ECONOMIC ANALYSIS

A. Background and Approach

1. The project is designed to expand the 66 kilovolt (kV) and 33 kV networks of the Electricity Supply Enterprise (ESE) to provide capacity for the connection of new electricity customers in the Ayeyarwady, Bago (East), and Magway regions; and Kayin State in Myanmar. The project includes the design, supply, installation, and commissioning of 66/33 kV, 66/11 kV, and 33/11 kV substations and related distribution lines; and is expected to enable the government to electrify an additional 400,300 households in more than 2,815 villages. It will also include the installation of a computerized distribution automation system (DAS) to allow the ESE to manage its network better and to reduce the impact of network faults.

2. An economic evaluation of the proposed project was carried out following the Asian Development Bank (ADB) guidelines for the economic appraisal of projects.[1] The analysis considers the project on an aggregate basis, comparing the economic internal rate of return (EIRR) against the hurdle rate of 9%.

B. Rationale for Intervention

3. The need for investment in Myanmar's electricity segment far outstrips the funding available. The private sector has a stable history of participation in power generation and is expected to continue its involvement, but private investment in bulk generation is contingent on the government's commitment to increasing electricity transmission and distribution capacity. In the two years, from 2018 to 2019, the Ministry of Electricity and Energy (MOEE) issued notices to proceed for nine privately financed generation projects totaling more than 5,300 megawatts. The MOEE issued an invitation to bid for the generation of 1,060 megawatts of solar power capacity in June 2020 and issued the corresponding notice to proceed in September 2020. The National Electricity Master Plan projects the required installed capacity to be about 23.6 gigawatts (GW) by 2030, four times higher than the installed capacity of 5.6 GW in 2018, requiring an investment of $20 billion.[2]

4. The government has had some success with its corporatization and internal franchising initiatives in the distribution segment, and high rates of demand growth in electricity consumption reflect the importance of electricity to the economy. To expand the network to parts of the country with lower load densities (and therefore lower financial returns on investment), the government plans to mobilize funding from development partners to invest in distribution. This provides the context and economic rationale for ADB's continued involvement in Myanmar's power transmission and distribution development.

C. Demand and Supply Balance Forecast

5. Up until 2009, growth in electricity consumption in Myanmar was constrained by generation availability and network capacity. However, the gradual removal of constraints has unlocked suppressed demand and annual consumption growth rates have accelerated since 2015. Consumption grew at an annual rate of 10%–12% during 2015–2019.

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

[2] Government of Myanmar. Ministry of Electricity and Energy (MOEE). National Electricity Master Plan. Unpublished.

6. The 2015 Myanmar Energy Master Plan's econometric forecast predicted 57,000 GWh and 9.5 GW of electricity demand by 2030 in its medium growth scenario, assuming an electrification ratio of 87% of households by 2030.[3] This analysis adopted the ESE's demand forecast (which is based on the Myanmar Energy Master Plan). Sensitivities to forecast growth assumptions have been tested.

7. Electricity generation is dominated by hydropower, with about 58% of installed capacity and total generation, followed by gas-fired power plants (open cycle and closed cycle turbines) with about 38% of installed capacity and generation in fiscal year (FY) 2016 (ended 30 September 2016). Myanmar has struggled to meet electricity demand when hydropower generation is reduced during the dry season because of the predominance of hydropower. The private sector has responded strongly to investing in power generation in recent years, with more than 5.0 GW of notices to proceed issued in 2018 and 2019. Development partners have also funded the rehabilitation of aging plants and financed new plants. This economic analysis assumes no constraints on the supply of electricity to the grid.

D. Alternatives Analysis

8. The project's distribution component has been designed to provide sub-transmission (66 kV and 33 kV) substation capacity to allow for grid extension. It has been confirmed that the proposed network topology and designs are efficient and reflect least-cost planning principles, and that the investment has a significantly lower cost than meeting forecast demand growth through local small-scale generation. The economic levelized cost of the proposed distribution investments is about MK5.4/kWh plus a long-run marginal cost (LRMC) of grid-scale generation and transmission connections of MK112.4/kWh (para. 15), compared with an economic levelized cost of about MK250/kWh for small diesel generators.

E. Project Economic Benefits

9. **Quantification of benefits.** The economic benefits of the project accrue as a consequence of (i) non-incremental consumption, where the conventional sources of energy are displaced by grid electricity (mainly kerosene for lighting and diesel to run small generators and motors); and (ii) incremental consumption, where (grid) electricity consumed in addition to the energy that would have been consumed without the grid connection.

10. The analysis assumed that the newly connected households (about 98% of new connections) will consume about 400 kWh per year, while other non-household consumers (2% of new connections) will consume 10,000 kWh per year on average. This is lower than the consumption of existing ESE customers (1,100 kWh for household consumers and 75,000 kWh for non-household consumers).[4] This demand is assumed to grow by 7% per year, reflecting the average underlying demand growth in Ayeyarwady, Bago (East), and Magway regions; and Kayin State since 2016. In the absence of the investment, electricity consumers would use expensive off-grid energy sources (primarily small diesel-fueled generators and kerosene lamps). Non-incremental consumption was estimated based on the existing consumption of alternative energy sources in unelectrified areas. For household consumers, an estimated 150 kWh per year of consumption is assumed to be non-incremental and 250 kWh per year is assumed to be incremental. For non-household consumers, about 4,000 kWh per year of consumption is estimated to be non-incremental and 6,000 kWh per year is estimated to be incremental.

[3] Government of Myanmar, National Energy Management Committee. 2015. *Myanmar Energy Master Plan*. Yangon.
[4] Ministry of Electricity and Energy (MOEE). Electricity Supply Enterprise (ESE). Electricity Statistics. Unpublished.

11. The DAS will reduce the number of short-term outages experienced by consumers because of faults that occur within the ESE's network. Based on international experience, an estimated that the number of 11 kV line faults experienced per year will be reduced from about 30 per feeder to 12 after the completion of the subproject. The duration of each outage will similarly decrease, from about 60 minutes to about 30 minutes. Overall, the reduction in outages will allow for about 20 GWh of additional demand to be served from the grid.

12. **Valuation of benefits.** The non-incremental output that is expected to occur as a consequence of the extended grid (about 92 GWh by 2028) and the implementation of the DAS (about 4 GWh by 2028) was valued at the estimated fuel cost of energy from kerosene lamps for lighting (household consumers) and small diesel-fueled generating sets for non-household consumers. Fuel costs were valued using World Bank projections for international crude oil prices, converted to border price equivalent values for kerosene and diesel fuels.[5] These prices were then shadow priced (para. 14), giving an economic fuel cost (in 2027, the first year of the expected output from the distribution component) of MK607/kWh for household consumers and about MK195/kWh for other consumers.

13. The incremental output (about 214 GWh by 2028) was valued by estimating the willingness to pay (WTP). The WTP was estimated separately for household and non-household consumers that will be connected because of the project. The WTP was estimated as the average of the price for grid electricity for each consumer type and the cost of alternative energy sources (fuel only). For simplicity, linear demand functions were assumed. The WTP was estimated at about MK314/kWh for household consumers and MK174/kWh for non-household consumers in the first year of benefits (expressed in real terms).

F. Project Economic Costs

14. The ESE provided the project costs. Cost estimates were formulated based on recent bid prices and reflect mid-2020 prices. Cost components were broken down into equipment, civil works and construction, land, 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 1.1 (which was based on the values of the shadow exchange rate factor used in a recently approved project in Myanmar).[6] The analysis assumed that no significant distortions in the wage rates for local skilled labor apply. In the case of unskilled labor, underemployment exists in the economy, and a shadow wage rate of 0.75 was adopted (footnote 6). The estimated market cost of land, provided by the ESE, was adopted as a proxy for its economic opportunity cost. Based on international benchmarks set by regulators, average incremental operation and maintenance were assumed to average 1.5% of capital costs.

15. **Cost of generation and transmission.** The 2015 Myanmar Energy Master Plan estimated the LRMC of generation (capacity and energy) at $0.718/kWh for its base case generation expansion plan. Adjusting to a 2020 price level provides an indicated LRMC of $0.0755/kWh. This analysis adopted a value of MK104.9/kWh as a proxy for the average cost of supply to the transmission network. The LRMC of the transmission system, estimated in the Myanmar Energy Master Plan at $0.0054/kWh, was also included as a project cost.

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5 World Bank. 2020. *Commodity Markets Outlook, April 2020*. Washington, DC.

6 ADB. 2018. *Report and Recommendation of the President to the Board of Directors: Proposed Loan to the Republic of the Union of Myanmar for the Power Network Development Project*. Manila.

16. **Cost of downstream network.** Downstream (11 kV and 0.4 kV) investment will be required to distribute electricity to consumers, as the project does not include expansion and reinforcement of 11 kV and 0.4 kV networks. These downstream networks will be constructed using funding from other development partners, the ESE's own funds, and local community contributions. The ESE provided the estimated cost of these downstream investments, about $120 million in financial terms. The estimated cost of the service connection to consumers and household wiring was also added to the project's capital cost, an estimated total cost of $80 million. This additional capital cost and its related operating and maintenance cost (assumed to be 2% of capital costs) was shadow priced and included as a project economic cost. Sensitivity to these assumptions was tested because of their inherent uncertainty.

G. Economic Internal Rate of Return and Sensitivity Analysis

17. Investment was assumed to take place over 2021–2027. Benefits are assumed to be realized from 2027 and a period of 25 years from commissioning was used for the economic evaluation. Asset residual value makes negligible difference and was ignored for the evaluation. The aggregate EIRR for the project is estimated at 10.6% which exceeds the assumed hurdle rate of 9%. EIRR calculation is summarized in Table 1. The risks that the proposed project does not achieve satisfactory economic returns was identified from both cost and benefit side. Downside scenarios were also tested in relation to assumed benefits, capital cost, operations and maintenance costs, electricity purchase costs, demand growth, and commissioning delays. For each of the risks identified, the sensitivity of the project EIRR was tested and switching values were calculated.[7] Sensitivity results are shown in Table 2. The EIRR exceeds 9% for most contingencies examined, although a 20% reduction in WTP would reduce the EIRR to 7.4%.

Table 1: Aggregate Economic Internal Rates of Return Calculation[a]
(MK million)

Year	Benefits		Emission	Costs				Net Economic Benefits
	Incremental	Non-Incremental		Project Capital	Other Capital	O&M	Supply	
2020	0	0	0	0	0	0	0	0
2021	0	0	0	469	322	0	0	(790)
2022	0	0	0	28,162	18,020	0	0	(46,182)
2023	0	0	0	45,250	24,498	0	0	(69,749)
2024	0	0	0	47,392	32,499	0	0	(79,891)
2025	0	0	0	53,001	39,950	0	0	(92,951)
2026	0	0	0	53,470	95,245	0	0	(148,715)
2027	33,026	34,146	1,956	10,623	21,744	5,491	27,745	3,524
2050	277,387	42,030	(26,174)	0	0	6,852	162,159	124,233
2051	295,363	42,030	(29,253)	0	0	6,852	173,510	127,779
							EIRR (post-tax real):	**10.6%**
							ENPV:	**56,280**

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

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

Table 2: Sensitivity Analysis

	Sensitivity Parameter	Variation (%)	EIRR (%)	ENPV (MK billion)[b]	Switching Value (EIRR) (%)
	Base case		10.6	56.3	
1	Project capital costs	20	9.7	26.0	35
2	Downstream capital costs[a]	20	9.8	28.4	38
3	Project O&M costs	25	10.3	46.9	15
4	Oil price	(25)	9.0	(1.4)	(24)
5	LRMC of supply	25	8.0	(30.6)	15
6	Willingness to pay	(20)	7.4	(47.6)	(10)
7	Reduction in outages	(50)	10.5	53.2	(931)
8	Demand growth[b]	(50)	8.6	(13.2)	(39)
9	Delayed commissioning	1 year	9.6	20.2	

EIRR = economic internal rate of return, ENPV = economic net present value, LRMC = long-run marginal cost, O&M = operation and maintenance.

[a] Capital expenditure required on downstream networks and consumers connections that is not included in the project.

[b] The assumed rate of demand growth was reduced by 50% (about 3.5 percentage points) for this scenario.

Source: Asian Development Bank estimates.

H. Project Sustainability

18. The cost of supplying rural customers is significantly higher than the cost of supplying urban customers. Thus, the end-use tariff structure employs cross-subsidization between urban and rural customers, i.e., urban customers (particularly non-household consumers) pay more than the cost of supplying electricity to them, whereas rural customers pay less than the cost of supplying electricity to them. The justification for and impact of this policy is evident in the results of the project analysis—the project is expected to provide robust economic returns but poor financial returns. In this context, it is encouraging that the government has consistently increased end-use tariffs to improve cost recovery across the energy sector, but further tariff margin increases are required before the distribution segment can operate without direct government support.

I. Distribution Analysis

19. The analysis assessed the distribution of costs and benefits among major stakeholders by comparing financial costs and benefits with economic costs and benefits. Overall, the economic net present value exceeds the financial net present value by MK303 billion at a discount rate of 9%. The economy suffers a net loss (MK232 billion), mainly because of the extent to which electricity supply is underpriced relative to its economic cost (although this is offset by the taxes and transfers). Electricity consumers will be the largest net beneficiaries of the investment (MK534 billion), mainly because their assumed WTP and avoided costs far exceed the electricity tariff they would pay for the incremental supply they will receive.