Chapter 3

Methodology

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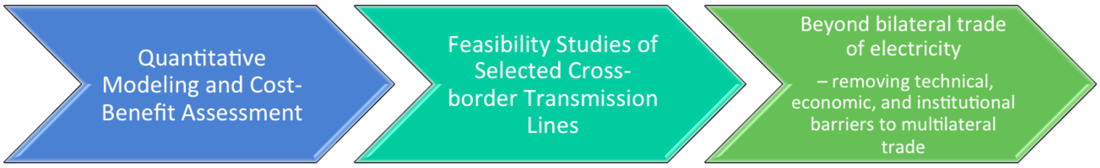
The initial step is to comprehensively survey the supply potential of solar PV, wind, coal, and natural gas power generation, and the supply and demand of electricity in China (north and northeast), Russia (east), Japan, Mongolia, and South Korea.

Figure 7: Geographical Scope of the Study

Source: Economic Research Institute for ASEAN and East Asia.

Based on ERIA's experience in the research for the ASEAN Power Grid, the three-step approach in carrying out the studies to address the research questions is proposed, as follows:

Figure 8: ERIA's Research Steps on Regional Power Grid Interconnection



Source: Economic Research Institute for ASEAN and East Asia.

(i) Conduct a quantitative modelling for cost–benefit assessment to identify an optimal overall vision for the Asian Super Grid. Depending on the availability of detailed data, the model not only addresses the overall economic rationale, it can also be used as a tool to identify future patterns of electricity trade and/or exchange, as well as priorities of specific cross-border transmission line project for power grid interconnection.

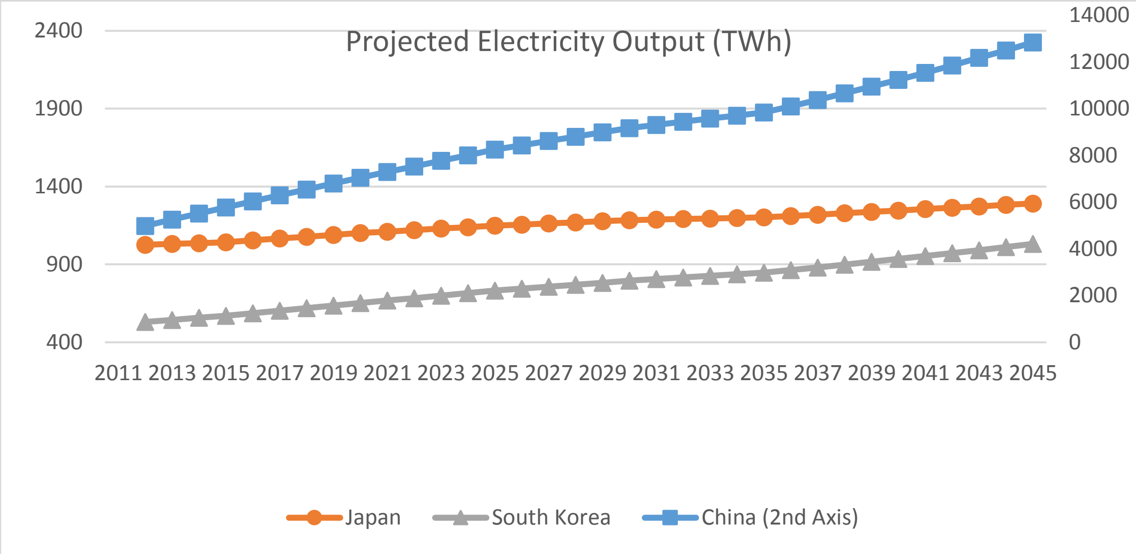
(ii) Carry out feasibility studies to assess in detail the financial feasibility of selected routes of cross-border transmission lines. This stage of study requires detailed data to estimate all costs of constructing and operating cross-border transmission lines in specific countries.

(iii) In view of the technical, regulatory, and other institutional barriers for multilateral power grid interconnection and electricity trade, conduct studies on how to harmonise these issues among the involved countries.

For the first year, ERIA will develop a quantitative model to assess the costs and benefits of power grid interconnection in the NEA region, based on cost minimisation for the region as a whole and dispatching of load by the order of merit. The model duly reflects the following key aspects of dynamics in the region's power sector in the next few decades or until 2045.

First is the growth of demand for electricity (Figures 9 and 10), and the daily and monthly patterns of demand for power (Figures 11 and 12). In the case of China and Russia, note that it is not realistic to model their overall demand for electricity. Thus, only the regional electricity demand and supply in northern China and Eastern Russia will be modelled. However, due to the unavailability of data, the growth rate for the projection of demand into the future will be assumed to be the same as the whole country, as the figures show.

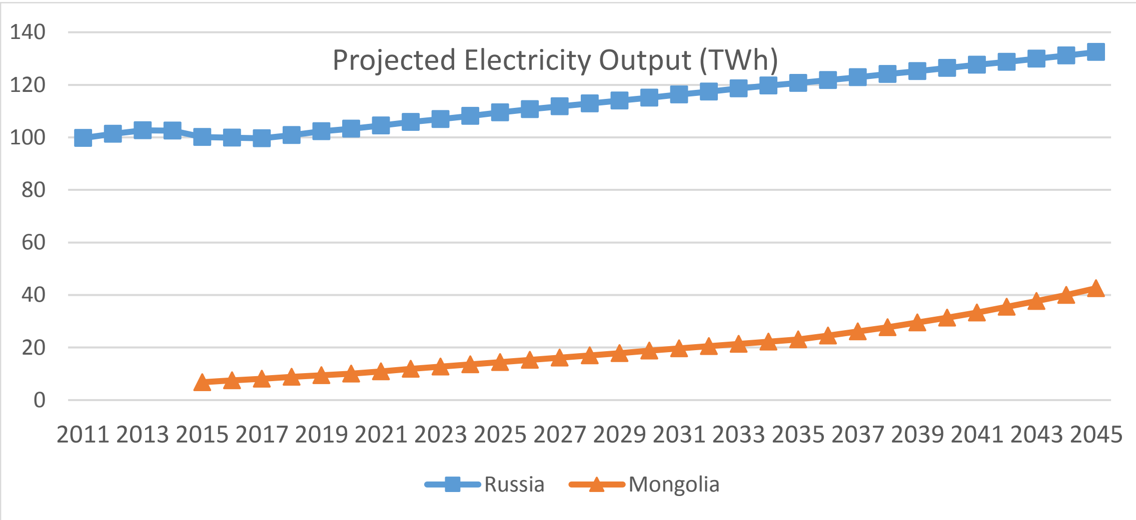
Figure 9: Projected Electricity Demand of China, Japan, and South Korea (TWh)



TWh = terawatt-hours.

Source: Economic Research Institute for ASEAN and East Asia.

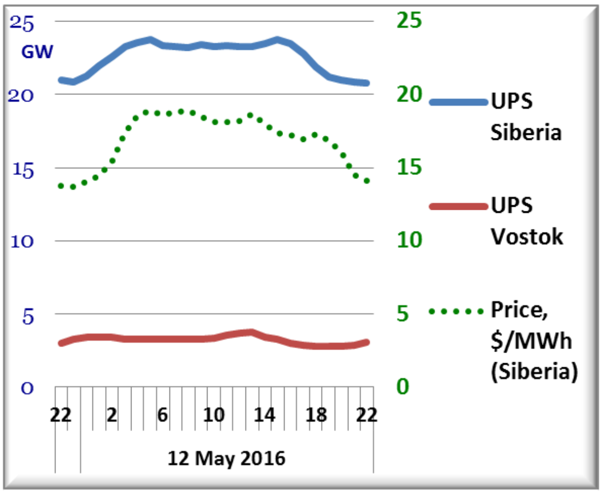
Figure 10: Projected Electricity Demand of Mongolia and Russia (TWh)



TWh = terawatt-hour.

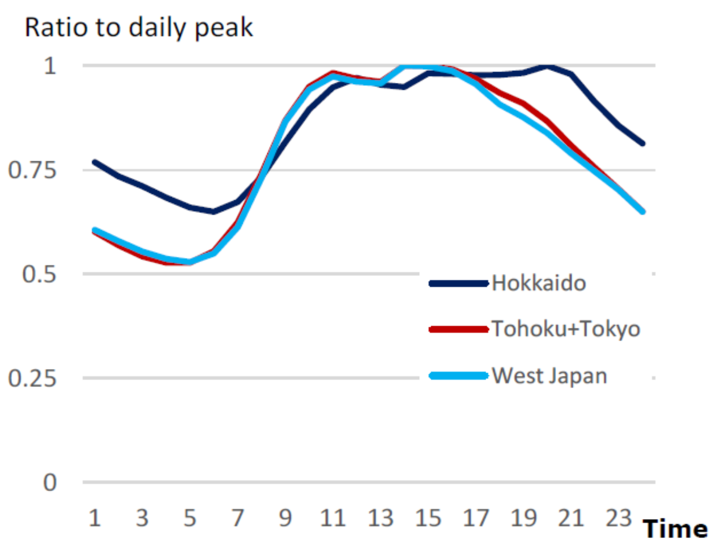
Source: Economic Research Institute for ASEAN and East Asia based on Energy Information Administration and Asian Development Bank data.

Figure 11: Hourly Consumption for UPS Siberia and UPS Vostok Prices in UPS Siberia



GW = gigawatt, MWh = megawatt-hour, UPS = uninterruptible power supply.
Source: ERIA Working Group.

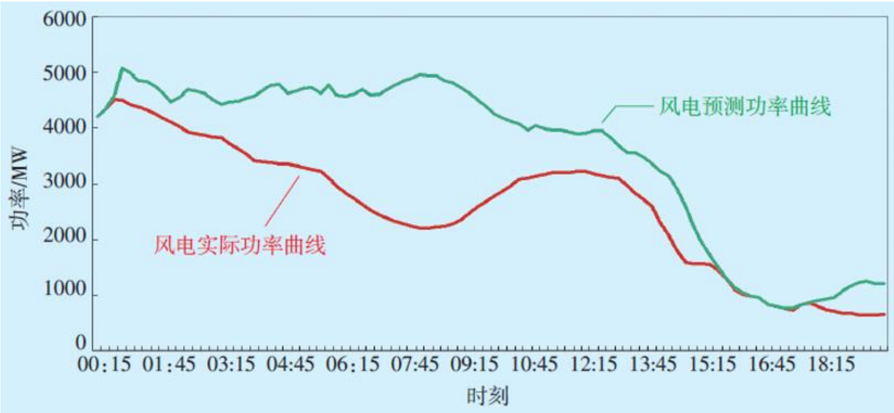
Figure 12: Typical Daily Load Curves during Summer in Japan



Source: ERIA Working Group.

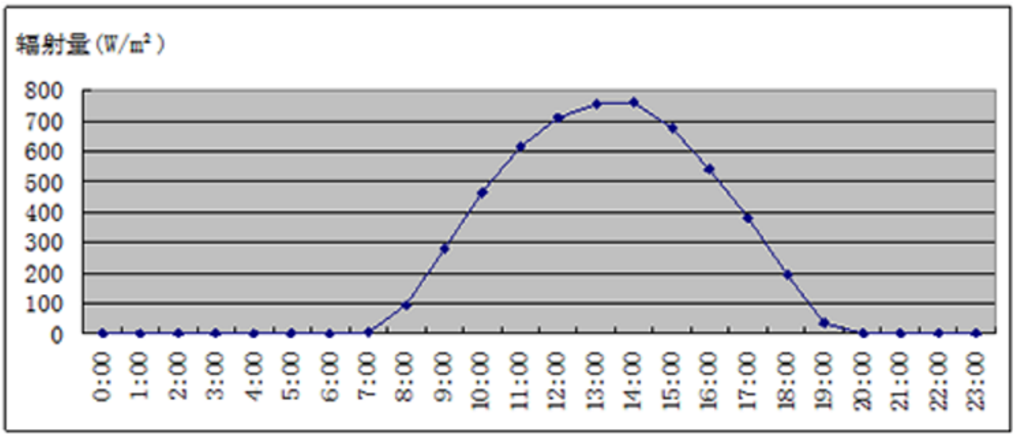
Second is availability of energy resources; daily and monthly patterns of changes in wind, solar, and hydro energy resources (Figures 13 and 14); costs of power generation of different technologies; and dynamics in the technological progresses in new and renewable energy.

Figure 13: Wind Generation Profile in Inner Mongolia*



* Vertical axis represents power in megawatts and horizontal axis represents the time of a day. Projected power profile is in green colour and actual power profile is in red colour.
Source: ERIA Working Group.

Figure 14: Solar Radiation Pattern in Baotou[a] in Summer



[a] City in Inner Mongolia.
Source: ERIA Working Group.

Third, the development of cross-border transmission capacity is imposed as constraints for the trade of electricity among NEA countries. The costs, losses, and financial viability of each transmission line are integrated into the model.

The value of transmission line should be determined by the cost of congestion in the grid and the idea of congestion charge is developed accordingly, which is the commercial value and the source of revenue of a transmission line in a competitive electricity market (Li and Chang, 2015). Figure 15 shows how the optimal amount of transmission capacity should be determined in a simplified case, which is a two-node electricity market.

The horizontal axis shows the power demanded in megawatts (MW) at nodes A and B, respectively, while the vertical axis shows the marginal cost of power generation in US$/megawatt-hour (MWh). Nodes A and B clearly have different levels of demand for power and different marginal cost curves of power generation. At node A, x MW of power is demanded, while at node B, y MW of power is demanded. Such renders different marginal costs of power at the two nodes, at levels corresponding to where points *a* and *b* are for nodes A and B, respectively.

If there is a transmission line to connect nodes A and B, node A could produce more than x MW and supply to node B at a lower marginal cost of power. If the transmission is free of cost, node A should supply as much as when its marginal cost of power is equal to that of node B at point e. This is known as the no congestion case. If transmission is costly, however, the optimal capacity of transmission is where the savings in the marginal cost (the difference between marginal cost of generation from node B and that from node A) is equal to the marginal cost of transmission capacity. Assuming that the marginal cost of transmission capacity is σ $/MWh, as shown in Figure 15, the optimal transmission capacity is determined at z MW.

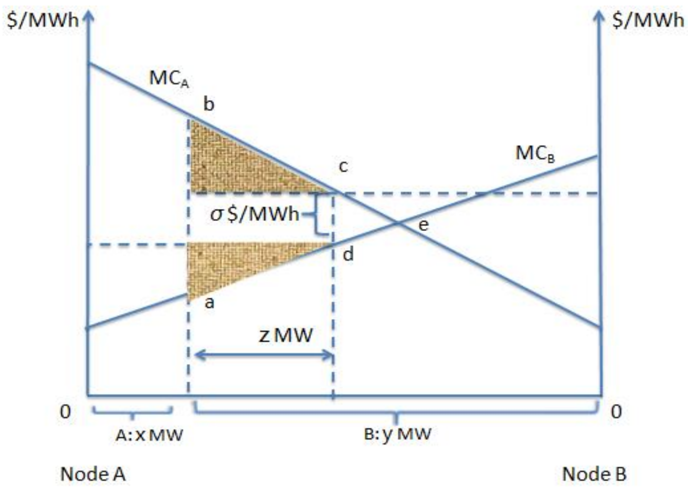
In this optimal case, σ $/MWh is equal to the congestion cost to the system and, therefore, the commercial value of the transmission line. In a competitive market, σ $/MWh should be charged accordingly for using the transmission line. The actual utilisation rate of the transmission line – which reflects how many MWh of electricity is transmitted – then determines if the investment in the transmission line could expect a reasonable return. This is usually where long-term, public–private partnership contracts come in to ensure the financial viability of the investment.

Such investments in the transmission capacity generate positive net savings to the system, which consists of nodes A and B. The savings are represented by the two shaded triangle areas in Figure 15. Such net savings prove the commercial viability of the new transmission line; otherwise, the line has no commercial value added and should not be built.

In a grid with multiple nodes, estimating the congestion cost is complicated and it is necessary to take a whole-grid/system approach. The network externality effect of new transmission lines further complicates the issue. This study takes a whole-grid/system approach in assessing the financial and commercial viability of new transmission projects with optimised pattern of power trade; the approach is also suitable for optimising the planning of new transmission capacities. First, the model integrates a 30-year-long contract for new transmission capacities, which ensures that the revenues collected over this period meet the commercial investors' requirement for a certain internal rate of return. Second, with costs of new transmission lines modelled as such, the system produces cost-minimisation planning for all power infrastructures – namely, power plants and cross-border transmission lines – to meet the growing demand for electricity in the region during the modelling period. Lastly, the minimised total system cost will be compared with the benchmark case where no new cross-border transmission line is built. Should the former be smaller than the latter, it means that net system savings resulted from the optimised planning for new cross-border transmission lines.

On net savings, recalling the simplified grid case as shown in Figure 15, power trade with the optimised planning of new transmission lines not only ensures investors' internal rate of return to be achieved but also delivers net system savings. This means that such a transmission investment plan stands both financially and commercially viable[2] as a whole. Should the net system savings be negative, it implies that the financial viability of the new projects with long-term contracts could not hold or be self-sustaining. This methodology is a major innovation and, thus, an important contribution to the literature. It enables a comprehensive assessment of financial viability of cross-border transmission investment plans from a systemic perspective.

Figure 15: Commercial Value of Transmission Line and Optimal Capacity

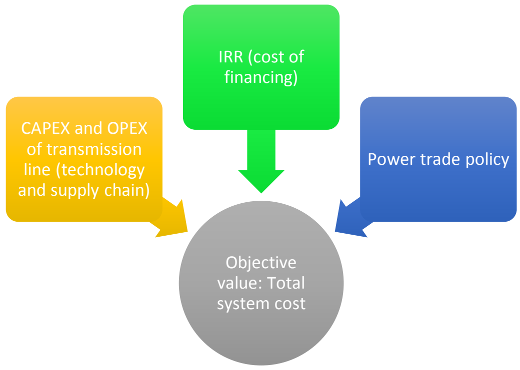


MC$_A$ = Marginal Cost at Node A, MC$_B$ = Marginal Cost at Node B, MW = megawatts, MWh = megawatt-hour.
Source: Li and Chang (2015).

[2] In other words, the new transmission lines have net commercial value, and the financial viability is not achieved at the expense of the total system but, in fact, by saving the total system costs.

Various policies are identified in the following subsections as key factors to the financial viability as shown in Figure 16. First, capital expenditure (CAPEX) and operating expenditure directly drive up the cost of transmission lines. Policies towards the introduction and absorption of new technologies could help reduce the cost. Other policies that help reduce lead time of the new transmission project by facilitating various logistics-related activities – such as project preparation, supply-chain coordination, construction, and grid connection – can also significantly reduce the cost of new transmission lines. Second, the financial costs of transmission line investments are very sensitive to the internal rate of return of investors, which in turn is sensitive to all project-related risks including market, technical, institutional, and political risks. Policies focusing on relieving these risks could help reduce the cost of transmission lines significantly. Third, power trade policies of countries in the region determine the demand for the import and export of power and the commercial value of the new transmission lines. In this study, such policies are modelled as the percentage of domestic power demand to be met through the trade of power with other countries.

Figure 16: Key Factors for Financial Viability of Cross-Border Transmission Lines



CAPEX = capital expenditure, IRR = internal rate of return, OPEC = operating expenditure.
Source: Li and Chang (2015).

Also in this study, scenarios were to be built where the cost of wind power, the solution and route of power grid interconnection, the financial cost of cross-border power transmission lines, and the cost of carbon vary to find under what circumstances the utilisation of renewable potential in the region, especially in Mongolia, could be maximised.

This study specifically models the power generation (from coal, diesel/ heavy fuel oil (HFO), natural gas, hydropower, small hydropower, geothermal, wind, solar PV, biomass, and nuclear) and transmission system, including cross-border transmission interconnection, of the five countries from 2013 to 2045. The model assumes that a regional carbon cost will start to be imposed on the power sector from 2020 in all NEA countries, reflecting the social cost of electricity and varying from US$1/ton to US$5/ton. The model also assumes that the cost of new renewable energy technologies – e.g. solar PV and wind power – will decline overtime while the operational cost, including fuel costs of conventional thermal such as coal, natural gas, and fuel oil generation will steadily increase overtime. More important, this model incorporates the intermittency and variation of solar PV and wind power through 24 hours in a day and four seasons in a year. The model thus optimises investment and utilisation of power infrastructure based on the optimal matching of intermittent renewable energy with the peak and non-peak demand of power through the day as well as through the season. The time difference between the five countries is also considered and modelled into the simulation. All cross-border transmission lines are assumed to apply heating, ventilating, and air conditioning (HVAC) technologies. Future studies could extend to include the option of HVDC.

Tables for the key data are presented in the appendix. It must be noted that due to lack of data inputs, wherever necessary, reasonable but still arbitrary assumptions have to be made. The research team looks forward to future research opportunities to improve the data and to deliver more solid analysis and accurate results.