ECONOMIC AND FINANCIAL ANALYSIS

A. Introduction

1. The economic and financial analysis was based on the *Guidelines for the Economic Analysis of Projects* (1997) and the *Financial Management and Analysis of Projects* (2005) of the Asian Development Bank (ADB).

2. The power transmission system enhancement in Afghanistan that will result from outputs of two separate proposed ADB projects was analyzed:

(i) **Transmission line and southern substation.** The proposed North–South Power Transmission Enhancement Project, a stand-alone grant-financed project, is to build a 225-kilometer, single-circuit, 500-kilovolt (kV) transmission line with a capacity of 1,000 megawatts (MW) from Pul-e-Khumri to Arghandy in southwest Kabul via the Salang Pass, and one 500-kV/220-kV substation at Arghandy to connect the 500-kV transmission line to the grid at the southern end.

(ii) **Northern substation.** The proposed tranche 5 of ADB's Energy Sector Development Investment Program, a multitranche financing facility, is to finance construction of the 500-kV/220-kV substation at Dashte Alwan to connect the new 500-kV transmission line at the northern end.[1]

3. Although financed by separate ADB interventions, the transmission line and the two substations are complementary and form a single, whole system whose incremental financial and economic benefits must be assessed overall and cannot be allocated to any of its individual parts. The economic and financial analysis therefore assessed the construction of the transmission line and the two substations as one project under a system approach.

4. Increasing the country's low 25% electrification rate is a top priority of Afghanistan's government. Demand for electricity already significantly exceeds supply. The commissioning of planned new generation facilities will not fully close the current gap, and power shortages may continue to inhibit economic growth and induce social unrest. It is therefore important to secure reliable interim supplies of energy. Since the majority of the power demand is in southern Afghanistan, increasing the capacity of the power transmission system through the project to move electricity from north to south is expected to increase supply in areas where the shortages are currently most severe.

B. Project Context

1. Demand Analysis

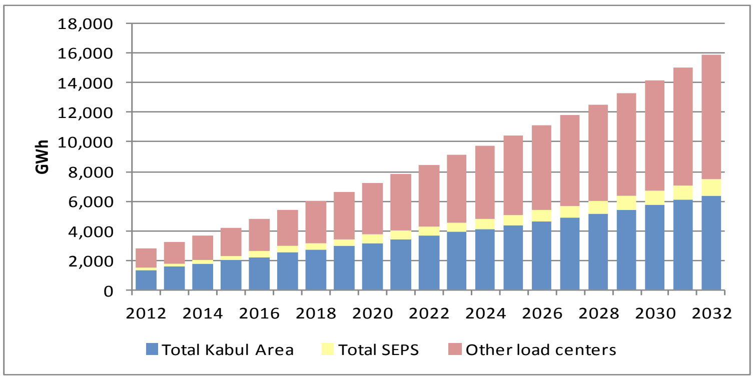
5. Afghanistan's aggregated peak demand was 700 MW in 2012. Unsuppressed peak demand was estimated to be 840 MW. In 2012, a power sector master plan was prepared for Afghanistan with ADB's support.[2] The objective was to identify the least-cost options for generation and transmission system expansion projects that would allow Afghanistan to meet its growing electricity demand. The master plan projected aggregated peak demand to grow to 3,500 MW by 2032, taking into account improvements in connection rates and Afghanistan's expected economic growth. It also estimated that average annual growth rate of net demand over the same period would be 9.8% and that demand would reach 15,909 gigawatt-hours

[1] ADB. 2008. *Report and Recommendation of the President to the Board of Directors: Proposed Multitranche Financing Facility and Administration of Grant Energy Sector Development Investment Program*. Manila (MFF 0026-AFG, $570 million, approved on 2 December).

[2] ADB. 2010. *Technical Assistance to Afghanistan for the Power Sector Master Plan.* Manila (TA 7637-AFG).

(GWh) in 2032. Figure 1 shows that the demand from the Kabul area would continue to account for approximately 50% of total national demand.

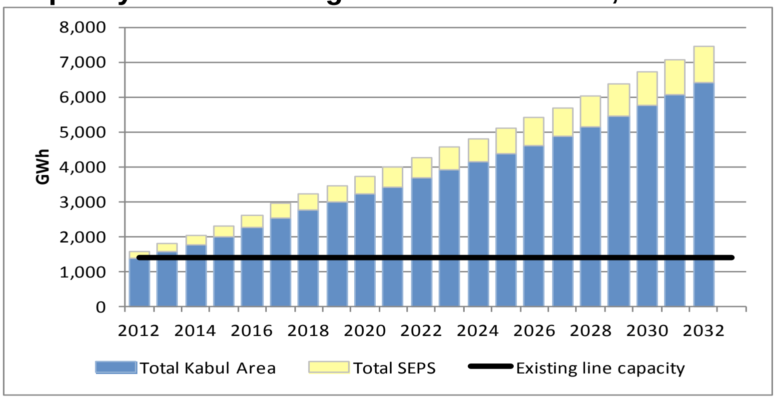
Figure 1: Projected Net Electricity Demand in Afghanistan, 2012–2032



GWh = gigawatt-hour, SEPS = south-east power system
Source: ADB estimates (footnote 2).

6. Afghanistan produces most of its domestically generated electricity through 256 MW of installed hydropower capacity. Its thermal power plants generate 220 MW of electricity and are vulnerable to price rises for the imported diesel fuel they need to operate. In 2012, about 70% of Afghanistan's overall electricity demand was supplied by imported power from Iran, Tajikistan, Turkmenistan, and Uzbekistan, which was the largest supplier (57%). Given its low fossil fuel reserves and low generation capacity, power imports from neighboring countries are expected to continue to be a major source of supply. However, despite rising demand in the south, where most of the people live and most of the economic development takes place, the existing 220-kV transmission line used to transmit imported power from the north southward across the Hindukush mountains is already at full capacity. This will significantly restrict supply to the load centers in Kabul and the rest of the south (Figure 2).

Figure 2: Demand in Afghanistan's Southern Region vs. Capacity of the Existing Transmission Line, 2012–2032



GWh = gigawatt-hour, kV = kilovolt, SEPS = south-east power system.
Source: ADB estimates.

7. To supplement electricity imports in filling the widening demand–supply gap, it is envisaged that the following new power generation plants will be constructed as part of Afghanistan's national power program:

(i) the Sherberghan gas-fired power plant in northern Afghanistan, which is to be commissioned in 2017 with an initial capacity of 150 MW and to increase its capacity to 400 MW by 2023;

(ii) the Kunar A hydropower plant (789 MW) to be commissioned in 2026 and the Kunar B hydropower plant (300 MW) in 2024, both of which will be located east of Kabul and south of the Salang Pass; and
(iii) the Bamyan coal-fired power plant planned to provide 400 MW by 2027 and 1,000 MW in 2029, which is to be connected to the town of Charikar, south of the Salang Pass.

8. Most of these plants will be commissioned only after 2023, which leaves an urgent need to enhance the power transmission capacity between the north and the south. The project being analyzed to build the 500-kV north–south transmission line and two new substations is intended to address the current bottleneck.

2. Tariff Analysis

9. Until 2006 the electricity tariff in Afghanistan was linked to a direct subsidy extended by the United States Agency for International Development (USAID) to Afghanistan for diesel fuel for power generation. The subsidized electricity tariff averaged $0.042 per kilowatt-hour (kWh). The end of the subsidy funding resulted in a 100% tariff increase to $0.083 per kWh. The increase was necessary to ensure the financial sustainability of Da Afghanistan Breshna Mousasa, the predecessor of DABS as the country electricity utility. In 2010, the average tariff charged by DABS was about AF4.5 per kWh, which was equivalent to $0.098 per kWh based on the prevailing foreign exchange rate and thus up about 18% since the subsidy ended. No adjustment has been made since 2010. Based on the current foreign exchange rate, the average tariff is now about $0.088 per kWh, a decrease in US dollar terms.

10. The current tariff level is not financially sustainable for DABS. The master plan proposed a tariff increase in line with the long-run marginal cost (LRMC) of electricity supply by taking into account the cost of new investment projects planned for future expansion. LRMC was estimated to be $0.15 per kWh, comprising a generation cost of $0.06–0.08 per kWh and transmission and distribution costs of $0.07–0.10 per kWh. The plan also assumed that the increase would be spread across 10 years until the tariff reached the targeted cost-recovery level. The increases would vary based on customer categories and locations.

C. Method and assumptions

1. Method

11. The project is considered the most efficient way to address the transmission bottleneck between the northern and southern parts of Afghanistan. The master plan identified two alternative routes across the Hindukush mountains: the Bamyan route, and the route via the Salang Pass along the existing 220-kV transmission line. The Salang Pass route chosen for the project was preferred by DABS because it was the shorter and less expensive to build of the two.

12. The with- and without-project scenario comparison considered only the incremental costs and benefits of the transmission line and two substations. Incremental costs and benefits were accounted for the analysis period and discounted to their net present value. The base year for discounting was 2013. Costs and benefits were expressed in 2013 constant prices and in US dollars.

13. A discount rate of 12% was used for the calculation of the economic internal rate of return (EIRR). For the financial analysis, the weighted average cost of capital (WACC) was estimated and applied as the discount rate for the calculation of the financial internal rate of return (FIRR). The analysis period extended over 25 years after project commissioning. The economic life of the transmission assets was set at 40 years and that of the substations at 30

years, and the assets were assigned a residual value at the end of the 25-year period. A sensitivity analysis examined the project's economic and financial viability if costs increase or benefits decline.

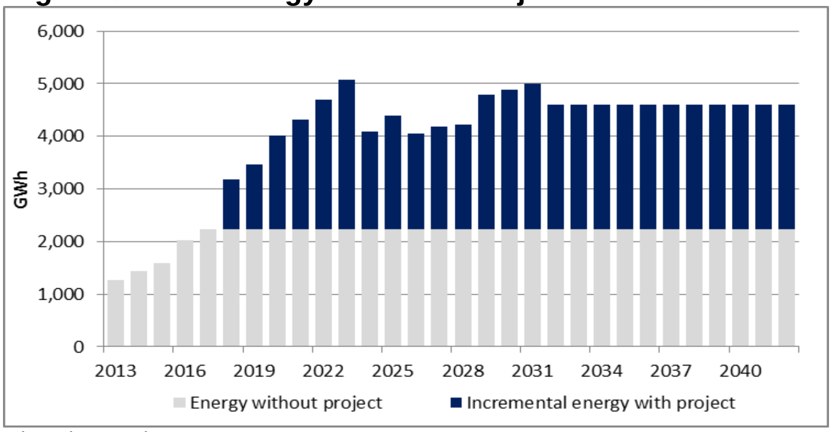
2. Incremental Benefits

14. In the financial analysis, the project benefits were the revenue stream DABS will derive from the incremental sales of electricity to its customers. These revenues were determined by (i) the incremental energy supplied to customers via the transmission line and substations, and (ii) the applicable tariff.

15. **Energy.** The energy transmitted on the new line between Pul-e-Khumri and Arghandy will flow mainly from the north to the south to supply the load centers in Kabul and farther south. Depending on the season and time of day, some energy will also be transmitted from the south to the north during 2024–2032 (the end of the forecast period) after a planned new domestic power plant is commissioned in the south.

16. The existing 220-kV transmission line is operating at full capacity. For this reason, the master plan recommended that it be rehabilitated in 2015 and its capacity increased from 300 MW to 450 MW. The without-project scenario has assumed that this project will be implemented and that, by the time the new 500-kV line is commissioned in 2018, the rehabilitated existing 220-kV line will be transmitting about 2,240 GWh of energy (net of losses) for sale by DABS. In this analysis, therefore, only the incremental energy beyond this amount was attributed as benefit to the new 500-kV line in the with- and without-project analysis. The incremental energy attributed to the new line increased from around 1,000 GWh in 2018 to around 2,500 GWh in 2032. It was assumed to remain at this level for the rest of the analysis period. Figure 3 illustrates the annual levels of incremental energy that would be transmitted with the project's new line and substations.

Figure 3: Total Energy Flow with Project from 2013 to 2042



GWh = gigawatt-hour
Source: ADB estimates.

17. **Tariff.** Because the current end-user electricity tariff is not financially sustainable for DABS, the analysis made the conservative assumption that it will be increased in increments to a full cost-recovery level and reach $0.15 per kWh by 2022. DABS' sales revenues at this tariff would ensure recovery of the incremental costs of the new transmission infrastructure, power generation and fuel imports, and the distribution network. Based on the assumption in the master plan, costs for the transmission system portion of the total network were put at $0.02 per kWh. In the calculation of the project's incremental revenue, it was therefore projected that the transmission tariff would increase to the LRMC level of $0.02 per kWh by 2022 and remain at that level.

18. The incremental benefits in the economic analysis included the increased electricity consumption that the enhanced project transmission system would enable. The project would allow power imports from neighboring countries and the new domestic generation planned in the north to move south to help meet the growing power demand in Kabul, its surrounding region, and other areas further south. The primary beneficiaries would be the residential users and small and medium-sized enterprises provided with a reliable, affordable supply of electricity all year round. The value of the incremental energy consumption—i.e., the overall consumption less the consumption of electricity transmitted by the existing 220-kV line—was based on willingness-to-pay (WTP).

19. WTP is the maximum amount electricity consumers are prepared to pay for electricity or alternative energy sources. Some consumers are able and willing to pay more than others. For example, in the absence of access to electricity from the grid, they will buy a diesel generator or use kerosene for lighting. WTP can be estimated as the area under the demand curve, which can be calculated as the existing tariff plus the consumer surplus. The current average sales tariff of $0.088 per kWh was taken as the existing tariff. The consumer surplus was calculated as 40% of the difference between the cost of the alternative diesel generation of approximately $0.300 per kWh and the average tariff of $0.088 per kWh (with the factor of 0.4 reflecting the concave negative slope in the demand curve). Thus, WTP for the incremental economic benefits was estimated at $0.173 per kWh. If the LRMC was used as the basis, the estimated WTP reached $0.21 per kWh. According to the master plan, the WTP in some Afghanistan provinces where the supply of electricity is extremely limited may reach $0.500 per kWh.[3] Therefore, $0.173 per kWh was considered a reasonable WTP and used in the calculation.

3. Incremental Costs

20. The capital cost of the project will extend over 4 years (2014–2017). The project costs considered in the analysis comprised the following:

- (i) capital costs of the transmission line and the two substations,
- (ii) consulting services costs,
- (iii) costs for project security,
- (iv) land acquisition and resettlement costs,
- (v) recurring costs for project management,
- (vi) taxes and duties (considered in the financial analysis only), and
- (vii) the physical contingency budgeted for the project.

21. The project financial investment costs were converted to economic costs by applying the standard conversion factor of 0.90 to the nontraded costs components and a conversion factor of 0.75 to the unskilled labor portion of the local component (assumed to be 35% of local civil works and infrastructure cost). The major difference between the economic and financial costs resulted from the exclusion of taxes and duties and price contingency from economic costs.

22. The new transmission line and substations would incur annual operation and maintenance (O&M) costs. These costs were spread equally over the analysis period rather than modeled as major capital expenditures at certain points in time. It was also assumed that the project assets would depreciate over their technical lifespans and would not be rehabilitated during this period. The incremental O&M costs were estimated to be 3% of the capital cost. In

[3] In 2010, the average residential customer paid $0.066 per kWh, industrial and commercial customers paid $0.180 per kWh, and the public sector paid $0.210 per kWh. However, tariffs vary significantly within these three categories. While the residential tariff was $0.400–$0.700 per kWh in the majority of the large load centers, it averaged $0.054 per kWh in heart, compared with $0.068 per kWh in Kabul. In some provinces, including provinces in the wider Kabul area with very limited consumption and expensive diesel generation, demonstrated WTP is considerably higher and reached more than $0.500 per kWh.

the economic analysis, O&M costs were also converted into economic costs by applying the conversion factor to the financial costs.

23. Sales tax was 20%, and the analysis set the weighted, straight-line depreciation at 2.8%, based on respective economic life of the transmission line and the two substations.

24. Given that WTP is the consumer tariff, incremental generation and distribution costs per each additional energy output were also considered. Generation cost was measured at $0.8 per kWh based on the average cost of energy generation and imports in Afghanistan. The distribution cost was estimated to be $0.5 per kWh.

4. Weighted Average Cost of Capital

25. The estimated WACC was based on the financial arrangement for the overall transmission system (the line and two substations), which will be financed by the two proposed ADB interventions (para. 2):

(i) The total project amount of the North–South Power Transmission Enhancement Project of $220 million is to be supported by (a) an ADB grant of $99 million, (b) an AITF grant of $117 million, and (c) $4 million from the Government of Afghanistan.

(ii) Tranche 5 of the Energy Sector Development Investment Program), amounting to $53 million, is to be supported by (a) an ADB grant of $49.1 million, and (b) $3.9 million from the government.

26. The grants from ADB and the AITF will be extended to the government, which will relend the funds for a 32-year period to DABS at an interest rate of 1.0% during construction and 1.5% thereafter. The grace period will be 8 years. The balance of the costs will be financed by DABS through self-generated funds. The risk-free rate was assumed at the domestic long-term depository rate of 12%. The other assumption included a domestic inflation rate of 5.0% and a tax rate of 20.0%. The WACC for the project is 0.87% (Table 1).

Table 1: Weighted Average Cost of Capital of the Project

Item	ADB Grant	AITF Grant	Gov't Equity	Total
Weighting	54.25%	42.86%	2.89%	100.00%
Nominal cost	1.50%	1.50%	12.00%	
Tax rate	20.00%	20.00%	0.00%	
Tax adjusted nominal cost	1.20%	1.20%	12.00%	
Inflation rate	0.50%	0.50%	5.00%	
Real cost	0.70%	0.70%	6.67%	
Weighted cost	0.38%	0.30%	0.19%	0.87%
Weighted Average Cost of Capital				**0.87%**

ADB = Asian Development Bank, AITF = Afghanistan Infrastructure Trust Fund
Gov't = Government of Afghanistan
Source: ADB estimates

D. Results

1. Financial Internal Rate of Return and Sensitivity Analysis

27. The FIRR for the project was calculated at 8.97%. This confirms the financial viability of the project, based on the WACC of 0.87% (Table 2).

Table 2: Financial Internal Rate of Return Estimates

($ million)

Year	Capital Cost	Taxes & Duties	Operation & Maintenance	Total Revenue	Net Benefit
2014	(0.32)	0.00	0.00	0.00	(0.32)
2015	(32.61)	(4.70)	0.00	0.00	(37.31)
2016	(114.96)	(16.56)	0.00	0.00	(131.52)
2017	(93.80)	(7.13)	0.00	0.00	(100.93)
2018	0.00	0.00	(5.81)	14.18	8.37
2019	0.00	0.00	(5.81)	18.78	12.97
2020	0.00	0.00	(5.81)	27.69	21.87
2021	0.00	0.00	(5.81)	33.96	28.15
2022	0.00	0.00	(5.81)	41.88	36.07
2023	0.00	0.00	(5.81)	48.12	42.31
2024	0.00	0.00	(5.81)	32.33	26.51
2025	0.00	0.00	(5.81)	37.05	31.24
2026	0.00	0.00	(5.81)	31.64	25.82
2027	0.00	0.00	(5.81)	33.76	27.95
2028	0.00	0.00	(5.81)	34.40	28.59
2029	0.00	0.00	(5.81)	43.55	37.74
2030	0.00	0.00	(5.81)	45.05	39.23
2031	0.00	0.00	(5.81)	46.85	41.04
2032	0.00	0.00	(5.81)	40.52	34.71
2033	0.00	0.00	(5.81)	40.52	34.71
2034	0.00	0.00	(5.81)	40.52	34.71
2035	0.00	0.00	(5.81)	40.52	34.71
2036	0.00	0.00	(5.81)	40.52	34.71
2037	0.00	0.00	(5.81)	40.52	34.71
2038	0.00	0.00	(5.81)	40.52	34.71
2039	0.00	0.00	(5.81)	40.52	34.71
2040	0.00	0.00	(5.81)	40.52	34.71
2041	0.00	0.00	(5.81)	40.52	34.71
2042	84.48	0.00	(5.81)	40.52	119.19
	(157.22)	(28.39)	(145.30)	934.96	604.05
Financial Internal Rate of Return (FIRR)					**8.97%**
Financial Net Present Value@Weighted Average Cost of Capital ($ million)					**463.20**

Source: ADB estimates.

28. As showed in Table 3, the results of the sensitivity analysis conducted confirmed the financial robustness of the project under adverse conditions. The variables considered were (i) higher than expected capital costs, (ii) less incremental energy transmission than projected, and (iii) greater O&M costs.

Table 3: Financial Results of Sensitivity Analysis of the Project

Scenario	**FIRR** (%)
Base case	8.97%
Increase in capital costs by 20%	7.32%
Decrease in energy transmitted by 20%	6.26%
Increase in operation and maintenance costs by 20%	8.37%

FIRR = financial internal rate of return.

Source: ADB estimates.

2. Economic Internal Rate of Return and Sensitivity Analysis

29. The EIRR was calculated at 26.19% based on the project’s incremental cost and benefit streams. This rate compares favorably with the 12% discount rate (Table 4).

Table 4: Economic Internal Rate of Return Estimates
($ million)

Year	Capital Investment	Operation & Maintenance	Generation & Distribution Cost	Incremental Electricity	Net Benefit
2014	(0)	0.00	0.00	0.00	(0.14)
2015	(26)	0.00	0.00	0.00	(26.05)
2016	(107)	0.00	0.00	0.00	(107.49)
2017	(87)	0.00	0.00	0.00	(86.63)
2018	0	(5.58)	(121.75)	161.83	34.51
2019	0	(5.58)	(159.17)	211.58	46.83
2020	0	(5.58)	(230.93)	306.96	70.45
2021	0	(5.58)	(269.97)	358.85	83.30
2022	0	(5.58)	(318.69)	423.61	99.34
2023	0	(5.58)	(369.37)	490.97	116.03
2024	0	(5.58)	(241.02)	320.37	73.77
2025	0	(5.58)	(279.41)	371.40	86.41
2026	0	(5.58)	(235.41)	312.92	71.93
2027	0	(5.58)	(252.66)	335.85	77.61
2028	0	(5.58)	(257.87)	342.76	79.32
2029	0	(5.58)	(332.24)	441.63	103.81
2030	0	(5.58)	(344.38)	457.76	107.80
2031	0	(5.58)	(359.02)	477.22	112.62
2032	0	(5.58)	(307.60)	408.87	95.69
2033	0	(5.58)	(307.60)	408.87	95.69
2034	0	(5.58)	(307.60)	408.87	95.69
2035	0	(5.58)	(307.60)	408.87	95.69
2036	0	(5.58)	(307.60)	408.87	95.69
2037	0	(5.58)	(307.60)	408.87	95.69
2038	0	(5.58)	(307.60)	408.87	95.69
2039	0	(5.58)	(307.60)	408.87	95.69
2040	0	(5.58)	(307.60)	408.87	95.69
2041	0	(5.58)	(307.60)	408.87	95.69
2042	69	(5.58)	(307.60)	408.87	164.76
	(151)	(139.45)	(7,155.52)	9,511.33	2,065.12
Economic Internal Rate of Return (EIRR)					**26.19%**
Economic Net Present Value@12% discount rate ($ million)					**243.54**

Source: ADB and consultant estimates.

30. The results of the sensitivity analysis of the project's economic viability are in Table 5. The variables considered were (i) an increase in capital costs, (ii) decreased incremental energy transmitted by project, (iii) higher O&M costs, and (iv) a higher WTP measured based on LRMC. The project remains robust under adverse circumstances.

Table 5: Economic Results of Sensitivity Analysis of the Project

Scenario	**EIRR** (%)
Base case	26.19%
Increase in capital costs by 20%	22.88%
Decrease in energy transmitted by 20%	21.86%
Increase in operation and maintenance costs by 20%	25.70%
Willingness-to-pay at US$21 cents per kWh, up from US$17.3 cents per kWh	41.57%

EIRR = economic internal rate of return.
Source: ADB estimates.

31. The sensitivity analysis showed that the project is both financially and economically viable.