ECONOMIC ANALYSIS

A. Background and Approach

1. Economic evaluation of the proposed additional financing project was carried out in accordance with economic analysis guidelines of the Asian Development Bank (ADB) using a with-project and without-project framework to compare the project's economic internal rate of return (EIRR) against an assumed hurdle rate of 9%.[1] The approach and most assumptions adopted reflect those used during appraisal of the original Electricity Grid Modernization Project in 2020. This document describes the economic evaluation of the additional financing components on a stand-alone basis and updates the EIRR of the overall project.

2. The additional financing covers the following subprojects that were excluded from the original project because of budget constraints: construction of an additional (i) 16 kilometers (km) of 132-kilovolt (kV) transmission lines from Kohalpur to Nepalgunj and from Chovar to Lagankhel, and (ii) 477 megavolt-amperes (MVA) of substation capacity in Dumkibas (Arun Kholta), Lagankhel, Mulpani, and Nepalgunj. The additional financing will also include implementation of an enterprise resource planning solution and revenue management system for Nepal Electricity Authority (NEA); the capital and maintenance costs of these items have been included in this analysis, although no economic benefits have been ascribed.

B. Demand and Supply Balance

3. The compound average electricity demand growth rate in Nepal during 2000–2019 was 9%, and during 2015–2019 it increased to about 15% as supply constraints were removed. In lieu of specific demand forecasts for the subproject areas, an average growth rate of 9% was adopted. Through effective and efficient demand- and supply-side management, NEA has gradually reduced load shedding; during fiscal year (FY) 2017 (ended 15 July 2017), load shedding was entirely avoided in the important commercial and tourist cities of Kathmandu and Pokhara. During FY2019, 62% of Nepal's electricity (energy and power) came from domestic hydropower plants, with the balance imported from India and with domestic load shedding reported by NEA to be less than 1% of demand. With the anticipated commissioning of new hydropower plants by 2023,[2] coupled with augmentation of cross-border transmission capacity with India, NEA expects it will be able to meet electricity demand all year round, and certainly in the project areas (if not in more remote parts of the country, where transmission and distribution capacity is still limited). This economic analysis therefore assumes no constraints on supply of electricity to the grid once the proposed project is fully commissioned in 2027, although the sensitivity to this assumption was tested.

C. Alternatives Analysis

4. The new transmission lines and substation capacity form part of the overall least-cost transmission master plan for Nepal. Capacity additions are timely and appropriately sized (given expected demand growth), and designs are consistent with international best practice.

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[1] Asian Development Bank (ADB). 2017. *Guidelines for the Economic Analysis of Projects*. Manila; and ADB. 2013. *Cost–Benefit Analysis for Development: A Practical Guide*. Manila.

[2] Hydropower capacity of more than 1,000 megawatts (MW) is under construction and financial closure has been achieved for a further 700 MW of capacity.

D. Project Economic Costs

5. Project costs were provided by NEA and were formulated on the basis of 2020 bid prices. They reflect a price level as of the second quarter of 2021. Cost components were broken down into 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 of 1.07 (which was based on values used in other recently approved projects in Nepal).[3] It was assumed that there are no significant distortions in the wage rates for skilled labor. In the case of unskilled labor, underemployment exists in the economy, and a shadow wage rate of 0.75 was adopted (based on values used in other recently approved projects in Nepal) (footnote 3). Land is a small component of project cost (about 5%) and therefore the estimated market cost of land, as provided by NEA, was adopted as a proxy for its economic opportunity cost. Average operation and maintenance costs of 1.5% of the project capital cost were adopted, reflecting international experience and the typical benchmarks set by jurisdictional regulators in India and elsewhere.

6. Contracted seasonal electricity purchase rates from independent power producers and from the 456 megawatt (MW) Upper Tamakoshi project—previously expected to be commissioned by December 2020 and designed to provide dry season (November–May) peak energy and capacity to Kathmandu, but delayed because of coronavirus disease-related delays to plant testing and to construction of the related interconnecting transmission line—were adopted as proxies for the long-run economic cost of electricity supply. Even though almost all independent power producer offtake rates are designed to decrease in real terms over time, to be conservative, rates were assumed to be constant in real terms from 2024 onward.

E. Project Economic Benefits

7. **Quantification of benefits.** The transmission capacity-related subprojects are principally designed to improve NEA's ability to meet demand growth in the project areas. Overall, about 477 MVA substation capacity, plus related transmission lines, will be added to the network. However, NEA will not be able to utilize all of this incremental capacity until corresponding downstream investments are made to increase the capacity of distribution networks; it is estimated that the project will allow NEA to supply an additional 100 MVA of demand. This translates to incremental annual electricity sales of about 337 gigawatt-hours by 2035, most of which is incremental consumption.

8. Given the large installed captive generation base (an estimated 500 MW nationally), the increase in supply capacity is expected to result in some resource cost savings because of 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.

9. By displacing energy from polluting alternative sources with emission-free electricity generated from hydropower, the subprojects covered by the additional financing will reduce greenhouse gas emissions by an estimated 31,000 tons of carbon dioxide equivalent per year (once the project's output has reached full capacity). This reduction provides an economic benefit, which was valued at a rate of $44.25 per tons of carbon dioxide equivalent (in 2021), increasing at 2% per year in real terms.

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[3] ADB. 2017. *Report and Recommendation of the President to the Board of Directors: Proposed Loan and Administration of Technical Assistance Grant to Nepal for the Power Transmission and Distribution Efficiency Enhancement Project.* Manila; and Economic Analysis (accessible from the list of linked documents in Appendix 2).

10. **Valuation of benefits.** Non-incremental output that is expected to occur as a consequence of the increase in transmission capacity was valued at the estimated fuel cost of energy from small diesel generating sets and lighting from kerosene lamps. Non-incremental output from the reduction in short-term outages was also valued using the fuel 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, and shadow priced.[4]

11. Incremental consumption was valued by estimating willingness to pay using the approach outlined in ADB's *Cost–Benefit Analysis for Development*.[5] The average unit cost of energy in the with-project case was taken as NEA's expected weighted average consumer tariff in each of the subproject areas. 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. For simplicity, a linear demand function was assumed.

F. Economic Internal Rate of Return, and Sensitivity and Risk Analysis

12. A period of 30 years was used for economic evaluation of the additional financing component to align with the evaluation period used for the original project. Investment is assumed to take place during 2023–2027, and benefits are assumed realized from 2028. Asset residual values are insignificant on a discounted basis and have therefore been ignored. The EIRR for the additional financing components is 14.5% (13.8% excluding environmental benefits), well above the hurdle rate of 9%. The aggregate EIRR of the overall project, including the additional financing components, is 14.6% (14.1% excluding environmental benefits), a slight decrease over the EIRR of 14.8% estimated during appraisal of the original project. The EIRR calculation for the additional financing components is shown in Table 1 and for the overall project in Table 2. Sensitivity analyses for the stand-alone additional financing components and for the overall project were updated, as shown in Tables 3 and 4. The EIRR exceeds 9% for all contingencies examined.

G. Conclusion

13. The economic analysis confirms that the additional financing components are economically viable on a stand-alone basis and also slightly improve the estimated EIRR of the overall project. Sensitivity analysis demonstrates that the project's expected economic performance remains robust and not particularly exposed to any specific risks.

Table 1: Economic Internal Rate of Return Calculation—Additional Financing Only
(NRs million)

	Benefits			**Costs**			**Net Economic Benefits**
Year	Incremental Output	Non-Incremental Output	Avoided Emissions	Capital	Supply	O&M	
2022	0	0	0	0	0	0	0
2023	0	0	0	696	0	0	(696)
2024	0	0	0	1,774	0	0	(1,774)
2025	0	0	0	2,589	0	0	(2,589)

4 World Bank. 2019. *Commodity Markets Outlook, April 2020*. Washington, DC.
5 ADB. 2013. *Cost–Benefit Analysis for Development: A Practical Guide*. Manila.

Year	Benefits: Incremental Output	Benefits: Non-Incremental Output	Benefits: Avoided Emissions	Costs: Capital	Costs: Supply	Costs: O&M	Net Economic Benefits
2026	0	0	0	2,338	0	0	(2,338)
2027	0	0	0	876	0	0	(876)
2028	65	15	3	0	28	124	(68)
2029	175	42	9	0	74	124	27
2030	417	100	21	0	177	124	237
2031	676	162	35	0	289	124	460
2032	1,456	344	77	0	685	124	1,067
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2050	4,088	931	296	0	1,890	124	3,301
						EIRR:	**14.5%**
						ENPV:	**5,032**

( ) = negative, EIRR = economic internal rate of return, ENPV = economic net present value, O&M = operation and maintenance.
Notes: Selected years shown for brevity. ENPVs discounted to 2021 at 9%.
Source: Asian Development Bank estimates.

Table 2: Economic Internal Rate of Return Calculation—Overall Project
(NRs million)

Year	Benefits: Incremental Output	Benefits: Non-Incremental Output	Benefits: Avoided Emissions	Costs: Capital	Costs: Supply	Costs: O&M	Net Economic Benefits
2022	0	0	0	3,526	0	0	(3,526)
2023	0	0	0	8,577	0	0	(8,577)
2024	0	0	0	9,789	0	0	(9,789)
2025	0	0	0	5,300	0	0	(5,300)
2026	0	91	2	2,587	0	170	(950)
2027	129	220	8	876	53	378	73
2028	409	314	22	0	170	502	616
2029	996	488	51	0	416	502	1,359
2030	1,820	726	94	0	779	502	2,839
2031	3,630	1,212	189	0	1,689	502	5,386
2032	6,750	2,031	358	0	3,251	502	(950)
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2051	21,727	5,253	1,570	0	10,014	502	18,034
						EIRR:	**14.6%**
						ENPV:	**25,507**

( ) = negative, EIRR = economic internal rate of return, ENPV = economic net present value, O&M = operation and maintenance.
Notes: Selected years shown for brevity. ENPVs discounted to 2021 at 9%.
Source: Asian Development Bank estimates.

Table 3: Sensitivity Analysis—Additional Financing Only

No.	Sensitivity Parameter	Variation	EIRR (%)	ENPV (NRs billion)	Switching Value (EIRR) (%)
	Base case		14.5	5.0	
1	Project capital costs	+10%	13.7	4.5	66
2	Project O&M costs	+10%	14.4	5.0	820
3	Oil price	–25%	13.7	4.2	(178)
4	Cost of generation	+25%	13.1	3.5	97
5	Willingness to pay	–20%	11.9	2.4	(43)
6	Demand growth[a]	–25%	12.5	3.2	(70)
7	Delayed commissioning	1 year	12.5	3.2	
8	Supply constraints[b]	–25%	10.2	0.9	(32)
9	Incremental supply (excluding India)[c]	+50%	9.0	0.0	50
10	Combination (1, 6, and 7)		10.2	1.2	

( ) = negative, EIRR = economic internal rate of return, ENPV = economic net present value, O&M = operation and maintenance.

[a] The base case assumed 9% annual demand growth. Demand growth of 75% of 9% (6.75%) was tested under this scenario.

[b] A reduction in available supply of 25% was tested in this sensitivity, limiting the delivery of benefits.

[c] In the base case, all incremental supply is assumed to be sourced from domestic hydropower. Under this sensitivity scenario, half of the incremental supply is assumed to be sourced from India. A grid emission factor of 0.754 tons of carbon dioxide equivalent per megawatt is used to estimate incremental regional emissions under this sensitivity scenario.

Source: Asian Development Bank estimates.

Table 4: Sensitivity Analysis—Overall Project

No.	Sensitivity Parameter	Variation	EIRR (%)	ENPV (NRs billion)	Switching Value (EIRR) (%)
	Base case		14.6	25.5	
1	Project capital costs	+10%	14.1	23.8	98
2	Project O&M costs	+10%	14.6	25.2	884
3	Oil price	–25%	14.0	21.8	(224)
4	Cost of generation	+25%	13.4	18.7	117
5	Willingness to pay	–20%	12.5	13.7	(52)
6	Reduction in outages	–50%	14.6	25.4	<(5,000)
7	Demand growth[a]	–25%	11.0	7.2	(38)
8	Delayed commissioning	1 year	13.2	18.9	
9	Supply constraints[b]	–25%	10.6	5.4	(35)
10	Incremental supply (excluding India)[c]	+50%	9.7	2.1	57
11	Combination (1, 7, and 8)		9.5	1.8	

EIRR = economic internal rate of return, ENPV = economic net present value, O&M = operation and maintenance.

[a] The base case assumed 9% annual demand growth. Demand growth of 75% of 9% (6.75%) was tested under this scenario.

[b] A reduction in available supply of 25% was tested in this sensitivity, limiting the delivery of benefits.

[c] In the base case, all incremental supply is assumed to be sourced from domestic hydropower. Under this sensitivity scenario, half of the incremental supply is assumed to be sourced from India. A grid emission factor of 0.754 tons of carbon dioxide equivalent per megawatt is used to estimate incremental regional emissions under this sensitivity scenario.

Source: Asian Development Bank estimates.