PROJECT ECONOMIC ANALYSIS

A. Overview

1. The economic analysis undertaken for the Electricity Transmission and Supply Improvement Project examines the economic viability of the project and each of its components from the country's perspective. Economic costs and benefits associated with the project cover the construction period (2012–2016) and a 30-year operating life. All values are expressed in domestic prices in constant 2012 Nepalese rupees (NRs) and discounted using a discount factor of 12%—the assumed opportunity cost of capital. Financial values given in US dollars are converted at the exchange rate of $1 = NRs72. Sensitivity and risk analyses were undertaken with respect to key risk variables to examine the robustness of the economic results. Finally, a distribution analysis of net benefits and a poverty impact analysis were conducted.

B. Project Justification and Economic Rationale

2. Part A, Transmission System Development, including three separate components, will expand the transmission system to enable Nepal to make further use of its hydropower resources to meet the demand for electricity and reduce the need for load shedding. Part B, Energy Access Improvement, will provide new 11 kilovolt (kV) distribution substations for 12 separate local areas where demand has reached the limit of the existing substation capacity. Part C, Small Hydropower Plant Rehabilitation, will renew key components of a 35-year old station at Tinau (1.00 MW) and an 80-year old station at Sundarijal (0.64 MW), which is the second oldest hydropower plant in Nepal.

C. System Expansion Planning

a. Demand Forecast

3. The demand forecasting methodology adopted by the Nepal Electricity Authority (NEA) was originally developed as part of the Power System Master Plan prepared by Norconsult in 1998, and has been regularly updated since. The forecast model is a classic top–down approach, forecasting demand for generation and peak power on the entire integrated national power system. The NEA disaggregates the national demand forecast by substation based on historical experience and available information regarding major new load additions. This effort is only an approximation, however, since it does not always allocate load to proposed substation additions.

4. Overall, the current demand forecast projects sales to grow by an average of 8.7% per annum over 2012–2028, and peak demand to grow by a slightly lower 8.1% as a result of an improvement in system losses from their recent level of considerably over 20% to a target efficiency of 15% by 2022 and a presumed 0.1% annual increase in system load factor. Some of the forecast demand is unserved because of load shedding; required generation is not available. In 2010, 15.5% of total demand was shed, and 20.3% was shed in 2011. Further, system loss projections appear optimistic against provisional 2011 losses of 28.4%.

5. Since forecasts are not available to capture differences in local area rates of demand growth, system-wide load growth assumptions have been applied to forecast future component demand over the planning horizon. Beyond 2028, a modest 3% annual sales growth has been assumed.

b. Least-Cost Development Plan

6. The NEA no longer prepares a least-cost system expansion plan in the traditional sense. Following the opening of the energy sector to private developers, the NEA is

responsible for only a portion of generation expansion. Further, while licenses have been issued for thousands of megawatts of new hydropower capacity, experience has taught the NEA system planners that such licenses are not a reliable indicator of project development. Obstacles, ranging from environmental permitting to financing, mean that only a small fraction of potential projects will be realized, and often not according to the original scheduling.

7. The NEA adopts an N-1 criterion for transmission planning, i.e., the company strives to plan network expansion such that any single component outage can be sustained without loss of load. NEA planners have identified the proposed transmission projects (part A of the project) as least-cost solutions to satisfy this planning criterion.

8. Proposed distribution substation expansion candidates (part B of the project) have been selected by the NEA because current substation maximum demand meets or exceeds the existing distribution transformer capacity. Tinau and Sundarijal hydropower stations (part C of the project) have been selected for rehabilitation because of their age and current condition, which restrict reliable operation at full capacity and would justify near-term retirement in the absence of rehabilitation investment.

D. Valuation of Project Costs and Benefits

a. Key Assumptions for Economic Evaluation

10. All costs and benefits for project evaluation are expressed at constant 2012 price levels. A domestic price numeraire has been adopted, and all costs and benefits are expressed in local currency (NRs). An exchange rate of NRs72 = $1 and a discount rate of 12% have been employed for the analysis.

11. Conversion factors have been estimated to adjust project costs to the domestic price numeraire. The shadow exchange rate factor (i.e., the inverse of the standard conversion factor) has been calculated as 1.06. The shadow wage rate factor has been estimated at 0.75 to reflect underemployment in Nepal's economy. A diesel fuel conversion factor has been estimated at 0.94 based on a current domestic market price of NRs73.5/liter and a world market price of $100 per barrel; a single value has been adopted to make the impact of a change more easily understood through sensitivity analysis.

b. Project Costs

12. Project financial costs, as prepared by NEA specialists responsible for each project component and reviewed by the project financial consultant, have been categorized as investment costs (including taxes and duties); other costs (i.e., land acquisition, environmental and social mitigation, and project management/construction supervision); and contingencies (both physical and price). For economic analysis, capital costs include physical contingencies, but exclude price contingencies as well as taxes and duties. Total costs have been allocated by economic classification (traded, non-traded, labor [foreign, skilled local, unskilled local], and fuel) based on assessment of recent bid documents submitted to the NEA for similar projects.

13. The total investment cost for all project components in financial terms, excluding the costs of project financing and interest during construction but including contingencies, is estimated to be NRs8.798 billion at constant 2012 prices. The total economic cost of the project is estimated to be NRs8,654. Annual operating costs have been estimated at 1.5% of capital cost.

c. Long-Run Economic Cost of Electricity Supply

14. Proposed project investments are only part of the total cost of delivering electricity to consumers, so it is important to estimate the total cost of supply. Incremental

transmission investments require continued investment in generation, other transmission, and distribution. Similarly, distribution investments require associated investment in generation and transmission.

15. While a detailed marginal cost study is beyond the scope of the present investigation, an approximation has been made based on proxy units. The marginal cost of generation during periods of adequate supply has been estimated as the cost of a hydropower station proxy (Chameliya station, under construction). When supplementary power is needed, i.e., when a shortfall is expected because of a shortage of firm winter capacity, the marginal cost of supply is estimated as the cost of diesel generation, including fuel cost. The long-run average incremental cost of transmission has been estimated based on a review of the transmission investment program of the NEA, adjusted downward to eliminate distortions resulting from very optimistic near-term investment targets. Distribution long run average incremental cost (LRAIC) has been assumed to equal the transmission estimate on a unit sales basis.

d. Project Benefits

16. Capacity constraints in both transmission and distribution networks mean that frequent supply interruption is required to ensure that networks are not overloaded. The three transmission components are primarily concerned with overcoming such network constraints while improving reliability and reducing losses. Three benefits have been identified, although data are not always available for benefits estimation: (i) increased network load-carrying capacity, (ii) reduced network losses, and (iii) reduction in energy not served.

17. The value of each of these benefits changes as the system evolves, and varies by season and time of day depending on whether system generation is in surplus or in deficit. Ideally, it would be possible to allocate the demand forecast by season and time of day to determine the adequacy of generation in each period.

18. Analysis is complicated since an accurate forecast of the load resource balance is not available because of uncertainty as to the level and timing of generation additions. Therefore, it is necessary to rely on assumptions and to subject these assumptions to careful sensitivity analysis. The following assumptions have been adopted for this analysis:

(i) Benefits resulting from increases in network load-carrying capacity are based on projected winter (dry season) peak loads, which are assumed to be coincident with the system peak, as identified by the NEA through network load flow studies. These loads are subsequently converted to generation and sales using annual load factors, loss factors, and sales demand growth projections for the entire grid; loads are not allocated by season or time of day.

(ii) Transmission system planners assume adequate generation to meet the load forecast, but evidence suggests that load shedding will continue for at least 5 years; for the calculations reported here, the FY2010 and FY2011 average level of shedding (18% of required generation) has been assumed to continue until 2018, and benefits have been adjusted downward to reflect this resulting constraint on sales.

(iii) Loss reduction on the entire grid and reduction in energy not served are additional project benefits, but they have not been incorporated into the economic analysis, as accurate engineering estimates of unit quantities are not available.

19. All of the above project outputs—benefits from new network load-carrying additions and hydropower life extensions—have been valued as either non-incremental or incremental.

(i) Non-incremental outputs result from end-users who are not now electrified, and thus rely on substitutes for grid electricity (e.g., residential consumers who rely on kerosene for lighting plus limited battery consumption, and nonresidential consumers who rely on diesel-fueled captive generation). Non-incremental outputs are valued at the resource cost savings that would result if the project were to proceed. It has been conservatively assumed that only 10% of project outputs would serve non-electrified consumers.

(ii) Incremental outputs result from new and increased usage by end-users who are currently electrified. These outputs are valued at the willingness to pay for electricity, which is estimated from a two-point demand curve, with one point representing the cost and quantity of substitutes, and the other point representing the cost and quantity for customers consuming average quantities of electricity.

E. Project Economic Internal Rate of Return

20. Project components have been analyzed using a with- and without-project approach. Without the project, it is assumed that bottlenecks will continue to cause disruption, and that newly available generation will not be delivered to final consumers. With the project, there will be increased capacity to evacuate newly available generation, resulting in increases in both non-incremental and incremental electricity consumption.

21. A summary of the economic evaluation by project component is in Table 1. The results indicate that the project will deliver a very positive economic return, averaging over 25%. An economic resource statement for the overall project is in Table 2.

Table 1: Summary of Economic Results by Project Component

Project Component	**Commissioning Year**	**EIRR** (%)	**AIEC** per kWh	**NPV** per kWh	**NPV** (NRs million)
Part A: Transmission System Development					
A1 Mahendranagar–Kohalpur 132 kV second circuit stringing	2015	19.3	14.9	3.6	2,156
A2 Tamakoshi - Kathmandu 400 kV Transmission Line	2017	25.4	13.8	4.7	7,980
A3 Expansion of Chapali grid substation	2015	22.7	14.6	3.9	2,503
Part B: Energy Access Improvement	2015	40.2	9.4	9.1	7,559
Part C: Small Hydropower Plant Rehabilitation	2015	18.8	11.9	6.6	170
Overall Project (Parts A, B, and C)		25.7	13.1	5.4	20,368

AIEC = average incremental economic cost; EIRR = economic internal rate of return; NPV = net present value
Source: Asian Development Bank

F. Sensitivity and Risk Analysis

22. Sensitivity analysis of the economic internal rate of return (EIRR) for the overall project indicates that returns remain very robust against unanticipated adverse conditions. Sensitivity was tested for increased costs, decreased benefits, and reduced operating life. Even when increased costs and reduced benefits, the project EIRR remains above the opportunity cost of capital of 12%. Only under extremely pessimistic assumptions—increased costs and reduced benefits coupled with a delay in the start of benefits and a reduced operating life—does the project EIRR fall slightly below this threshold.

23. For the risk analysis three key risk factors were identified: (i) capital investment costs, (ii) project-related sales, and (iii) the value of project benefits. Probability distributions were assigned to each variable as follows: the risk analysis was conducted based on 10,000 iterations, with the output variable being the expected EIRR. The mean EIRR of all simulated combinations is 25.2%, nearly matching the base case EIRR. The values of EIRR range from a maximum of 33.7% to a minimum of 18.0%.

Table 2: Project Economic Internal Rate of Return (2012 NRs million)

	GROSS BENEFITS			ECONOMIC COSTS					Net
	Nonincrem	Increm	Total Benefits	Capital Investment	Assoc. Supply	Assoc. Distribution	O&M	Total Cost	Economic Benefit
Year	(NRs million)	(NRs million)	(NRs million)	(NRs million)	(NRs million)	(NRs million)	(NRs million)	(NRs million)	(NRs million)
2012	0.00	0.00	0.00	432.66	0.00	0.00	0.00	432.66	(432.66)
2013	0.00	0.00	0.00	1672.40	0.00	0.00	0.00	1672.40	(1672.40)
2014	0.00	0.00	0.00	4227.30	0.00	0.00	0.00	4227.30	(4227.30)
2015	258.51	1496.32	1754.83	1624.61	2618.21	0.00	60.17	4302.99	(2548.16)
2016	358.92	2077.49	2436.40	696.26	3668.06	0.00	60.17	4424.49	(1988.08)
2017	1243.50	7197.60	8441.10	0.00	13135.54	0.00	129.80	13265.33	(4824.24)
2018	1652.91	9567.34	11220.25	0.00	5939.41	0.00	129.80	6069.20	5151.04
2019	1793.85	10383.15	12177.00	0.00	6422.94	0.00	129.80	6552.74	5624.26
2020	1903.08	11015.38	12918.46	0.00	6785.91	0.00	129.80	6915.71	6002.76
2021	2019.78	11690.86	13710.64	0.00	7173.42	0.00	129.80	7303.22	6407.42
2022	2090.32	12099.16	14189.48	0.00	7388.23	0.00	129.80	7518.03	6671.45
2023	2153.60	12465.43	14619.03	0.00	7570.62	0.00	129.80	7700.41	6918.61
2024	2221.44	12858.06	15079.50	0.00	7765.93	0.00	129.80	7895.73	7183.77
2025	2294.21	13279.30	15573.51	0.00	7975.27	0.00	129.80	8105.07	7468.44
2026	2372.31	13731.37	16103.69	0.00	8199.73	0.00	129.80	8329.53	7774.16
2027	2456.16	14216.67	16672.82	0.00	8440.48	0.00	129.80	8570.28	8102.54
2028	2542.72	14717.72	17260.44	0.00	8688.95	0.00	129.80	8818.75	8441.68
2029	2619.00	15159.25	17778.25	0.00	8949.62	0.00	129.80	9079.42	8698.83
2030	2697.57	15614.02	18311.60	0.00	9218.11	0.00	129.80	9347.91	8963.69
2031	2778.50	16082.45	18860.94	0.00	9494.66	0.00	129.80	9624.45	9236.49
2032	2861.85	16564.92	19426.77	0.00	9779.49	0.00	129.80	9909.29	9517.48
2033	2947.71	17061.87	20009.58	0.00	10072.88	0.00	129.80	10202.68	9806.90
2034	3036.14	17573.72	20609.86	0.00	10375.07	0.00	129.80	10504.86	10105.00
2035	3127.23	18100.93	21228.16	0.00	10686.32	0.00	129.80	10816.12	10412.04
2036	3221.04	18643.96	21865.00	0.00	11006.91	0.00	129.80	11136.71	10728.30
2037	3317.67	19203.28	22520.95	0.00	11337.11	0.00	129.80	11466.91	11054.04
2038	3417.20	19779.38	23196.58	0.00	11677.23	0.00	129.80	11807.03	11389.56
2039	3519.72	20372.76	23892.48	0.00	12027.55	0.00	129.80	12157.34	11735.14
2040	3625.31	20983.94	24609.25	0.00	12388.37	0.00	129.80	12518.17	12091.08
2041	3734.07	21613.46	25347.53	0.00	12760.02	0.00	129.80	12889.82	12457.71
2042	3846.09	22261.87	26107.96	0.00	13142.82	0.00	129.80	13272.62	12835.34
2043	3961.48	22929.72	26891.20	0.00	13537.11	0.00	129.80	13666.91	13224.29
2044	4080.32	23617.61	27697.93	0.00	13943.22	0.00	129.80	14073.02	13624.91
2045	1644.03	9515.92	11159.95	0.00	6097.63	0.00	69.63	6167.25	4992.69
2046	1693.35	9801.40	11494.75	0.00	6280.56	0.00	69.63	6350.18	5144.56

Increm = incremental; Nonincrem = non incremental; O&M = operation and maintenance; ( ) = negative
Source: Asian Development Bank

G. Distribution of Project Effects and Poverty Impact Ratio

24. For the distribution analysis, beneficiaries are separated into four stakeholder groups: the NEA, Government of Nepal, labor involved in project construction and operation, and consumers. Overall, the economic net present value (NPV) exceeds the financial NPV by over NRs22,000 million, with almost all of the benefits accruing to consumers. The NEA is a net loser in the analysis, as its return is negative when discounted at the opportunity cost of capital. The distribution analysis has been applied to estimate the impact of the project on poverty reduction. By apportioning the gains and losses according to the proportion of each beneficiary group, a poverty impact ratio may be estimated. These assumptions imply a poverty impact ratio of 31% for the entire project.

H. Conclusion

27. Economic evaluation of the proposed project indicates that the planned investment is economically viable. The estimated EIRR for the entire project is 25.7%. The project remains viable even when subjected to pessimistic sensitivity tests. Project returns fall below the opportunity cost of capital (12%) only when a combination of adverse cost and benefit outcomes are assumed. Finally, project risk assessment confirms that the project can be expected to achieve an EIRR above the opportunity cost of capital.