Integrated Investment Appraisal of a Cogeneration Electricity Project Agreement with Global Environment Externalities

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Abstract

This paper reports on integrated investment appraisal of cogeneration electricity project that uses the waste heat from a steel manufacturing factory to power this thermal electricity generation plant. It examines how an independent power producer, a large steel manufacturing, a dedicated consumer of electricity and a state electricity board, through a series of contractual agreements, managed to facilitate the investment in a 260 megawatt (MW) dual fuel-based thermal power project in the state of Karnataka, India. Since the early 1990's, India has attempted to expand its power generation capacity by foreign investors to participate in build, own, and operate power projects. This paper reports on an integrated investment appraisal of the project.

Keywords: Cogeneration, independent power producer, integrated investment appraisal, India

JEL Classification: H43

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Introduction

This study examines how an independent power producer, a dedicated consumer of electricity, and a state electricity board, through a series of contractual agreements, managed to facilitate investment in a 260 megawatt (MW) dual fuel-based thermal power project in the state of Karnataka, India since the early 1990's. India has attempted to expand its power generation capacity by foreign investors to participate in build, own, and operate power projects. India is also searching for ways to import power from neighboring countries1.

At independence in 1947 India had 1,447 MW of installed capacity. By 1994/95 installed capacity, of both public utilities and non-utilities combined, had grown to 92,264 of which the public utilities produced 81,164 MW and the non-utilities produced 11,100 MW, (Center for Monitoring the Indian Economy 1996, p. 27).

Traditionally, state authorities have controlled both the generation and distribution of electricity. The central government and state governments have been involved in various aspects of electricity generation, transmission, and distribution through the Central Electricity Authority, the State Electricity Board, and implementing agencies, like the National Thermal Power Corporation, the National Hydro Power Corporation, and the Power Grid Corporation. As of March 1996 State Electricity Board owned 64.2 percent of public utilities, federal agencies owned 31.5 percent, and private entities owned 4.3 percent (Center for Monitoring the Indian Economy 1996, p. 1). Some 10 to 12 percent of India's power needs were met by captive power plants, of which the utility sector owned 20 percent (Roy 1998).

As of 1995/96, India's capacity mix was as follows: 25.2 percent hydroelectricity; 71.1 percent thermal; 2.7 percent nuclear; and 1 percent non-conventional sources, including wind energy. Considering the size of its economy, India is poorly endowed with energy resources. It has modest reserves of oil and natural gas, which will last for only a few decades unless major new deposits are discovered. Its coal reserves are 70 billion metric tons, enough to meet the bulk of its energy needs for the next 250 years (World Bank 1996/97, p. 1). However, the coal has a

[1] India has imported electricity from Bhutan since the late 1980s. More recently, the government has been examining options for importing power from Bangladesh, Nepal, and Pakistan.

high percentage of ash content, creating an ash handling problem, and most of the deposits are located in east India, with the resulting transportation problems. About 70 percent of India's coal is converted into electric power, and this share is increasing. Unless nuclear fuel becomes a viable alternative for thermal power generation, India will likely to continue relying on coal to supply its electricity. Most hydroelectric sources in peninsular India have already been tapped, and those located in the northeast are thousands of kilometers away from the main consumption centers.

In the past, electricity demand increased by 10 percent per year (Indian Institute of Public Opinion 1987). Except in the 1960s, additions to capacity have lagged behind the growth in demand. In the Eighth Development Plan (1992–97) the central government envisaged adding 30,537 MW of installed capacity, but actual additions made amounted to some 17,668 MW, leaving a huge gap between demand and supply. The Ninth Development Plan (1997–2002) proposed adding 56,783 MW, with the private sector making a substantial contribution. As of September 1996 the private sector, both foreign and Indian companies, had invested in 49 power projects totaling 10,192 MW of installed capacity. The private companies have also signed memoranda of understanding to undertake 265 new projects that will create 63,238 MW of generation capacity. As of September 1996, foreign companies were expected to participate in 55 projects with a total of 26,668 MW in installed capacity (CIME, 1996, p. 27 survey on investment in power projects).

Despite the promising private initiative, peak power shortages have continued to prevail nationwide. The projected peak energy demand of 95 billion kilowatt hours (kWh) and total energy demand of 500 billion kWh by 2000 would be difficult to meet if the private sector power projects could not be implemented as scheduled. Estimated required generation capacity for 2005 is 142,000 MW, a huge increase from the present level of electricity supply.

In the past public enterprises have dominated the power sector; however, since 1991 the government has been liberalizing the economy, and has identified the power sector as one of the key areas for private investment. To attract private investment and to improve efficiency in the generation, transmission, and distribution of electricity, the government has undertaken the following measures:

- Amended the 1910 Electricity Act to permit private companies to generate power.
- Opened up the possibility for 100 percent foreign ownership.
- Granted five-year tax holidays.
- Reduced import duties on power equipment.
- Guaranteed a 16 percent rate of return on paid-up and subscribed equity and an additional return on equity for every percentage point of performance above a 68.5 percent plant load factor (PLF) for thermal power plants and a 90 percent plant availability factor for hydroelectric power plants (Government of India 1995, p. 1).
- Formulated model power purchase agreements (PPAs) and creating different entities in the state electricity boards for generation, transmission, and distribution (for an analysis of PPAs see Jenkins and Lim, Case 2).

This study focuses on one independent power producer project promoted by a local company in collaboration with a foreign partner. The project is basically a captive power generation plant of a major steel manufacturing company. The company undertakes the cost of the generation capacity and assumes the market risk associated with the project through PPA. The use of the flue gas (known as corex gas), which would otherwise be wasted, as an energy source creates significant cost savings and positive environmental externalities.

The Project

The Jindal Tractebel Power Company, Ltd. (JTPC) is a build, own, and operate project promoted by the O.P. Jindal Group of India and the Tractebel Company of Belgium to supply power to its dedicated consumer, the Jindal Vijayanagar Steel Company, Ltd. (JVSL). It will be located close to the power plant, 350 kilometers from Bangalore in the state of Karnataka. The project's designed capacity is 260 MW. Electricity will be tapped through a generator transformer to a 220-kilowatt switchyard for transmission to JVSL or sent to distribution networks owned by the Karnataka Electricity Board (KEB). The nearest ports are Madras and Mormugao, which have facilities for bulk cargo handling and are connected to the project site by a broad-gauge railway.

The power plant uses corex gas as one of the primary fuels. It is designed to operate 11 months of each year with corex gas and 1 month with coal. The design energy conversion efficiency is 2,500 kilocalorie (kcal)/kWh. Corex gas is a mixture of approximately carbon monoxide (42 percent), carbon dioxide (35 percent) and hydrogen (18 percent), and compounds of nitrogen and methane generated at JVSL during the steel making process based on corex technology. Two corex modules each generate 120,000 Newton cubic meters (Nm^3)/hour of corex gas with an average heat content of 1,830 kcal/Nm^3. Corex gas does not require a secondary fuel to support its combustion. However, when coal is used as the primary fuel, 3.5 milliliters/kWh of furnace oil are required for startup and to maintain flame stability.[2]

The project investment cost is Rs 11,948.8 million in 1995 prices. The rupee component is estimated at Rs 7,764 million and the dollar component at US $119.5 million. As table 4.1 shows, the main cost items are land (Rs 14 million); preliminary and pre-operating expenses (Rs 2,264.5 million); engineering, procurement, and construction contracts (Rs 9,070.5 million); miscellaneous fixed assets (Rs 415 million); and financing for working capital (Rs 184.9 million). These expenditures include import duties, excise duties, royalties, sales taxes, worktaxes, and income taxes as per the rules of the central and state governments.

[2] Dual fuel firing boilers are larger than coal-based boilers; 100 percent coal firing is possible if corex gas is not available.

Table 4.1: Investment Cost Schedule, 1995-99 (1995 Prices)
(Rs. in millions)

Year ended March 31

Category	Rs millions	US$ millions	Rs millions	1995	1996	1997	1998	1999
Preliminary and pre-operating expenses								
Salaries and wages	111	1.4	160.0	100.0	60.0	0	0	0
Travel	0	0.4	14.0	9.0	5.0	0	0	0
Technical consultation	74	1.1	112.5	100.0	12.5	0	0	0
Legal fees	0	1.4	49.0	40.0	9.0	0	0	0
Financial advisers	0	2.8	98.0	80.0	18.0	0	0	0
Financing fees	1362	13.4	1831.0	1000.0	831.0	0	0	0
Sub-Total			**2264.5**					
Land	14	0.0	14.0	14.0	0	0	0	0
Engineering, procurement, and construction contracts								
Plant (material)	804	0.0	804.0	100.0	300.0	404.0	0	0
Plant (labor)	910	0.0	910.0	150.0	300.0	300.0	150.0	10.0
Machinery and equipment	4000	69.9	6446.5	0	0	2346.0	3314.5	785.5
Technical consultation fee	0	26.0	910.0	172.0	199.5	200.0	150.0	188.5
Sub-Total			**9070.5**					
Miscellaneous fixed assets								
Housing	30	0.0	30.0	30.0	0	0	0	0
Substation	250	0.0	250.0	0	50.0	50.0	150.0	0
Ash Pond	130	0.0	130.0	0	15.0	30.0	40.0	45.0
Office and support equipment	5	0.0	5.0	5.0	0	0	0	0
Sub-Total			**415**					
Working Capital								
Inventory of coal	0	3.1	109.9	0	0	0	109.9	0
Cash	74.9	0.0	74.9	0	0	0	74.9	0
TOTAL	7764.9	119.5	11948.8	1800.0	1800.0	3330.0	3989.3	1029.0

Source: Project Appraisal Report, p. 17.

The project is being financed through equity participation, domestic borrowing, suppliers' credits, and external borrowing. As table 4.2 shows, the equity holders contribute Rs 3,600 million, the Industrial Credit and Investment Corporation of India (ICICI) provides Rs 4,770 million in term loans, the U.S. Exim Bank provides US $75.1 million through a suppliers' credit, and US $27.1 million is raised through external commercial borrowing from the international financial market. Table 4.2 also breaks down the phasing of the capital disbursement as required by the investment plan.

Table 4.2: Investment Disbursement Plan, 1995-99

(Rs. in Millions, 1995 Prices)

Sources	Rs millions	US$ millions	1995	1996	1997	1998	1999
Domestic loan, ICICI	4770	0	0	0	1900	2280	590
U.S. Exim Bank	0	75.1	0	0	30.0	36.0	9.1
External commercial borrowing	0	27.1	0	0	10.9	12.9	3.4
Jindal's equity contribution	1496.6	8.67	900	900	0	0	0
Tractbel's equity contribution	1496.6	8.67	900	900	0	0	0

Source: Project Appraisal Report, p. 24.

The Bharat Heavy Electrical Limited–Raytheon consortium has been contracted to undertake the project work at a fixed price, turnkey engineering, procurement, and construction contract.[3] As specified in the contract, the first unit (130 MW) of the project was expected to be commissioned by May 1998 and the second unit (130 MW) by November 1998. The contract specifies performance guarantees with a penalty payment of Rs 100 million for every MW shortfall in power plant output and Rs 1.73 million for every kcal increase in the heat rate (the heat rates for coal and corex gas are 2,500 kcal/kWh and 2,330 kcal/kWh, respectively). The contract also specifies time overrun guarantees of US $75,000/day for the first month and US $150,000/day for the second month. The total damages are, however, capped at 15 percent of the contract value, which is half of the existing maximum penalty payments normally specified for construction projects in India.

Management is entrusted to a board of directors comprising representatives of the O. P. Jindal Group and Tractebel South Asia, numbering 6 in total. Financial institutions are not currently represented on the board, but the company's articles of association provide scope for expanding board membership to 12. The financial institutions that provide rupee term loans have the right to nominate board members.

The promoters are experienced industrialists. The domestic partner, the Jindal Group, is one of India's biggest industrial conglomerates with a net worth valued at Rs 14,270 million (March 31, 1995). It also owns JVSL, JTPC's dedicated customer. The foreign partner, Tractebel South Asia, is a newly created subsidiary of the Tractebel Group. It operates power

[3] Raytheon Engineers and Contractors, USA (Raytheon) is one of the major technology-based companies that has wide experience in engineering, procurement, and construction and CM contracts both in India and elsewhere. Bharat Heavy Electrical Limited (BHEL) is one of largest engineering manufacturing companies.

plants in Belgium, Canada, North Ireland, Oman, and Portugal, with total installed capacity of 14,319 MW through its Europe-based subsidiary, Electrabel.

Contractual Arrangements

JTPC is an independent power producer that has JVSL as a dedicated consumer. JVSL supplies the required fuels, corex gas and coal, under a fuel supply agreement (FSA), underwrites the cost of the plant's generation capacity, and purchases electricity at a tariff that is defined by the PPA. Electricity generated in excess of JVSL's requirements is supplied to third party exclusive consumers (TPECs) in Karnataka by using KEB's transmission and distribution networks based on a wheeling, banking and grid support agreement (WBGSA).

Fuel Supply Agreement.

As agreed in the FSA, JVSL shall supply coal and corex gas at a cost that is anchoring to the average landed price of high calorific value imported coal from Australia, China, or South Africa[4]. Except for furnace oil, the fuel price (FP) in rupees per million kcal is determined by:

$$FP = [A*\{N + Q*(1+k)\} + B + C]/ (N + Q) \qquad (4.1)$$

Where A is the average landed cost of coal per million of kcal, N is the monthly quantity of energy delivered from coal in million kcal, Q is the monthly energy delivered from corex gas in millions of kcal per year, B is the monthly stocking charge in millions of rupees, C is the monthly losses in millions of rupees due to pilferage from the coal stock, and k is the premium over the coal price for corex gas.

According to the FSA, JTPC guarantees a minimum corex gas off-take of 960 million Nm^3 per year with heat content in the range of 1,600 to 1,900 kcal/Nm^3. In turn, JVSL agrees to maintain a year round coal stock of 200,000 metric tons with heat content in the range of 5,000 to 7,000 kcal/kilogram (kg). The stock is adequate for a 100 percent capacity run for three months,

[4] The average landed cost consists of cost, insurance and freight (cif) price; import duty, countervailing duty; sales tax; port handling charge; and freight and insurance from Madras or Mormugao to the project.

and the stocking charge includes the financing cost of the stock (we have used the interest rate on working capital to calculate the financial cost).

Power Purchase Agreement

As agreed in the PPA, the electricity tariff in kWh is split into an energy charge (EC) and a capacity charge. The energy charge is basically passing on the fuel cost from JTPC to JVSL, including the cost of fuel required for consumption of the auxiliary power at the plant. The energy charge is determined by the relationship:

$$EC = FP * SPC / (1-AC) \quad (4.2)$$

where FP is the fuel price in rupees per million kcal payable to JVSL; SPC is the heat required per kWh, that is, 10,900 kilojoules/kWh during the stabilization period and 10,500 kilojoules/kWh during full output; and AC is auxiliary power consumption at the plant.

The capacity charge (CC) for each kWh consists of fixed costs, namely, interest payments on loans, annual economic depreciation expenses, operation and maintenance costs, return on equity, income tax payments, and the costs of incentives to generate more power. The PPA specifies a 16 percent guaranteed nominal return to equity on its dollar value whether the equity participation is in dollars or in rupees (the rupee component in equity is treated as an equivalent investment in U.S. dollars only for the purpose of calculating the PPA tariff). The annual provision for operation and maintenance is 2.5 percent of the project cost, adjusted annually to reflect domestic inflation rates. As the contract is not explicit, and provides incentives for operating the plant at more than 68.5 percent PLF and disincentives for operating it at less than 68.5 percent PLF, we have assumed (a) that the fixed cost is the sum total of each of the cost components at 68.5 percent PLF, and (b) that dividing the discounted sum total of fixed costs by the discounted energy sales over the life of the project yields the base fixed cost for each unit of electricity (we have used 10.5 percent as the discount rate, which is the domestic partner's expected real rate of return). If the plant operates at more than 68.5 percent PLF, the independent power producer will get an incentive of 0.7 of the percentage return on equity for each percentage point increase in the actual plant load factor (APLF) above a 68.5 percent load factor. That is, capacity charge (Rs/kWh) = fixed cost* [1+ 0.7 * (APLF – 68.5 percent)* percentage return on equity]

If the plant operates at less than 68.5 percent PLF, the capacity charge paid to the independent power producer will be less the return on equity. That is,

capacity charge (Rs/kWh) = fixed cost*[1 - percentage return on equity]

In this contract, disincentives to operate the plant below 68.5 percent PLF are strong. Technically, we have assumed that at a 68.5 percent PLF, the project will generate at least some positive net present value (NPV) from the perspective of stakeholders to encourage them to make commitments to the project. Operation of the plant above 68.5 percent of the installed capacity will improve the project's viability from the perspectives of bankers and equity holders.[5]

Wheeling, Banking, and Grid Support Agreement

The WBGSA agreement permits the sale of excess electricity to TPECs in any part of Karnataka through KEB's transmission and distribution networks. However, KEB does not permit spot sales of electricity to TEPCs. It requires JTPC to contract energy sales to TEPCs based on its capacity to deliver a reliable quantity of electricity. To compensate for supplies not delivered during outages, KEB provides an energy banking facility by levying a monthly banking fee equivalent to 1 percent of the maximum permissible energy deposit with KEB. The maximum amount of permissible energy is 50 million kWh, and the energy balance is computed as follows:

Closing balance = opening balance + deposit - drawdown - 0.50 MU (million units (kWh))

If the closing balance is less than or equal to zero, then the opening balance is zero, and if the closing balance is greater than 50 million kWh, then the opening balance is 50 million kWh for the next month. In the event of a negative energy balance of 5 million kWh or more, the energy cost to JTPC shall be 1.5 times the applicable tariff. This penalty clause requires JTPC to assess the plant availability factor properly, and then only enter into contract sales with TEPCs to

[5] Technically 68.5 percent should be the plant availability factor. As the actual PLF depends on load demand on the plant, the plant availability factor should be the criterion for designing the incentive mechanism.

avoid penalty payments to KEB caused by excess withdrawals of electricity. The imposition of an upper limit on energy deposits is also intended to help JTPC avoid penalty payments by storing energy with KEB when supplies are plentiful.

The wheeling charge of electricity is 10 percent of the gross valued of energy metered by end users. This arrangement does not specify who bears the transmission losses. Given the rate specified in the contract and the nature of electricity leakage during transmission, it is understood in the contract that JVSL will bear the transmission and delivery losses. Also, the supply from JTPC is routed to the steel plant by synchronizing it with KEB's supply system, and there is a cost of fluctuating load due to the use of electricity at the hot strip mills. Therefore, JTPC is required to pay Rs 14.6 million per year to KEB as a grid support fee in addition to the wheeling charge and banking fee; however, JVSL refunds these expenditures to JTPC.

The Electricity Market

JVSL is JTPC's only dedicated consumer. Its estimated peak power demand is 212 MW, and its annual energy requirement is 1,174 million kWh. Based on the average power requirements of the steel plant, oxygen plant, oxygen furnace, and pelletization plant, the estimated average base load demand is 134 MW. At an 85 percent availability factor, JTPC can generate 1,936 million kWh of electricity annually. Deducting its auxiliary consumption of 6.9 percent of total generation, the energy available for sale is 1,802 million kWh. This leaves only 629 million kWh of electricity for sale to TPECs. In addition, JVSL may eventually absorb JTPC's entire generation capacity, because its annual steel production capacity is expected to expand from the current level of 1.25 million metric tons to 3 million metric tons.

Karnataka has had capacity and energy shortages for several decades. As of 1994, the state's total installed capacity was 3,280 MW, of which 76.9 percent was hydroelectric, 19.2 percent was thermal, and 3.9 percent was diesel. Of the total electricity generated in 1995/96, agriculture consumed 43 percent, industry consumed 35 percent, domestic lighting consumed 16 percent, and other uses consumed the remaining 6 percent. The hydroelectric supply may decline in the future, because more water will be required for drinking, irrigation, and other uses because of the growth in population. Even today, energy shortages are acute during the cultivation period, although hydropower generation normally improves during the monsoon. As table 4.3 shows, peak power deficits and energy shortages are likely to remain at about 10 percent.

Table 4.3: Peak Power and Energy Demand, 1994-95 to 1999-2000

	PEAK				ENERGY		
Year	Installed capacity[a] (mw)	Projected demand (mw)	Projected availability (mw)	Deficit (%)	Projected demand (hwh millions)	Projected Availability (hwh millions)	Deficit (%)
1994-95	4,048	3,771	3,279	13.0	21,650	18,958	12.4
1995-96	4,181	3,980	3,387	14.8	22,884	19,582	14.4
1996-97	4,772	4,201	3,865	7.9	24,188	22,346	7.6
1997-98	4,865	4,434	3,941	11.1	25,567	22,785	10.8
1998-99	5,255	4,679	4,257	9.0	27,025	24,612	8.9
1999-2000	5,465	4,938	4,427	10.3	28,865	25,595	10.4

[a]Includes projected installed capacity in Karnataka and the state's share in power from central sector projects. Assume peak power availability at 81 percent of the installed capacity at an average annual PLF of 66 percent.

Note: Annual energy generation estimates are based on an 81 percent plant availability factor, which is on the high side, because the bulk of electricity supply comes from hydroelectric sources, which depend on the seasonal variability of rainfalls. Projected demands also depend on the government's policy on subsidizing electricity users.

Source: Data from the Fourteenth Electric Power Survey, Government of India.

Given Karnataka's investment–friendly environment and human resource base, the growth of demand for electricity will likely be ahead of that in many states because of its good prospects for rapid industrial development. As a result, many TPEC's will be available to consume the project's surplus electricity at competitive prices.

Karnataka provides electricity to agricultural users for free, and in 1994/95 the average tariff across India was Rs 1.25/kWh. Even though industrial and commercial tariffs are higher than those for agriculture and for domestic users, sales prices do not reflect the true cost of electricity for any group of consumers.[6] Therefore, unless JVSL finds additional dedicated consumers, it will have to sell the excess quantity of electricity generated at the prevailing subsidized rate of Rs 2.10/kWh. Thus JVSL is unlikely to be interested in generating more

[6] The tariff rates for different users were Rs 0.88/kWh for domestic users, Rs 0.22/kWh for agricultural users, Rs 2.10/kWh for industrial users, (these figures are for all India average, and not specific to the state of Karnataka) Rs 2.41/kWh for railways, and Rs 1.91/kWh for commercial users.

electricity than it requires unless KEB adjusts its tariff or it finds other dedicated customers willing to pay a premium over the KEB price. Nevertheless, once JVSL expands its production capacity, it will be able consume JTPC’s entire supply.

Financial Analysis

The following seven parties are interested in the project’s financial viability, and we analyze the project from each viewpoint:

- *Equity holders.* The promoters, who have invested about 30 percent of the total capital, are interested in knowing the project’s financial viability.
- *Bankers.* The bankers, who provide 70 percent of the total capital in rupees, dollars, and supplier credits, are interested in knowing whether or not the project is capable of repaying the loans with interest.
- *JVSL*. JVSL, which has signed the PPA and FSA with JTPC, would like to know the savings resulting from this project in relation to alternative electricity sources.
- *KEB.* KEB, which provides wheeling, banking, and grid support facilities based on the WBGSA, would like to know how it will gain financially from the project.

  In addition, the interests of the domestic equity holder and foreign equity holder differ.
- *Domestic equity holder*. The O. P. Jindal Group owns JVSL; hence it has the option to transfer the project’s benefits by underpricing the electricity supply.
- *Tractebel South Asia.* The foreign equity holder does not have the option of transferring the project’s benefits. The PPA builds the fuel cost into the tariff as a “pass-off” and since JVSL is the dedicated consumer and supplier of primary fuels, Tractebel South Asia must ensure that the provisions in the fixed cost components constitute the major portion of the PPA tariff, thereby guaranteeing the specified rate of return to the equity holders. Therefore the foreign partner wants to know its rate of return separately, and find out what would be the rate of return to the domestic partner would when the project is evaluated separately and in combination with the financial gains to JVSL.

- *JTPC and JVSL Combined.* The O. P. Jindal Group promoter and domestic partner in JTPC, also owns JVSL. In reality, the domestic partner would be more interested about the project's overall financial benefits to the O.P. Jindal Group and not to JTPC alone. There is, therefore, a need to evaluate the financial gains of JTPC in conjunction with that of JVSL.

Specifications and Assumptions

Our financial analysis is based on the following technical specifications and assumptions:

- *Power plant*. The power plant has 260 MW in installed capacity. We estimate that each year it operates on corex gas for 11 months and on coal for 1 month at an APLF of 85 percent. Two corex modules supply the corex gas, each with production capacity of 120,000 Nm^3/ hour.

- *Input requirements*. Coal and corex gas are the primary fuels. The coal has a heat content of 6,000 kcal/kg and a heat rate of 2,500 kcal/kWh. The corex gas has a heat content of 1,830 kcal/ Nm^3 and a heat rate of 2,330 kcal/kWh. For start up and flame stability, auxiliary fuel with a heat content of 11,200 kcal/kiloliter is required. Its consumption is 3.5 milliliters/kWh. Water is required to generate steam at the rate of 0.0089 m^3/kWh, and the steam is continuously circulated in the system. In 1995 prices the cost of inputs are: coal, cost, insurance, and freight (cif) price of US $62.92 per metric ton; corex gas, 20 percent premium over the average, landed cost of coal at the project based on its equivalence in heat content[7]; auxiliary fuel, Rs. 6.53 per liter; and water, Rs.3 per m^3.

- *Operation and maintenance expenses*. These are assumed at 2.5 percent of the total investment cost in 1995 prices. Of this, 15 percent is used for labor and 85 percent is for spare parts and repair materials.

- *Electricity market*. The peak power demand of the steel plant is 212 MW, whereas its annual average load is only 134 MW. In Karnataka, the projected demand for energy in 2000 is 28,567 million kWh, and the estimated energy supply position is 25,595 million

[7] The landed cost of coal at the project includes a tariff; central excise tax; sales tax; and 4 percent of the cif value as the cost of freight and insurance from the port to the project.

kWh. Given the 2,972 million kWh gap between demand and supply, we assumed that power rationing is in effect.

- *Working capital*. The delays in electricity bill payments vary from one to six months in India. We assume that accounts receivable are 12 percent of annual sales revenue, equivalent to a 45-day delay in bill payment. We assume that accounts payable are equal to the requirement of cash balances, either estimated at 8.33 percent of annual recurring costs, or equivalent to a 30-day delay in payments. We use these figures to construct cash flow models for all the viewpoints.
- *Economic depreciation*. We assume the project's operating life to be 15 years. The Indian government's guidelines stipulate the economic life of buildings, civil works, machinery, and equipment at 20 years and of miscellaneous fixed assets at 10 years.
- *Tax depreciation*. The same guidelines stipulate a 7.5 percent annual tax depreciation rate for buildings and civil works, 25 percent for machinery and equipment, and 10 percent for miscellaneous fixed assets, plus 10 years for amortizing development expenditures.
- *Macroeconomic information*. In the past, inflation rates in India have varied from 4 to 18 percent. We assume the average annual domestic inflation rate to be 8 percent. The foreign currency used in this project is in U.S. dollars. U.S. inflation rates have varied from 2 to 6 percent, and for this analysis we have assumed the average annual U.S. inflation rate to be 3.5 percent. For 1995 we assumed an exchange rate of Rs 35 to the U.S. dollar. We have estimated the economic opportunity cost of capital (EOCK) and the foreign exchange premium for India at 10.74 and 24.1 percent, respectively (estimated using 1995 statistics and based on the methodology in Jenkins and Harberger 1996).
- *Taxes, duties, and royalties*. After the government of India adopted the policy of economic liberalization, it reduced import duties on machinery and equipment purchased specifically for power projects. In this analysis, the rate of import duty is 24 percent for machinery and equipment, 22 percent for coal, 30 percent for furnace oil, 85 percent for steel, and 10 percent for cement. In addition, we assume excise duty of 10 percent; countervailing duty of 10 percent; local sales tax of 4 percent; royalties of Rs 15 per metric ton on sand, gravel, and stone; stamp duty of 7.5 percent; and construction tax of 4

percent. The prevailing corporation tax rate is 43 percent. For this project the government gives a corporate tax rebate of 100 percent for the first five years and 13 percent for the next five years. The personal income tax rate is 20 percent

- *Rupee term loan.* ICICI provides a loan of Rs 4,770 million at an effective nominal interest rate of 17.6 percent. Removing the impact of the 8 percent domestic inflation rate, the effective real advance interest rate is assumed at 8.91 percent, inclusive of ICICI's premium of 3 percent over its advance rate. In 1995 prices the loan disbursements are Rs 1,900 million in 1997, Rs 2,280 million in 1998, and Rs 590 million in 1999. The loan is repaid in 36 quarterly equal installments beginning in 2000.

- S*uppliers' credit*. The U.S. Exim Bank provides suppliers' credits worth US $75.1 million. In 1995 prices the disbursements are US $30 million in 1997, US$ 36 million in 1998, and US $9.1 million in 1999. The credit loan carries an effective nominal interest rate of 7.22 percent. Removing the impact of the 3 percent rate of foreign inflation, the real interest rate for the credit loan is 4.1 percent, including the guarantee commission. The loan is repaid in 20 half-yearly equal installments beginning 2001.

- *External commercial borrowing loan*. This loan of US $27.1 million is obtained from the international financial markets. In 1995 prices the withdrawals are US$ 10.9 million in 1997, US$ 12.9 million in 1998, and US$ 3.4 million in 1999. The loan carries an effective nominal interest rate of 8 percent (based on movement in the LIBOR rate). Removing the impact of the U. S. inflation rate of 3 percent, the real interest rate for the external commercial borrowing loan is assumed to be 4.83 percent, including a premium of 1.5 percent over the LIBOR rate and guaranteed commission of 1.6 percent. It is repaid in six half-yearly equal installments beginning 2003.

- *FSA.* JTPC guarantees annual off-take of 960 million m^3 of corex gas, and JVSL is required to maintain a year-round coal inventory of 200,000 metric tons to avoid fuel shortages. The heat content of corex gas is assumed to be in the range of 1,600 to 1,900 kcal/Nm^3, and that of coal to be 5,000 to 7,000 kcal/kg. The financing cost of the coal stock is estimated at the ICICI landing interest rate on year-round stock value, and the cost of carpet loss (loss sustained due to spread of coal in dump yard) is assumed at 1.5

percent of the value of the annual stock. The maximum permissible dust content in the corex gas supply is 5 mg/Nm^3, and the supply is guaranteed to meet the requirements of primary fuel for 11 months per year. Except for emergencies, coal is used as the primary fuel for one month per year. The FSA does not include the cost of auxiliary fuel in pricing the fuel cost.

- *PPA.* The PPA splits the electricity price into an energy charge and a capacity charge. To compute the energy charge we assume a heat rate of 10,500 kilo joules/kWh for normal operation and 10,900 kilo joules/kWh during the stabilization period.[8] The capacity charge includes interest payments, deprecation expenses; a 16 percent guaranteed return on the equity in dollar terms, operation and maintenance expenses, and income tax payments. Of these, only the operation and maintenance expenses are adjusted for annual inflation rates. Further adjustments are made based on the PPA guidelines to include an incentive point of 0.7 for every percentage point increase in the actual PLF from the 68.5 percent level. The PPA also punishes the project if it operates below 68.5 percent PLF, making it lose the component of return on equity in the tariff calculation.

- *Price of electricity for JTPC.* The price of electricity for JTPC is the PPA tariff, which is the sum of the energy and capacity charges.

- *Price of electricity for TPECs.* In the base case analysis, we assume that the price of electricity for TPECs is the same as the price for the supply from KEB. In 1995 the average tariff for industrial users was Rs 2.10/kWh, much lower than the market-clearing level.

- *Wheeling fee.* JTPC pays as wheeling fee of 10 percent of the gross value of energy consumed by the TPECs. The WBGSA does not specify any deductions for transmission and distribution losses, but levies a penalty charge of 50 percent on the applicable electricity tariff in the event KEB is required to make up any shortages in the commitments given to TPECs. JVSL refunds the wheeling fee to JTPC, but not the penalty payments.

[8] The number of kcal per kilojoules is 0.2388

- *Banking fee*. The WBGSA permits JTPC to deposit a maximum of 50 million kWh of electricity per month with KEB. Its banking fee is equal to 1 percent of the 50 million units, with provision to draw down the deposit to negative 5 million kWh without any penalty. Every month, energy deposits and withdrawals are computed with a statement of the opening balance and the closing balance. The opening balance in excess of the maximum permissible deposit is treated as zero. As in the case of the wheeling fee, JVSL refunds the banking fee to JTPC.

- *Grid support fee.* JTPC pays Rs 14.6 million per year to KEB as a grid support fee. This is adjusted each year to reflect the domestic inflation rate, and JVSL refunds the cost to JTPC.

Methodology

The analyses use the usual methodology for computing cash flow statements from the different viewpoints. The inflows primarily consist of sales revenues, changes in accounts receivable, loan inflows, liquidation values, and refunds from JVSL to JTPC or payments from JTPC to KEB. The outflows consist of investment costs, recurring costs, interest payments, capital repayments, changes in accounts payable, and cash balances. The given values in the project report are in 1995 prices, and the currencies involved are the Indian rupee and the U.S. dollar. We must therefore compute inflation indices for the rupee and dollar to estimate nominal inflows and outflows.

We calculate inflation indices by building annual inflation rates (gpe) into the compounding factor $(1+gpe)^t$. We compute inflation indices for 1995 through 2015, and then calculate the relative index by dividing the rupee index by the dollar index. We calculate the expected exchange rates during the project's life by multiplying the 1995 exchange rate (Rs 35=US$1) by the corresponding relative index for each year. The relative indices capture the relative movements of prices in the respective countries, and the relative movements cause fluctuations in the expected nominal exchange rates in addition to real appreciation or depreciation of the currency, which occurs because of changes in macroeconomic parameters.

Once we have computed the indices we multiply rupee components in 1995 prices by the rupee indices to obtain the corresponding years' estimates in nominal rupees.

Similarly, we multiply the estimates of dollar components in 1995 prices by the estimated U. S. price index and the expected nominal exchange rate to obtain the corresponding years' estimates in nominal rupees. Except for the capital investment costs, all other inflows or outflows require the estimation of future values.

The estimates of recurring costs and sales revenues are based on the annual quantity of electricity generated and supplied. In the base case analysis, we assume that, on average, the plant operates at 85 percent PLF from 2000 to 2014, generating 1,936 million kWh of electricity per year. Of this amount 6.9 percent is consumed at the power plant, leaving 1,802 million kWh available for sale. Of this amount, each year JTPC supplies 1,174 million kWh to JVSL and 629 million kWh to TPECs, assuming no transmission losses. However, some transmission losses always occur. As the WBGSA does not make specific reference to such losses, we make no provision for adjustments necessitated by transmission losses[9].

Nevertheless, JTPC cannot make spot sales of electricity. It is required to provide advance notification about the quantity of electricity that it can supply to the TPECs. There are terms and conditions for withdrawals of electricity from KEB to meet any shortages or for deposits of electricity with KEB in excess of 50 million kWh, which are reflected in the closing balance. Table 4.4 depicts the project's energy generation and supply position at 85 percent APLF, which is also the declared plant availability factor.

[9] Because the bulk of electricity consumption occurs at JVSL, which is close to the power project, the contractual arrangement is silent on transmission and distribution losses.

Table 4.4: Calculation of Electricity generation and Supply, and Selected Years 1999-2014

Year end, March 31

PLEASE PROVIDE UNITS FOR EACH ROW	1999	2000	2001	2002	2003	2004	2014
Average PLF **(%)**	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Energy generation with corex gas	887	1775	1775	1775	1775	1775	1775
Energy generation with coal	81	161	161	161	161	161	161
Gross energy generation	968	1936	1936	1936	1936	1936	1936
Auxiliary energy consumption	67	134	134	134	134	134	134
Energy available for supply	901	1802	1802	1802	1802	1802	1802
Energy required by JVSL	1174	1174	1174	1174	1174	1174	1174
Energy available for TPECs	0	629	629	629	629	629	629
Energy supplied through JVSL (deposit)	0	629	629	629	629	629	629
Opening balance	0	0	50	50	50	50	50
Commitment to TPECs	0	565	565	565	565	565	565
Banking fee	0	6	6	6	6	6	6
Excess drawdown from KEB	0	0	0	0	0	0	0
Closing balance	0	58	108	108	108	108	108
Energy wheeled by KEB	0	623	673	673	673	673	673

Except for operation and maintenance expenses, running costs change with the APLF, that is, with units of electricity generated. The costs of primary fuels are based on the FSA and are estimated at Rs 1.57/kWh in 1995 prices (table 4.5).

Per the PPA, the electricity tariff is calculated by adding the energy charge and the capacity charge. When calculated using the PPA formulas, the capacity charge in 1995 prices is Rs 1.92/kWh for 1999, Rs 1.47/kWh for 2000, Rs 1.39/kWh for 2001, Rs 1.47/kWh for 2002, Rs 1.21/kWh for 2003 Rs 1.24 kWh for 2014. Such fluctuations in the capacity charge occur because of changes in interest payments and corporate tax payments and because of inflation. If the actual tariff fluctuated to this extent, it would cause panic among industrial consumers, particularly those who use electricity as a major input.

Thus, we consider the appropriate calculation of the levelized capacity charge as the solution to this practical problem. We calculate the levelized capacity charge by dividing the present value (PV) of capacity costs by the PV of total energy generated at a 68.5 percent PLF. The discount rate we use for this purpose is 10.5 percent, which is same as the expected real rate of return to equity of the domestic partner and almost equal to India’s social discount rate.

Table 4.5: Calculation of Primary Fuel Cost, and Selected Years 1999-2014

Year ended March 31

Category	1999	2000	2001	2002	2003	2004	2013	2014
Coal price cif Madras ($/MT)	72.25	74.78	77.39	80.10	82.91	85.81	116.95	121.04
Coal price cif Madras (Rs/MT)	2,998	3,238	3,497	3,777	4,079	4,405	8,806	9,510
Tariff (percent of cif)	660	712	769	831	897	969	1,937	2,092
Freight and handling (percent of cif)	120	130	140	151	163	176	352	380
Countervaling duty	378	408	441	476	514	555	1,110	1,198
Sales tax	166	180	194	209	226	244	488	527
Cost at the plant (Rs/MT)	4,321	4,667	5,040	5,444	5,879	6,350	12,693	13,708
Calorific value of coal (kcal/kg)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Cost at the plant (Rs/million kcal)	720	778	840	907	980	1,058	2,115	2,285
Coal requirement (kg millions)	34	67	67	67	67	67	67	67
Coal delivered/year (kcal millions)	201,663	403,325	403,325	403,325	403,325	403,325	403,325	403,325
Energy delivered/month from coal	16,805	33,610	33,610	33,610	33,610	33,610	33,610	33,610
Corex gas requirement (Nm^3/millions)	1,130	2260	2,260	2,260	2,260	2,260	2,260	2,260
Calorific value of corex gas (kcal/Nm^3)	1,830	1830	1,830	1,830	1,830	1,830	1,830	1,830
Energy delivered from corex gas(kcal millions)	2,067,444	4,134,888	4,134,888	4,134,888	4,134,888	4,134,888	4,134,888	4,134,888
Energy delivered/month from corex gas	172,287	344,574	344,574	344,574	344,574	344,574	344,574	344,574
Financing cost, coal stock (Rs millions)	152.31	164.50	177.65	191.87	207.22	223.79	447.36	483.15
Financing cost of coal stock/month	12.69	13.71	14.80	15.99	17.27	18.65	37.28	40.26
Carpet losses, coal stock (Rs millions)	12.96	14.00	15.12	16.33	17.64	19.05	38.08	41.12
Carpet losses in coal stock/month	1.08	1.17	1.26	1.36	1.47	1.59	3.17	3.43
Fuel price per FSA (Rs/million kcal)	851.48	919.60	993.16	1072.62	1158.43	1251.10	2500.96	2701.03
Fuel price per FSA (Rs/kwh)	2.13	2.31	2.49	2.69	2.90	3.14	6.27	6.77
Fuel price per FSA (Rs/kwh in 1995 prices)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57

cif cost, insurance and freight
MT Metric ton

We estimate the levelized capacity charge in 1995 prices at Rs 1.35/kWh. Adding to it 70 percent of the guaranteed rate of return on equity for every 1 percent increase in the actual PLF above the norm of 68.5 percent, the adjusted levelized capacity charge is calculated as Rs 1.38/kWh for the plant operating, on average, during the year at 85 percent PLF. This yields a PPA tariff of Rs 3.06/kWh by adding the energy charge of Rs 1.69/kWh in 1995 prices (Table 4.6).

In Karnataka, the long-run marginal cost of supplying electricity to industrial consumers is estimated at Rs 2.73/kWh in 1995 prices (ICICI 1995b, p. 10). We assume that the tariff for TPECs will be Rs 2.10/ kWh, KEB’s prevailing rate for industrial users.

The estimation of the fuel charge, capacity charge, and annual generation of electricity enables us to calculate inflows and outflows either from the sales of electricity or from the consumption of inputs. Together with information about capital investment costs; operation and maintenance expenses; and assumptions about accounts payable, accounts receivable, and cash balances, we can construct tables of cash flow statements from the viewpoints of the different stakeholders after computing liquidation values, interest and loan repayments, and income tax payments. We estimate the liquidation values of capital items by subtracting the cumulative depreciation from the initial book values. Loan servicing and loan repayments are estimated based on the PMT function, and the corporate tax payments are estimated by including deductions for the loss caused by the depreciation of the rupee in the principle repayments of foreign capital. The summary statistics, such as NPV, internal rate of return (IRR), annual debt service capacity ratio (ADSCR), and debt service capacity ratio (DSCR), are calculated to analyze the project's financial viability from the viewpoint of each stakeholder.

Table 4.6: Calculation of the PPA Tariff, and Selected Years 1999-2014

Year ended March 31

	1999	2000	2001	2002	2003	2004	2013	2014
Energy charge								
Energy charge per PPA (Rs/million kcal)	915	988	1,067	1,152	1,244	1,344	2,686	2m901
Energy charge per PPA (Rs/kwh)	2.29	2.48	2.67	2.89	3.12	3.37	6.74	7.27
Energy charge per PPA (Rs/kwh, real)	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69
Capacity charge								
Interest expenses, loan (Rs millions)		1277.14	1209.13	1513.76	1585.08	1410.26		
Depreciation expenses (Rs millions)	741.48	800.80	864.86	934.05	1008.78	1089.48	2409.00	2601.72
Operation and maintenance expenses (Rs millions)	406.41	438.92	474.03	511.95	552.91	597.14	1193.69	1289.19
Return on equity (Rs millions)	723.66	755.12	787.95	822.21	857.96	895.26	1313.11	1370.20
Corporate income tax (Rs millions)	0.00	0.00	0.00	0.00	0.00	0.00	3225.05	3699.57
Energy available for supply (kwh millions)	901.19	1802.38	1802.38	1802.38	1802.38	1802.38	1802.38	1802.38
Capacity charge (Rs/kWh)	2.08	1.82	1.85	2.10	2.22	2.21	4.52	4.97
Capacity charge (Rs/kwh, real)	1.53	1.24	1.17	1.22	1.20	1.11	1.13	1.15
Capacity charge @ 68.5% PLF (Rs/kWh)	1.88	1.45	1.38	1.45	1.43	1.33	1.19	1.22
Unit energy (kwh)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
PV of tariff @68.5% PLF and 10.5% DR	10.26	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
PV of unit kwh @68.5% PLF and 8.8% DR	7.60	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Levelized capacity charge (Rs/kwh, real)	1.35	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Adjusted capacity charge (Rs/kwh, real)	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38
Tariff,JTCL (Rs/kwh, 1995 prices)	3.06	3.06	3.06	3.06	3.06	3.06	3.06	3.06
Adjusted tariff for TPEC (Rs/kwh, real)	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Unadjusted tariff for TPEC (Rs/kwh, real)	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Adjusted tariff, industrial users, (Rs/kwh, real)	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Unadjusted tariff, industrial users (Rs/kwh, real)	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Marginal cost, industrial users (Rs/kwh, real)	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73

DR Discount rate

Remember that the estimate of NPV from a particular viewpoint depends on the relevant discount rate for that stakeholder. For this project we have estimated the real discount rate of 12 percent for the foreign partner by subtracting the impact of the 3.5 percent U.S. inflation rate from 16 percent, the government's guaranteed nominal rate of return for foreign equity investments in power projects in India. The real discount rate for the domestic partner, JVSL, and KEB is assumed to be 10.5 percent, which is 1.5 percent lower than that of the foreign partner and nearly equal to India's social discount rate. The discount rate for the equity holders is calculated at 11.3 percent by taking the weighted average of the discount rates for the domestic partner and the foreign partner. We have distinguished between the discount rates of the foreign partner and the domestic partner based on our thesis that the foreign investor faces, and must be compensated for, a higher level of political risk than that faced by the domestic partner.

Cash Flow Statements

Table 4.7 is the project's real cash flow statement from the viewpoint of bankers or of total investment. In addition to the usual inflows and outflows found in generic cash flow statements, we treat the banking and grid support fee and the wheeling fee both as inflows and outflows, because JVSL refunds these expenditures to JTPC based on the WBGSA. This is our basic cash flow table from which we shall derive cash flow statements from the viewpoints of the domestic partner, the foreign partner, JVSL, and KEB by adding or removing lines.

To analyze the project from the viewpoint of bankers we need to know whether or not the project is capable of servicing the loans and amortizing the debt under the terms and conditions specified in the loan agreement. Calculation of the ADSCR enables us to gain insight into the situation and we calculate the ADSCR for each year by dividing the real net cash flows by the corresponding annual total repayments. The ADSCRs, as shown in table 4.7, indicates that the project would not face a cash crunch resulting from the repayment of debts and loan servicing in any years. If it does face a liquidity problem, this is most likely to occur in Year 2004 when the ADSCR is 1.07.

We can get a better picture of the repayment schedule as a whole by calculating the DSCR. We obtain the ratios by dividing the PV of all the net cash flows by the PV of all the repayments for the remaining period where there is debt outstanding. The rate discount used is the weighted average cost of the debt. With the real weighted average cost of the debt calculated

Table 4.7: Cash Flow Statements, Bankers' Viewpoint, and Selected Years 1995-2015 (Rs millions, 1995 prices)

Year ended March 31

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2013	2014	2015
Receipts													
Sales to JVSL	0	0	0	0	2760	3595	3595	3595	3595	3595	3595	3595	0
Sales through JVSL	0	0	0	0	0	1925	1925	1925	1925	1925	1925	1925	0
Collection of JTPC revenue	0	0	0	0	0	1320	1320	1320	1320	1320	1320	1320	0
Refund(banking and grid support fee)	0	0	0	0	15	27	27	27	27	27	27	27	0
Refund of wheeling fee	0	0	0	0	0	131	141	141	141	141	141	141	0
Changes in accounts receivable	0	0	0	0	-333	-531	-63	-62	-62	-62	-62	-62	779
Liquidation value	0	0	0	0	0	0	0	0	0	0	0	0	0
Land	0	0	0	0	0	0	0	0	0	0	0	0	14
Plant (buildings and civil works)	0	0	0	0	0	0	0	0	0	0	0	0	384
Machinery and equipment	0	0	0	0	0	0	0	0	0	0	0	0	1596
Miscellaneous fixed assets	0	0	0	0	0	0	0	0	0	0	0	0	158
Cash Inflows	0	0	0	0	2442	6467	6945	6946	6946	6946	6946	6946	2932
Expenditures													
Investment costs													
Pre-operate expenses	1329	936	0	0	0	0	0	0	0	0	0	0	0
Land	14	0	0	0	0	0	0	0	0	0	0	0	0
EPC contract	422	800	3250	3615	984	0	0	0	0	0	0	0	0
Miscellaneous fixed assets	35	65	80	190	45	0	0	0	0	0	0	0	0
Margin money	0	0	0	185	0	0	0	0	0	0	0	0	0
Operating costs	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	127	253	253	253	253	253	253	253	0
Corex gas	0	0	0	0	1392	2785	2785	2785	2785	2785	2785	2785	0
Auxiliary fuel	0	0	0	0	1	2	2	2	2	2	2	2	0
Cooling water	0	0	0	0	14	28	28	28	28	28	28	28	0
Operation and maintenance expenses	0	0	0	0	299	299	299	299	299	299	299	299	0
Wheeling fee to KEB	0	0	0	0	0	131	141	141	141	141	141	141	0
Banking and grid support fee	0	0	0	0	15	27	27	27	27	27	27	27	0
Penalty payment	0	0	0	0	0	0	0	0	0	0	0	0	0
Refund of TPECs revenue to JVSL	0	0	0	0	0	1320	1320	1320	1320	1320	1320	1320	0
Changes in accounts payable	0	0	0	0	-143	-250	-29	-28	-28	-28	-28	-28	355
Changes in cash balance	0	0	0	0	-28	250	29	28	28	28	28	28	-355
Income tax	0	0	0	0	0	0	0	0	0	318	926	926	0
Cash outflows	1800	1800	3330	3989	2705	4845	4856	4856	4856	5173	5781	5781	0
Net cash flow after tax	-1800	-1800	-3330	-3989	-264	1622	2090	2091	2091	1773	1165	1165	2932
ADSCR analysis													
Dividend payment	n.a.	n.a.	n.a.	n.a.	n.a.	0	0	0	0	0	n.a.	n.a.	n.a.
Cash available for debt servicing	n.a.	n.a.	n.a.	n.a.	n.a.	1622	2090	2091	2091	1773	n.a.	n.a.	n.a.
Debt repayment	n.a.	n.a.	n.a.	n.a.	n.a.	1,132	1,048	1,397	1,751	1,655	n.a.	n.a.	n.a.
ADSCR	n.a.	n.a.	n.a.	n.a.	n.a.	1.43	1.99	1.50	1.19	1.07	n.a.	n.a.	n.a.
Annualized DSCR analysis													
WACL, real (%)	6.9												
Time-line	0	1	2	3	4	5	6	7	8	9	n.a.	n.a.	n.a.
Discounting factors @ WACL	1	0.94	0.88	0.82	0.77	0.72	0.67	0.63	0.59	0.55	n.a.	n.a.	n.a.
PV of available cash	n.a.	n.a.	n.a.	n.a.	n.a.	1162	1400	1311	1226	972	n.a.	n.a.	n.a.
Present value of debt	n.a.	n.a.	n.a.	n.a.	n.a.	811	702	876	1027	908	n.a.	n.a.	n.a.
Annualized DSCR	n.a.	n.a.	n.a.	n.a.	n.a.	1.51	1.52	1.46	1.46	1.53	n.a.	n.a.	n.a.

EPC engineering, procurement, and construction

WACL Weight Average Cost of Loan
Source: Table 1 and Project Report Information
at 6.9 percent, the minimum DSCR is estimated at 1.46 for 2003 and the maximum DSCR is estimated at 3.9 for the last year of the repayment period. A snapshot analysis of the cash flow statements from the bankers' viewpoint establishes that the project would be in a position to service the debt and amortize the loan each year as specified in the loan agreement.

Table 4.8: Cash Flow Statements, Equity Holders', Foreign Partner's, and Domestic Partner's Viewpoint, Selected Years 1995-2015 (1995 Prices)

Category	Year ended March 31												
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2013	2014	2015
Equity holders													
After tax NCF without financing (Rs millions)	(1,800)	(1,800)	(3,330)	(3,989)	(264)	1,622	2,090	2,091	2,091	1,773	1,165	1,165	2,932
Loan inflow (Rs millions)	-	-	3,330	3,990	1,029	-	-	-	-	-	-	-	-
Repayment (principle + interest) (Rs millions)	-	-	-	-	-	1,132	1,048	1,397	1,751	1,655	-	-	-
After tax NCF with financing (Rs millions)	(1,800)	(1,800)	0	1	765	490	1,042	693	340	117	1,165	1,165	2,932
NPV@real discount rate of 11.3% (Rs millions)	353												
IRR (%)	12.3												
Domestic partner (JTPC)													
After tax NCF without financing (Rs millions)	(900)	(900)	0	0	382	245	521	347	170	59	582	582	1,466
NPV@real discount rate of 10.5% (Rs millions)	315												
IRR (%)	12.3												
Foreign partner													
After tax NCF (nominal US$ millions)	-25.71	-26.61	0.00	0.01	12.54	8.31	18.29	12.60	6.39	2.29	30.91	31.99	83.33
After tax NCF (real US$ millions)	-25.71	-25.71	0.00	0.01	10.93	7.00	14.88	9.91	4.86	1.68	16.64	16.64	41.88
NPV @ real discount rate of 13% (US$ millions)	1.46												
IRR (%)	12.3												

NCF Net cash flow

Table 4.8 contains the cash flow statements from the viewpoint of equity holders, the foreign partner, and the domestic partner (JTPC). It is obtained by adding the loans and subtracting the principle and interest repayments to the net cash flows in the relevant years of inflow and outflow (from table 4.7). The adjusted net cash flows yield Rs 353 million in NPV at a discount rate of 11.3 percent and an IRR of 12.3 percent. We then divide the net cash flows of the equity holders into two halves to calculate the NPV and the IRR for the foreign partner and the domestic partner, respectively. When discounted by 10.5 percent, the net cash flows yield Rs 315 million in NPV for the domestic partner (JTPC). The other half, when converted into real dollars and discounted by 13 percent, yields US$ 1.46 million in NPV for the foreign partner.

Table 4.9 shows the cash flow statement from the viewpoint of JVSL. Its inflows are from the sale of electricity to TPECs, from the sale of primary fuels to JTPC, and from avoided cash outflows. The inclusion of avoided cash outflows is justified because the 1.25 million ton per year steel plant has been already established, and JVSL had no option but to buy electricity from KEB at the rate of Rs 2.10/kWh.[10] The outflows are payments for electricity to JTPC at the PPA tariff; payments for the purchase of 200,000 metric tons of coal; and refunds of wheeling, banking, and grid support fees to JTPC. The net cash flows, upon discounting at the real rate of 10.5 percent, yield Rs 5,401 million in PV. Note that we have ignored outflows of capital costs, if any, for the corex gas supply, be it for the construction of storage tanks or for laying pipelines.

Table 4.10 is the cash flow statement from the viewpoint of KEB. KEB has no outflows. It receives as inflows the wheeling fee at the rate of 10 percent of the value of gross energy wheeled; the banking and grid fees at 1 percent of the maximum permissible deposit of energy with the KEB (50 million kWh), priced at the KEB tariff; and any penalty payments for withdrawals of excess electricity from KEB. As specified in the WBGSA, the penalty payments are applicable only when the monthly closing balance of electricity with KEB falls below 5 million kWh, and it will be charged at 1.5 times KEB's tariff for industrial users. As there are no outflows, the net cash flows of the project from the viewpoint of KEB are all positive, and upon discounting them at the real rate of 10.5 percent, yield Rs 822 million in PV. This establishes that

[10] The avoided cash outflows for JTPC are underestimated, because as the supply from KEB was not reliable, it could have paid as much as Rs 2.73/kWh.

the project is viable from the viewpoint of KEB, and that the benefits are due to fuller utilization of its existing surplus transmission and distribution capacity.

Table 4.9: Cash Flow Statement, JVSL's Viewpoint, and Selected Years 1995-2015 (Rs millions, 1995 Prices)

Year ended March 31

Category	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2013	2014	2015
Avoided cash outflows	0	0	0	0	1892	2465	2465	2465	2465	2465	2465	2465	0
Electricity sale to TPECs	0	0	0	0	0	1320	1320	1320	1320	1320	1320	1320	0
Revenue from fuel, coal	0	0	0	0	127	253	253	253	253	253	253	253	0
Revenue from fuel, corex	0	0	0	0	1392	2785	2785	2785	2785	2785	2785	2785	0
Changes in account receivable of JVSL due to JTPC	0	0	0	0	-127	-165	-19	-19	-19	-19	-19	-19	234
Cash inflows	0	0	0	0	3285	6658	6804	6804	6804	6804	6804	6804	234
<u>Expenditures</u>													
Payments for electricity	0	0	0	0	2760	5520	5520	5520	5520	5520	5520	5520	0
Payments for coal	0	0	0	0	108	217	217	217	217	217	217	217	0
Refund (banking and grid support fee)	0	0	0	0	15	27	27	27	27	27	27	27	0
Refund (wheeling charge)	0	0	0	0	0	131	141	141	141	141	141	141	0
Changes in accounts payable of JVSL due to JTPC	0	0	0	0	-342	-541	-65	-64	-64	-64	-64	-64	795
Cash outflows	0	0	0	0	2541	5354	5841	5842	5842	5842	5842	5842	795
Net cash flows	0	0	0	0	744	1304	963	963	963	963	963	963	-561
NPV of net cash flow @ 10.5%	5,401												

Table 4.10: Cash Flow Statement, KEB's Viewpoint, and Selected Years 1995-2015 (Rs Million, 1995 Prices)

Year ended March 31

Category	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2013	2014	2015
Wheeling charge	-	-	-	-	-	131	141	141	141	141	141	141	-
Banking and grid support fee	-	-	-	-	15	27	27	27	27	27	27	27	-
Supply to TPECs at 25% premium					-	-	-	-	-	-	-	-	-
Changes in accounts receivable	-	-	-	-	(2)	(17)	(3)	(1)	(1)	(1)	(1)	(1)	19
Cash inflows	-	-	-	-	13	141	166	167	167	167	167	167	19
PV of NCF at 10.5%	822												

Essentially, the O.P. Jindal Group, promoter and domestic partner in JTPC, also owns JVSL. In reality, the domestic partner would be more concerned about the project's overall financial benefits to the O. P Jindal Group and not just to JTPC. Therefore, we obtain the financial gains to the domestic partner (JTPC + JVSL) by adding the NPV of the domestic partner (JTPC) to the PV of the financial benefit to JVSL. This amounts to a present value of Rs 5,716, measured in 1995 prices, a huge gain.

Results of the Financial Analysis

As the cash flow statements demonstrate, the project is financially viable from the viewpoint of bankers, the domestic partner, the foreign partner, the dedicated consumer (JVSL), and the utility (KEB). The bankers are satisfied because the project generates adequate net cash flows to service the loans and interest payments. The foreign partner, Tractebel South Asia, is happy because the project's NPV from its viewpoint is US $1.46 million, registering a real rate of return of 12.3 percent on its equity capital. The domestic partner, the Jindal group of industries, benefits because JTPC is recording a project NPV of Rs 315 million and JVSL is gaining Rs 5,401 million, yielding a combined benefit of Rs 5,716 million. Finally KEB registers a gain of Rs 822 million. However, the project's financial viability has been established based on the stationary values of parameters in the financial models, which may not be the case when parameters change individually or in combination.

Sensitivity Analysis

The deterministic estimates of NPV are based on a set of parameters that may not necessarily remain the same through out the project life. We have therefore conducted sensitivity analyses on a set of key variables to examine their impacts on the NPV of equity holders, the foreign partner, the domestic partner (JTPC), JVSL, and the combined domestic partner (JTPC + JVSL) and on the ADSCR for 2004. We also assess the impacts on the PV of KEB, on the capacity charge, and on the electricity supply to the TPECs when considered necessary for clarity.

INVESTMENT COST OVERRUN FACTOR. The engineering, procurement, and construction contract between JTPC and Bharat Heavy Electrical, Limited-Raytheon has provisions for arresting a cost escalation trend caused by poor management. Nevertheless, the actual costs may be more or less than the project estimates, which would affect the NPV from the viewpoint of bankers and equity holders. As table 4.11 shows, the NPV from the viewpoints of the domestic and foreign partners improves if actual capital investment is less than estimated costs and deteriorates if actual costs exceed estimated costs. Once actual costs exceed estimated costs by 5 percent, the NPV turns negative for the equity holders and the foreign partner. A deviation of up to 30 percent from initial estimates is not impossible for large projects of this type.

Table 4.11: Effect of Changes in Investment Costs (1995 Prices)

Change in capital cost (1%)	NPV Equity holders (Rs millions)	NPV Foreign partner (US$ millions)	NPV Domestic partner (Rs millions)	IRR Equity holders (%)	IRR Foreign partner (%)	NPV JVSL (Rs millions)	NPV JVSL plus domestic partner (Rs millions)
	352.5	1.5	315	12.3	12.3	5,401	5,716
-5	816.1	8.0	549	14.0	14.0	5,401	5,950
-3	630.6	5.4	455	13.3	13.3	5,401	5,856
0	352.5	1.5	315	12.3	12.3	5,401	5,716
5	-111.0	-5.1	81	10.9	10.9	5,401	5,482
10	-574.6	-11.7	-153	9.7	9.7	5,401	5,248
12	-641.9	-12.7	-184	9.6	9.6	5,401	5,218
14	-827.9	-15.3	-278	9.2	9.2	5,401	5,124
15	-921.0	-16.6	-325	9.0	9.0	5,401	5,077

PRICE OF PRIMARY FUELS. As table 4.12 shows, an increase in the real price of coal has a negative impact on the NPV from the viewpoints of the equity holders, the foreign partner, and the domestic partner (JTPC) as well as on the PV of JVSL. The impacts are positive if the real price of coal decreases. As the ADSCR remains the same, the impact of changes in fuel prices on net cash flows is neutralized by the corresponding increase in the PPA tariff. The gain due to the fuel price increase does not improve the NPV of JVSL, because it is neutralized by the corresponding increase in electricity payments.

Table 4.12: Effect of Changes in Real Price of Fuel (1995 Prices)

% Change Fuel Price	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	NPV of JVSL Rs Million	NPV of JVSL plus DP Rs Million	ADSCR 2004
	352.5	1.5	315	5,401	5,716	1.07
-9 %	379.8	1.8	329	5,495	5,824	1.07
-6 %	370.7	1.7	324	5,464	5,788	1.07
-3 %	361.6	1.6	320	5,433	5,752	1.07
0 %	352.5	1.5	315	5,401	5,716	1.07
3 %	343.4	1.3	310	5,370	5,680	1.07
6 %	334.3	1.2	305	5,339	5,644	1.07
9 %	325.2	1.1	301	5,307	5,608	1.07

The PPA provides a premium of 20 percent to the corex gas supply over the price of imported coal. As table 4.13 shows, an increase in the premium decreases the project's NPV from the viewpoint of the equity holders, the foreign partner, and the domestic partner (JTPC), but increases the PV of JVSL. However, the net effect on the NPV of the domestic partner combined (JTPC + JVSL) is negative. A decrease in the premium has a positive impact on the NPV of the equity holders, the foreign partner, and the NPV of domestic partner combined. It also improves the ADSCR, making the project more attractive from the bankers' viewpoint. All the stakeholders gain when corex gas is supplied at no cost; however, this will not be the situation on the PV of the domestic partner combined if the government of Karnataka implements a structural change in the price of electricity to industrial consumers.

Table 4.13: Effect of Changes in Premium on Corex Gas Supply (1995 Prices)

Percentage Change in Premium	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	NPV of JVSL Rs Million	NPV of JVSL + DP Rs Million	ADSCR 2004
	352.5	1.5	315	5,401	5,716	1.07
-100	632.8	5.3	459	5,328	5,787	1.09
-75	574.4	4.5	429	5,341	5,770	1.08
-54	525.3	3.9	404	5,353	5,757	1.08
-25	457.6	2.9	369	5,371	5,740	1.08
-5	410.9	2.3	345	5,384	5,729	1.07
0	399.2	2.1	339	5,388	5,727	1.07
10	375.9	1.8	327	5,395	5,721	1.07
20	352.5	1.5	315	5,401	5,716	1.07

INFLATION RATES. As table 4.14 shows, an increase in the domestic inflation rate decreases the project's NPV from the viewpoint of equity holders, the foreign partner, and the domestic partner (JTPC), but increases the NPV of JVSL. The net effect on the NPV of the domestic partner combined (JTPC +JVSL) is positive, and some improvement occurs in the ADSCR for 2004. The impacts are due to changes in the real values of accounts payable, accounts receivable, and cash balances. The increase in the ADSCR is due to the decrease in debt repayments relative to net cash flow.

Table 4.14: Effect of Changes in Inflation Rates (1995 Prices)

Domestic inflation rate

Change in inflation Rate (%)	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	NPV of JVSL Rs Million	NPV of JVSL + DP Rs Million	ADSCR 2004
	352.5	1.5	315	5,401	5,716	1.07
6	395.4	2.1	336	5,351	5,687	1.06
8	352.5	1.5	315	5,401	5,716	1.07
10	309.0	0.8	293	5,450	5,743	1.08
12	265.4	0.2	272	5,496	5,768	1.09
14	222.0	(0.4)	250	5,541	5,791	1.09
16	179.1	(1.0)	229	5,584	5,813	1.10
18	137.0	(1.6)	208	5,626	5,834	1.11

US inflation rate

	352.5	1.5	315	5,401	5,716	1.07
1.0	370.7	1.7	324	5,443	5,767	1.08
1.5	366.9	1.7	322	5,434	5,757	1.08
2.0	363.1	1.6	320	5,426	5,746	1.08
2.5	359.5	1.6	318	5,418	5,736	1.07
3.0	356.0	1.5	317	5,410	5,726	1.07
3.5	352.5	1.5	315	5,401	5,716	1.07
4.0	349.1	1.4	313	5,393	5,706	1.07
4.5	345.8	1.4	311	5,385	5,696	1.07
5.0	342.6	1.3	310	5,377	5,686	1.07

Based on the past, India's inflation rate could vary from 6 to 18 percent per year. Although on their own changes in domestic inflation rates may not turn the project's NPV negative from the viewpoint of the domestic partner, the NPV of the foreign partner might turn negative if changes in the inflation rate work in combination with the impacts of the other variables.

The impacts of changes in the foreign inflation rate are in the opposite direction of changes in the domestic inflation rate.

REAL EXCHANGE RATE. The impact of a real appreciation or depreciation of the rupee in relation to the U.S. dollar is shown in table 4.15. About 30 percent of the project's capital costs are in U.S. dollars. Therefore any appreciation in the U.S. dollar would lower the capital cost, improving the NPV from the bankers' viewpoint. The pricing of the primary fuels is also based on the U.S. dollar, and the price of fuel is built into the sales price of electricity. The movement in the NPV will be in the same direction for both revenues and fuel costs. Appreciation also improves the NPV of JVSL because of the decrease in fuel costs, a component of the PPA tariff. By contrast, depreciation improves the NPV of the domestic partner, because it is paid in the rupee equivalent of the return of its equity share in the capital investment. This benefit is nullified in the case of the foreign partner, as the rupee gain is converted to U.S. dollars.

Table 4.15: Effect of Changes in the Real Foreign Exchange Rate (1995 Prices)

Change in foreign exchange rate	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	NPV bankers Rs Million	PV of JVSL Rs Million	PV of DP Rs Million	PV of Loan	PV of Repayment	PV of $PV_L – PV_R$
	353	1.5	315	-1,079	5,401	5,716	6,252	7,424	(1,172)
-10	309	0.8	297	-1,019	5,505	5,803	5,984	7,171	(1,187)
-8	318	0.9	301	-1,031	5,485	5,785	6,038	7,222	(1,184)
-5	331	1.2	306	-1,049	5,453	5,759	6,118	7,297	(1,179)
-3	339	1.3	310	-1,061	5,433	5,742	6,172	7,348	(1,176)
0	353	1.5	315	-1,079	5,401	5,716	6,252	7,424	(1,172)
5	374	1.7	324	-1,108	5,349	5,673	6,386	7,550	(1,164)
10	396	2.0	332	-1,138	5,297	5,630	6,520	7,677	(1,156)
15	418	2.2	341	-1,167	5,245	5,586	6,654	7,803	(1,149)
20	440	2.4	350	-1,197	5,193	5,543	6,788	7,930	(1,141)

ACCOUNTS RECEIVABLE. As table 4.16 indicates, the impact of changes in accounts receivable on the project's NPV from the viewpoint of the equity holders is profound, turning the NPVs negative when accounts receivable as a percentage of annual sales revenue exceed 15 percent for the foreign partner and 25 percent for the domestic partner (JTPC). As expected the PV of JVSL improves with the increase in accounts receivable of JTPC because it is the sole buyer of electricity. The ADSCR decreases with the increase in accounts receivable because of the decrease in the net cash flow. In India, particularly for state electricity boards, accounts receivable have varied from one to six months of sales revenues. However, as in this case an independent power producer is involved, the situation may not be same as for state electricity boards.

Table 4.16: Effect of Changes in Accounts Receivable (1995 Prices)

Percentage Change in accounts receivable	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(EH)	IRR (FP)	PV of JVSL Rs Million	PV of DP Rs Million	ADSCR 2004
	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
5	754.6	7.0	522	13.6%	13.6%	4,986	5,509	1.09
10	467.4	3.1	374	12.7%	12.7%	5,283	5,657	1.08
15	180.2	(0.9)	226	11.8%	11.8%	5,579	5,805	1.06
20	(107.0)	(4.9)	78	10.9%	10.9%	5,876	5,953	1.05
25	(394.3)	(8.9)	-71	10.1%	10.1%	6,172	6,102	1.03
30	(681.5)	(12.8)	-219	9.3%	9.3%	6,469	6,250	1.01
35	(968.7)	(16.8)	-367	8.6%	8.6%	6,766	6,398	1.00
40	(1,255.9)	(20.8)	-516	7.9%	7.9%	7,062	6,547	0.98

ACCOUNTS PAYABLE. As table 4.17 reveals, the impact of accounts payable is in the opposite direction of that of accounts receivable. The project's NPV from the viewpoint of the equity holders, the foreign partner, and the domestic partner (JTPC) increases with an increase in accounts payable. The PV of JVSL decreases with the increase because it is the sole supplier of fuel. As expected, the ADSR improves with the increase in accounts payable because the project will have more cash available, which is reflected in the net cash flow. The overall impact onto the domestic partner combined (JTPC + JVSL) is negative. In the base case we have assumed accounts payable at 8.33 percent of annual purchases, equivalent to payments being delayed for 30 days; however, payments could easily be delayed from 15 to 45 days, meaning that accounts payable could vary from 5 to 12 percent.

Table 4.17: Effects of Changes in Accounts Payable
(1995 Prices)

Change in Accounts receivable	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(EH)	IRR (FP)	PV of JVSL Rs Million	PV of DP Rs Million	ADSCR 2004
	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
5	227.3	(0.3)	250	11.9%	11.9%	5,489	5,739	1.06
10	415.3	2.3	347	12.5%	12.5%	5,357	5,705	1.07
15	603.4	4.9	444	13.1%	13.1%	5,225	5,670	1.08
20	791.4	7.5	541	13.7%	13.7%	5,094	5,635	1.09
25	979.4	10.1	639	14.4%	14.4%	4,962	5,600	1.11
30	1,167.5	12.7	736	15.0%	15.0%	4,830	5,565	1.12
35	1,355.5	15.3	833	15.7%	15.7%	4,698	5,531	1.13
40	1,543.6	17.9	930	16.3%	16.3%	4,566	5,496	1.14

ACTUAL PLF. Table 4.18 depicts the generation of electricity, the distribution of electricity between JVSL and the TPECs, and the variation in capacity charge with the changes in actual PLF. The changes in capacity charge are due to the terms and conditions specified in the PPA. It suddenly decreases and becomes stationary at Rs 1.12/kWh after the APLF falls below 68.5 percent, the normative plant load factor, but then increases again once the APLF rises above 69%.

Table 4.18: Effect of Changes in Actual PLF
(Million kWh)

Change in APLF (%)	Bus Bar	JVSL	TPECs	Capacity Charge (Rs/kWh)
	1,802	1,174	629	1.38
50	1,060	1,060	-	1.12
53	1,124	1,124	-	1.12
56	1,187	1,174	14	1.12
59	1,251	1,174	77	1.12
69	1,453	1,174	279	1.35
72	1,516	1,174	342	1.36
75	1,580	1,174	406	1.36
78	1,643	1,174	470	1.37
79	1,675	1,174	501	1.37
81	1,718	1,174	544	1.37
83	1,760	1,174	586	1.37
85	1,802	1,174	629	1.38

The power plant could well not operate at an APLF of less than 75 percent or more than 90 percent. As table 4.19 shows the impact of the APLF on the NPV of equity holders, the foreign partner, and the domestic partner is profound, but not on the same scale as its effect on the PV of JVSL. The NPV turns negative at 83 percent APLF for the foreign partner and at 79 percent APLF for the domestic partner (JTPC). The PV of JVSL decreases gradually because of the reduction in the sale of corex gas until it reaches the normative PLF of 68.5 percent. At this transition point, where the PPA spells out a fixed deduction from the capacity cost, the PV rises again because of the reduction in electricity payments to JTPC but not in revenue from the TPECs. The PV of JVSL declines again as the use of corex gas and the sale of electricity to TPECs decrease with the fall in the APLF. The PV of JVSL or of the domestic partner combined does not become negative even when the APLF falls below 50 percent because of the gains from the use of corex gas. The PV of KEB is always positive; because it collects revenue for the services it provides and collects penalty payments for making up shortages in the supply to the TPECs. As expected, the ADSCR moves with the PLF because of the losses in sales revenue.

Table 4.19: Effect of Changes in Actual PLF (1995 Prices)

Change In annual APLF (%)	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(EH)	IRR (FP)	PV of JVSL Rs Million	PV of DP Rs Million	PV(KEB) Rs Million	ADSCR 2004 Ratio
	353	1.46	315	12.3 %	12.3 %	5,401	5,716	822	1.07
50	(6,806)	(95)	(3,494)	#DIV/0!	#DIV/0!	4,917	1,423	2,964	0.15
53	(6,476)	(90)	(3,317)	#DIV/0!	#DIV/0!	5,217	1,900	2,964	0.19
56	(6,112)	(85)	(3,122)	#DIV/0!	#DIV/0!	5,450	2,328	2,994	0.24
65	(4,335)	(62)	(2,174)	#DIV/0!	#DIV/0!	6,191	4,017	2,215	0.48
68.5	(2,496)	(37)	(1,200)	2.9 %	2.9 %	4,752	3,552	1,912	0.78
72	(1,923)	(29)	(896)	4.9 %	4.9 %	4,886	3,990	1,652	0.87
74	(1,392)	(22)	(613)	6.7 %	6.7 %	4,995	4,382	1,436	0.95
78	(827)	(14)	(313)	8.6 %	8.6 %	5,143	4,830	1,133	1.06
79	(522)	(10)	(151)	9.6 %	9.6 %	5,206	5,055	1,003	1.11
81	(114)	(5)	67	10.9 %	10.9 %	5,288	5,354	830	1.17
83	120	(2)	191	11.6 %	11.6 %	5,329	5,520	772	1.05
85	353	1	315	12.3 %	12.3 %	5,401	5,716	822	1.07

STRUCTURAL ADJUSTMENT RATE. In 1995 KEB charged Rs 2.10/kWh, which was to be the tariff for TPECs. In 1995 prices, the estimated breakeven tariff for industrial users is estimated at Rs 2.73/kWh, which is considered to be the long-run marginal cost of electricity for the utility. Therefore, there is a possibility for raising the tariff from Rs 2.10/kWh to Rs 2.73/kWh in 1995 prices, making the adjustment annually at a fixed percentage of the present tariff. The government of Karnataka has the option to make a one-shot adjustment or to spread the adjustments over time until the tariff levels off at Rs 2.73/kWh. In either case, the project's NPV will improve from the viewpoint of JVSL and KEB because of the increase in tariff revenue and wheeling charges. The gain will be largest if it is adjusted once and for all by a 30 percent increase over the current tariff. Table 4.20 depicts the improvements in NPVs in relation to annual adjustment rates.

Table 4.20: Effect of Changes in the Structural Adjustment Rate (1995 Prices)

Change in adjustment rate (%)	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	NPV(KEB) Rs Million	PV of JVSL Rs Million	PV of DP Rs Million
	353	1.5	315	822	5,401	5,716
3.0	328	1.1	302	955	8,617	8,919
5.0	322	1.0	299	989	9,449	9,748
10.0	316	1.0	296	1,020	10,210	10,506
15.0	314	0.9	295	1,032	10,503	10,798
20.0	313	0.9	294	1,036	10,616	10,910
25.0	312	0.9	294	1,040	10,728	11,022
30.0	311	0.9	294	1,044	10,841	11,134
35.0	311	0.9	294	1,044	10,841	11,134

CAPACITY CHARGE. In the model, the levelized capacity charge has been estimated based on the cost components specified in the PPA. To it we add the fuel charge to arrive at the PPA tariff. As the cost of fuel is passed on to the consumers, the real item for negotiation in the PPA is the magnitude of the levelized capacity charge. Table 4.21 indicates that an increase in the levelized capacity charge causes an increase in the project's NPV from the viewpoint of equity holders, the foreign partner, and the domestic partner (JTPC), but decreases the PV from the viewpoint of JVSL. The higher capacity charge contributes toward an increase in the PPA tariff, thereby affecting an increase in sales revenues and electricity payments. An increase in the capacity charge from Rs 1.35/kWh to Rs 1.50/kWh would enhance the IRR to the promoters to above 15 percent and reduce JVSL's benefit by about one-third. This obviously improves the ADSCR, as the increase in the capacity charge improves net cash flow, thereby enhancing bankers' confidence in the investment. The present terms and conditions in the PPA for fixing capacity charge seem to be at the margin, and any attempt to negotiate a lowering of the capacity charge would put the foreign partner in a tight situation.

Table 4.21: Effect of Changes in Capacity Charge (1995 Prices)

Capacity charge Rs/kWh	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(FP)	IRR(DP)	PV of JVSL Rs Million	PV of DP Rs Million	ADSCR 2004
	353	1.5	315	12.3%	12.3%	5,401	5,716	1.07
1.30	(14)	(3.5)	120	11.2%	11.2%	5,885	6,005	1.03
1.32	131	(1.5)	197	11.7%	11.7%	5,694	5,891	1.05
1.34	275	0.4	274	12.1%	12.1%	5,503	5,777	1.06
1.36	420	2.4	351	12.5%	12.5%	5,313	5,663	1.08
1.38	564	4.3	427	13.0%	13.0%	5,122	5,549	1.09
1.40	709	6.3	504	13.4%	13.4%	4,931	5,435	1.11
1.50	1,432	16.0	888	15.5%	15.5%	3,978	4,866	1.19

NORMATIVE PLF. The normative PLF is the breakeven PLF for a given size of power plant supplying electricity to a particular group of consumers at a particular location in a specific country. In the base case scenario the normative PLF is set at 68.5 percent, as specified in the PPA. As table 4.22 shows, a decrease in the normative PLF by 2 percent increases the project's NPV from the viewpoint of equity holders by about Rs 23 million and of the foreign partner by US$0.3 million, and decreases the PV of JVSL by Rs 30 million.

Table 4.22: Effect of Changes in Normative PLF
(1995 Prices)

Change in annual normative PLF	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(FP)	IRR(DP)	PV of JVSL Rs Million	PV of DP Rs Million	ADSCR 2004
	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
60.5	443.5	2.7	363	12.6%	12.6%	5,281	5,645	1.08
62.5	420.7	2.4	351	12.5%	12.5%	5,311	5,662	1.08
64.5	398.0	2.1	339	12.5%	12.5%	5,341	5,680	1.08
66.5	375.3	1.8	327	12.4%	12.4%	5,371	5,698	1.07
68.5	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
70.5	329.8	1.2	303	12.3%	12.3%	5,431	5,734	1.07
72.5	307.0	0.8	291	12.2%	12.2%	5,461	5,752	1.07
74.5	284.3	0.5	279	12.1%	12.1%	5,491	5,770	1.06
76.5	261.6	0.2	267	12.1%	12.1%	5,521	5,788	1.06

INCENTIVE POINT. As table 4.23 reveals, for every increase in the incentive point of 1/10th, the project's NPV from the viewpoint of equity holders, the foreign partner, and the domestic partner (JTPC) increases, but the PV of JVSL decreases. The incentive point could be an item to negotiate in the PPA, as it not only improves the gains to promoters, but also helps build incentives to improve plant efficiency and transfer benefits from the domestic partner combined (JTPC + JVSL) to the foreign partner.

Table 4.23: Effect of Changes in Incentive Point
(1995 Prices)

Change in incentive point	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(EH)	IRR (FP)	PV of JVSL Rs Million	PV of DP Rs Million	ADSCR 2004
	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
0.50	298.9	0.7	286	12.2%	12.2%	5,472	5,758	1.07
0.60	325.7	1.1	301	12.2%	12.2%	5,437	5,737	1.07
0.70	352.5	1.5	315	12.3%	12.3%	5,401	5,716	1.07
0.80	379.3	1.8	329	12.4%	12.4%	5,366	5,695	1.07
0.90	406.1	2.2	343	12.5%	12.5%	5,331	5,674	1.08
1.00	432.9	2.5	358	12.6%	12.6%	5,295	5,653	1.08

Table 4.24: Effect of Changes in Real Interest Rates
(1995 Prices)

	Change in interest rate (%)	NPV(EH) Rs Million	NPV(FP) US$ Million	NPV(DP) Rs Million	IRR(EH)	IRR (FP)	ADSCR 2004
Domestic borrowing rate		353	1.5	315	12.3%	12.3%	1.07
	4	617	5.1	454	13.1%	13.1%	1.11
	6	353	1.5	315	12.3%	12.3%	1.07
	6	340	1.3	308	12.3%	12.3%	1.07
	7	195	(0.7)	232	11.8%	11.8%	1.05
	8	46	(2.7)	153	11.4%	11.4%	1.03
Supplier's credit rate		353	1.5	315	12.3%	12.3%	1.07
	2.0	390	2.0	335	12.4%	12.4%	1.08
	2.5	353	1.5	315	12.3%	12.3%	1.07
	3.0	314	1.0	294	12.2%	12.2%	1.06
	3.5	275	0.4	273	12.1%	12.1%	1.06
	4.0	235	(0.1)	252	12.0%	12.0%	1.05
	4.5	193	(0.7)	230	11.8%	11.8%	1.04
LIBOR Rate		353	1.5	315	12.3%	12.3%	1.07
	1.5	359	1.5	318	12.3%	12.3%	1.07
	2.0	345	1.4	311	12.3%	12.3%	1.07
	2.5	332	1.2	304	12.3%	12.3%	1.06
	3.0	318	1.0	297	12.2%	12.2%	1.05
	3.5	304	0.8	289	12.2%	12.2%	1.05
	4.0	289	0.6	281	12.1%	12.1%	1.04
	4.5	274	0.4	273	12.1%	12.1%	1.03

INTEREST RATES: Three different interest rates can affect the project, namely, domestic borrowing; the suppliers' credit provided by the U.S. Exim Bank; and the LIBOR rate, which affects external commercial borrowing. As table 4.24 shows, an increase in the real interest rate decreases the project's NPV from the viewpoint of equity holders, the foreign partner, and the domestic partner (JTPC). The NPV of the foreign partner becomes negative if the real interest rate for domestic borrowing exceeds 8 percent, and for the suppliers' credit exceeds 4.5 percent.

Conclusions of the Financial Analysis

The project yields positive NPVs for all the participants if the project management is able to use the plant to its maximum capacity. This requires a high-quality operation and maintenance team at the plant, and the independent power producer must work in close-coordination with JVSL and KEB. The plant's capacity utilization, which is measured by the average APLF, depends not only on the effectiveness with which repairs and maintenance are carried out and the reliability of input supplies, but also on the load demand. If the plant operates at 85 percent PLF, the project's

NPV from the viewpoint of equity holders is Rs 315 million, discounted at an 11.3 percent real rate; from the viewpoint of the foreign partner is US $1.46 million, discounted at a 13 percent real rate; and from the view point of the domestic partner (JTPC) is Rs 315 million, discounted at a 10.5 percent real rate. At a 10.5 percent real discount rate, the PV of JVSL is Rs 5,401 million and of KEB is Rs 822 million. The domestic partner combined has a PV of Rs 5,716 million, and the ADSCRs are greater than one for all the repayment years.

The much opposed 16 percent guaranteed nominal rate of return on the dollar investment is not yielding that magnitude of rate of return to the foreign partner. In reality, the overall rate of return to the foreign partner would slide below 5 percent if the APLF fell to 72 percent, which is not impossible in the power industry. The end result could be even worse for the foreign partner if the estimates of parameters fluctuated from the base case, which could happen. This puts the foreign partner in an extremely precarious situation, as opposed to the domestic partner, which is compensated for losses caused by financial gains to JVSL. The domestic partner can absorb the loss even at 50 percent APLF. This underscores the need for further risk analysis to establish the combined effects of parameter changes on the NPV or PV of the stakeholders, particularly from the viewpoint of the foreign partner.

Economic Analysis

So far we have examined the project from the viewpoint of each stakeholder without assessing the project's impact on the economy. India suffers from chronic electricity shortages. In such a situation, there is a difference between the amount consumers are willing to pay and the financial price they pay for each unit of electricity. A number of economic benefits arise because corex gas, which is normally released as waste into the atmosphere, is being used as one of the primary fuels, for example, resource savings from the reduced purchases of imported coal and social benefits accruing to society because of the avoidance of greenhouse gas emissions. Finally, India, like other countries, has taxes, production subsidies, and import duties on the goods and services used as inputs during the construction and operating periods of the project. These distortions create wedges between the financial and economic values, requiring adjustments in the cost streams to correctly measure the economic NPV. Thus, to calculate the project's true contribution to India's economy we must estimate the economic values of the benefit and cost streams.

Methodology

We use an integrated financial and economic analysis framework to derive the statement of economic cash flows (see Jenkins and Harberger 1996). First, we need to categorize the goods and services produced or used by the project into those that are tradable and those that are non-tradable[11]. Second, we estimate the economic values of tradable goods by adjusting the financial values for the impacts of taxes, subsidies, tariffs, and the foreign exchange premium. Third, we adjust the financial values of non-tradable goods or services for market distortions to derive their supply prices (P^s) and their demand prices (P^d). We then calculate the economic values (pe) by taking the average of P^s and P^d based on the weights assigned to the demand response (w^d) and the supply response (w^s); that is, $pe= p^s. w^s +p^d.w^d$. Fourth, we calculate commodity-specific conversion factors for each tradable and non-tradable good and service by taking the ratio of the economic value (p^e) and financial value (p^f) for each item. Fifth, we calculate conversion factors for each line item in the cash flow table expressed from the bankers' viewpoint by apportioning the share of the commodity-specific conversion factors of tradable and non-tradable goods and services if the line items are a cost or a benefit from tradable and non-tradable sources or a combination of more than one good or service. Estimating the economic value of electricity and corex gas requires specific methodologies.

Economic Value of Electricity

The economic value of electricity is estimated based on the principle of maximum willingness to pay. To operate its plant of 1.25 million metric tons per year, JVSL requires a reliable source of power. Currently KEB, the sole supplier of electricity in the state, is not in a position to fulfill the requirements of the steel plant, because it already suffers from chronic power shortages. It will also not be able to supply the steel plant's future needs, as the fourteenth electrical power survey

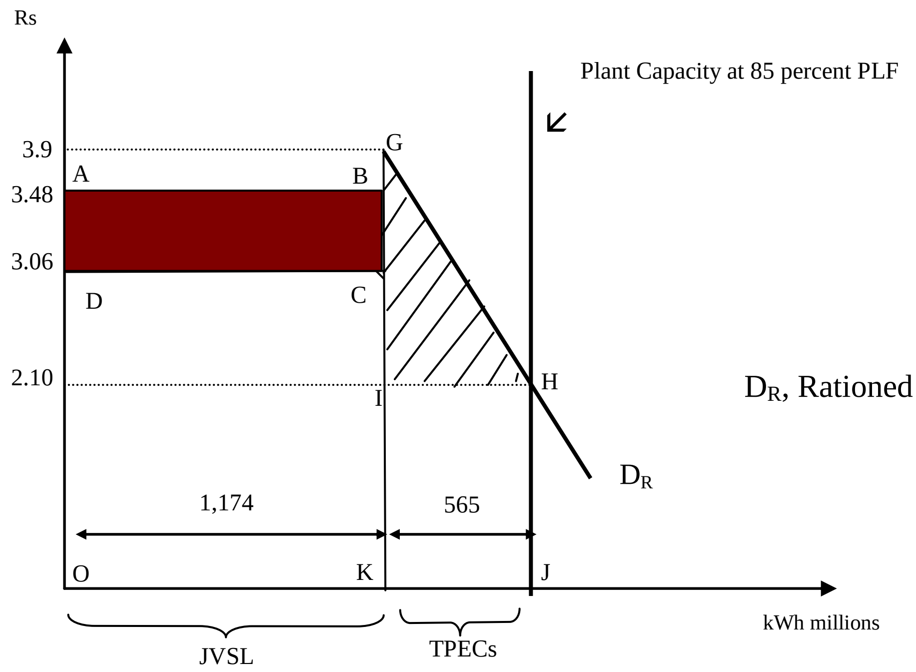
[11] A good or service is tradable when an increase in demand (or supply) by a project does not affect the amount demanded (or supplied) by domestic consumers (or producers). A good or service is non-tradable if its domestic price lies above its free on board export price or below its cif price.

predicts capacity and energy shortages of 527 MW and 3270 million kWh, respectively, by 2000. Thus if JTPC did not undertake this project, JVSL would have to establish its own generating plant.

The capacity cost of a power plant depends on the type of load it will serve. According to the principle of optimal stacking, for a thermal generation regime a coal-fired plant would be cost-effective for serving a base-load, oil-fired plant for an intermediate load, and a gas-fired plant would be cost-effective for peak load (see Harberger 1976, pp. 233-47), although recently developed combined cycle technology could substitute coal-fired generation for base and intermediate load supply. However, in India coal is the most commonly used fuel for generating power in plants with an installed capacity exceeding 100 MW. We therefore assume that in the absence of the power project JVSL would opt for a medium-size, coal-fired plant to supply electricity for the steel plant, and use the supply price of coal as the basis for estimating the maximum willingness to pay for the base load supply.

JVSL operates the steel plant, the oxygen plant, and the oxygen furnace and pelletization plant simultaneously or in sequence. Its peak load demand is 212 MW and its average load demand is 132 MW. The plant operates three shifts a day, eight hours a shift, using the night shift for daily maintenance as necessary.Therefore, JTPC primarily faces base load demand for the steel pant, and supplies 1,174 million kWh per year to meet this requirement. At 85 percent PLF it will generate 1,936 million kWh, leaving more than 629 million kWh for supply to the TPECs after deductions for auxiliary consumption and JVSL's requirements. KEB wheels the surplus electricity to the TPECs in the state. Like other consumers in the state, the TPECs are also subject to the proportional rationing irrespective of the type of load they demand. Obviously their maximum willingness to pay for the supply is different. Figure 4.1 depicts JTPC's supply and demand situation.

Figure 4.1: the Project's Demand for Electricity



If JVSL could draw a reliable quantity of electricity from KEB it would not have agreed to underwrite plant capacity at the PPA tariff. In the absence of the JTPC supply, JVSL could build a coal-fired thermal power plant of 260-MW installed capacity, whose marginal cost of generation in 1995 prices is estimated at Rs 2.73/kWh for a plant operating at 85 percent annual PLF, generating 1,932 million kWh as gross energy, with auxiliary consumption of 6.9 percent at the plant (ICICI 1995b).

As is the case with the current project, the steel plant would not have consumed the entire supply of electricity generated. At its current level of steel production JVSL would use only 1,174 million kWh, leaving 628 million kWh for supply to other consumers using KEB's transmission and distribution facilities. Deducting 10 percent of the available supply for the cost of delivery and transmission and delivery losses, the amount of electricity that would have been sold to other consumers at Rs 2.1/kWh is 565 million kWh (Figure 4.1). Thus JVSL would have faced a marginal cost of Rs 3.48/kWh for its base load had it opted to build a coal-fired plant of the same size as JTPC (calculated by weighing the quantities supplied to each group with their respective marginal costs to reflect the original estimate of Rs 2.73/kWh). This is JVSL's maximum willingness to pay for the base load supply. Dividing this by its financial price of Rs 3.06 yields a conversion factor of 1.14 for the base load supply.

The TPECs would face the same rationed demand curve as any other users of electricity in Karnataka. Given the general shortage of electricity, the regulatory authority rations the available supply proportionately among all consumers or does not provide potential customers with connections. Therefore the supply from JTPC would face the rationed demand, priced at Rs 2.1/kWh. As noted earlier, the TPECs are also industrial users, using electricity for industrial production, but with a smaller demand for electricity, demanding an intermediate load supply. What is their maximum willingness to pay for the JTPC supply?

There is 48-MW of cushion capacity between JVSL's peak load demand and JTPC's installed capacity. In the absence of the JTPC supply, the TPECs tap electricity from KEB, dealing with the shortages. Those consumers who wished to obtain a reliable supply of electricity could have set up diesel-run generating sets with standby generating facilities. Based on the theory of optimal stacking, operating an oil-fired plant to meet an intermediate load demand would be cost-effective. This means that the TPECs' maximum willingness to pay for the JTPC supply is given by the sum of capital costs, fuel costs, and investment costs for a standby generating facility using an oil-fired power plant.

Diesel-generating sets are relatively common in India, and on average, the supply cost amounts to Rs 3/kWh in 1995 prices for a plant supplying power for 10 to 14 hours a day. This implies an average PLF of 55 percent, varying from 42 to 68 percent. Capital costs would be approximately Rs 1.0/kWh, and 90 percent of these costs would be for generating machinery and equipment. Adding this cost to the average supply price of Rs 3/kWh yields Rs 3.9/kWh as the TPECs maximum willingness.

Therefore in Figure 4.1, area KGHJ represents the gross economic value of the supply to the TPECs, and is estimated at Rs 1,695 million. The area KIHJ depicts the financial value, estimated at Rs 1,186.5 million. Thus taking the ratio of the economic and financial values, we estimated the conversion factor of the electricity supply to the TPECs as follows:

area KGHJ = area KIHJ + area IGH

= KI * IH + 0.5*(IG * IH)

= 2.1 * 565 + 0.5 (3.9 - 2.1)*565

= 1186.5 + 508.5

= Rs 1,695 million

area KIHJ = KI * IH

= 2.1 * 565

= Rs 1,186.5 million

conversion factors of nonbase = area KGHJ/area KIHJ = 1.43

We can also estimate the conversion factor for the total supply of electricity by applying the weights of the quantity supplied to the conversion factors of each group as follows:

Conversion factors of the total supply = (1.14 * 1174 + 1.43 *565)/(1174 + 565) = 1.23

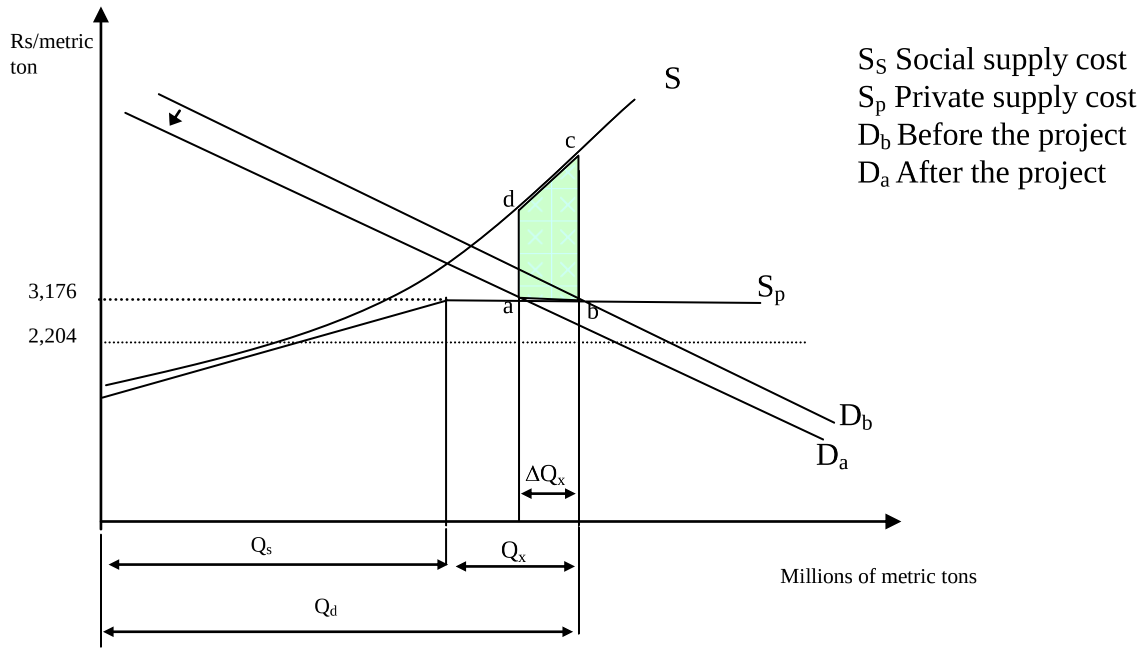
Economic Value of Corex Gas

As stated earlier, corex gas is a waste product of the steel manufacturing process with a heat content of 1,600 to 1,900 kcal/Nm^3. At a heat rate of 2,500 kcal/kWh, 1.2/Nm^3 of corex gas is required to generate 1 kWh of electricity. The choice of the corex-based steel manufacturing technology is based on competitive pricing. Note that the financial viability of the steel plant is not dependent on the sale of corex gas. If JVSL did not sell the gas to JTPC, it would simply have released it into the atmosphere, thereby dissipating its heat content. The supply arrangement has a negligible capital investment cost, and was not included in JVSL's financial cash flow statements.

The plant is designed to operate 11 months each year on corex gas and 1 month on imported coal. In the past, the government did not permit coal-fired thermal power plants to import coal. Recently, however, India has changed its policy and power plants, particularly in the coastal areas of southern and western India, are permitted to import coal. The project's FSA links the supply of corex gas and coal. It requires JVSL to supply the total quantity of fuel needed using a combination of corex gas and imported coal with 6,000 kcal/kg in heat content. Should JVSL encounter a technical problem in generating corex gas with the requisite heat content, it will have to import coal. Thus the use of corex gas saves the economy from spending foreign exchange on coal imports and avoids the emission of greenhouse gases, especially carbon dioxide, resulting from the combustion of fossil fuels.

Figure 4.2 depicts the demand for and supply of coal in India. In 1995 India produced 295.6 million metric tons, imported 8.87 million metric tons, and exported 0.9 million metric tons (International Energy Analysis 1995, pp. 1-11). If corex gas were not used, the quantity of coal imported for the project would increase from 0.068 to 0.810 million metric tons per year, which would require additional foreign exchange resources. The use of corex gas has avoided coal imports, shifting the demand curve to the left from D_b to D_a. In the process, the economy has lost the tariff revenue, countervailing duty, and sales tax, but has saved the foreign exchange premium for coal imports avoided.

Figure 4.2: Coal Consumption, India



In 1995 the estimated cif price of imported coal in Madras was Rs 2,204 per metric ton, and the landed cost of coal, including tariffs, countervailing duty, freight and insurance, and sales tax, was Rs 3,176 per metric ton (Figure 4.2). By not importing the coal, the government's losses on each metric ton are Rs 488 in tariff revenue, Rs 278 in countervailing duty, and Rs 122 in sales tax. The total loss to the government amounts to Rs 885 per metric ton. [[488 + 278 + 122 + 888]] Given the distortion in the foreign exchange market, the economy compensates for these losses by the savings in the foreign exchange premium. At the estimated premium of 24 percent, the savings to the government resulting from the use of corex gas in place of imported coal amount to Rs 529 per metric ton. Thus the net loss to government revenues amounts to Rs 356 per metric ton.

Thus the use of corex gas deprives the government of revenues of Rs 254 million per year in 1995 prices. This is the foregone cost from using the corex gas, which otherwise has an economic value of zero. Hence in the statement of economic benefits and costs we will show the cost of corex gas as zero, but will include the foregone benefits of annual tax collection from imports of coal with equivalent heat content as its economic cost.

In addition to saving resources by avoiding coal imports, there is an environmental benefit from not burning coal. To produce each kWh of electricity requires 0.42 kg of imported coal. The imported coal consists of 53 percent of fixed carbon, 90 percent of which converts into greenhouse gases releasing 0.21 kg of carbon, or 0.77 kg of carbon dioxide, into the atmosphere for each kWh of electricity generated (see Jorgenson 1998, p. 196). Thus the use of corex gas prevents the dumping of 0.37 million metric tons of carbon or 1.37 million metric tons of carbon dioxide into the atmosphere each year, requiring us to assess the value of damage caused by carbon emissions.

Most scientists now agree that the emission of greenhouse gases leads to global warming. The global carbon equation is being affected partly because of the depletion of tropical forests and partly because of the burning of fossil fuels for power generation and as fuel for vehicles and machinery. Scientists predict that global warming will shift vegetation and storm patterns, benefiting some countries and creating disastrous conditions for others (Brown, Kathryn S., 1999, p. 1440). In 1990 world per capita carbon emissions were 1.1 metric tons, compared with 0.5 metric tons for India, 1.0 tons for China, and 6 metric tons for the United States (Environmental Impact Assessment, International Energy Outlook, 1997, p. 13). The energy sector is responsible for about two-thirds of global emissions. India is among the five largest carbon polluting countries in the world, contributing 237 million metric tons in 1997 from the consumption and flaring of fossil fuels (Environmental Impact Assessment, International Energy Outlook, 1997, p. 236).

Two approaches are used for measuring the avoided cost of carbon emissions: the marginal cost of using abatement technology or the foregone benefits of energy consumption due to a carbon tax on fossil fuels. In the 1990s a number of pioneering studies estimated the costs of carbon emission. In the United States the National Academy of Science (1992), the Energy Modeling Forum of Stanford University (1993) and the Center for Clean Air of Wisconsin University (1995) all examined the impacts of carbon abatement in the U.S. energy sector and estimated a marginal cost of US $20 to US $25 per ton of carbon, using a mix of energy sources and a swap for forest conservation (see Salazar 1999, pp. 69-71). Using a uniform modeling methodology, the Commission of the European Community (1991) estimated that the marginal cost per metric ton of carbon emission varies from almost nothing for Denmark, France, Germany, and United Kingdom to US $127 for the Netherlands, US$ 108 for Greece, US $104 for Italy, US $85 for Spain, and US $71 for Belgium. A similar study conducted by the United Nations Environment Program (1994) measured a negligible marginal cost of carbon abatement for Brazil, Thailand and Zimbabwe for reducing emissions by 5 percent, but recorded a sharp increase in the cost for achieving a higher level of reduction.

In the absence of such information for India, we use an estimated marginal cost of sequestering a metric ton of carbon emissions of US $20.[12] As the coal consists of 53 percent of fixed carbon, 90 percent of which is convertible into carbon emissions, 1 metric ton of emission carbon is equivalent to a little more than 2 metric tons of coal. Using the 1995 exchange rate, the avoided cost of carbon emission due to the use of corex gas is Rs 700 per metric ton of carbon or Rs 334 per metric tons of coal. As the use of corex gas avoids imports of 0.74 million metric tons of coal, we estimate the annual social benefit in terms of avoided cost at Rs 247 million. Note, however, that the plant uses 0.067 million ton of coal and 0.28 million liters of auxiliary oil per year, which does create atmospheric pollution, including carbon emissions.

The beneficiaries of avoided carbon emissions are not only Indians but the global community as a whole. As S_s in Figure 4.2 represents the social marginal cost of coal consumption for the world [DEFINED AS "SOCIAL SUPPLY COST" IN THE FIGURE] and S_p represents the private marginal cost of supply, [DEFINED IN THE FIGURE ONLY AS "PRIVATE SUPPLY COST"] the area abcd approximates the annual environmental cost of carbon emissions avoided because of the use of corex gas.

Foreign Exchange Premium and Social Discount Rate

We have adopted the Jenkins and Harberger (1996) methodology to estimate the foreign exchange premium and the EOCK for India. Based on the 1995 statistics, the premium is estimated at 24 percent and the EOCK at 10.74 percent.

[12] This is the least marginal cost estimated by Rosenthal and others [LIST ALL OTHERS IF OTHERS IF LESS THAN FOUR TOTAL] (1993) using a mix of forests and abatement technology options in the United States.

The Statement of Economic Benefits and Costs

Table 4.25 shows the statements of economic benefits and costs from the viewpoint of the Indian economy. It is derived from the cash flow statement from the bankers' viewpoint by multiplying each line item by its respective conversion factor. We have assumed the conversion factor for corex gas to be zero, the conversion factor for the refund of the wheeling and grid support fee to be zero, and maintained the conversion factor or the penalty payments the same as for supplying electricity to the TPECs. Our reason for assuming a zero conversion factor for the wheeling and grid support fee is based on our belief that the marginal cost of wheeling electricity for KEB is zero, because the excess capacity is comparable to the marginal cost for boarding a passenger in a plane about to fly.

The net resource flows in the table reflects the net flow of annual benefits to India over the life-span of the project. Discounting the net economic resource flows with the economic discount rate of 10.74 percent yields Rs 19,870 million in economic NPV and an IRR of 31 percent. These estimates do not reflect the gains from environmental externalities and the potential loss of tax revenues from avoided coal imports. The PV of the positive environmental externalities amounts to Rs 1,738 million, discounting at India's EOCK. The PV of the discounted stream of potential revenue losses comes to Rs 1,842 million. The adjusted NPV for India becomes Rs 18,028 million and the total social benefit from the perspective of the global economy amounts to Rs 19,765 million.

Sensitivity Analysis

The project's NPV from the viewpoint of the Indian economy is unlikely to become negative, although it is likely to be sensitive to changes in some of the key variables examined in the financial models. The variables that are specific to the contractual agreements are not included in the sensitivity test; as such transfers would not affect the economy.

COST OVERRUN FACTOR. The economy gains if actual capital investment requirements are less than the estimated cost of building the power plant. Table 4.26 shows the changes in the economic

Table 4.25: Statement of Benefits and Costs, Viewpoint of India's Economy, Selected Years 1995–2015 (Rs Million, 1995 Prices)

Year ended March 31

Category	Conversion Factors	1995	1996	1997	1998	1999	2000	2001	2002	2003	2013	2014	2015
Resource inflows													
Sales to JVSL	1.140	0	0	0	0	3146	4097	4097	4097	4097	4097	4097	0
Sales through JVSL to JTPC	1.140	0	0	0	0	0	2194	2194	2194	2194	2194	2194	0
Collection of TPEC revenue	1.429	0	0	0	0	0	1886	1886	1886	1886	1886	1886	0
Refund of banking and grid support fee	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Refund of wheeling fee	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Change in accounts receivable	1.24	0	0	0	0	-413	-659	-79	-77	-77	-77	-77	966
Liquidation value		0	0	0	0	0	0	0	0	0	0	0	0
Land	0.92	0	0	0	0	0	0	0	0	0	0	0	13
Plant (buildings and civil works)	0.86	0	0	0	0	0	0	0	0	0	0	0	330
Machinery and equipment	0.88	0	0	0	0	0	0	0	0	0	0	0	1402
Miscellaneous fixed assets	0.89	0	0	0	0	0	0	0	0	0	0	0	140
Benefit inflows		0	0	0	0	2733	7517	8098	8099	8099	8099	8099	2852
Resource outflows													
Investment cost													
Preoperative expenses	1.08	1430	1007	0	0	0	0	0	0	0	0	0	0
Land	0.92	13	0	0	0	0	0	0	0	0	0	0	0
Engineering, procurement, and construction Contract	0.87	368	697	2835	3153	858	0	0	0	0	0	0	0
Miscellaneous fixed assets	0.85	30	55	68	162	38	0	0	0	0	0	0	0
Margin money	0.94	0	0	0	173	0	0	0	0	0	0	0	0
Operating costs		0	0	0	0	0	0	0	0	0	0	0	0
Coal	0.89	0	0	0	0	113	226	226	226	226	226	226	0
Corex gas	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Auxiliary fuel	0.84	0	0	0	0	1	2	2	2	2	2	2	0
Cooling water	1.00	0	0	0	0	14	28	28	28	28	28	28	0
Operation and maintenance expenses	0.97	0	0	0	0	290	290	290	290	290	290	290	0
Wheeling fee to KEB	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Banking and grid support fee	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Penalty payment	1.43	0	0	0	0	0	0	0	0	0	0	0	0
Refund of TPEC revenue to JVSL	1.43	0	0	0	0	0	1886	1886	1886	1886	1886	1886	0
Changes in accounts payable	0.200	0	0	0	0	-29	-50	-6	-6	-6	-6	-6	71
Changes in cash balance	1.00	0	0	0	0	-28	250	29	28	28	28	28	-355
Income tax	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Cost outflows		1841	1760	2903	3488	1258	2631	2455	2454	2454	2454	2454	-284
Net resource outflow		-1841	-1760	-2903	-3488	1475	4886	5643	5646	5646	5646	5646	3136
NPV for India @ EOCK of 10.74 percent	19,870												
IRR for India	31%												
Potential tax revenue losses						131	262	262	262	262	262	262	
Avoided cost of CO_2 generation						123	247	247	247	247	247	247	
PV of potential tax revenue losses	1842												
PV of avoided cost of CO_2 generation	1,738												
NPV for India, with adjustment for tax losses	18,028												
NPV for world @ EOCK of 10.74%	19,765												

NPV. The project will not have a negative NPV even if the capital cost increases by 100 percent. Its economic internal rate of return (EIRR) remains higher than the EOCK for India.

Table 4.26: Effect of Cost Overrun's on the Economic NPV

Change in Capital Cost	Economic NPV (Rs Millions, 1995 prices)	EIRR (%)
	19,870	31
-5	20,303	32
-3	20,130	32
0	19,870	31
20	18,134	27
40	16,399	24
80	12,928	20
100	11,192	18
110	10,324	17

ACTUAL PLF. The economy would lose if the plant were to operate at an actual PLF of less than 40.5 percent. Table 4.27 shows the impact of changes in the actual PLF, recording a sharp increase in the NPV from Rs 3,469 to Rs 19,870 million, as the actual PLF increases from 50 to 90 percent of its installed capacity. Even if the plant operated to meet JVSL's demand only, the project would register an EIRR above 15 percent.

Table 4.27: Effect of Actual PLF on the Economic NPV

Annual change in the actual PLF (%)	Economic NPV (Rs Millions, 1995 prices)	EIRR (%)
	19,870	31
30.0	(3,693)	4
40.5	67	10.8
50.0	3,469	15
60.0	7,686	20
70.0	12,721	25
80.0	17,769	29
85.0	19,870	31

STRUCTURAL ADJUSTMENT RATE. The economic NPV and the EIRR decrease with the larger changes in the structural adjustment rate, because JVSL's maximum willingness to pay for electricity from JTPC decreases with the increase in KEB's tariff rate (table 4.28). This is based on our estimate that the marginal cost of supplying electricity from a coal-fired plant of the same size operating at 85 percent PLF and using 6.9 percent of the total generation for auxiliary consumption would be Rs 2.73/kWh. The opportunity cost of electricity for JVSL would then be determined by the proportion of electricity it consumes and the proportion it sells to other consumers at KEB's rate. If KEB increased its tariff, JVSL's opportunity cost of electricity would decrease.

Table 4.28: Effect of Structural Adjustment of the KEB Tariff on the Economic NPV

Change in Annual rate (%)	Economic NPV (Rs Millions, 1995 prices)	EIRR (%)
	19,870	31
5.0	19,360	30
10.0	18,895	30
15.0	18,436	30
20.0	17,979	29
25.0	17,521	29
30.0	17,062	29
35.0	17,062	29

Table 4.29: Effect of Domestic Inflation Rate on Economic NPV

Domestic Inflation

Change in Inflation (%)	Economic NPV (Rs Millions, 1995 prices)	EIRR (%)
	19,870	31
6	19,968	31
8	19,870	31
10	19,775	31
12	19,685	31
14	19,599	31
16	19,517	31
18	19,438	31

Foreign Inflation

Change in Inflation (%)	Economic NPV (Rs Millions, 1995 prices)	EIRR (%)
	19,870	31
1.0	19,870	31
1.5	19,870	31
2.0	19,870	31
2.5	19,870	31
3.0	19,870	31
3.5	19,870	31
4.0	19,870	31

INFLATION RATES. An increase in the domestic inflation rate from 6 to 18 percent affects an Rs 530 million decrease in the economic NPV (table 4.29). The variation occurs primarily because of the losses in the real values of accounts receivable and cash balances, but some of this loss is compensated for by gains in accounts payable. Changes in the foreign inflation rate have no effect on either the economic NPV or the EIRR.

REAL EXCHANGE RATE AND REAL COAL PRICE. As table 4.30 shows the economic NPV improves with an appreciation of the rupee in relation to the U.S. dollar and deteriorates when the rupee depreciates. This is primarily because appreciation makes imports cheaper, which means smaller capital investment costs and a lower cost for imported raw materials (table 4.30). This is also reflected in the PV of potential tax losses to the government. Table 4.31 depicts a similar trend for changes in the real price of coal.

Table 4.30: Effect of the Real Exchange Rate on the Economic NPV

Change in the foreign exchange rate (%)	Economic NPV (Rs Millions, 1995 prices)	PV tax losses (Rs Million)	Adjusted economic NPV (Rs Million)
	19,870	1,842	18,028
-10	20,070	1,658	18,412
-8	20,030	1,694	18,335
-5	19,970	1,750	18,220
-3	19,930	1,787	18,143
0	19,870	1,842	18,028
5	19,769	1,934	17,835
10	19,669	2,026	17,643
15	19,568	2,118	17,450
20	19,467	2,210	17,257

Table 4.31: Effect of the Real Price of Coal on the Economic NPV

Change in the fuel price (%)	Economic NPV (Rs Millions, 1995 prices)	PV tax losses (Rs Million)	Adjusted economic NPV (Rs Million)
	19,870	1,171	18,028
-9	19,998	1,066	18,322
-6	19,955	1,101	18,224
-3	19,912	1,136	18,126
0	19,870	1,171	18,028
3	19,827	1,206	17,930
6	19,784	1,241	17,832
9	19,741	1,276	17,734

COREX GAS PREMIUM. As we assigned the economic value of corex gas as zero, a change in the premium has no effect on outflows. It will, however, affect resource inflows through changes in the fuel charge in the PPA tariff. The economic value improves when corex gas is supplied free of charge, because the FSA considers coal as a companion input and calculates the fuel price of electricity generation for the combined heat content based on the price of the imported coal. This is somewhat misleading, as a negative premium improves the economic NPV because a negative premium or discount automatically reduces the price of fuel, including coal, which is imported. This unusual arrangement is reflected by the movement in the PV of the tax revenue loss.

Table 4.32: Effect of the Corex Gas Premium on the Economic NPV

Change in premium (%)	Economic NPV (Rs Millions, 1995 prices)	PV tax losses (Rs Million)	Adjusted economic NPV (Rs Million)
	19,870	1,171	18,028
-100	21,132	88	19,290
-75	20,884	314	19,042
-54	20,667	503	18,825
-25	20,359	765	18,517
-5	20,143	945	18,301
0	20,088	991	18,247
10	19,979	1,081	18,137
20	19,870	1,171	18,028

Table 4.33: Effect of the Cost of Carbon Emissions

Change in CO_2 emissions (US$/metric ton)	Economic NPV (Rs Millions, 1995 prices)	PV of AC (Rs Million)	World NPV (Rs Millions, 1995 prices)
	19,870	1,738	19,765
20.00	19,870	1,738	19,765
32.00	19,870	2,780	20,808
44.00	19,870	3,823	21,851
56.00	19,870	4,865	22,893
68.00	19,870	5,908	23,936
80.00	19,870	6,951	24,978
92.00	19,870	7,993	26,021
104.00	19,870	9,036	27,064
116.00	19,870	10,078	28,106
127.00	19,870	11,034	29,062

COST OF CARBON EMISSIONS. Table 4.33 shows that the PV of the costs of avoided carbon emissions increases from Rs 1,738 million to Rs 11,034 million as the carbon emission cost for each metric ton of carbon increases from US $20 to US $127. In 1995 prices these were the estimated ranges for different industrial countries, with US $20 for the United States to US $127 for the Netherlands. At US $127/metric ton the PV of avoided carbon emissions amounts to 65 percent of the economic benefits of the project to India. Academics have yet to agree what percentage of such benefits should be assigned to the host country, because such benefits are not restricted by political boundaries, and the impacts of carbon emission change from country to country depending on the level of socioeconomic development and the population density.

Conclusion of the Economic Analysis

The results of the economic analysis establish that the project is attractive from the viewpoint of the Indian economy, registering an IRR of 31 percent and an NPV of Rs 19,870 million, discounted at 10.54 percent. The economic NPV does not turn into a negative value for any of the relevant parameters tested during the sensitivity analysis except when the actual PLF falls below 40.5 percent. This is unlikely to happen unless the plant experiences a major technical breakdown every year. JVSL alone consumes 56 percent of actual generation at 85 percent APLF, guaranteeing a sustained load demand.

The major sources of economic benefits derive from the use of corex gas and from the higher economic value of electricity to consumers. We can only determine how much of this benefit comes from which sources and goes to which group once we conduct the stakeholder analysis.

The PV of potential revenue losses to India and the PV of avoided carbon emission costs to the world are Rs 1,842 million and Rs 1,738 million respectively, both discounted at the EOCK. When adjusting these corex-gas-related externalities, economic NPV for India amounts to Rs 18,028 million, and the economic NPV for the world to Rs 19,765 million. The PV of the avoided carbon emission costs is not added to India's NPV, because it is not restricted within the country's borders.

Stakeholder Analysis

Projects generate externalities because of the differences in economic values and financial values of cost or benefit streams in cash flow statements. The differences arise because of taxes, subsidies, and tariffs, which are included in the financial values as either costs or benefits. Also, the economic price of foreign exchange is often larger than the official exchange rate. It will understate the value of the benefits if the project sells tradable outputs and understate costs if the project uses tradable inputs. Similarly, the price customers are willing to pay and the price they actually pay could differ, particularly when electricity is in short supply. Once we know who uses the outputs or who provide the inputs, we can distribute the project's externalities among the different stakeholders. The government, consumers, or suppliers capture each of the transfers.

The steps followed to identify and allocate externalities are as follows:

- Identify the source of externalities from the computation of conversion factors and subtract, line, by line the financial cash flows from the bankers' viewpoint from the economic cash flows to obtain the statements of externalities.
- Reduce the statements of externalities to a single figure by computing the PV of each line stream at the economic discount rate.
- Allocate externalities to various affected stakeholders in the economy.

Table 4.34 shows the distribution of externalities among the different stakeholders. JVSL, the TPECs, the government of India, KEB, and the world community share the total externalities generated by the project. The project generates a total of Rs 20,618 million in externalities, of which JVSL captures Rs 14,693 million, the TPECs capture Rs 2,743 million, the government captures Rs 2,361 million, KEB captures Rs 820 million, and the world community captures Rs 1,738 million.

When discounted at the EOCK (10.74 percent), the NPV of the total investment is a negative Rs 748 million, although the financial NPV from the viewpoint of equity holders is Rs 353 million, discounted at 11.3 percent. As the externalities generated from a project are measured above the opportunity costs of capital in an economy, the negative NPV is adjusted from the total externalities, which should be equal to the project's economic NPV. Hence the economic NPV, estimated at Rs 19,870 million, is equal to the sum of the present value of the externalities, estimated at Rs 20,618 million (excluding the potential revenue loss), plus the financial NPV of negative Rs 748 million . That is,

NPV^{econ} @economic discount rate = NPV^{fin} @economic discount rate + PV^{ext} @economic discount rate

19,870 = -748 + 20,618

19,870 = 19,870

Table 4.34: Allocation of Externalities

(Rs millions, 1995 prices)

Category	PV of externalities	JVSL	TPECs	World	Government of India	KEB
Source						
Sales to JVSL	2522	2522				
Sales through JVSL	1304	1304				
Collection from TPECs	2743		2743			
Refund for WBGSA	-820	-820				
Benefits of avoided CO_2	1738			1738		
Liquidation value	-35				-35	
Expenditure						
Preliminary and preoperating expenses	166				-166	
Land	-1				1	
Engineering, procurement, and construction contract	-908				908	
Miscellaneous fixed assets	-62				62	
Margin money	-9				9	
Cost of coal	-141				141	
Cost of corex gas	-14432	14432				
Cost of auxiliary fuel	-2				2	
Operation and maintenance expenses	206				-206	
Refund of collection to JVSL	2743	-2743				
Payments for WBGSA	-820					820
Income tax	-1645				1645	
Potential revenue loss	1842				-1842	
Total		14693	2743	1738	2361	820

Primarily the gains accrue to JVSL from the savings in the cost of coal imports it would otherwise have needed to generate its electricity needs. It gains Rs 14,441 million from the savings of coal imports and Rs 3,826 million in consumer surplus, but pays Rs 820 million to KEB as a wheeling and grid support fee and provides Rs 2,743 million in tariff subsidies to the TPECs. Its share as a percentage of total externalities is 71 percent, and as percentage of the economic NPV is 74 percent. Of all the groups, JVSL gains the most.

The gains to TPECs arise because of the increase in consumers' surplus. The group gains Rs 2,743 million. This is realized because of the differences between their willingness to pay for electricity in Karnataka (Rs 3.90/kWh) and the financial price they pay for the supply from the project (Rs2.10/kWh).

The gains to the government are Rs 2,361 million, which derive from sales taxes, income taxes, countervailing duties, import duties, and the foreign exchange premium. This gain falls to Rs 519 million if Rs 1,842 million is deducted for the use of corex gas, that is, to account for the cost of foregone tax collection or duties on coal imports.

The gain to KEB arises because of the fuller utilization of its transmission and distribution capacity because of the supply from the project. This estimate is based on the assumption that the marginal cost of wheeling the additional energy is zero for KEB. The project's NPV from the viewpoint of KEB is Rs 820 million (net of tax) at a 10.5 percent discount rate.

The gain to the world community is Rs 1,738 million. The estimate of this gain is based on our assumption that the marginal social cost of carbon sequestering is equal to Rs 334 per ton of coal. This could increase significantly, because the marginal cost of carbon sequestering per ton of coal in different countries varies from US $20 to more than US $100.

Risk Analysis

We obtained better results than expected in terms of likely returns from the project for all the identified stakeholders in the financial analysis: the bankers, the equity holders, the foreign partner, the domestic partner, JVSL, and KEB. The Indian economy, which is the sole custodian of all the economic benefits, has an IRR almost three times the EOCK. The bankers, who are providing 70 percent of the capital requirements in loan financing, will recover their loans with interest, because the ADSCRs during the loan repayment period are greater than one. Clearly every stakeholder is a winner if we do not internalize the effect of variations in the key parameters that yielded negative outcomes, particularly for the equity holders, in the sensitivity analysis. This calls for risk modeling of the results of the financial and economic analyses to measure the probability, if any, of negative outcomes.

Selection of Results for Inclusion in the Model

The results of the sensitivity analysis suggest that the NPV of equity holders, the foreign partner, and the domestic partner are susceptible to negative outcomes. The PVs of JVSL and KEB were not negative in the sensitivity analysis. Nevertheless, we include these results in the model, because the simulations establish the range for minimum and maximum values, with the probability of occurrences of the expected value. In addition, we prefer to include the IRR for the economy, the IRR for the foreign partner and the ADSCR for 2004 in the model. The expected rate of return to the economy can be compared with the EOCK, which is a measure of the marginal rate of return on all productive capital. The expected IRR of the foreign partner enables us to gauge the effectiveness of the 16 percent guaranteed nominal rate of return to the foreign partner (paid in the capacity charge), which translates into the actual returns to equity capital during the life of the project. The risk analysis of the ADSCR in 2004, which is the lowest for the entire repayment period, tells us whether or not the project will have adequate cash to service and amortize its debts.

Identification of Risk Variables

The risk variables are identified based on the results of the sensitivity analysis. The variations in the results, for example, in the NPV, IRR, 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 project specific, that is, their variations are to some extent within management's control. Some of the parameters are beyond the purview of project management, but their variations affect the financial and economic results. Other variables, for example, the corex gas premium, are tied to contracts, and any variation will result from contract renegotiations. A change in the tariff rate to the TPECs can occur only through a policy change by the government of Karnataka.

We therefore divide the risk parameters into four categories: exogenous variables, endogenous variables, contract-tied variables, and policy-change variables. In each category the variables might change from year–to–year, change during a specific period but otherwise remain constant, or undergo a one-shot change and then remain the same. Thus we have (a) exogenous variables that fluctuate with the booms and the busts of the domestic economy or with changes in the external environment, (b) endogenous variables that are project specific and whose fluctuations could be stabilized with improved technical or business management, (c) contract-tied variables that can change only by means of negotiation and (d) policy-change variables whose changes are subject to policy changes in the external environment. Based on these precepts, we organize the parameters in the sensitivity analysis into four scenarios for risk modeling.

Structure for Risk Analysis

The issue in risk analysis is the cumulative effect of parameter changes. This means it is better to include as risk variables even those parameters that have small influences on the results of the sensitivity analysis. We divide the analysis into four scenarios as follows:

- Scenario 1: variation in exogenous variables
- Scenario 2: variation in exogenous variables + endogenous variables
- Scenario 3: variation in exogenous variables + endogenous variables + contract-tied variables
- Scenario 4: variation in exogenous variables + endogenous variables + contract-tied variables + policy change variables.

The scenario analysis enables us to isolate the risk from these four sources and build a defensive mechanism to protect the project from exposure to the risks depending on the magnitude of their impacts and the cost involved in taking protective measures. For this project the domestic and foreign inflation rates, the real exchange rate of the rupee in relation to the U.S. dollar, the movement in the real price of fuel, the movement in the real interest rate of foreign borrowing, and cost overruns are exogenous variables; the annual PLF, accounts receivable, and accounts payable are endogenous variables; the normative PLF is a contract-tied variable; and the annual structural adjustment rate of KEB’s industrial tariff and the real ICICI interest rate are policy change variables.

Identification of the Probability Distribution Function

One of the central issues in risk analysis is identifying the probability distribution function. Based on the information we provide, the risk modeling package does the rest of the work. Our favorite defined risk variable is the custom designed, step distribution function. We start by examining the data sets; filtering the data, if necessary, to remove any outliers or to counteract the influence of uncommon events; calculating their probabilities of frequency distributions; and using the information in a custom designed probability distribution function. The advantage of the custom designed distribution function is that it is flexible. We can readily adjust it for yearly changes in distribution patterns, which is likely in today's dynamic policy environments. Researchers also frequently use a normal distribution function or a lognormal distribution, depending on their data. Based on our examination of the historical data and our experience with power projects, we have defined the variation ranges and the probability distributions of each of the risk variables in table 4.35.

Table 4.35: Specification of Risk Variables

Risk variable	Type	Distribution	Base value (%)	Range (%)	Probability (%)
Variations in annual domestic inflation rate	Exogenous	Custom	0	-10 to -5	29
				-5 to 0	43
				0 to 5	14
				5 to 10	14
Annual U.S. inflation rate	Exogenous	Normal	3.50	Standard deviation of 0.3	
Variations in real exchange rate, US$/Rs	Exogenous	Custom	0	-10 to -5	25
				-5 to 0	25
				0 to 5	37.50
				5 to 10	12.50
Variations in real price of fuel	Exogenous	Custom	0	-10 to -5	44.40
				-5 to 0	22.20
				0 to 5	22.20
				5 to 10	11.20
Suppliers' credit, U.S. Exim Bank	Exogenous	Normal	2.50	Standard deviation of 0.3	
External commercial borrowing, open market	Exogenous	Normal	1.73	Standard deviation of 0.3	
Capital cost overruns	Exogenous	Custom	0	-10 to 0	65
				0 to 10	20
				10 to 20	10
				20 to 30	5
Accounts receivables	Endogenous	Custom	12.00	8 to 10	19.50
				10 to 12	29.10
				12 to 14	38.60
				14 to 16	9.70
				16 to 17	2.90
Accounts payable	Endogenous	Custom	8.33	4 to 6	17
				6 to 8	30
				8 to 10	40
				10 to 12	10
				12 to 14	3
Normative PLF	Contract tied	Triangular	68.50	Min 60.5	Max 78.5
Real interest rate on ICICI loan	Policy change	Uniform	5.91	Min 4	Max 8
Annual structural adjustment rate of KEB tariff	Policy change	Uniform	0	Min 0	Max 30

Co-relation of Risk Variables

Sometime we can avoid assigning a probability distribution function to a risk variable by defining a correlation coefficient between two risk variables. The computer calculates values of the dependent risk variable depending on the value the computer picks for the independent variable based on its range, the probability distribution function, and the correlation coefficient defined between the two. For example, in our case the PPA defines a perfect correlation between the fuel price and the electricity tariff. As the electricity tariff is the sum of the capacity charge and the fuel charge, any increase in the fuel cost is passed on in the PPA tariff, which is eventually paid by the consumers. The correlation coefficient is already formulated in the calculation of the PPA tariff, so we need not establish the correlation between the fuel price and the tariff in the risk analysis.

The possibility of defining a risk variable over a probability function and of nullifying independent variation of one risk variable through a correlation coefficient open up an avenue for risk shifting. In our case, the PSA shifts the risk in tariff fluctuations for the supply of electricity to the TPECs from JTPC to JVSL. Similarly, the cost of inefficient operation of the plant such that it generates less electricity than it committed to is passed onto JTPC through the penalty clause in the WGBSA, which authorizes KEB to supply the shortfall, but at 1.5 times its regular tariff to industrial consumers. The consumers pay their usual tariff, and JTPC bears the additional cost as penalty payments.

Scenario analysis is useful in such a complex situation. It helps us compare the impacts of one set of risk variables over another set, thereby enabling us to gauge the magnitude of variations in the risk results and to confirm whether the sources of the variations are from the exogenous, endogenous, contract-tied, or policy-change variables.

Results of Risk Analysis

Table 4.36 shows the results of the risk analysis. In summary, the investors, including the bankers, risk loosing money from this project, while JVSL and KEB bear no risk. The sensitivity analysis confirms these results.

Table 4.36: Risk Results

Category	NPV equity holders (Rs millions)	NPV foreign partner (US$ millions)	NPV domestic partner (Rs millions)	PV JVSL (Rs millions)	PV KEB (Rs millions)	ADSCR 02	EIRR (%)	Financial IRR (%)
Scenario 1								
Minimum value	-753	-15.53	-268	5139	819	0.94	29	8.6
Maximum value	1081	11.78	697	5580	817	1.33	33	14.8
Expected value	144	-1.37	204	5380	824	1.10	31	11.7
Probability of negative return (%)	20	60	5	0	0			
Mean standard error	2.47	0.04	1.30	0.68	0.01	0.00	0.01	0.01
Scenario 2								
Minimum value	-885	-18.80	-321	5079	779	0.60	29	8
Maximum value	1217	15.67	769	5730	976	1.70	34	15.6
Expected value	157	-1.2	211	5405	847	1.11	31	11.7
Probability of negative return (%)	20	60	5	0	0			
Mean standard error	2.80	0.04	1.48	0.84	0.24	0.00	0.01	0.01
Scenario 3								
Minimum value	-879	-16.26	-333	5084	768	0.58	28	8.42
Maximum value	1159	14.63	742	5908	982	1.73	34	15.32
Expected value	157	-1.19	211	5418	845	1.10	31	11.72
Probability of negative return (%)	20	60	5	0	0			
Mean standard error	2.83	0.04	1.49	1.04	0.24	0.00	0.01	0.01
Scenario 4								
Minimum value	-1244	-19.96	-526	5241	808	0.55	27	7.7
Maximum value	1460	17.11	901	11279	1215	1.76	33	15.72
Expected value	105	-1.85	184	10087	1044	1.10	30	11.6
Probability of negative return (%)	30	65	10	0	0			
Mean standard error	3.1	0.05	1.75	11.0	0.55	0.00	0.01	0.01

The results for scenario 1 show that the expected mean (returns) of the equity holders shifts by more than one-half from the results of the base case, but not by the same scale as for JVSL and KEB. The IRR from the viewpoint of the economy remains the same. We attribute this to the movement in the real exchange rate and the inflation rates.

Scenario 2 depicts the combined impacts of the exogenous and endogenous variables. The expected results from the viewpoints of all the stakeholders improve somewhat, although the minimum range of the ADSCR falls from 0.94 to 0.60. We attribute this to the expected gain of 0.5 percent in the annual PLF as determined in the step distribution function. We consider this appropriate, because the plant is likely to maintain a higher PLF than the one specified in the base case partly because of the involvement of foreign experts in the operation and maintenance team, partly because it will not suffer from a lack of load demand, and partly because the management will be extra vigilant about maintaining a higher PLF to avoid the penalty payments.

Scenario 3 adds only the normative PLF as a risk variable; the change in results is not dramatic. The variations in the normative PLF affect the capacity charge, resulting in some improvement in the NPV of the equity holders and a small decrease in the PV of JVSL. Further deterioration in the minimum value of the ADSCR is due to variations in the PPA tariff.

Scenario 4 depicts a dramatic change because of the influence of policy variables. The probability of a negative NPV recedes from 20 to 30 percent for the equity holders, from 60 to 65 percent for the foreign partner, and from 5 to 10 percent for the domestic partner. This is due primarily to the increase in the KEB tariff, which affects the equity holders through penalty payments in the event that actual supplies are less than the committed amount. JVSL and KEB gain because of the increase in the tariff, and the economy loses, because the increase in the KEB tariff to industrial consumers decreases the opportunity cost of electricity generated by this project.

Conclusions of Risk Analysis

The results of the risk analysis establish that the rate of return from this project will be 0.7 percent less than the expected rate of return of the foreign partner, which is more exposed to risk than other stakeholders. The IRR to the foreign partner varies from 7.7 to 15.72 percent, with an expected mean of 11.6 percent.

There is no substantive change in the results of the risk analysis when the impacts of the endogenous variables are added to the impacts of the exogenous variables, indicating that the sources of the risk are outside the purview of the project's management. Therefore the equity holders, particularly the foreign partner, have no option for reducing the risk without increasing the PPA tariff.

The penalty clause in the WBGSA increases the risk for the equity holders. While it enforces work efficiency at the power plant, it exposes the foreign partner in particular to a higher risk, and is an influence from outside the project.

Conclusions

This is a complex project, involving many stakeholders through the fixed cost turnkey contract, the FSA, the PPA, and the WBGSA.

The equity holders combined, O. P. Jindal Industries Group, and Tractebel South Asia earn their expected rate of return in the base case analysis with an NPV of Rs 353 million, discounted at 11.3 percent. The NPVs from the viewpoints of the individual equity holders are US $1.46 million, discounted at 13 percent, for the foreign partner, and Rs 315 million, discounted at 10.5 percent, for the domestic partner. The PV of financial gains to JVSL, the dedicated consumer and the contracted supplier of corex gas, is Rs 5,401 million, and that of KEB is Rs 822 million, both discounted at 10.5 percent. The gains to JVSL derive from the avoided cash outflow for purchasing electricity and from the sale of corex gas, and the gains to KEB derive from the fuller utilization of its transmission and distribution capacity.

The project creates enormous economic gains because of the use of corex gas, which was previously released into the atmosphere. The project's economic NPV is Rs 18,028 million for India, yielding a huge EIRR of 31 percent. In addition, the project creates positive environmental externalities of Rs 1,738 million because of the use of corex gas. The stakeholders in this economic pie are JVSL Rs 14,693 million, the TPECs Rs 2,743 million, the government of India Rs 519 million, and KEB Rs 820 million. JVSL captures about 74 percent of the total economic gain.

The results of the risk analysis established that the equity holders are exposed to a risk of variations in the exogenous variables, such as the foreign exchange rate, inflation rates, the price of imported coal, and the interest rates on foreign borrowing. As the loss in returns to the domestic partner is compensated for by JVSL's gains, a business venture of the O. P. Jindal Industries Group, the foreign partner alone is subjected to the risk of variations in the base parameters. The inclusion of the penalty payment clause in the WBGSA increases the risk from 20 to 30 percent for the equity holders combined, and from 60 to 65 percent for the foreign partner. Other stakeholders face no risk from the project.

The FSA clause should be revised as it pertains to the calculation of energy charges. Under the existing arrangement any discount for the use of corex gas is automatically applied to the price of imported coal. This gives a misleading picture in the sensitivity analysis, because a decrease in the corex gas premium increases the gains to all the stakeholders including JVSL, the supplier of corex gas. The foreign partner's risk can be reduced by transferring some of JVSL's economic gains by increasing the capacity charge. This can be done by lowering the normative PLF, increasing the incentive point, or increasing the guaranteed rate of return on the dollar-denominated equity from its present nominal rate of return of 16 percent. An increase in all three parameters is desirable, because the share of Tractebel South Asia in JTPC is only 15 percent of the total capital investment.

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