ECONOMIC ANALYSIS

A. Economic Rationale

1. **Project description.** The Grid Reinforcement Project will support Electricité du Cambodge (EDC), Cambodia's state-owned power utility, in improving the capacity and stability of its transmission network. The project team will (i) expand the electricity transmission infrastructure by constructing 115-kilovolt (kV) and 230 kV lines and 10 substations in Phnom Penh and surrounding provinces (output 1); and (ii) introduce as a pilot the first utility-scale battery energy storage system (BESS) in Cambodia (output 2). The outputs are combined for the economic analysis because the transmission subprojects and the BESS all contribute to improving the quality of grid electricity supply. The economic analysis follows Asian Development Bank (ADB) guidelines.[1]

2. **Sector context.** Electricity consumption grew on average 18.8% year-on-year between 2010 and 2019 to 10,287 gigawatt-hours (GWh), while supply increased on average by 19.1% year-on-year to 12,015 GWh.[2] Over the same period, connected households increased from 23% of all households to 75%. However, electricity services continue to be of poor quality. The system load increasingly exceeds capacity, leading to brownouts and blackouts. The project will reduce load shedding caused by insufficient capacity, and help meet demand that would otherwise be unserved.

3. **Rationale for public sector involvement.** EDC is responsible for electricity supply, transmission, and distribution. Private domestic and foreign investors are encouraged to invest in electricity generation and also finance part of the transmission system. It is estimated that EDC will need to invest about $2.27 billion in transmission and distribution infrastructure between 2020 and 2025. As EDC does not receive budgetary support, it finances its investment needs from operational cash flows and by mobilizing external financing. Concessionary financing from development partners is a crucial supplement to EDC and private sector financing, and essential for accelerating infrastructure development that will boost economic growth and poverty alleviation.

4. **Least-cost analysis.** EDC studied various options for expanding transmission capacity to relieve the load on its existing substations. The proposed subprojects were identified as representing optimal locations and sizes for this purpose, considering the existing network and the location of new demand centers, and making maximum use of public land for siting new substations. The grant-financed pilot BESS will enable EDC to gain experience ahead of scaling up energy storage to support the further expansion of intermittent generation from renewable sources.

5. **Demand forecasts.** The most recent Power Development Plan, approved in February 2020, projects peak demand to rise to 10,183 megawatts by 2030, an increase of 5.6 times the 2018 level. This forecast was prepared before the impacts of the coronavirus disease (COVID-19) pandemic became apparent. For the purposes of the analysis presented here, an alternative demand forecast was prepared based on the following assumptions:

   (i) For 2020, the current low-demand forecast prepared by EDC is used. This is for a 2.5% fall in full-year sales relative to 2019 as a result of the COVID-19 pandemic (sales in January–March 2020 were 14% above 2019 levels).

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[1] ADB. 2017. Guidelines for the Economic Analysis of Projects.
[2] Electricity Authority of Cambodia. 2019. Salient Features of Power Development in the Kingdom of Cambodia 2019.

(ii) Gross domestic product (GDP) growth is assumed to gradually recover from 2021 onward, reaching 5.5% by 2030. This is still below pre-crisis growth rates, which averaged 7.1% annually from 2010 to 2019.

(iii) Electricity sales are assumed to grow by 2.72 times the rate of GDP growth, representing the average ratio of sales to GDP growth over the preceding 10 years.

Table 1: Summary of Demand Forecast Assumptions

	2019	**2020**	**2021**	**2025**	**2030**	**Average** (% pa) 2019–2030
Electricity supply (GWh)	11,318	11,038	11,969	18,538	35,067	10.8
Change from previous year (%)	20.1	(2.5)	8.4	12.2	15.0	
Peak load (MW)	1,800	1,756	1,904	2,948	5,577	10.8

( ) = negative, GWh = gigawatt-hour, MW = megawatt, pa = per annum.
Source: Intelligent Energy Systems and Asian Development Bank.

B. Project Economic Analysis

1. Output 1 (Transmission grid infrastructure expanded)

6. Output 1 benefits and costs are estimated for a 25-year period following commissioning of the subprojects in 2024. Costs and benefits are calculated annually for the period to 2030, and are assumed to remain constant from 2031 onward.

7. **Valuation of costs**. Investment costs are calculated as the sum of base costs plus physical contingencies, excluding taxes and duties. Traded cost components are converted to economic costs assuming a shadow exchange rate factor of 1.10.[3] Labor costs are converted to economic costs assuming a shadow wage rate factor of 0.90.[4] The costs of engineering, procurement, and construction (EPC) contracts are assumed to comprise a traded cost share of 81% (matching the share of equipment costs), a non-traded cost share of 9%, and a labor cost share of 10%. The costs of land acquisition and resettlement and of environmental safeguards are assumed to be non-traded. The costs of the project implementation consultants are assumed to be 75% traded (representing the share of international consultant costs) and 25% non-traded. The resulting total investment costs are estimated at $157.6 million. Operating and maintenance (O&M) costs are estimated at $2.4 million annually.

8. **Valuation of benefits**. The incremental benefit for output 1 is the additional demand served relative to the without-project case. For each year, the forecast demand by substation is compared with existing capacity and with capacity added under the project. Where demand exceeds capacity, the excess is considered to represent load shedding. The difference in load shedding with and without the project represents the incremental demand served.[5] Incremental benefits are valued as the difference between the value of additional supply (reduced load shedding) to customers and the costs of supplying this energy. The value to customers of the additional electricity supply is conservatively proxied by the current average retail tariff of $0.154 per kilowatt-hour (kWh), or 15.4 ¢/kWh. This is likely to understate the value of more reliable supply—industrial customers, for example, have identified power cuts as a major cost of doing

[3] ADB. 2019. Report and Recommendation of the President to the Board of Directors: Proposed Loan to the Kingdom of Cambodia for the National Solar Park Project. Manila

[4] Applies a conversion factor of 1.00 for skilled labor and 0.75 for unskilled labor, with an assumed ratio of skilled to unskilled labor of 60:40 reflecting the technical requirements of the proposed investments.

[5] Hourly loading data for December 2019 at each existing substation was obtained from EDC. These loads are assumed to grow in line with the demand forecast.

business in Cambodia.[6] This valuation is assumed to remain constant in real terms, reflecting the assumption that the benefits of electricity supply do not decline over time. To this, the consumer surplus, estimated following ADB guidelines, is added.[7] For the purposes of estimating the consumer surplus, the willingness to pay for supply is assumed to be the cost of self-supply using diesel generating sets at an average of 20 ¢/kWh.

9. The costs of supply are estimated as the sum of the marginal cost of generation and the average distribution cost. The marginal cost of generation has been estimated for each hour using dispatch modeling conducted by Intelligent Energy Systems (IES) as part of ADB technical assistance to the preparation of a new Power Development Plan for Cambodia.[8] This cost varies by year with a minimum average of 5.7 ¢/kWh in 2025, when the marginal supply source during the dry season is imports from lignite power plants in Laos, and during the wet season is predominantly imports from Thailand. By 2030, the cost is forecast to increase to 8.8 ¢/kWh, the marginal sources being liquefied natural gas power plants in Cambodia and imports from Thailand.

10. The distribution cost is estimated as the difference between the average retail tariff and the tariff charged to distribution licensees connected to EDC's transmission network (and thereby not using EDC's distribution system). This equals 3.2 ¢/kWh in 2020 and is assumed to remain constant in real terms. An allowance is made for transmission and distribution losses. The increase in carbon emissions resulting from incremental consumption as a result of reduced load shedding is calculated using an average grid emission factor of 0.580 $kgCO_2$/kWh[9] and a social cost of carbon calculated following ADB guidelines[10] of 43.3 $/$tCO_2$ in 2025, increasing thereafter.

11. Non-incremental benefits are estimated as the change in transmission losses resulting from the project. Reducing losses does not in itself increase the supply to customers, as supply is constrained by inadequate transmission capacity rather than insufficient generation. However, it does deliver cost savings by reducing the quantity of generation needed to meet demand. Conducted load flow studies estimate that the project will reduce losses from 2.5% to 1.9%. The reduction is applied to forecast demand in the provinces covered by the project. In 2025, this equates to a reduction of 80 GWh annually, rising to 151 GWh in 2030. The value of non-incremental benefits is estimated as the sum of the avoided supply costs and the reduction in carbon emissions.

2. Output 2 (Pilot utility-scale battery energy storage system)

12. Output 2 benefits and costs are estimated for a 10-year period in accordance with the expected life of the BESS installation, following its commissioning in 2022. Costs and benefits are calculated annually to 2030, and are assumed to remain constant from 2031 onward.

13. **Valuation of costs.** Investment costs are calculated as the sum of base costs plus physical contingencies, excluding taxes and duties.[11] The costs comprise a traded cost share of 89% (the share of equipment costs) and a labor cost share of 11%. The total economic investment

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[6] For example: Chan S. "Cheaper electricity on the way for businesses and families". *Khmer Times*. 28 January 2020.
[7] ADB. 2002. Measuring Willingness to Pay for Electricity. ERD Technical Note No. 3.
[8] ADB. 2018. *Technical Assistance for Southeast Asia Energy Sector Development, Investment Planning and Capacity Building Facility*. Manila.
[9] IFI Technical Working Group. 2019. The IFI Dataset of Default Grid Factors v2.0 (accessed 4 July 2020).
[10] ADB 2017. Guidelines for the Economic Analysis of Projects. The social cost of carbon is set at 36.3 $/$tCO_2$ in 2016, increasing by 2% annually in real terms (¶163).
[11] A containerized solution is assumed, with lower capital and higher O&M costs than for a dedicated building.

costs are estimated at $7.93 million. O&M costs for the initial 3 years are included in the EPC contract price. Following this, these costs are estimated at $0.05 million annually. The costs of power for air-conditioning and electronics are estimated at $0.16 million annually.

14. **Valuation of benefits.** The services provided by the pilot BESS are described Table 2. Since the BESS is generally increasing supply from the same marginal source when charging while it reduces supply from the same marginal supply when discharging, there is no change in grid emissions.

Table 2: Battery Energy Storage System Services

Benefit / Valuation	Solar Plant Output Smoothing	Curtailment Reserve	Primary Frequency Response	Transformer Upgrade Deferral
Description	Charging when solar PV output is above target and discharging when below target	Charging continuously and discharging to avoid load shedding	Charging continuously and discharging to restore frequency	Charging off-peak and discharging at peak to relieve transformer overloading
Without project	Differences from target value are met from imported energy	Load shedding because of lack of supply	Frequency response provided by imported energy	Additional transformer capacity needed to meet peak demand
With project	PV+BESS output constant at target value	Load shedding avoided	Frequency response provided by BESS, avoiding imports	Peak demand met from BESS discharging
Daily discharge[a]	17.8 MWh/day	10.7 MWh/day	11.2 MWh/day	4.9 MWh/day (varies by year)
Cost of charging	Marginal supply source	Marginal supply source	Marginal supply source	Marginal supply source at off-peak
Benefit of discharging	Marginal supply source	Average retail tariff	Marginal supply cost	Deferred transformer investment

BESS = battery energy storage system, MWh = megawatt-hour, PV = photovoltaic.
[a] The BESS continually charges and discharges, going through multiple cycles in one day for some services.

C. Economic Cost–Benefit Analysis

15. Table 3 presents the economic net present value (ENPV) and the economic internal rate of return (EIRR) for the project, including sensitivities. Table 4 presents the details of the cost and benefit streams.

Table 3: Summary of Economic Evaluation

	Base Value	ENPV $ million	EIRR	Switching Value	Change from Base
Project		371.4	30.6%		
+20% power supply cost (¢/kWh)	8.3	(50.8)	8.2%	9.8	17.6%
+20% investment cost ($ million)	165.5	344.2	27%	596.2	273.2%
(20%) in willingness to pay (¢/kWh)	15.4	23.4	14.5%	12.1	(21.3)%
2-year delay in project (years)	4	303.6	27.7%		

( ) = negative, ¢ = cent, EIRR = economic internal rate of return, ENPV = economic net present value (using social discount rate of 9%), kWh = kilowatt-hours.
Source: Asian Development Bank calculations.

16. The project is sensitive to an increase in power supply costs and a reduction in willingness to pay (the tariff). An increase in power purchase costs will likely be offset by an increase in demand, which this analysis projected conservatively low, and in general by expanded lower-cost supply and contracted energy purchases. Between 2015 and 2020, EDC has been implementing a tariff reduction plan to pass through to customers the benefits of falling power purchase costs while maintaining cost recovery and a regulated return.

Table 4: Economic Analysis

Year	Benefits from Transmission Services (Output 1)							Benefits from BESS Services (Output 2)					Benefits	Costs				Net Benefits
	Avoided System Losses GWh	Value of Avoided Losses $ million	Additional Supply GWh	Value of Additional Supply $ million	Consumer Surplus $ million	Net Change in Emissions $ million	Sub-Total $ million	PV Load Levelling $ million	Curtailment Reserve $ million	Primary Frequency Response $ million	Transmission Upgrade Deferral $ million	Sub-Total $ million	Total $ million	Capital $ million	O&M $ million	Incremental Supply $ million	Total $ million	$ million
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	(43.5)	-	-	(43.5)	(43.5)
2022	-	-	-	-	-	-	-	-	-	-	-	-	-	(74.5)	-	-	(74.5)	(74.5)
2023	-	-	-	-	-	-	-	(0.0)	0.1	(0.0)	0.1	0.1	0.1	(31.6)	(0.2)	-	(31.8)	(31.7)
2024	-	-	-	-	-	-	-	(0.0)	0.1	(0.0)	0.3	0.4	0.4	(15.9)	(0.2)	-	(16.0)	(15.6)
2025	80	4.5	1,108	170.5	25.6	(25.9)	174.7	(0.0)	0.2	0.2	-	0.4	175.1	(0.1)	(2.6)	(109.2)	(111.8)	63.3
2026	89	5.2	1,536	236.3	35.4	(37.1)	239.8	(0.0)	0.2	0.2	0.4	0.8	240.6	-	(2.6)	(153.3)	(155.9)	84.7
2027	102	6.2	2,062	317.3	47.6	(51.3)	319.7	(0.0)	0.2	0.2	-	0.4	320.1	-	(2.6)	(212.4)	(215.1)	105.0
2028	115	7.1	2,705	416.2	62.4	(69.1)	416.5	(0.0)	0.2	0.2	-	0.4	416.9	-	(2.6)	(278.7)	(281.3)	135.5
2029	131	11.0	3,486	536.5	80.4	(91.4)	536.5	(0.0)	0.1	0.1	0.1	0.3	536.8	-	(2.6)	(448.2)	(450.8)	86.0
2030	151	13.3	4,501	692.6	103.8	(120.9)	688.9	(0.0)	0.1	0.1	-	0.1	689.0	-	(2.6)	(600.2)	(602.8)	86.1
2031	151	13.3	4,501	692.6	103.8	(123.3)	686.5	(0.0)	0.1	0.1	-	0.1	686.6	-	(2.6)	(600.2)	(602.8)	83.7
2032	151	13.3	4,501	692.6	103.8	(125.7)	684.0	(0.0)	0.1	0.1	0.2	0.3	684.3	-	(2.6)	(600.2)	(602.8)	81.5
2033	151	13.3	4,501	692.6	103.8	(128.3)	681.5	-	-	-	-	-	681.5	-	(2.4)	(600.2)	(602.6)	78.8
2034	151	13.3	4,501	692.6	103.8	(130.8)	678.9	-	-	-	-	-	678.9	-	(2.4)	(600.2)	(602.6)	76.3
2035	151	13.3	4,501	692.6	103.8	(133.4)	676.3	-	-	-	-	-	676.3	-	(2.4)	(600.2)	(602.6)	73.7
2036	151	13.3	4,501	692.6	103.8	(136.1)	673.6	-	-	-	-	-	673.6	-	(2.4)	(600.2)	(602.6)	71.0
2037	151	13.3	4,501	692.6	103.8	(138.8)	670.9	-	-	-	-	-	670.9	-	(2.4)	(600.2)	(602.6)	68.3
2038	151	13.3	4,501	692.6	103.8	(141.6)	668.1	-	-	-	-	-	668.1	-	(2.4)	(600.2)	(602.6)	65.5
2039	151	13.3	4,501	692.6	103.8	(144.4)	665.3	-	-	-	-	-	665.3	-	(2.4)	(600.2)	(602.6)	62.7
2040	151	13.3	4,501	692.6	103.8	(147.3)	662.4	-	-	-	-	-	662.4	-	(2.4)	(600.2)	(602.6)	59.8
2041	151	13.3	4,501	692.6	103.8	(150.3)	659.5	-	-	-	-	-	659.5	-	(2.4)	(600.2)	(602.6)	56.8
2042	151	13.3	4,501	692.6	103.8	(153.3)	656.5	-	-	-	-	-	656.5	-	(2.4)	(600.2)	(602.6)	53.8
2043	151	13.3	4,501	692.6	103.8	(156.4)	653.4	-	-	-	-	-	653.4	-	(2.4)	(600.2)	(602.6)	50.8
2044	151	13.3	4,501	692.6	103.8	(159.5)	650.3	-	-	-	-	-	650.3	-	(2.4)	(600.2)	(602.6)	47.6
2045	151	13.3	4,501	692.6	103.8	(162.7)	647.1	-	-	-	-	-	647.1	-	(2.4)	(600.2)	(602.6)	44.4
2046	151	13.3	4,501	692.6	103.8	(165.9)	643.8	-	-	-	-	-	643.8	-	(2.4)	(600.2)	(602.6)	41.2
2047	151	13.3	4,501	692.6	103.8	(169.2)	640.5	-	-	-	-	-	640.5	-	(2.4)	(600.2)	(602.6)	37.9
2048	151	13.3	4,501	692.6	103.8	(172.6)	637.1	-	-	-	-	-	637.1	-	(2.4)	(600.2)	(602.6)	34.5
2049	151	13.3	4,501	692.6	103.8	(176.1)	633.7	-	-	-	-	-	633.7	-	(2.4)	(600.2)	(602.6)	31.0
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EIRR	30.6%
ENPV @ 9%	371.3

EIRR = economic internal rate of return, ENPV = economic net present value, GWh = gigawatt-hour, O&M = operation and maintenance, PV = photovoltaic.
Source: Asian Development Bank calculations.