ECONOMIC ANALYSIS

A. Introduction

1. The economic cost–benefit analysis of the Jamshoro Power Generation Project in Sindh province of Pakistan was conducted in accordance with Asian Development Bank (ADB) guidelines, using 2013 constant prices.[1] The economic internal rate of return (EIRR) was calculated by comparing the "with-" and "without-project" scenarios and discounting the incremental annual cashflows over 30 years. All financial prices have been converted into economic prices by applying the corresponding conversion factors.

2. The project comprises (i) construction of a 600 megawatt (MW) supercritical coal-fired power unit with adequate emission control devices at Jamshoro thermal power station (TPS); (ii) a training program for coal-fired power plant operations through on-the-job training and inclusion of coal-fired power plant operations in training school curriculum; (iii) a fixed term 5-year operation and maintenance (O&M) service contract for O&M (inclusive of spare parts) of the 600 MW supercritical coal-fired power unit; and (iv) installation of emission control devices for existing power units at Jamshoro TPS, and remediation of the site, including soil bioremediation. Existing peripheral infrastructure including transmission capacity and access to transportation have been reviewed and are considered sufficient for power evacuation.[2]

3. Funding for the project will be supported by ADB's ordinary capital resources, the Asian Development Fund, Islamic Development Bank, and the Government of Pakistan. Financing from the Asian Development Fund will be used for capacity development and implementation supervisory. Government's contribution will be in the form of equity to be injected into the implementing agency (Jamshoro Power Company Limited).

B. Demand Analysis

4. Pakistan suffers from a severe power shortage. About 30% of the population has no access to grid electricity, and relies mostly on non-commercial sources. Cities have up to 10–18 hours per day without power, while the average time without power in rural areas is up to 20 hours per day. Pakistan's skewed energy mix significantly affects the reliability of current supply. About 62% of power is generated using a mix of expensive imported oil (i.e. furnace oil and high speed diesel) and dwindling supplies of domestic gas. Domestic gas reserves are forecast to be exhausted by 2030, placing increasing reliance on imported oil; this is expected to continue in the absence of substitute means of power generation. However, payments to fuel suppliers have not been timely, leaving the suppliers unable to provide a steady supply of fuel to the power generators. This has resulted in disrupted and abated power production by the thermal generation plants. If the energy mix is not changed, the Pakistan Business Council has estimated that in 2025 the total energy import bill will be $90 billion (assuming a price of $100 per barrel for imported oil).

5. The inadequacy and lack of reliability of the existing supply resulted in an electricity shortfall of 6,620 MW in 2012.[3] Table 1 presents the historical gap between power supply and demand.

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[1] ADB. 1997. *Guidelines for the Economic Analysis of Projects.* Manila.

[2] The transmission line to evacuate additional capacity will be financed through tranche 3 of ADB. 2006. *Report and Recommendation of the President to the Board of Directors: Proposed Multitranche Financing Facility to the Islamic Republic of Pakistan for the Power Transmission Enhancement Investment Program*. Manila.

[3] National Transmission and Despatch Company. 2013. *Electricity Demand Forecast, 2013*. Islamabad.

Table 1: Historical Power Supply vs. Demand

Period	Power Demand (MW)	Power Supply (MW)	Surplus or Deficit (MW)	Surplus or Deficit (% of power demand)
2009–2010	18,467	13,445	(5,022)	27.2%
2010–2011	18,521	13,193	(5,328)	28.8%
2011–2012	18,940	12,320	(6,620)	35.0%

( ) = negative, MW = megawatt.
Source: National Transmission and Despatch Company data.

6. Based on the National Transmission and Despatch Company demand forecast, by 2016 the projected power shortage will be 5,000 MW during the summer and 2,400 MW in winter. The available supply as a percentage of installed capacity is worse in winter, given the limited generation capacity of hydroelectric power plants, with actual capacity falling as low as 16% of total installed capacity during the winter (Table 2).

Table 2: Installed Capacity of Existing Power Plants in the National Transmission and Despatch Company System

Plant Type	Installed Capacity (MW)	Current Available Capacity (MW) Summer	Current Available Capacity (MW) Winter
Hydroelectric	6,805	4,962	1,097
Thermal – GENCOs	4,829	3,580	3,580
Independent Power Producers (IPP)	8,405	7,682	7,682
Nuclear	665	615	615
Total	**20,704**	**16,839**	**12,974**

GENCO = generation company, IPP = independent power producer, MW = megawatt.
Source: National Transmission and Despatch Company data and project preparatory technical assistance consultant estimates.

7. Pakistan’s electricity demand is projected to increase by approximately 7% annually during 2011–2025. Power generation capacity could be enhanced through investment in and development of hydro and renewable power. The government is working to develop these sources, and exploring new gas fields. However most of these sources cannot reduce power shortage in the near term because of the unfavorable investment environment that results from the high investment cost, long lead time and Pakistan’s geopolitical situation. Large hydropower dams are primarily viable as long-term solution and renewable power is not suited for base load. Coal-fired generation and imported liquefied natural gas (LNG)-based generation are the most viable alternatives in the short to medium term. Indigenous Thar coal is still under development, while international price estimates for LNG limit the extent to which the use of LNG would reduce Pakistan’s generation cost. In view of the strong and urgent need for an increase in thermal generation capacity in Pakistan, the government plans to diversify its fuel input sources to include more imported coal, and has recently issued an upfront tariff for new coal-fired power generation projects, which aims to encourage diversification to fuels other than oil.

C. Least-Cost Analysis

8. The project is considered the least-cost option to ensure sufficient base-load generation capacity and cost efficiency in the medium term. Coal-fired power generation plants are considered the most reliable, cost-effective solution. Other alternatives will involve higher capital and O&M costs, while coal-fired power generation can increase supply with a shorter lead time, and at a lower overall generation cost. Jamshoro TPS was selected because of its importance as a power supplier to the national grid, as well as its proximity and rail link to port facilities for coal imports, and the availability of land for coal storage and ash disposal.

D. Project Benefits

9. The project is expected to provide incremental economic benefits through generation capacity enhancement and efficiency improvement at Jamshoro TPS. The new supercritical power plant is expected to increase Jamshoro's installed capacity by 600 MW, with a net efficiency of 40.9%–41.5%. Power generated by the new plant will be transmitted to the National Transmission and Despatch Company. Given the significant gap between power demand and supply, the analysis assumed that demand would exist for the additional power generated by the new supercritical unit, excluding system losses, for full consumption. The economic price for additional power was calculated based on the consumers' willingness-to-pay (WTP) for power alternatives in the absence of electricity from the national grid. A survey conducted by the project preparatory technical assistance consultant included the WTP data of four consumer categories (residential, agricultural, commercial and industrial).[4] The weighting of each alternative within each consumer group differs as a result of affordability and use preference.

10. Residential and commercial consumers use diesel, uninterrupted power supply systems or kerosene lamps as alternatives to electricity from the national grid. The estimated WTP for residential consumers was Rs22.7/kWh, and for and commercial users Rs21.5/kWh. For industrial and agricultural consumers, diesel generators are the typical alternative, with a WTP of Rs19.5/kWh for industrial users, and Rs20.6/kWh for agricultural users. A weighted WTP of Rs21.0/kWh was estimated based on the consumer surplus and average marginal tariff. This was used to calculate the value to the country of the incremental electricity supply.

11. It was assumed there would be no non-incremental benefit, because the project consists of the construction of additional power generation units, and is not a replacement project; therefore there would be additional (i) emissions (resulting in no expected proceeds from the sale of Clean Development Mechanism rights), and (ii) fuel costs (resulting in no fuel savings).

E. Project Costs

12. The total project cost consists of the capital investment cost and physical contingencies. Taxes and duties were excluded from the calculation. For the conversion of financial prices at world price numeraire to economic prices, a standard conversion factor of 0.92 was applied to the non-tradable items and a shadow wage rate factor of 0.8 was applied to the unskilled domestic labor, which was assumed to be 25% of local costs. The standard conversion factor was calculated based on value and elasticity of exports and imports, as well as the average tax on both exports and imports,[5] and the shadow wage rate factor was estimated after reviewing local wages for unskilled versus skilled labor.

13. The opportunity cost of the land to be acquired for the ash disposal was also considered. The surrounding environment is arid, and the location remote, with limited access for power plant operation only; thus agricultural or commercial activities are not considered viable alternatives. Because there are no other activities in the region that could provide an indicative zonal value, it was assumed that land had a minimal (or zero) opportunity cost. However a sensitivity analysis was carried out assuming the financial price of the land as the proxy for the

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[4] The consultant, Hagler Bailly Pakistan, used Pakistan State Oil statistics (http://www.psopk.com/) for fuel costs. Data regarding electricity sold and the proportions of load shedding in each consumer category was extracted from the National Transmission and Despatch Company statistics for FY2012.

[5] Formula applied to calculate the SCF was: SCF = (e X + n M)/[e X (1 – t x) + n M (1 + tm)]. "e" = elasticity of export supply; "n" = elasticity of import demand; "X" = free on board value of exports; "M" = cost insurance freight value of imports; "tx" = average tax on exports; "tm" = average tax on imports.

opportunity cost for the additional land that may be required in the event the ash cannot be sold to the cement company.

14. The cost of fuel constitutes the largest cost component in the incremental O&M costs, and the border price was used. Additional transmission and distribution costs associated with transmission of the incremental electricity were calculated based on transmission and distribution costs per kWh, determined by the National Electric Power Regulatory Authority. Non-incremental costs include a penalty as a result of additional CO^2 emissions, which was measured at €5.47 ($7.31) per ton of carbon dioxide.[6]

F. Economic Internal Rate of Return

Table 3: Project Economic Internal Rate of Return ($ million)

Year	Capital Investment	Fuel Cost	Operation and Maintenance	Emission Penalty	Incremental Electricity	Net Benefit
2014	(1.6)	0.0	0.0	0.0	0.0	(1.6)
2015	(253.2)	0.0	0.0	0.0	64.0	(189.2)
2016	(343.4)	0.0	0.0	0.0	64.0	(279.4)
2017	(421.0)	0.0	0.0	0.0	32.0	(389.0)
2018	(158.9)	0.0	0.0	0.0	0.0	(158.9)
2019	(1.8)	(190.0)	(20.0)	(24.9)	851.3	614.7
2020	(1.8)	(190.0)	(20.0)	(24.9)	851.3	614.7
2021	(1.8)	(190.0)	(20.0)	(24.9)	851.3	614.7
2022	(1.8)	(190.0)	(20.0)	(24.9)	851.3	614.7
2023	(1.8)	(190.0)	(20.0)	(24.9)	851.3	614.7
2024	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2025	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2026	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2027	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2028	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2029	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2030	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2031	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2032	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2033	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2034	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2035	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2036	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2037	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2038	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2039	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2040	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2041	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2042	0.0	(190.0)	(19.8)	(24.9)	851.3	616.6
2043	196.3	(190.0)	(19.8)	(24.9)	851.3	812.9
	(990.5)	(4,749.8)	(496.5)	(622.0)	21,442.5	14,583.7
Economic Internal Rate of Return						**36.3%**
Economic Net Present Value@12% discount rate ($ million)						**2,058.4**

( ) = negative.

Source: Asian Development Bank and project preparatory technical assistance consultant estimates.

[6] Intercontinental Exchange Futures Europe EU Allowances were €5.47 per ton of carbon dioxide as of 14 June 2013.

15. The economic internal rate of return (EIRR) of the project is 36.3% which exceeds the economic opportunity cost of capital of 12%.

G. Sensitivity Analysis

16. A sensitivity analysis was conducted to assess the economic viability of the project by varying key projections (Table 4). The analysis indicates that the EIRR of the project is sufficiently robust in the event of (i) a 20% increase in capital and O&M costs, and (ii) a 20% decrease in revenues. To further test the projects economic viability two additional sensitivity analyses were carried out, on the WTP, and additional land acquisition. The EIRR decreases by 0.04% from the base case should additional land be required. The result of applying a discounted WTP as a tariff shows that the project will remain economically viable. The EIRR for two coal-fired power units is 38.7%.

Table 4: Results of Sensitivity Analysis of the Project

Item	EIRR (%)
Base case	36.3%
Increase in capital costs by 20%	31.3%
Increase in operation and maintenance costs by 20%	36.2%
Decrease in revenues by 20%	28.9%
Willingness-to-pay discounted by 30%	24.7%
Additional land required for ash disposal	36.3%
Two supercritical coal-fired units built	38.7%

EIRR = economic internal rate of return.

Source: Asian Development Bank estimates.