ECONOMIC ANALYSIS

A. Background and Approach

1. The project is designed to increase electricity transmission and distribution capacity in and around the Kathmandu Valley. This analysis covers the three project components: (i) augmentation of transmission substation capacity for supply to the Kathmandu Valley; (ii) reconstruction and upgrade of medium-voltage and low-voltage distribution networks in the Kathmandu Valley, starting with the central (Ratnapark) and northern (Maharagunj) distribution centers; and (iii) introduction of smart grid elements in the Kathmandu Valley (including 240,000 smart meters) and capacity building within the Nepal Electricity Authority (NEA) in relation to these technologies.

2. Given the inherent interconnectedness of the three project components, this economic evaluation was carried out for the project as a whole. This was done by comparing the project's economic internal rate of return (EIRR) against an assumed hurdle rate of 9%. The sensitivity of the EIRR to adverse changes in the underlying assumptions was also assessed. This evaluation excludes the Japan Fund for Poverty Reduction (JFPR) grant to support gender inclusiveness.

B. Demand Forecast

3. NEA does not produce a separate demand forecast for the Kathmandu Valley. In lieu of a specific demand forecast, an average peak growth rate of 9% was adopted to reflect NEA's expectation of faster demand growth in Kathmandu than in the rest of the country. This rate of growth appears reasonable given the high levels of suppressed demand as a consequence of years of significant load shedding imposed by NEA on its customers.[1] To take a conservative approach and in recognition of other investments that will be required to meet demand, cumulative load growth in Kathmandu Valley was capped at 300% over the estimated base-year load of 400 megawatt (MW) for modeling purposes. Sensitivity to the demand growth rate was also tested. An expectation of a flattening load profile over time was incorporated in the analysis through a gradual increase in the load factor throughout the forecast period.

4. **Demand and supply balance.** Nepal has historically experienced significant shortages in electricity supply, particularly in the dry winter months when output from run-of-river hydropower plants is curtailed. In FY2016, NEA managed to supply approximately 820 MW, compared with an estimated peak demand of 1,390 MW. NEA now expects that, with anticipated commissioning of new hydropower plants over the next 3–4 years,[2] coupled with an increase in cross-border transmission capacity with India, it will be able to meet electricity demand throughout the year, and certainly in the Kathmandu Valley. This economic analysis therefore assumes no constraints on supply of electricity to the grid once the proposed project is fully commissioned in 2019.

C. Least-Cost Analysis

5. A World Bank-funded transmission master plan was prepared during 2015–2016, and it has been confirmed that the transmission component of the project is included in the master plan and is thus a component of the least-cost power system expansion plan for the country, taking into account uncertainties regarding future independent power producers (IPPs), forecast demand for electricity in load centers, and export of electricity to India.

[1] Load shedding has historically been required as a result of supply-side constraints, but since 2012, constraints on the transmission and distribution networks also required load shedding from time to time.

[2] Over 1,000 MW of hydropower capacity is currently under construction and financial closure has been achieved for a further 700 MW of capacity.

6. As part of the analysis of the distribution component, a possible increase in distribution voltage from 11 kilovolts (kV) to 22 kV and 33 kV was assessed to identify the least-cost solution. Analysis confirmed that the retention of 11kV and an upgrade to 22kV had similar total cost outcomes over the 25-year analysis period. A subsequent risk assessment undertaken by NEA and the government supported a decision to retain 11kV as the distribution voltage.

D. Project Economic Costs

7. Project costs were provided by NEA and were formulated on the basis of recent bid prices, and reflect a fourth-quarter 2016 price level. Cost components were broken down into the following broad categories: equipment, civil works and construction, land, preparatory work, external project management, and environmental and social mitigation. The domestic price numeraire was used. Traded inputs and fuel were valued at their border price equivalent values and then adjusted to the domestic price numeraire by multiplying by a shadow exchange rate factor (SERF) of 1.07 (which was based on values for SERF used in other recently approved projects in Nepal). It was assumed that no significant distortions in the wage rates for skilled labor apply. In the case of unskilled labor, underemployment exists in the economy, and a shadow wage rate (SWR) of 0.75 was adopted (based on values for SWR used in other recently approved projects in Nepal). Land was valued at its opportunity cost. A fuel conversion factor was estimated at 0.98 based on current fuel prices in the domestic market. Average operation and maintenance costs of 1.5% and 2.0% of the capitalized project cost were adopted for the transmission and distribution components, respectively, reflecting international experience and the typical benchmarks set by jurisdictional regulators.[3]

8. Seasonal electricity purchase rates from IPPs and from the 456 MW Upper Tamakoshi project (expected to be commissioned by 2019 and designed to provide dry-season peak energy and capacity to Kathmandu) were adopted as proxies for the long-run economic cost of supply. Even though almost all IPP offtake rates are designed to decline in real terms over time, to take a conservative approach, rates were assumed to be constant in real terms from 2024.

E. Project Economic Benefits

9. **Quantification of benefits.** The project is principally designed to improve NEA's ability to meet demand growth in the Kathmandu Valley. In the absence of the project, NEA would face constraints on its ability to transfer power from generators to the east and northeast of Kathmandu, and on its ability to distribute power around the valley. These constraints would ultimately result in additional load shedding and an increase in demand not served.

10. Overall, the project will add 270 megavolt-amperes (MVA) of substation capacity to the Kathmandu Valley (a 36% increase over the existing installed transformer capacity). In principle, this additional capacity would allow NEA to meet 270 MVA of incremental peak demand. However, NEA will not be able to utilize all of this incremental capacity until corresponding downstream investments are made to increase the capacity of the distribution network in the Kathmandu Valley; the project investment includes reconstruction of two of NEA's 11 Kathmandu distribution centers. Based on the intended capacity of the upgraded medium-voltage circuits in these two distribution centers and on an assessment of spare distribution capacity elsewhere in the valley, it is estimated that the project will allow NEA to meet an incremental 90 MVA of demand in the Kathmandu Valley. This translates into incremental annual electricity sales of approximately 600 gigawatt-hours (GWh) by 2030, most of which is incremental consumption. However, given

[3] In practice, it is likely that the proposed investment in the Kathmandu Valley distribution system will result in lower expenditure on operation and maintenance than is currently required on the dilapidated network.

the large installed captive generation base (an estimated 500 MW, the majority of which is in the Kathmandu Valley), the increase in incremental supply capacity is expected to result in some resource cost saving thanks to displacement of self-generation (i.e., in the “without project” case, some demand for electricity that cannot be met from the grid would instead be met through the use of alternative energy sources).

11. Further economic benefits accrue from the expected improvement in quality of supply that the project will bring, and in particular a reduction in the frequency and duration of medium-voltage and low-voltage outages in the two distribution centers to be rebuilt. At present, faults and overloads occur frequently as a consequence of poor network conditions and inadequate capacity, resulting in prolonged outages for NEA’s customers. To quantify this benefit (a reduction in unserved energy), the estimated average outage frequency (faults per feeder per year) and duration (minutes of outage) on medium-voltage feeders was derived from raw data provided by NEA, and an 80% reduction was then assumed as a result of the project.

12. Total losses on the medium-voltage and low-voltage distribution system in Kathmandu are estimated to be 15% (comprising 8% technical loss and 7% commercial loss). Loss reduction is expected to be significant in the two distribution centers included in the project. The larger conductor sizes that NEA will introduce and changes to network topography are expected to result in technical losses declining by about 25% on upgraded parts of the network (i.e., from 8% to 6%).

13. With the adoption of underground cables and aerial bundled conductors for medium-voltage and low-voltage networks, and the introduction of smart metering technology enabled for remote reading, commercial losses are also expected to decrease significantly. An overall commercial loss reduction of 75% is assumed (on upgraded parts of the distribution network), half of which is being converted to sales and the other half resulting in a reduction of electricity purchases. From an economic perspective, only the latter is ascribed economic value; net economic output is assumed to be unchanged as a consequence of the conversion from commercial losses to sales.[4]

14. Loss reduction that occurs in periods when grid capacity would be adequate to meet demand in the without-project case would result in a reduction generation into the grid in the with-project case. This is considered as nonincremental output in the form of a resource cost saving. At other times, loss reduction would result in additional demand being served (incremental output).

15. **Valuation of benefits.** Nonincremental output that is expected to occur as a consequence of the increase in substation capacity was valued at the estimated levelized (long-run) cost of energy from small diesel-fueled generating sets and lighting from kerosene lamps. Nonincremental output from the reduction in short-term outages was valued at the estimated variable (short-run) cost of energy from these sources. Fuel was valued using the World Bank’s projections for international crude oil prices, converted to border price equivalent values for kerosene and diesel fuels.[5] These prices were then shadow-priced, giving an economic levelized cost (in FY2020, the first year of project output) of NRs60 per kilowatt-hour (kWh) for domestic consumers and approximately NRs47 per kWh for other consumers, and short-run costs of NRs58

[4] Under this project, NEA intends to procure a quantity of smart meters and distribution transformers beyond the requirements of the two distribution centers to be rebuilt under this loan (Maharajganj and Ratnapark). Because other network investments are expected to be necessary to fully capture their benefits, only the costs of these additional smart meters and transformers are included in this analysis.

[5] World Bank. 2016. *Commodity Markets Outlook*. July 2016 update.

per kWh for domestic consumers and NRs30 per kWh for other consumers. Nonincremental output arising from loss reduction was valued at the average cost of IPP purchases (NRs4.3 per kWh in 2020, the first year of project output) as a conservative proxy for the long-run cost of generation.

16. Incremental consumption was valued by estimating willingness to pay (WTP) using the approach outlined in ADB's Cost Benefit Analysis for Development: A Practical Guide (2013). Consumers' average unit cost of energy in the without-project case was estimated on the basis of the total cost paid for alternative energy sources and electricity from the grid (a weighted average cost of NRs11.0 per kWh in 2020, increasing to NRs12.7 per kWh by 2026 as capacity constraints reduce the quantity of electricity available from the grid in the without-project case). The average unit cost of energy in the with-project case was taken as NEA's expected average consumer tariff (a real price of NRs11 per kWh expressed in 2016 terms). For simplicity, a linear demand function was assumed, resulting in an average WTP of NRs11.0 per kWh in 2020, increasing to NRs11.5 per kWh by 2026.

17. For the expected reduction in short-term outages in the with-project case, the cost of energy not served was also based on the short-run cost of backup generation from small diesel-fueled sets and lighting from kerosene lamps (NRs58 per kWh for domestic consumers and NRs30 per kWh for other consumers).

F. Economic Internal Rate of Return

18. A period of 25 years has been used for the economic evaluation. Investment is assumed to take place during 2017–2019, and benefits are assumed to be realized from 2020. Given an expectation of an average economic life of the assets of at least 30 years, asset residual value was ascribed. The EIRR is estimated to be 14.1%, as shown in Table 1. This is above the assumed hurdle rate of 9%. It should be noted, however, that the full benefits of the new substation capacity to be developed by the project will not be realized until further investments are made to enhance the capacity of the rest of the distribution system in the Kathmandu Valley; these investment are planned but not yet funded, and so have been excluded from this analysis.[6] Further, potential new demand for electricity in the areas surrounding the new Barhabise, Changunarayan, and Laphsiphedi substations has been ignored.[7] In this context, the EIRR calculated here is a minimum estimate, and on this basis the project investment appears to be economically viable.

Table 1: Economic Benefits
(NRs million)

	Benefits		Costs			Net
Year[a]	Nonincremental Output	Incremental Output	Capital	Supply	Incremental O&M	Economic Benefits
2017	0	0	2,251	0	0	(2,251)
2018	0	0	3,417	0	0	(3,417)
2019	0	0	5,516	0	0	(5,516)
2020	27	0	5,865	2	199	(6,039)
2021	159	273	1,577	111	303	(1,559)
2022	278	521	0	200	332	268

[6] The capital cost to rehabilitate the rest of the Kathmandu Valley distribution system is likely to be around $200 million. Adding this cost to the EIRR calculations and allowing for all 270 MVA of new substation capacity to deliver benefits (compared with 90 MVA in the analysis presented here) would increase the EIRR to about 18%.

[7] These new substations include 5 MVA of medium-voltage capacity, but at this stage distribution networks are not planned to be built in these relatively unpopulated areas.

Year[a]	Benefits: Nonincremental Output	Benefits: Incremental Output	Costs: Capital	Costs: Supply	Costs: Incremental O&M	Net Economic Benefits
2023	327	623	0	208	332	411
2024	739	1,410	0	385	332	1,432
2025	1,135	2,252	0	774	332	2,282
2026	1,592	3,201	0	1,271	332	3,189
….						
2041	3,173	6,492	0	2,322	332	7,011
			Terminal value:			24,677
				EIRR:		**14.1%**

( ) = negative, EIRR = financial internal rate of return, O&M = operation and maintenance.
[a] For brevity, only selected years are shown.
Source: Asian Development Bank staff estimates.

G. Sensitivity and Risk Analysis

19. The risks that the proposed project does not achieve satisfactory economic returns was identified from both cost and benefit side. For each of the risks identified, the sensitivity of the project EIRR was tested and switching values were calculated.[8] Sensitivity results are shown in Table 2. The EIRR exceeds 9% for all contingencies examined.

Table 2: Sensitivity Analysis

	Sensitivity Parameter	Variation	EIRR (%)	Switching Value (%)
	Base case		14.1	
1.	Capital cost increase	10%	13.2	60.7
2.	Benefit reduction	(10%)	12.8	(40.0)
3.	O&M increase	20%	13.9	512.2
4.	Delay	1 yr	12.1	
5.	Lower than forecast demand growth [a]	(25%)	10.7	
6.	Combination of 1–5		10.6	

( ) = negative, EIRR = economic internal rate of return; O&M = operation and maintenance.
[a] The base case assumed 9% per annum demand growth. Demand growth of 75% of 9% (6.75%) was tested here.
Source: Asian Development Bank staff estimates.

H. Conclusion

20. The economic analysis confirms that the proposed project is least cost and economically viable. The analysis yields an overall EIRR of 14.1%. Sensitivity and risk analysis demonstrates that the project's expected economic performance is somewhat sensitive to demand growth (in particular), but the analysis undertaken is inherently conservative as benefits of the project are not expected to be fully realized until further investments are made to improve the distribution system in Kathmandu Valley. The higher load densities and revenue yields in Kathmandu than in the rest of the country mean that the project is financially viable and will improve NEA's financial performance and position (as long as the planned introduction of an automatic tariff adjustment mechanism is implemented).

[8] A switching value measures the percentage change in the variable required to reduce the EIRR to the assumed hurdle rate.