	**6.3**	**6.2**	**6.9**	**7.3**	**7.1**	**7.3**	**7.2**	**8.0**	**8.4**	**8.2**
Add: Loan Disbursements	4.8	4.7	6.1	6.3	7.3	7.0	7.0	6.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Additional Interest Expense	0.1	0.4	0.6	0.9	1.2	1.6	2.1	2.5	6.2	6.1	6.0	5.8	5.7	5.6	5.4	5.3	5.1	5.0	4.8	4.7	4.5	4.2
NET CASH FLOW AFTER FINANCING	**-1.0**	**-0.5**	**0.0**	**-0.5**	**-0.2**	**0.4**	**-0.2**	**-0.2**	**-2.0**	**-0.3**	**0.3**	**0.3**	**0.6**	**0.6**	**1.5**	**2.0**	**2.0**	**2.3**	**2.4**	**3.3**	**3.9**	**4.0**
EEHC	**0.1**	**0.3**	**0.6**	**0.9**	**1.2**	**1.6**	**2.1**	**2.4**	**6.2**	**6.1**	**5.9**	**5.8**	**5.7**	**5.6**	**5.4**	**5.3**	**5.1**	**5.0**	**4.8**	**4.7**	**4.5**	
ADSCR							**1.70**	**1.66**	**0.68**	**0.96**	**1.04**	**1.04**	**1.10**	**1.11**	**1.27**	**1.37**	**1.39**	**1.47**	**1.49**	**1.71**	**1.86**	
DSCR							**1.21**	**1.15**	**1.09**	**1.15**	**1.17**	**1.19**	**1.22**	**1.24**	**1.26**	**1.26**	**1.23**	**1.19**	**1.12**	**1.00**	**1.86**	

Table 14: Debt Service Ratios of EEHC with 6.0% Real Tariff Increase in 2011

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ADSCR	2.40	2.36	1.00	1.23	1.39	1.41	1.49	1.52	1.70	1.84	1.88	1.99	2.05	2.31	2.50
DSCR	1.65	1.56	1.48	1.54	1.59	1.62	1.65	1.67	1.70	1.70	1.67	1.62	1.52	1.35	2.50

5.4.3 Nominal Increase of Tariffs by 5.75% p.a. over 2011-15: As it is easier for the EEHC and government to operate with nominal figures, the necessary real tariff increase can be spread over several years. If the Government continues the nominal tariff increase over the period 2011-15 but now with a rate of 5.75% per year. With an expected rate of inflation of 3.5% per annum, the projected debt service ratios of the company will appear as this in Table 15. The two options, whether to raise tariffs once-for-all by 6.0% in real terms in 2011 or to phase out this increase over 2011-15 through nominal increases of 5.75%, are roughly equivalent, provided that the domestic inflation rate remains within the 3.5% p.a. range. Any unexpected increase in the inflation will erode the revenues of the electric utility.

Table 15: Debt Service Ratios of EEHC with 5.75% Nominal Tariff Increase 2011-2015

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ADSCR	1.92	2.13	1.00	1.42	1.67	1.73	1.83	1.88	2.08	2.24	2.31	2.45	2.54	2.83	3.06
DSCR	1.90	1.84	1.77	1.88	1.94	1.98	2.02	2.06	2.09	2.09	2.06	1.99	1.87	1.65	3.06

It may appear that both tariff adjustment options are equivalent in terms of achieving gap-free cash flow coverage of the scheduled debt payments. However, there is a substantial risk associated with the second method of nominal tariff adjustment. Any increase in the rate of domestic inflation beyond the expected 3.5% p.a. will effectively lower the ability of the company to service its debt.

5.5 Financial Sensitivity Analysis of EEHC

The financial sensitivity analysis of the EEHC is also carried over for several key parameters affecting its performance.

Domestic Inflation: The rate of domestic inflation in Egypt is a very important determinant of the financial viability of the electric utility, especially in a situation when the tariffs are fixed in nominal terms and no automatic mechanism exist to adjust the tariffs for erosive impact of inflation. Table 16 shows that inflation has a strong impact on the EEHC, whose expenditures would rise without appropriate adjustment in the fixed electricity tariffs. In an inflationary environment, the company will find it more difficult to service its debt unless tariffs are raised.

Table 16: Sensitivity Test of Domestic Inflation

Domestic Inflation	ADSCR 2011	ADSCR 2012	ADSCR 2013	DSCR 2011	DSCR 2012	DSCR 2013
0.0%	1.81	1.75	0.72	1.22	1.15	1.08
1.0%	1.78	1.73	0.71	1.23	1.16	1.09
2.0%	1.75	1.70	0.70	1.23	1.16	1.10
3.0%	1.71	1.68	0.69	1.22	1.16	1.10
3.5%	1.70	1.66	0.68	1.21	1.15	1.09
4.0%	1.68	1.65	0.68	1.20	1.14	1.09
6.0%	1.61	1.58	0.65	1.16	1.11	1.05
8.0%	1.54	1.52	0.62	1.11	1.06	1.01
10.0%	1.47	1.45	0.59	1.05	1.01	0.96
12.0%	1.40	1.38	0.56	1.00	0.95	0.91

Price of Natural Gas: The electric utility is very sensitive to the cost of natural gas, which is the main feedstock of the whole generation sub-sector. It is clear that removal of subsidy on the natural gas will make the EEHC to spend more on fuel, thus reducing the net cashflow and having less cash available for servicing the debt payments. Given the fact that the EEHC has no ability to pass on the fuel cost increases on the consumers, this parameter is critical to survival of the company. Table 17 illustrates this relationship between the price of natural gas and the debt service of the electric utility.

Table 17: Sensitivity Test of Price of Natural Gas

Natural Gas Price (EGP/m3)	ADSCR 2011	ADSCR 2012	ADSCR 2013	DSCR 2011	DSCR 2012	DSCR 2013
0.12	2.20	2.14	0.90	1.51	1.43	1.36
0.141	1.70	1.66	0.68	1.21	1.15	1.09
0.16	1.25	1.23	0.49	0.94	0.90	0.85
0.18	0.77	0.78	0.28	0.65	0.63	0.60
0.20	0.30	0.32	0.08	0.37	0.36	0.35
0.22	-0.23	-0.18	-0.15	0.05	0.06	0.08
0.26	-1.13	-1.04	-0.54	-0.49	-0.45	-0.40
0.30	-2.08	-1.95	-0.96	-1.06	-0.98	-0.90
0.35	-3.27	-3.08	-1.47	-1.78	-1.65	-1.53
0.40	-4.46	-4.22	-1.99	-2.49	-2.32	-2.16

Electricity Tariffs: Another critical parameter for the electric utility is level of tariffs. The company is exposed to the inflation through its operating expenses and interest obligations. In such a situation, the level of tariff is a key to the financial health of the company. Since the Government has already committed a series of nominal tariff increases until 2010, a sensitivity test in Table 18 examines the EEHC's debt service ratios under a range of real tariff increases in 2011. It is assumed that until 2010, the rate of domestic inflation will not exceed 3.5% p.a. and the increase in tariff in 2011 is a once-for-all raise in addition to the inflation. The resulting impact on the debt service is dramatic because a 6% real increase ensures 100% coverage of the scheduled annual repayments in 2013, the worst year of service. The annual and cumulative debt ratios in all other periods also rise significantly.

Table 18: Sensitivity Test of Additional Tariff Increase in 2011, Real

Tariff Increase	ADSCR 2011	ADSCR 2012	ADSCR 2013	DSCR 2011	DSCR 2012	DSCR 2013
0.0%	1.70	1.66	0.68	1.21	1.15	1.09
2.5%	1.99	1.95	0.81	1.39	1.32	1.25
5.0%	2.28	2.24	0.95	1.58	1.49	1.41
6.0%	2.40	2.35	1.00	1.65	1.56	1.48
7.5%	2.57	2.52	1.08	1.76	1.66	1.57
10.0%	2.85	2.80	1.20	1.94	1.83	1.73
12.5%	3.13	3.08	1.33	2.12	2.00	1.89
15.0%	3.41	3.35	1.45	2.30	2.17	2.05

Accounts Receivable: The financial health of the electric utility depends on the successful reduction of the accounts receivable from the public sector. The base assumption is that by 2010 the stock of receivables from the Government and public sector industries will not exceed 90 days. Table 19 looks at the length of receivables and its impact on the ability of the EEHC to service debt repayments. Note that the impact of accounts receivables from the public sector is very significant because there is a substantial amount of cash outstanding on bills of the Government and public utilities. In a situation of fixed nominal tariffs and no automatic inflation adjustment, the issue of receivables is critical.

Table 19: Sensitivity Test of Duration of Accounts Receivable from Public Sector 2010 & Thereafter

Receivables (days)	ADSCR 2011	ADSCR 2012	ADSCR 2013	DSCR 2011	DSCR 2012	DSCR 2013
60	1.73	1.69	0.69	1.22	1.16	1.10
90	1.70	1.66	0.68	1.21	1.15	1.09
120	1.66	1.63	0.67	1.20	1.14	1.09
150	1.63	1.60	0.66	1.19	1.13	1.08
180	1.59	1.56	0.65	1.18	1.13	1.07
210	1.56	1.53	0.64	1.17	1.12	1.07
240	1.53	1.50	0.63	1.16	1.11	1.06
270	1.49	1.47	0.62	1.15	1.10	1.05

6. ECONOMIC APPRAISAL

6.1 Approach and Economic Parameters

The economic appraisal of a project deals with the effect of the project on the entire society and determines if the project increases the total net economic benefits accruing to the society as a whole. The economic appraisal needs to translate all financial transactions (i.e., receipts and expenditures) into benefits and costs in the economic resource statement in order to reflect their value to the society.

An important feature of the economic analysis using the integrated appraisal framework is that the economic evaluation is directly linked to the financial model of the project. The economic module of project appraisal is absolutely consistent with the financial analysis, and allows the analyst to stage sophisticated inquiries into the project financial and economic performance at the same time.

To ensure such a consistent transformation from the financial evaluation into economic analysis, the model is based on the financial values and parameters of the project. A number of adjustments are made to convert these financial values into their corresponding economic values. In general, the economic prices of tradable goods are all estimated free of taxes and subsidies but including the foreign exchange premium due to variety of distortions associated with the markets for traded goods. They replace the values used in the financial analysis for value of receipts or expenditures in the financial cashflow statement. Before discussing the estimation of the economic values of the project's costs and benefits, the following parameters and assumptions have to be defined.

National Parameters

- Economic cost of capital (EOCK) is taken as a real rate of 10.0%.[25]
- Foreign exchange premium (FEP) is estimated as 9.0%.[26]
- Shadow price of non-tradable outlays (SPNTO) is taken as 0.5%.
- Average rate of tax distortion in traded and non-traded sectors (d*) is 8.0%.

Economic Value of Fuel

- The economic value of natural gas is taken as the netback value of exports, derived from the international price of liquefied natural gas, which closely follows the crude oil prices. The expected crude oil price is taken as 30 US$/barrel.
- Economic value of diesel fuel is estimated using the netback approach staring from the border price.

Valuation of Benefits

- Economic valuation of system off-peak savings comprises savings of fuel, the natural gas, and saving on O&M costs in economic terms. Fuel savings are valued at their economic price and O&M savings are adjusted for taxes and foreign exchange premium.
- The assessment of peak savings comprises savings of fuel, saving on O&M costs in economic terms, and capital savings valued at the economic opportunity cost of capital.

Taxes and Import Duties

- There is a general sales tax of 10% on most of the consumer purchases in Egypt, including sales of electricity to consumers, but excluding transactions with natural gas.
- Custom duties: high-duty imports are commodities that can be domestically manufactured and are subject to import duty of 30%. Low-duty imports are commodities that have no domestic equivalent, and are subject to a tariff rate of 5% of their CIF value.
- The EEHC will withhold personal income tax on monthly income of employees: below EGP 10,000 is exempt, the income between EGP 10,000 and EGP 13,000 is subject to 10% rate; income between EGP 13,000 and EGP 16,000 is liable to a 15% rate, and above is taxed at 20%. There is a compulsory contribution to the social security / pension fund, set at a maximum of EGP 1,125 a year.

6.2 Economic Value of Project Items

This section describes the application of the methodology of estimation of economic values for project's inputs and output. The resulting economic conversion factors used in the development of the economic resource flow statement are also presented.

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[25] While no specific analysis was done in regard to estimation of the economic opportunity cost of capital (EOCK) for Egypt, 10.0% real is assumed for the purpose of this analysis. See for example, Kuo, Jenkins, and Mphahlele, "The Economic Opportunity Cost of Capital for South Africa", South African Journal of Economics, June 2003.

[26] An estimation of the value of foreign exchange premium in Egypt yielded a rate of 9%. The value of shadow price of non-tradable outlays was assumed to be 0.5%.

6.2.1 Economic Value of Natural Gas

Financial Cost of Natural Gas: Egypt is endowed with substantial reserves of natural gas which are mainly underdeveloped. Government's policies in the energy sector are aimed at securing sufficient and affordable energy supplies to meet the requirements of all segments of the economy, to improve sector efficiency, and to optimize both domestic utilization of the country's energy resources and energy export. The domestic prices of natural gas have been regulated by the Government and kept at low levels, substantially less than the international prices. The regulated price charged to other industrial user is EGP 0.22 per cubic meter in 2005. The power sector has enjoyed even a lower gas prices through preferential agreements setup with the state-controlled natural gas utility EGEAS. The effective cost of natural gas for the EEHC is 0.14 EGP/m3.

Netback Value of Natural Gas Exports: Currently, natural gas production sufficiently covers all domestic needs by residential and industrial users, and the excess is exported as liquefied natural gas (LNG). Egypt has been steadily increasing the volume of LNG exports in the recent years and the trend is said to continue in the future. The shipment of LNG by the EGEAS is facilitated through contracts with international traders and, unfortunately, the contractual prices are not known. However, the international price of natural gas has been following the price of the crude oil closely. A specific formula of LNG price as a function of the crude price was developed by gas exporters to be used during contract negotiations:

LNG Price (US$/GJ) = 0.1567 * Crude Oil Price (US$/bbl) + 0.79

For a crude price of 30 US$/barrel, which is assumed to be long-run average price of crude oil, the corresponding price of LNG will be 5.49 US$/GJ. There are processing and shipping costs for natural gas (from source to the port), comprising about 3.0 US$/GJ and 1.0 US$/GJ, respectively. This implies that the border value of natural gas is 2.49 US$/GJ. This figure translates into the netback value of 1.49 US$/GJ or 1.71 US$/cuf.[27] There is already an existing gas pipeline to the Module I of El Kureimat plant, thus no new pipeline will be needed for Module II. The average domestic cost of gas delivery from the EGEAS to the plant is assumed 0.285 US$/cuf. Thus, the value of natural gas used by the proposed plant is 2.00 US$/cuf or 0.0567 US$/m3. With the current foreign exchange rate of 6.0154 EGP/US$, the value of natural gas at the project site is therefore 0.3406 EGP/m3.

Economic Value and Conversion Factor: A foreign exchange premium of 9.0% has to be added to the netback value as forgone forex earnings on the sale of LNG. The resulting economic value of the natural gas is 0.3713 EGP/m3. An economic conversion factor (CF) is simply the ratio of the economic value to financial value. Thus, the economic value of natural gas is 2.633 times the financial value, and the economic conversion factor for natural gas is therefore equal to 2.633 (= 0.3713 / 0.1410).

6.2.2 Economic Value of Investment Costs, O&M Items and System Savings

Investment Costs: In regard to the investment costs which are mainly tradable items, except civil works, the economic valuation removes all import duties and other indirect taxes imposed on the items. In addition, the values of foreign exchange premium and shadow price of non-tradable outlays have to be incorporated.

[27] The gross calorific value of natural gas is 38,493 Btu/m3 or 40,612,246 J/m3. Since one cubic feet of natural gas corresponds to 0.02832 cubic meters, the gross calorific value per cubic feet is equal to 1,150,011 Joules. The gas value of 1.49 US$/GJ, or 0.000001491 US$/J, is then multiplied by the number of Joules in one cubic feet, or 1,150,011 J/cuf, in order to derive the border value of natural gas of 1.71 US$/cuf.

For non-tradable civil works, the analysis also looks at the distortions in the inputs markets (i.e., taxes and subsidies on the goods and services used in civil works).[28] It is assumed the tradable inputs to civil works attract both the import duty and general sales tax, while non-tradable inputs and only subject to the general sales tax. An additional adjustment for the foreign exchange premium and shadow price of non-tradable outlays on the respective content of the supply price of civil works was also incorporated.

Operation and Maintenance: The main components of O&M expenditures on a combine-cycle plant are replacement parts and equipment necessary to ensure a smooth operation of the gas and steam turbines of the plant. These items are all tradable commodities even though some can be procured from domestic suppliers. The distortions in the market for these inputs include the import duty and general sales tax. It is assumed that periodic maintenance expenditure, maintenance materials, and general plant expenses consist of commodities that attract low import duties. The following items are taken as subject to high import duty rate: fixed supplies and expenses, sponsor expenses, admin and general costs, cooling water chemicals, water treatment chemicals, consumables and supplies, and other variable expenses. The value of foreign exchange premium has to be factored in the estimation of the economic cost of all these O&M items.

Labor: The economic cost of labor (EOCL) employed by the project is estimated using the supply price approach. The approach starts with the wage paid by the project and deducts all applicable withholding and income taxes to arrive at the net income received by the labor.[29] It is assumed that 90-95% of the labors employed by the project are attracted from the labor force, and the project, being part of a public sector utility, pays no specific performance bonuses. The standard package of social security benefits is provided to the employees.

For expatriate staff, the economic cost of labor is estimated by incorporating the foreign exchange premium on the remittances of net income abroad, while also including the amount of taxes collected on the consumption in Egypt.[30]

Economic Value of System Savings: The economic valuation of off-peak system savings builds on the financial analysis, and includes two types of savings: fuel savings and O&M savings. The fuel savings are valued at the economic cost of natural gas. The economic value of O&M savings is estimated by applying an O&M conversion factor on the financial amount of O&M savings.

For peak savings, the economic valuation of fuel and O&M savings is identical in the approach used for the off-peak savings. The assessment of economic value of capital savings, or economic value of avoided gas turbine capacity cost, during the peak periods requires a re-estimation of a capital charge. Two changes must be done in this procedure to be used in the economic analysis. The first is to remove the import duties and taxes from the capital costs of installed gas turbine capacity, and to add the value of foreign exchange premium on the tradable expenditures. The

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28 The composition of inputs in civil works is assumed to follow the structure of the infrastructure and public works construction in South Africa. Appendix F, Cambridge Resources International, Inc. (2004). *Integrated Investment Appraisal: Concepts and Practice*.

29 The EOCL is equal to the willingness of people to supply labor for the project activities, net of taxes and social security contributions: $EOCL = Gross\ Income^{Project} - Soc.Security^{Project} - [Taxes^{Project} - (Taxes^{Alternative} * Share^{Alternative}) - Soc.Security^{Alternative}]$. For expatriate labor: EOCL = Net Income + (Net Income * %Repatriated * FEP) – (Net Income * %Consumption * Sales Tax), where the net income is equal as the gross annual salary minus taxes and social security contribution.

30 Appendix D, Cambridge Resources International, Inc. (2004). *Integrated Investment Appraisal: Concepts and Practice*.

second is to substitute the financial rate of return with the economic cost of capital. Thus, the economic value of capital charge amounts to US$ 7.76 cents/kWh.[31]

Conversion Factors for Working Capital: For the changes in accounts payable, the conversion factor is linked to the value of economic costs. For the changes in cash balance, the conversion factor is taken as one. The changes in the diesel inventory are valued at the economic value of diesel.

Summary of Economic Conversion Factors: The economic value of all inputs used by the project is estimated, and the resulting economic conversion factors are summarized in Table 20. Multiplying these conversion factors by the corresponding cash flow items in the financial statement of the project will arrive at the economic costs and benefits of the economic resource statement. Some of the project items do not have a specific economic conversion factor, as their values are based on the annual flow of the related resource.

Table 20: Economic Conversion Factors

Item	CF
System peak / off-peak cost savings	no CF
Liquidation value	1.090
Civil works	0.942
Gas turbine generator; Steam turbine generator; Heat recovery steam generator; Switchyard;	1.090
Environmental monitoring; Project management	0.984
Wrap-up insurance	1.005
Gas / Diesel expenditure	no CF
Maintenance materials; General plant expenses; Periodic maintenance	0.940
Fixed supplies and expenses; Sponsor expenses; Admin and general costs; Cooling water chemicals; Water treatment chemicals; Consumables and supplies; Other variable expenses	0.771
Manager's Office	0.984
Labor: Operations; Maintenance; Technical support	1.000
Expatriate labor	0.898
Overheads	1.000
Change in A/P	no CF
Change in C/B	no CF
Change in diesel inventory	no CF

6.3 Economic Feasibility of Project

In the economic analysis all prices are measured in economic terms, and the resulting economic resource statement of the project is presented in Table 21. The economic benefits of the project are the savings of the natural gas that can be exported by the country and the savings of O&M and capital expenditures for the EEHC. Using the economic opportunity cost of capital for Egypt at 10% real, the estimated economic NPV of the proposed plant is EGP 667.8 million, which implies that the country as a whole is better of with the proposed project. The economic wealth of Egypt will be expanded due to the contribution made by this plant.

[31] The financial cost of installed capacity of 400 US$/kW must be adjusted for import duties and local taxes. The resulting economic cost is 388.0 US$/kW. A 25-year lifespan and a 10% economic rate of return on capital requires a 14% capital charge a year, or 54.32 US$/kW. As the gas turbine is used for 700 hours/year, the per-unit charge is US$ 7.76 cent/kWh.

Table 21. Economic Resource Flow Statement, 2005 prices (million EGP)

BENEFITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030	2033	2035	2040	2045	2047	2048
System off-peak cost savings	0	0	0	183	452	529	529	528	531	529	517	519	516	515	513	503	489	468	310	451	436	421	418	0
System peak cost savings	0	0	0	83	209	248	248	246	252	250	247	246	245	243	242	239	231	222	145	214	206	199	196	0
Other revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	316
Total Benefits	**0**	**0**	**0**	**267**	**661**	**777**	**777**	**774**	**782**	**779**	**765**	**765**	**761**	**759**	**755**	**742**	**720**	**690**	**456**	**665**	**642**	**619**	**614**	**316**
COSTS																								
Investment Costs	156	654	812	315	86	0	0	0	0	0	0	0	0	0	0	0	0	0	644	0	0	0	0	0
Operating Costs																								
Fuel costs	0	0	0	100	255	304	305	305	298	301	299	300	300	289	292	290	283	275	173	261	251	243	243	0
O&M	0	0	0	39	84	90	90	89	136	89	89	89	88	135	88	88	86	85	39	84	83	82	81	0
Labor	0	0	0	18	32	32	32	32	32	33	33	33	33	33	33	33	34	35	35	36	36	37	38	0
Change in working capital	0	0	0	37	-4	-1	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	-12	-21
Total Costs	**156**	**654**	**812**	**509**	**453**	**425**	**427**	**427**	**467**	**422**	**421**	**421**	**421**	**457**	**413**	**411**	**403**	**395**	**894**	**380**	**371**	**363**	**350**	**-21**
NET RESOURCE FLOW	**-156**	**-654**	**-812**	**-243**	**207**	**352**	**350**	**347**	**315**	**357**	**344**	**344**	**339**	**301**	**343**	**331**	**317**	**295**	**-439**	**285**	**271**	**257**	**264**	**337**

NPV @ EOCK: 10% real	**EGP 667.8 million**
Economic Internal Rate of Return, real	**EIRR: 13.9%**
Levelized Energy Cost, real	**US 2.41 cent/kWh**

The value of economic benefits realized by the country is significantly larger than the amount of resources used for the installation of the proposed plant, which is also confirmed by the estimated internal rate of return on economic net resource flow (EIRR) being 13.9%. The next question to ask is whether the proposed plant is a reasonable method of generating electricity in economic terms. The model allows separating the economic benefits and economic costs of the project in order to estimate the levelized cost of electric power, which is the present value of all investment and operating costs in economic prices over the present value of energy sent out from the plant. Apparently, the project is an economically sound way of generating the power as the resulting economic cost of electricity is US$ 2.41 cent/kWh. This figure, while somewhat higher than the cost of power in financial model, is very competitive by regional and international standards.

6.4 Economic Sensitivity Analysis

Plant Utilization: The utilization of the plant is an important factor affecting the economic performance of the project. If, for any reason, the actual plant availability declines by 10%, the economic NPV will decrease by EGP 311.7 million, which is equivalent to a loss of 12.8% of the investment value in economic terms, which is the present value of economic investment costs plus the economic net present value. Table 22 shows that the management's ability to maintain the turbines and facilities in a working condition is essential for the project economic returns. It is not surprising that the economic cost of energy supplied by the project will increase if the utilization of the plant is lower than expected.

Table 22: Sensitivity Test of Plant Availability

Utilization Factor	ENPV (EGP million)	Economic Unit Cost (US$ cent/kWh)
85%	200.0	2.63
90%	356.1	2.55
95%	512.0	2.48
100%	667.8	2.41
105%	823.4	2.36
110%	978.6	2.30
115%	1,133.6	2.25

Investment Costs Overrun: A 10% escalation of investment cost leads to a loss of EGP 152.1 million, or 6.4% of the investment value in economic terms. Table 23 shows the resulting economic outcomes under a range of possible cost overruns. The unit cost of production will also increase, as a higher amount of investment costs will have to be spread over the energy generated by the plant throughout its lifespan.

Table 23: Sensitivity Test of Investment Costs Overrun

Costs Overrun	ENPV (EGP million)	Economic Unit Cost (US$ cent/kWh)
-5%	743.1	2.37
0%	667.8	2.41
5%	592.0	2.45
10%	515.7	2.49
15%	439.0	2.53
20%	361.9	2.57
25%	284.6	2.61
30%	206.9	2.65

International Price of Crude Oil: The new plant actually saves exportable natural gas, whose selling price is closely linked to the price of crude oil on international market. Table 24 shows that if the base price of crude oil increases from 30 US$/bbl to 40 US$/bbl, the economic NPV of the project rises by EGP 916.8 million, reflecting the opportunity value of natural gas. This additional gain is of a size of 37.7% of the investment value in economic terms. Needless to say, the economic cost of electricity production with higher oil prices will have to increase, regardless of the savings the project generates.

Table 24: Sensitivity Test of International Price of Crude Oil

Crude Oil Price (US$/bbl)	ENPV (EGP million)	Economic Unit Cost (US$ cent/kWh)
20.0	-248.9	1.50
24.0	117.8	1.87
30.0	667.8	2.41
36.0	1,217.9	2.96
40.0	1,584.6	3.32
50.0	2,501.3	4.23
60.0	3,418.1	5.15

Electricity Demand Growth: The rate of electricity demand growth affects the optimal stacking decisions taken by the electric utility in terms of using a particular mix of generation plants to meet the perceived demand. The new plant, being a part of the system, is also dependent on the operational decisions of the EEHC. Table 25 confirms that a lower demand growth rate would lead the company to adjust its generation schedule, and the savings from the new plant will be less. If the annual rate of electricity demand over 2005-12 does not exceed 4.0% p.a. on the average, the economic NPV of the project will decline by EGP 144.8 million, which is equivalent to a loss of 6.0% of the investment value in economic terms. The economic cost of electricity generation at the plant is not affected by the demand growth rate.

Table 25: Sensitivity Test of Electricity Demand Growth 2005-12

Demand Growth Rate	ENPV (EGP million)	Economic Unit Cost (US$ cent/kWh)
2.0%	307.3	2.41
4.0%	523.0	2.41
6.0%	613.4	2.41
7.5%	667.8	2.41
8.0%	690.4	2.41
10.0%	699.1	2.41

7. STAKEHOLDER IMPACTS

Stakeholder analysis identifies the winners and losers and how much they would gain and lose as a result of the project implementation. The financial and economic analysis of the integrated project analysis can provide the basic data for estimating the specific stakeholder impacts.

7.1 Identification of Externalities

The stakeholder analysis of the El Kureimat project is conducted to identify which particular segments of society reap the benefits and which ones, if any, lose from the implementation of the plant. The stakeholder analysis of any project builds on the following relationship:

$$P_e = P_f + \sum_{i=1} E_i$$

Where: Pe is the economic value of an input or output;
Pf is the financial value of the same variable; and
ΣEi is the sum of all the externalities that make the economic value different from the financial value of the item.

In other words, the economic value of an item can be expressed as the sum of its financial price plus the value of externalities, such as taxes, tariffs, consumer/producer surplus. On the basis of identity above, the following relationship also holds, if a common discount rate is applied:[32]

$$NPV_e^{EOCK} = NPV_f^{EOCK} \quad + \quad PV^{EOCK}\left(\sum Ext_i\right)$$

Where: NPV_e^{EOCK} is the net present value of the net economic benefits;
NPV_f^{EOCK} Is the net present value of the financial net cash flow; and
$PV^{EOCK}\left(\sum Ext_i\right)$ Is the sum of the present value of all the externalities generated by the project?

The project generates two types of net benefits: financial net benefits, which accrue directly to those that, have a financial interest in the project; and externalities, which are allocated to different segments of society. The stakeholder analysis requires the following steps:

- Identifying the stakeholder impacts of the project, item-by-item, by subtracting the financial cash flow statement from the economic statement of benefits and costs.
- Calculating the present value of each line item's flow of externalities, using the economic cost of capital as the discount rate.
- Allocating the present value of the externalities to the relevant groups in the economy.

Table 26 presents the reconciliation between the financial, economic and externalities of the proposed project, all discounted by economic cost of capital of 10% real. If the economic NPV is equal to the financial NPV plus the present value of distributional impacts, using a common discount rate, it indicates that the analysis was carried out in a consistent manner. The economic NPV is the same as shown in Table 21, however the financial NPV is not equal to one displayed in Table 2. Where the financial net cashflow is discounted at the required rate of return on equity of 6.0% real.

By implementing this project, the economy of Egypt will end up saving substantial amounts of natural gas. This natural gas would be available to be sold abroad as liquefied natural gas. The net back value of the natural gas sold is substantially larger than the low price that the EEHC is required to pay. Table 26 suggests that this financial loss due to using a preferential discount rate of 6% real is EGP 345.8 million.[33] At the same time, the economic impact of the project measured by the economic flows is sufficiently high to offset this discount rate setback. The economic NPV of the project is EGP 667.8 million. The difference between the financial NPV and the economic NPV, both discounted at the economic cost of capital of 10% real, is the present value of all externalities created by the project, equal to EGP 1,013.6 million.

[32] In this case the economic opportunity cost of capital.

[33] The financial NPV discounted at the EOCK of 10.0% real, instead of target return on equity of 6.0% real, is estimated as EGP 345.8 million.

Table 26: Present Value of Financial Cashflows, Economic Resource Flows and Externalities, 2005 prices (million EGP)

	Financial	Externalities	Economic
BENEFITS			
System off-peak cost savings	2,318.3	1,496.3	3,814.5
System peak cost savings	1,139.9	654.2	1,794.1
Other revenues	474.1	-468.8	5.2
Total Benefits	**3,932.3**	**1,681.6**	**5,613.9**
COSTS			
Investment Costs	1,816.7	-54.4	1,762.3
Operating Costs			
Fuel costs	1,300.0	882.7	2,182.8
O&M	875.9	-156.0	720.0
Labor	264.8	-8.0	256.8
Change in working capital	20.7	3.6	24.3
Total Costs	**4,278.1**	**668.0**	**4,946.1**
NET FLOW	**-345.8**	**1,013.6**	**667.8**

7.2 Distributive Analysis

It is important to know what is the net contribution of the project to all stakeholders. While some of the involved parties may gain due to the project activities, the others may have to incur a certain loss. The net impact on all stakeholders created by the project is a sum of negative and positive externalities imposed on the involved stakeholders. On the benefits side, the externalities amount to EGP 1,681.6 million and there is a total of EGP 668.0 million in externalities on the cost side. These two add up to a net of EGP 1,013.6 million that is created by the project and accrues to the stakeholders of the project.

Also, it is necessary to assess the magnitude of any burden imposed on the stakeholders. This can be measured by the incremental net cash flows that are expected to be realized by each group. Then the question becomes whether the project addresses the needs of the right group of stakeholders. Table 27 presents the allocation of economic externalities generated by this project among the Government's Treasury and the state-controlled gas utility. The figures in the table are the present values of impacts, discounted by the EOCK of 10%.

The integrated appraisal framework allows the analyst to reconcile the total externalities with the gains and losses accruing to a particular group of stakeholders. The middle column with externalities in Table 27 is the same as the net impact on public sector in Table 28. The resulting net impact on the gas utility is a gain of EGP 1,163.0 million due to additional sales of natural gas over the duration of the project. As a partial offset to this amount there is a net loss in tax revenues of EGP 149.4 million, which includes all indirect taxes, subsidies and foreign exchange premium. Hence, the net impact on the public sector amounts to EGP 1,013.6 million, which implies that the benefits to the energy sector realized due to this project overweigh the additional costs to the Government.

In terms of the allocation of the net financial gain of the project, which amounts to EGP 740.1 million, it is clear that the EEHC would use this contribution to maintain its existing network and to re-invest into new assets. In contrast to some other countries, the electric utility in Egypt is not an aggressively profit-oriented company. Its main task is to match the demand and supply of energy in the country, and the financial gain of the project will be passed on to the consumers. Hence, the public at large will benefit from the project indirectly.

Table 27: Allocation of Externalities, 2005 prices (million EGP)

	GOVERNMENT Taxes, subsidies, FEP	PETROLEUM EXPORTER Savings	PUBLIC SECTOR Net Impact
BENEFITS			
System off-peak cost savings	123.6	1,372.7	1,496.3
System peak cost savings	54.0	600.1	654.2
Other revenues	-468.8	0.0	-468.8
Total Benefits	**-291.2**	**1,972.8**	**1,681.6**
COSTS			
Investment Costs	-54.4	0.0	-54.4
Operating Costs			
Fuel costs	72.9	809.8	882.7
O&M	-156.0	0.0	-156.0
Labor	-8.0	0.0	-8.0
Change in working capital	3.6	0.0	3.6
Total Costs	**-141.8**	**809.8**	**668.0**
NET EXTERNALITY FLOW	**-149.4**	**1,163.0**	**1,013.6**

7.3 Sensitivity Analysis of Stakeholder Impacts

Plant's Utilization: Plant utilization has a significant impact on the size of externalities. If, for any reason, the actual plant utilization rate declines by 10%, the net externality will decrease by EGP 82.5 million, which is equivalent to 3.9% of the investment value of the project in economic terms. Table 28 shows that a decline in the plant's utilization implies a higher domestic demand for natural gas and a lower export volume to generate economic externalities. Meanwhile, it is reasonable to expect the Government, which has a negative impact in terms of net collection of non-petroleum taxes and foreign exchange, to have the size of this negative impact will increase further with a higher utilization rate of the plant.

Table 28: Sensitivity Test of Plant Availability

Plant Utilization	PV Net Externality (EGP million)	PV Government (EGP million)	PV Gas Exporter (EGP million)
85%	889.6	-105.5	995.2
90%	931.1	-120.1	1,051.3
95%	972.4	-134.7	1,107.2
100%	1,013.6	-149.4	1,163.0
105%	1,054.6	-164.0	1,218.6
110%	1,095.4	-178.6	1,274.0
115%	1,135.9	-193.3	1,329.3

International Price of Crude Oil: The results of sensitivity test in Table 29 show that this parameter is critical in determining not only the total size of economic externalities created by the project but also the relative distribution of these impacts between the Government and its gas utility. If the price of crude oil increases from 30 US$/bbl to 40 US$/bbl, the net externality rises by EGP 916.8 million, reflecting the high opportunity cost of natural gas. This is equivalent to 37.7% of the investment value of the project in economic terms. As a result, the gas exporter will be able to sell natural gas at a higher rate and the Government will collect more foreign exchange on the sales proceeds.

Table 29: Sensitivity Test of International Price of Crude Oil

Price of Crude Oil (US$/bbl)	PV Net Externality (EGP million)	PV Government (EGP million)	PV Gas Exporter (EGP million)
20.0	96.9	-228.0	324.9
24.0	463.6	-196.6	660.1
30.0	1,013.6	-149.4	1,163.0
36.0	1,563.7	-102.1	1,665.8
40.0	1,930.4	-70.7	2,001.1
50.0	2,847.1	8.0	2,839.1
60.0	3,763.9	86.7	3,677.2

Growth Rate of Electricity Demand: The new plant, being a part of the system, is also dependent on the operational decisions of the EEHC. Table 30 confirms that a lower rate of growth of demand for electricity will lead the company to adjust its generation schedule, and the savings from the new plant would be less. If the annual growth rate of electricity demand over 2005-12 does not exceed 4.0% per year, the net externality would decline by EGP 89.8 million, which is equivalent to 3.7% of the investment value of the project. As a consequence, the impact on the Government and gas exporter is a reduction in the amount of benefits accrued to each party.

Table 30: Sensitivity Test of Electricity Demand Growth Rate 2005-12

Demand Growth Rate	PV Net Externality (EGP million)	PV Government (EGP million)	PV Gas Exporter (EGP million)
2.0%	790.0	-167.8	957.9
4.0%	923.8	-156.8	1,080.6
6.0%	979.9	-152.1	1,132.0
7.5%	1,013.6	-149.4	1,163.0
8.0%	1,027.7	-148.2	1,175.9
10.0%	1,033.0	-147.8	1,180.8

8. RISK ANALYSIS

8.1 Sensitivity Analysis vs. Risk Analysis

The main drawback of the deterministic analysis discussed so far is the implicit assumption that the values used for the project variables are known with a 100% certainty and, consequently, that the estimated project NPVs are also 100% certain. Unfortunately, the cash flow projections are uncertain over the life of the project and thus the static model of the financial and economic analyses do not account for the uncertainties and fluctuations in the real world. Hence, it is important to run a deterministic model of a project through a Monte-Carlo simulation in order to obtain mean estimates of the possible project outcomes.

A risk analysis is performed to analyze the variability in the financial and economic returns of the project. In the analysis, the uncertainty associated with the critical variables of a project is expressed in terms of probability distributions. Monte Carlo simulations, a form of risk analysis, provide one of the most practical methods to approximate the dynamics and uncertainties of the real world. The risk analysis repeats the simulation of the financial and economic analyses many times using distributions for the values of the most sensitive and uncertain variables that affect the project. This allows collecting and analyzing statistically the results of the simulations so as to arrive at a distribution of the possible outcomes of the project and the probabilities of their occurrence.

A risk simulation is carried out as a part of the integrated appraisal approach is quite different from the traditional sensitivity analysis. Firstly, under a sensitivity analysis only one or two project parameters are altered to test the project outcomes. By its nature, risk analysis allows for modeling of multiple parameters and for testing their combined effect on the project returns. Secondly, the sensitivity analysis is mainly about testing the project outcomes under the assumption that no variation in the tested parameter is possible from one period to another. In contrast, risk analysis is flexible enough to have annual variations in the tested parameter. Also, it is possible to model a partial lagged response from one period to next. Third, the impact of the correlation between the tested parameter and other parameters is not taken into account in the sensitivity analysis, while the risk analysis incorporates such relationships into the model. Fourth, the range of values over which a sensitivity test is carried out does not generally represent the actual scope of possible fluctuation of the tested parameter. Unless an additional inquiry into the nature and causes of the tested parameter is done, as in risk analysis, the range of values of the sensitivity tests is not realistic. Fifth, even if a range of values is chosen correctly, the sensitivity test does not assign any probability to the likelihood of getting a particular value in the range. Often, the very extreme points of the range have a very little probability of occurrence as compared to the values in the middle of the range. Any risk model collects this information about the likelihood of occurrence and builds it into the probability distribution of a risk assumption, while sensitivity analysis ignores this important issue altogether.

8.2 Selection of Risk Variables and Probability Distributions

The first step in conducting risk analysis of a project is to identify the key risk variables using sensitivity analysis. The sensitivity analysis is carried out as a part of financial and economic assessment has already helped finding the critical parameters affecting the performance of the proposed project. The risk variables are identified based on the results of the sensitivity analysis, and the candidates for being risk variables are both sensitive and uncertain. The variations in the results such as in the NPV or PV are affected by the changes not only in one year, but also from year–to–year over the life-span of the project. In addition, some of the parameters are to some extent within management’s control, while other parameters are beyond the purview of project management, but their variations affect the financial and economic results. Table 31 presents a summary of identified risk factors faced by the El Kureimat project.

The objective of the risk analysis is to assess the impact of the factors identified in Table 31 on the project’s outcome. Some risk factors such as plant utilization and cost overruns can be controlled by project managers to a certain extent. At the same time other factors can only be addresses at the level of the EEHC, and these include collection and invoicing efficiency and electricity tariffs to some degree. A number of factors listed in Table 31 fall into the domain of the Government of Egypt and can only be mitigated by the Government. Domestic inflation is largely dependent on the monetary and fiscal policy of the state. Two other factors can be directly regulated by the Government at its will: cost of natural gas and electricity tariffs. The growth of demand for electricity is also a factor dependent on the general growth of the economy, and the Government has no direct control over it. The world price of oil and rate of foreign inflation are totally exogenous factors that none of the Egyptian institutions can address.

Table 31: Risk Factors, their Impact and Risk Significance

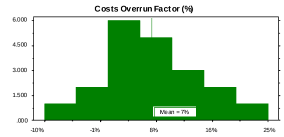
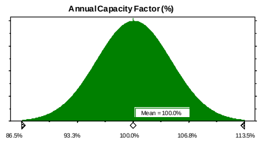
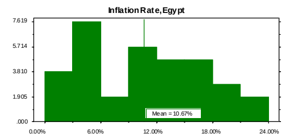
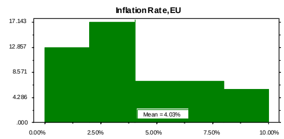
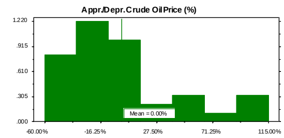
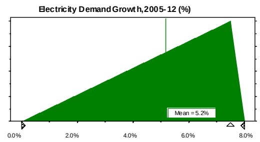
Risk variables	Impact and risk significance
Investment cost overruns	Direct increase of investment costs. Management can control it to a large extent.
Plant utilization	Reduction of benefits. Management can control it.
Domestic inflation	Large effects on operating costs, working capital and interest rate on loan. Beyond management control; based on economic factors and policies.
EU inflation	Mainly affects the investment costs and loan repayment. Beyond Egypt's control; based on EU policies and economy.
Cost of natural gas to the EEHC	Critical impact on performance of project and electric utility. Beyond management control. The Government directly controls the prices for oil and natural gas in Egypt.
World price of crude oil	Little impact on the financial results, but it is the main factor of economic viability of the project and allocation of stakeholder impacts. Beyond Egypt's control.
Electricity Demand Growth	Large effect on the EEHC generation decisions and, as a consequence, on the project. Beyond management control; based on economic factors and policies.
Electricity Tariffs	Tremendous impact on the EEHC revenues and profitability. As of now the management can not change the tariffs without approval by the Cabinet of Ministers.
Collection efficiency	Direct effect on the EEHC revenues and profitability. The management controls the efficiency to a large extent.
Invoicing efficiency	Direct effect on the EEHC revenues and profitability. The management controls the efficiency to a large extent.

Once the risky variables are identified, the second step is to select an appropriate probability distribution and the likely range of values for each risk variable, based on a historical observation of this variable. The probability distributions of each risk variable and the possible range of its values are presented in Table 32.

Using a Monte Carlo simulation generates a probability distribution of the outcome of the project including the NPV or debt service capacity ratio based on the underlying uncertainty surrounding each of the key risk variables specified in Table 32. During the risk simulation for this project, the following project indicators were monitored:

(i) project's financial NPV;
(ii) financial cost of electricity generation;
(iii) EEHC' ADSCR in 2011/12/13;
(iv) EEHC' DSCR in 2011/12/13;
(v) economic NPV;
(vi) economic cost of electricity generation;
(vii) PV of net externalities;
(viii) PV of impact on each stakeholder.

Table 32: Probability Distributions for Risk Variables

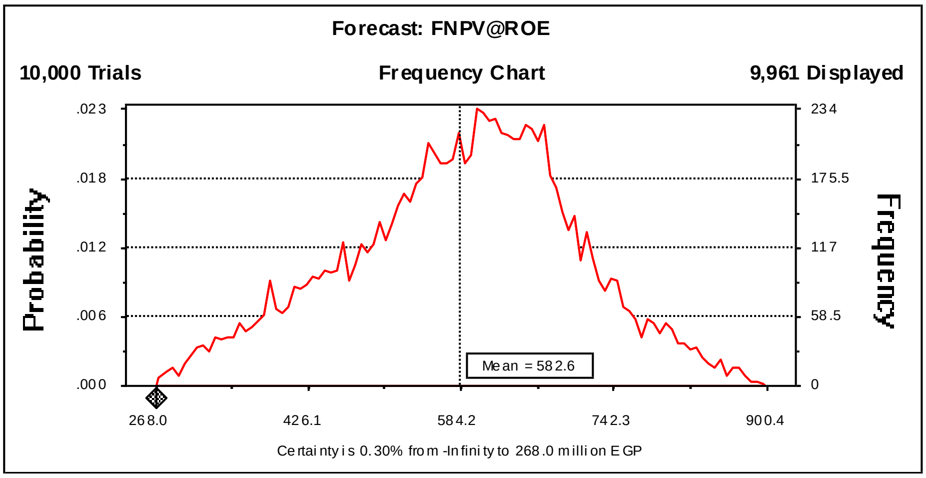
Variable	Distribution Type		Range and Parameters	Mean Value
Investment Cost Overruns Factor (%)	Step Distribution		**Min** **Max** **Likelihood** -10% to -5% 0.05 -5% to 0% 0.10 0% to 5% 0.30 5% to 10% 0.25 10% to 15% 0.15 15% to 20% 0.10 20% to 25% 0.05	Assumption: 0% Expected Mean: 6.8%
Annual Utilization Factor (% of annual plant availability)	Normal Distribution		Mean 100% St. Deviation 4.5%	Assumption: 100% Expected Mean: 100%
Annual Rate of Domestic Inflation (%)	Step Distribution		**Min** **Max** **Likelihood** 0% to 3% 0.11 3% to 6% 0.23 6% to 9% 0.06 9% to 12% 0.17 12% to 15% 0.14 15% to 18% 0.14 18% to 21% 0.09 21% to 24% 0.06	Assumption: 3.5% Expected Mean: 10.7%
Annual Rate of EU Inflation (%)	Step Distribution		**Min** **Max** **Likelihood** 0% to 2% 0.26 2% to 4% 0.34 4% to 6% 0.14 6% to 8% 0.14 8% to 10% 0.11	Assumption: 2.0% Expected Mean: 4.0%
Annual Change in Real Price of Crude Oil (%)	Step Distribution		**Min** **Max** **Likelihood** -60% to -35% 0.20 -35% to -10% 0.31 -10% to 15% 0.25 15% to 40% 0.05 40% to 65% 0.08 65% to 90% 0.03 90% to 115% 0.08	Assumption: 0% Expected Mean: 0%
Annual Electricity Demand Growth 2006-12 (%)	Triangular Distribution		Minimum 0.0% Likeliest 7.5% Maximum 8.0%	Assumption: 7.5% Expected Mean: 5.2%

8.3 Interpretation of Results

A Monte-Carlo risk simulation was carried out over 10,000 trials with the help of Crystal Ball™ software. The results suggest that there is a very limited risk of substandard financial and economic outcome of the project.

8.3.1 Financial Outcomes: Figure 3 presents the frequency distribution of financial outcomes of the proposed project. This is a graphical presentation of the range of possible values that the financial NPV can take and the likelihood of occurrence of these values. The expected value of financial NPV (EGP 582.6 million) is different from the deterministic outcome of the financial analysis of EGP 740.1 million. The mean value of EGP 582.6 million represents the value of the NPV averaged over 10,000 simulation trials. The result also shows that no possibility of having a financial loss exists. The standard deviation of the mean is EGP 122.0 million. At extreme lower end of the possible range the minimum gain (EGP 268.0 million) is about 9.7% of the investment value of project, while in the best case scenario the maximum gain (EGP 900.4 million) is 32.7% of the initial value of the investment.

Figure 3: Probability Distribution of Financial Outcomes



The debt service ratios are also tested through the risk analysis in order to assess the ability of the EEHC to service its debt without external cash injections. Using the base case of the utility cashflows without additional tariff adjustment beyond 2010 but with the assumption of annual inflation adjustment after 2010, a Monte Carlo risk simulation was carried out to obtain the annual and cumulative debt service ratios during the first four years of loan repayment in 2011-14. The results presented in Table 33 reveal that the expected values of the resulting outcomes are different from the deterministic debt service ratios, shown in the first row of Table 33.

As Table 33 shows, the expected values of most of some debt ratios are lower than in the deterministic case, implying that the ability of the EEHC to service debt in a timely manner is not as optimistic as those discussed in Section 5.4. The standard deviation indicates the dispersion of the results around their means, for example, all the annual debt ratios have significantly higher standard deviations than the corresponding cumulative ratios. This suggests that the annual outcomes in the first few years of loan repayment are more likely to fluctuate much more than their cumulative counterparts. The minimum and maximum of the range indicate the value of the lowest and highest outcomes might be achieved.

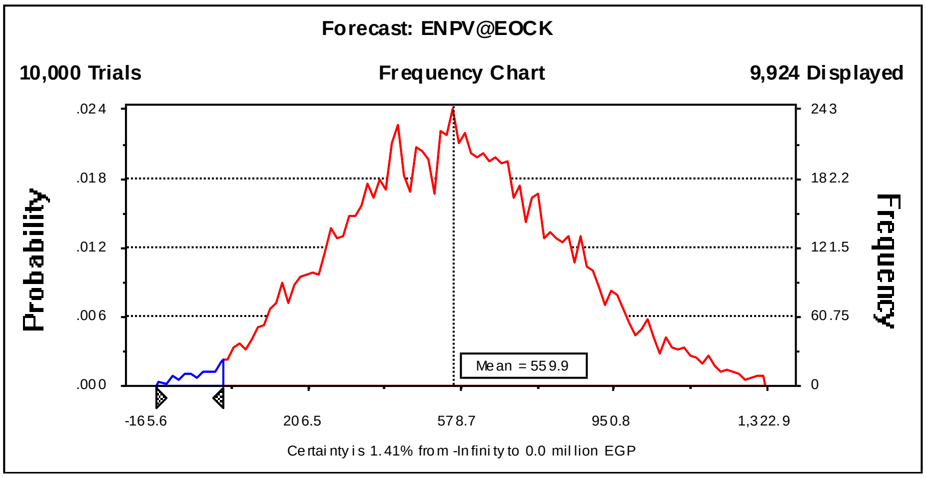
Table 33: Probability Distribution for Debt Service Ratios

	ADSCR					DSCR			
	2011	**2012**	**2013**	**2014**	**2015**	**2011**	**2012**	**2013**	**2014**
Deterministic Value:	**1.70**	**1.66**	**0.68**	**0.96**	**1.04**	**1.21**	**1.15**	**1.09**	**1.15**
Risk Statistics:									
Mean	1.45	1.44	0.58	0.85	0.94	1.09	1.03	0.97	1.03
St. Dev.	0.27	0.26	0.12	0.14	0.15	0.05	0.05	0.05	0.05
Minimum	0.89	0.87	0.33	0.54	0.61	0.90	0.87	0.82	0.85
Maximum	2.01	2.00	0.84	1.16	1.26	1.28	1.20	1.15	1.21
Prob. Sub-standard	3.4%	3.8%	99.9%	82.7%	62.2%	4.3%	27.5%	70.7%	27.5%

Finally, the AfDB should be aware of what is the cumulative likelihood of having sub-standard debt service ratios, i.e. periods when the cashflows of the EEHC are not sufficiently high to meet the scheduled repayments. The last row of Table 33 shows the proportion of all simulation outcomes that have a ratio of net cashflows to debt repayment being less than one. Again, the annual ratios are more likely to have sub-standard outcomes. In 2011 and 2012, the probability of substandard ratios is at a very low level, below one percent. However, in 2013 and 2014 when the first debt repayments of the loans on the EL Kureimat plant and other projects undertaken within the expansion program are due, the likelihood of having an insufficient cashflows is almost 100% certain. After that period, the probability of insufficient debt service ratios declines to a more comforting level. For the cumulative debt ratios, the likelihood of having an insufficient present value of net cashflows is very low, below one percent.

8.3.2 Economic Outcomes: In regard to the economic results, the economic NPV has recorded an expected value of EGP 559.9 million, and the probability of having a return below the economic cost of capital of 10.0% real is 1.4%. Figure 4 shows the probability distribution of economic outcomes of the proposed project. The standard deviation of the mean is EGP 278.2 million. As Figure 4 illustrates, there is a wide range of possible values of the economic NPV of this project. In the worst case scenario the maximum loss (EGP -165.6 million) is about 6.8% of the investment value of project, while in the best case scenario the maximum gain (EGP 1,322.9 million) is 54.4%. Moreover, the overall risk of having a real return below 10.0% real is 1.4%, which can be also considered low. It should be noted that the economic internal rate of return never becomes zero or negative.

Figure 4: Probability Distribution of Economic Outcomes



8.3.3 Stakeholders' Impacts: The risk analysis shows that net impact on the public sector is always a positive contribution, with the expected present value of EGP 958.5 million and a zero probability of having a negative value. The Government is expected to have a net loss due to this project in terms of taxes and subsidies. The expected value of that loss is EGP 149.3 million. Given that the standard deviation of results around the mean is EGP 25.2 million, there is a very little variation around the expected value.

On the other hand, the gas exporting utility, controlled by the state, is a definite winner as the mean of present value of gain it realizes due to the project is EGP 1,166.3 million. The standard deviation of the mean is EGP 232.7 million, and there is nil probability of having a present value of this gain below zero.

9. CONCLUSION

9.1 Findings

The integrated investment appraisal methodology has been used in the evaluation of this project. The nature of the proposed combine cycle generation plant is a provision of additional capacity to a large electricity utility, which will use the unit in the base load of its system. The EEHC has already been supplying all energy needs of the consumers and industry. While the utility continues to satisfy the projected demand, no incremental sales will be credited to the project itself. The role of this plant is to substitute the existing steam plants during the off-peak time and to avoid installation of additional gas turbine capacity during the peak load.

The financial and economic analysis has confirmed that the project is a viable and sustainable investment for the EEHC because major savings of fuel, O&M and capital costs will be realized by the company. The financial NPV of the project is EGP 740.1 million, using a real discount rate of 6.0% and resulting FIRR is 12.3%. Likewise, the estimated economic NPV of the proposed plant is EGP 667.8 million, using an EOCK of 10% real, and its EIRR is 13.9%. The levelized financial cost of energy supply from the plant is US$ 1.71 cent/kWh, and levelized economic cost is US$ 2.41 cent/kWh, which is very low by regional and international standards.

The amount of net financial savings by the project itself is sufficient to repay the loan from the AfDB, however the present financial situation of the EEHC is of a concern as the company struggles to repay some of the current debt obligations to other donors.

A projection of the financial cashflows of the EEHC was integrated into the standard power generation appraisal. The financial analysis of the electric utility suggests that unless additional tariff increases are approved by the Government and undertaken by the company, the utility will find it difficult to meet the debt obligations for this plant and for other projects in the system expansion program 2005-12. If the Government accepts to continue the policy of at least 5.75% per year nominal increases in the electricity tariff until 2015, the EEHC should be able to service all its debt and to have a modest return on equity.

The proposed project is expected to save a substantial amount of natural gas for the state-controlled gas utility, which will be able to export the gas and earn foreign exchange for the Government. The present value of the impact on the gas utility is EGP 1,163.0 million. As a partial offset to this gain there is a net loss to the Government of EGP 149.4 million, which includes all taxes, subsidies and foreign exchange premium. As the positive impact overweigh the loss of tax revenues to the treasury, the Government still stands to win with the proposed project.

9.2 Risks and Mitigating Measures

It is expected that the EEHC can control the technical and implementation risks of this project using its vast experience and through efficient management of procurement and construction activities. The performance of the project is dependent on the plant’s operational availability that can be reasonably assured by a competent management team. The financial design and economic concept of the proposed project are subject to a low risk exposure at the project level, as the project actually improves the EEHC ability to withstand a number of adverse factors beyond its control.

The project enables the parent company to resist the negative impacts of domestic and foreign inflation, price of natural gas, low electricity tariff rates, and low collection of receivables from public sector customers. It is clear that this new efficient combine cycle plant is able to supply power at a lower cost than the existing generating units in the system, and within that environment the project itself has a very little chance of weak financial or economic performance.

On the project basis, the service of the loan by the AfDB is well covered by the cash savings that the project will generate for the parent EEHC Company. The repayment of the loan by the Bank is however in the hands of the EEHC financial operation and unless an additional tariff increases are undertaken in 2010-15, the company is likely to have difficulty with repayment. The Government of Egypt has agreed to act as the borrower to the Bank and be legally responsible for debt servicing. Under this arrangement, the Government will pass the funds to the EEHC and collect the loan repayments from the company.

This proposal should make the loan approval significantly more comfortable for the AfDB, however as worldwide experience in developing countries has shown that a government guarantee by itself does not imply that the project is a sound investment. The role of a development bank is to ensure that the funds made available to a country are indeed channeled to an activity that improves the well-being of its citizens, and an investment appraisal is an invaluable tool for carrying out the basic financial, economic, stakeholder and risk analysis of such potential projects.

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