Investigation into transmission options for cross-border power trading in ASEAN power grid

Tofael Ahmed, S. Mekhilef, Rakibuzzaman Shah, N. Mithulananthan

ABSTRACT

This work is a feasibility study of high voltage AC (HVAC) and high voltage DC (HVDC) transmission option for the Association of Southeast Asian Nations (ASEAN) Power Grid (APG) interconnections. An optimal power flow, a minimum-cost power generation model, is developed in the MATPOWER simulation platform to perform this analysis. Electricity generation and consumption data are taken from the latest power development plans of individual ASEAN countries for the evaluation of optimal cross-border power flow through the interconnections. Results show that APG can enhance power generation from countries with abundant renewable resources to meet the growing demand at load centers in the ASEAN member nations. An annual cost is used as the output matrix for this study. The analysis results reveal that in some interconnections, implementing HVDC link instead of currently planned HVAC could be economically beneficial for the APG. The findings in this paper would serve as valuable references for the APG planners.

1. Introduction

The member countries in the Association of Southeast Asian Nations (ASEAN) comprise the world’s third-fastest-growing economy (IEA, 2015a). Due to high economic growth, this region has a high growth rate in electricity demand in the world context. Meeting this growth rate in a techno-economic and sustainable way is challenging for the ASEAN nations (Chang and Li, 2015; IEA, 2015a). The interconnection of the proposed regional market in ASEAN region may contribute to meet this challenge in a secure, sustainable, and cost-effective way. Hence, the ASEAN Power Grid (APG) development is being implemented in ASEAN member countries (ACE, 2010; Ibrahim, 2014). APG may increase the access to energy resources by reducing the cost of the development of energy infrastructure. Moreover, it will enable the more economic power transfer from a power surplus region to a power deficit region. Furthermore, APG may reduce the overall operation cost of the generation system by reducing inefficient generation units. If APG is fully built, it can contribute towards the development of the geographically distributed variable renewable power generation capacity enhancement of ASEAN countries.

At present, ASEAN countries are generating power by prioritizing the affordability and availability of fuel types rather than the environmental sustainability. As a result, conventional energy sources, mainly oil, coal, and gas, are the dominant fuel mix, which contributed 82% of electricity generation in 2013 (IEA, 2015b). Nonetheless, this region is rich in renewable energy resources (RESs). The RESs of this region can be utilized for electricity generation. However, the geographical distribution of RESs limits their eventual utilization (Huber et al., 2015; Lidula et al., 2007; Taggart et al., 2012). Moreover, the lack of transmission facilities among the RESs and load centers is one of the major barriers to RESs utilization (Das and Ahlgren, 2010). Power generation from RESs can be promoted by APG, which in turn expedites cross-border trade and free movement of green electricity within the ASEAN region (Sambodo, 2013). To implement cross-border trade, a comprehensive investigation is sought, especially on technical, economic, and environmental issues during the interconnection of the power systems of individual countries.

Among the grid interconnection issues, selecting the transmission technology (i.e., HVAC and HVDC) is the most critical because a massive investment is associated with commissioning the long-distance regional transmission line. More advanced and robust planning of transmission grids is necessary for the justification of the investments and the efficient grid design during practical implementation (Ergun et al., 2012; Torbaghan et al., 2015).
HVDC transmission technology is becoming more attractive over AC technology because of the bulk power transferring capability from both onshore and offshore locations (ADB, 2014; Bahram and Johnson, 2007). Nonetheless, HVDC has some advantages such as cost-effectiveness, reduced size and weight, low power loss due to the use of two cables, reactive power management, and harmonics. Though, HVDC transmission options are commonly preferred for transmission systems above a certain distance, evaluation of the detailed cost and benefit when choosing transmission options is necessary because distance is not only the factor in selecting transmission options (Ahmed et al., 2017; Van Eeckhout et al., 2010; Wang et al., 2008).

Several studies evaluated the HVAC and HVDC transmission options in (Elliott et al., 2016; Hur, 2012; Meah and Ula, 2007; Sousa et al., 2012; Van Eeckhout, 2008; Van Eeckhout et al., 2010; Wang et al., 2008). However, most of the research focused on the transmission options for offshore wind power plants in Europe. Recently, a comparative study between HVAC and HVDC transmission options for connecting the offshore wind farm in Great Britain was presented by Elliott et al. (2016). The authors indicated that the HVDC option would be economically feasible than the HVAC in the large power transmission from the offshore wind farms.

Nevertheless, limited research on transmission expansion planning has been reported for the ASEAN context, in particular, for APG establishment. Developing optimal power generation to meet the growing power demand of ASEAN countries by prioritizing renewable generation integration was presented by Chang and Li (2013). The benefits of different amounts of cross-border electricity transmission by considering the macroeconomic data of power generation and transmission, as well as the cost of losses and emission pricing, were also discussed by Chang and Li (2015). However, the availability of renewable sources (e.g., solar and wind) and the feasibility of transmission options are not considered by Chang and Li (2013). The financial sustainability of interconnecting cross-border power system for the ASEAN+2 (China and India) was presented in the study of Li and Chang (2014), where the benefits of different amounts of cross-border power transmission were analyzed. Matsuo et al. (2015) conducted a quantitative assessment of a future APG (ASEAN + Yunnan Province of China + North East India) interconnection based on the optimum power generation planning model and the supply reliable evaluation model for 2010–2035. This study considered maximum peak power demand, power generation cost, transmission loss, and transmission cost for optimal design of APG. The cost and benefit of various interconnection routes interconnecting Vietnam, Lao PDR, and Thailand were analyzed in this study. However, this study only considered hydropower as a potential candidate for power exchange instead of optimal generation. Huber et al. (2015) proposed an optimal sustainable power system development for the ASEAN region by considering all possible renewable generation resources. Cost–benefit analysis for three specific routes of APG was conducted by Fukasawa et al. (2015). However, the comparison between HVAC and HVDC transmission options for the selected routes was not presented by Fukasawa et al. (2015). Operation and maintenance costs were also not considered for cost calculation. Another evaluation study was conducted by ADB (2014) for the Borneo and Mindanao power systems. ADB (2014) concluded that the HVDC transmission options are suitable for certain routes for this part of the APG; however, more evaluation studies are required.

Based on research gaps, this study aims to compare the HVAC and HVDC transmission options for the point-to-point transmission interconnections toward the development of APG for the 2030 generation and demand scenarios. This study also analyzes the ASEAN electricity transmission network and the future needs of additional cross-border power transmission for a low-cost generation by considering the available power generation options of individual countries. The APG model for the 2030 scenario was developed to evaluate the HVAC and HVDC options. However, the developed APG model characterizes the representative APG based on publicly available data for the ASEAN region. This work considers all the proposed potential routes projected in the ASEAN Interconnection Master Plan Study (ACE, 2010; Ibrahim, 2014). The developed APG network represents a minimum-cost power dispatch model for the ASEAN power transmission network, which was developed for analyzing HVAC and HVDC options.

The rest of this paper is organized as follows: Section 2 presents the methodology of APG modeling and the scenario assumptions. Section 3 presents results and discussions of economic feasibility between the HVDC and HVAC transmission options, as well as a sensitivity analysis on total annual costs and transmission distances. Section 4 summarizes the major conclusions, contributions, and implications of this work.

2. Methodology

2.1. Overview of the APG model

The APG model is developed here to analyze the economic characteristics of HVAC and HVDC connection options for all cross-border interconnections by considering the maximum requirements for cross-border transmission capacity under 2030 scenarios. This model also focused on minimum-cost power generation options to meet the growing electricity demand. Accordingly, all types of generation portfolios and maximum peak demands of 10 ASEAN countries are considered in this analysis. The variable generation costs of each type of generation are considered during the calculation of the optimal cross-border power flows among the interconnections. However, the model does not consider optimal cross-border transmission routes toward APG establishment.

The individual power transmission networks of APG are considered as a single node; the internal network constraints are not considered here. The reasons for this consideration are the lack of publicly available data (e.g., transmission line capacity, electricity consumption, and generation time series) on the entire ASEAN transmission network and the computational complexity associated with a large geographic transmission network. In addition, the unavailability of detailed demand and generation data for ASEAN countries compels the representation of large geographical countries, such as Myanmar, Thailand, Vietnam, and Laos, by only one single region in this model. Nevertheless, the results could give the idea about the future cross-border power transmission scenario for the ASEAN region to the investors and policy makers.

2.2. APG network

APG network is represented in this study by 15 nodes because of the presence of 15 isolated Transmission System Operators (TSOs) in the interconnection project. Myanmar, Thailand, Laos, Cambodia, Vietnam, Singapore, Brunei, and Philippines (i.e. Luzon grid) are represented by a single node. Malaysia is represented by three nodes, namely, Peninsular Malaysia, Sarawak, and Sabah. Indonesia is represented by four nodes, namely, Sumatra, Batam, W. Kalimantan, and E. Kalimantan. These 15 nodes are interconnected by cross-border transmission links (ACE, 2010; Ibrahim, 2014). In this model, no capacity limit is considered for the cross-border transmission links.

The transmission network is parameterized by publicly available data in the given transmission voltage level for the power flow and optimal power flow (OPF) modeling. The typical single-circuit reactance value used in this model is 0.31 Ω/km for 380 kV lines at 50 Hz during the DCOPF modeling (Say, 1973). Resistance and shunt admittance have been ignored in the DC power flow model for simplicity (Zhou and Bialek, 2005). Only distances of the cross-border interconnections are considered to model the APG (ADB, 2014; Energy Commission, 2016; Fukasawa et al., 2015). In countries where more
than one cross-border interconnection takes place, the longest distance among these interconnections are considered in the model. Table 1 presents the individual cross-border interconnection distances, which are considered during the modeling of APG network in this study.

### 2.3. Modeling of generation

Power generation from all types of conventional and non-conventional energy sources is considered for this study. Each type of source is represented by an aggregated equivalent power plant with the total net installed capacity of the respective node. However, the model divided the total installed capacity of all energy sources, except oil-based power generation plants, in a node into a single unit with a maximum rated capacity of 1000 MW. The rated capacity of 400 MW is considered for oil-based power plants. The reserve margins of each node are not modeled individually but are partly considered when setting up the minimum and maximum power output levels of individual generating units. Various operational constraints of the individual generating units have been considered following the studies of Hewes et al. (2016), Martinez-Anido et al. (2013), and Zhou and Bialek (2005). These operational constraints are explained in the following sections.

#### 2.3.1. Conventional generation

Coal is the largest contributor to the fuel mix because of its availability and low cost. It is anticipated that the coal will be contributing roughly 35.67% of the total installed capacity in 2030. A coal power plant has a high capital cost and low fuel cost. It has been considered as a base-load in the power plant in this model, and the output can vary at 70–100% of its available rated power. Natural gas is the second largest contributor to the fuel mix, and it will be contributing roughly 25.63% of the total installed capacity in 2030. Its power output is limited to 40–100% of its available capacity. By contrast, because of its high operating cost, an oil-based power plant is considered here as a peak-load in the power plant. Its output can vary between the minimum and maximum available capacities. The outputs of individual power plants are corrected by the availability factor of the respective type of power plant (Chang and Li, 2015). It should be noted that Vietnam has a plan to introduce a nuclear power plant. Given its high capital cost and low operational cost, a nuclear power plant is also considered as a base-load in the power plant. Its output can vary at 70–100% of its available rated power. The availability factor of nuclear energy is taken from World Nuclear Association (WNA, 2016). Table 2 summarizes the operational constraints of the individual power plants.

#### 2.3.2. Renewable generation

Hydropower is the most abundant and reliable renewable energy source in the ASEAN region and it will be contributing to about 26.63% of the installed capacity in 2030. Both large and small hydropower generators can have varying generation levels at 0–100% of the available generation capacity. Despite the high potential of solar and wind, ASEAN countries will have a small contribution of these types in power generation with a combined contribution of 4.66% of the installed capacity. Because of the weather dependency, 25% and 50% generation capacity are considered here for solar and wind power plant respectively. Furthermore, geothermal energy sources have a high potential in the Philippines and Indonesia. Therefore, the geothermal power plant is also included in the model and its output is considered to vary between the minimum and maximum available capacities. In addition, ASEAN countries have a great biomass potential. Biomass power plant output is constrained by the maximum available capacity in the model. Although biomass is cheaper than natural gas, it is not considered as a base-load in the power plant because of the limitations of its supply chain.

#### 2.4. Modeling of demand

The load demand of each node has a significant effect on OPF. Unfortunately, no publicly available data about the demand of each individual zone are available. Therefore, peak electricity demand of each node is considered as the load demand for this model.

#### 2.5. Modeling of the variable generation cost

The objective of this model is to maximize the social welfare or minimize the variable generation costs for the ASEAN countries by giving priority to cross-border transmission. Variable generation costs are the sum of the operation and maintenance costs and the fuel costs for individual electricity generation sources. The levelized variable generation cost of electricity for 2030 is calculated based on Chang and Li (2015), EIA (2015), Huber et al. (2015), IEA (2015b), NREL (2016), and Short et al. (1995), in which all assumptions are in 2014 US dollars. Operation and maintenance costs, lifetime, and capacity factor of the various power plants for the ASEAN region are presented in Table 3.

#### 2.6. Scenario data

Electricity generation and demand data for the 2030 scenario are taken from publicly available sources, mostly from the power development plans of TSOs. Scenarios with key considerations on the assumptions for the electricity installed capacity and demand of individual nodes are given in Table 4. Electricity installed capacity and demand data are presented in Table 5 by considering the scenarios in Table 4.

#### 2.7. Energy market simulation

To calculate the realistic cross-border transmission requirement of
the ASEAN countries for 2030 scenario, energy market simulation is incorporated into this model. The market simulation model is designed for the minimum cost of the ASEAN power generation model for the APG. Energy market simulation is conducted as an optimization problem according to MATPOWER’s OPF formulation in Zimmerman et al. (2011):

\[
\text{Minimize} f(x) \quad (1)
\]

Subject to

\[
g_p(x) \leq 0 \quad (2)
\]

\[
h(x) \leq 0 \quad (3)
\]

\[
x_{\min} \leq x \leq x_{\max} \quad (4)
\]

where; (1) is the total active power generation cost, and (2), (3), and (4) are the power balance equation, line power flow constraints, and optimization variable constraints respectively. As this optimization model is considered a DC OPF model, the optimization variables are reduced to (5) according to Zimmerman et al. (2011).

\[
x = \begin{bmatrix} \theta \\ P_g \end{bmatrix} \quad (5)
\]

In (5), \(\theta\) and \(P_g\) are the voltage angle and generator real power injection, respectively.

Based on the above discussion, the objective function of the OPF considers the polynomial cost functions of real power injections for each generator. Total active power generation cost in (1) can be written as shown in (6).

\[
\min \sum_{i \in \mathcal{G}} f_i' (p_i^g) = \min \sum_{i \in \mathcal{G}} (a_i p_i^g + b_i p_i^g + c_i) \quad (6)
\]

In (6), \(n_g\) is the number of generators in the system, \(f_i' (p_i^g)\) is the active power generation cost of generator \(i\), \(p_g\) is the active power injection, and \(a_i, b_i, c_i\) are the cost coefficient of generator \(i\).

The optimization is subject to the load balance in each node. So, power balance equality constraints of (2) can be represented as (7).

\[
F_{\min} \leq F(\theta) \leq F_{\max} \quad (7)
\]

In (7), \(F_{\min}\) and \(F_{\max}\) are the upper and lower power flow limits, and \(F(\theta)\) are the power flows in both positive and negative directions respectively.

Optimization variable constraints of (4) can be represented as (10) and (11).

\[
\theta_{i_{\min}} \leq \theta_i \leq \theta_{i_{\max}} \quad (10)
\]

\[
P_{g_{\min}} \leq P_g \leq P_{g_{\max}} \quad (11)
\]

where \(\theta_{i_{\min}}\) and \(\theta_{i_{\max}}\) are the upper and lower phase angle limits, \(\theta_i\) is the angle of generator \(i\), \(P_{g_{\min}}\) and \(P_{g_{\max}}\) are the upper and lower injection limits of node \(i\).

### Table 3

Levelized O & M cost for ASEAN countries (Chang and Li, 2015; EIA, 2015; Huber et al., 2015; IRENA, 2016; Short et al., 1995).

<table>
<thead>
<tr>
<th>Type</th>
<th>Total O &amp; M cost (USD/MWh)</th>
<th>Lifetime (Years)</th>
<th>Capacity Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal CCS</td>
<td>26.98</td>
<td>30</td>
<td>75</td>
</tr>
<tr>
<td>Coal</td>
<td>22.85</td>
<td>30</td>
<td>75</td>
</tr>
<tr>
<td>Gas OC</td>
<td>38.01</td>
<td>25</td>
<td>60</td>
</tr>
<tr>
<td>Gas OC</td>
<td>34.87</td>
<td>25</td>
<td>75</td>
</tr>
<tr>
<td>Oil</td>
<td>139.62</td>
<td>30</td>
<td>75</td>
</tr>
<tr>
<td>Advanced Nuclear</td>
<td>24.00</td>
<td>30</td>
<td>90</td>
</tr>
<tr>
<td>Hydro</td>
<td>29.05</td>
<td>35</td>
<td>33</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>31.47</td>
<td>35</td>
<td>33</td>
</tr>
<tr>
<td>PV</td>
<td>21.10</td>
<td>20</td>
<td>17.5</td>
</tr>
<tr>
<td>Wind</td>
<td>21.74</td>
<td>20</td>
<td>27</td>
</tr>
<tr>
<td>Geothermal</td>
<td>16.92</td>
<td>20</td>
<td>75</td>
</tr>
<tr>
<td>Biomass</td>
<td>17.55</td>
<td>30</td>
<td>75</td>
</tr>
</tbody>
</table>

### Table 4

Scenarios of electricity generation and demand for the ASEAN.

<table>
<thead>
<tr>
<th>Node</th>
<th>Key Considerations</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Myanmar</td>
<td>Least cost generation scenario.</td>
<td>(Nam et al., 2015)</td>
</tr>
<tr>
<td>Thiland</td>
<td></td>
<td>(Energy Policy and Planning Office, 2015)</td>
</tr>
<tr>
<td>Lao PDR</td>
<td></td>
<td>(EDL, 2013; Phonekeo, 2015)</td>
</tr>
<tr>
<td>Cambodia</td>
<td>The annual average power demand increment rate for 2025–2030 will be same as that for 2021–2024.</td>
<td>(Electricity Authority of Cambodia, 2015; ERIA, 2013; Ministry of IME, 2009)</td>
</tr>
<tr>
<td>Vietnam</td>
<td></td>
<td>(Hung, 2014; MOIT/GIZ, 2016)</td>
</tr>
<tr>
<td>Peninsular Malaysia</td>
<td>The coal and natural gas-based power generation increment rate for 2026–2030 will be the same as that for 2015–2025.</td>
<td>(ARES, 2015; Energy Commission, 2016; IRENA, 2014)</td>
</tr>
<tr>
<td>Sarawak</td>
<td>Less hydro and more solar and biomass will be developed due to low hydro potentials.</td>
<td>(Energy Commission, 2016)</td>
</tr>
<tr>
<td>Sumatra, Batam, West Kalimantan, East Kalimantan</td>
<td>The annual average generation and demand increment rate for 2025–2030 will be same as that for 2015–2024.</td>
<td>(RUPTL, 2015)</td>
</tr>
<tr>
<td>Brunei</td>
<td>Geothermal power development will be prioritized.</td>
<td>(A. Tabrani, 2015; APERC, 2012)</td>
</tr>
<tr>
<td>The Philippines (Luzon)</td>
<td>Single-cycle gas power plant will be converted to combined cycle with an efficiency of 45%.</td>
<td>(APERC, 2013; Asirit, 2012; Department of Energy, 2012; Tampinco, 2013)</td>
</tr>
</tbody>
</table>
and are the maximum and minimum allowable active power generation of generator $i$, and $P_{g}^{i}$ is the actual active power generation of generator $i$.

### 2.8. Economic appraisal to compare the HVDC and HVAC options

The comparison between HVDC and HVAC can be completed regarding the capital expenditure, including reactive compensation requirement and costs associated with maintenance and loss.

#### 2.8.1. Capital costs

Capital costs of HVAC transmission systems include transmission line costs and substation costs for either end of the interconnection, including all the necessary components and transformers. Also, the reactive compensation required by an HVAC transmission system to facilitate sufficient active power transmission. This reactive compensation has significant capital costs and usually considered for every 160 km-line length (Fukasawa et al., 2015).

The capital costs of HVDC systems are the AC–DC converter costs at either end of the interconnections and transmission line costs. The HVDC transmission system can be arranged either by a monopole (one AC–DC converter per end with two cables) or a bipolar (two AC–DC converters at each with three cables) (Callavik, 2013). The capital cost assumptions for HVAC and HVDC transmission systems are given in Tables 6 and 7, respectively, which are based on the values published in (Fukasawa et al., 2015). From the Tables 6 and 7, it can be seen that the transmission line costs are higher for HVAC comparing to HVDC transmission systems and AC – DC converter costs are higher for HVDC comparing with the substation costs of HVAC transmission system. However, the costs of the equipment depend upon market conditions, in particular, the price of the copper and semiconductor devices.

#### 2.8.2. Operation and maintenance costs

The lifetime cost of a transmission link contains a significant contribution from operational costs: energy losses in the system and maintenance costs. Losses in the AC transmission system primarily occur in cables although losses also occur within the substations. These losses are compensated by using additional generators. The cost associated with this is referred to as operational costs.

The active and reactive components of the cable are considered during cable loss calculation. Transmission cable capacitance is evenly distributed throughout the transmission line. It produces a specific amount of reactive power for each unit of length (Elliott et al., 2016). Transformer and reactive compensators also have losses that vary between 0.2% of the nominal power flow for the no-load condition and 0.6% of the nominal power flow for load-dependent elements (Brakelmann, 2003). The typical cable parameters considered in this study are the 500 kV ACSR cable (0.1275 Ω/km resistance, 0.0018 mF/km capacitance, and 0.17 A/km charging current) for the overhead lines and the 500 kV XLPE cable (0.0441 Ω/km resistance, 0.19 mF/km capacitance, and 17.6 A/km charging current) for the underground lines (Abb, 2010a; ACSR, 2013).

Losses in the HVDC transmission system depend on cable losses and AC–DC conversion losses. Cable losses are related to cable resistance and active power transmission. AC–DC conversion losses have fixed no-load components and proportional power flow components. The typical cable parameters considered in this study are the 320 kV ACSR cable (0.0266 Ω/km resistance) for overhead lines and the 320 kV XLPE cable (0.009 Ω/km resistance) for underground lines (Abb, 2010b; ACSR, 2013). The no-load components of the AC–DC conversion losses are considered 0.16% of the nominal power flow, and it can increase to 1.1% of the full load conditions for VSC–HVDC converters (Elliott et al., 2016; Torbaghan et al., 2015).

Maintenance costs also have a significant contribution to the

### Table 5


<table>
<thead>
<tr>
<th>Nodes</th>
<th>Installed generation capacity (GW)</th>
<th>Peak Demand (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Myanmar</td>
<td>5.03</td>
<td>14.54</td>
</tr>
<tr>
<td>Thailand</td>
<td>4.76</td>
<td>11.00</td>
</tr>
<tr>
<td>Laos</td>
<td>1.80</td>
<td>5.03</td>
</tr>
<tr>
<td>Cambodia</td>
<td>2.50</td>
<td>5.03</td>
</tr>
<tr>
<td>Vietnam</td>
<td>75.00</td>
<td>24.20</td>
</tr>
<tr>
<td>P. Malaysia</td>
<td>15.60</td>
<td>21.18</td>
</tr>
<tr>
<td>Singapore</td>
<td>14.97</td>
<td>11.00</td>
</tr>
<tr>
<td>Sumatra</td>
<td>14.97</td>
<td>18.00</td>
</tr>
<tr>
<td>Batam</td>
<td>14.97</td>
<td>5.00</td>
</tr>
<tr>
<td>Sarawak</td>
<td>1.98</td>
<td>5.00</td>
</tr>
<tr>
<td>W. Kalimantan</td>
<td>2.02</td>
<td>6.08</td>
</tr>
<tr>
<td>E. Kalimantan</td>
<td>4.30</td>
<td>11.94</td>
</tr>
<tr>
<td>Brunei</td>
<td>1.29</td>
<td>4.52</td>
</tr>
<tr>
<td>Sahah</td>
<td>1.66</td>
<td>2.15</td>
</tr>
<tr>
<td>The Philippines (Luzon)</td>
<td>7.88</td>
<td>16.48</td>
</tr>
</tbody>
</table>

### Table 6

Presumed capital cost for HVAC connections (Fukasawa et al., 2015).

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost (Million USD)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 kV overhead cable transmission lines</td>
<td>0.45/km/circuit</td>
<td>Maximum capacity 1.8 GW/circuit</td>
</tr>
<tr>
<td>500 kV submarine cable transmission lines</td>
<td>5/km/circuit</td>
<td>Maximum capacity 1.8 GW/circuit</td>
</tr>
<tr>
<td>Substations</td>
<td>20/occupation</td>
<td>Required for the other side of the transmission line</td>
</tr>
<tr>
<td>Substations equipment</td>
<td>10/circuit</td>
<td></td>
</tr>
<tr>
<td>Existing substation extension</td>
<td>10/circuit</td>
<td></td>
</tr>
<tr>
<td>Substations for reactive compensation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
lifetime operational cost of a transmission system. Therefore, maintenance costs are considered in calculating the operational cost through a lifetime. For both the HVAC and HVDC transmission lines, 1% of the annualized investment cost is considered the maintenance cost (Ergun et al., 2012). In addition, substations’ maintenance costs also have a significant contribution to the operational costs. 0.4% and 0.5% of the annualized investment cost is considered as the maintenance cost for HVAC and HVDC respectively (Bresesti et al., 2007).

3. Results and discussions

3.1. Energy market simulation results

Optimal cross-border power transmission for ASEAN region is shown in Fig. 1. The optimal cross-border power flowing through the APG system is also given in this figure. In Fig. 1, the arrows indicate the dominant power flow directions between the nodes. Power mainly flows from the nodes with a large generation capacity with low generation costs, and demand toward the nodes with high generation costs and demand. From the figure, Myanmar, Lao PDR, Cambodia, Sumatra (Indonesia), Batam (Indonesia), and Sarawak (Malaysia) are identified as the net exporter of electricity to the neighboring nodes because of the availability of low-cost generating resources (hydro-power and geothermal generations) compared to the load demand of the respective nodes. On the other hand, Thailand, Vietnam, P. Malaysia, Singapore, W. Kalimantan (Indonesia), E. Kalimantan, Brunei, Sabah (Malaysia), and Luzon (Philippines) are identified as the net importers of electricity given the lack of sufficient low-cost power generation sources to meet the demand. Thailand, P. Malaysia, Sarawak, and Sabah can become electricity transportation hubs in this region by transmitting electricity from low-cost-generating nodes to high-cost-generating nodes to meet the electricity demand through the APG system.

3.2. Economic comparison between HVDC and HVAC options

The annualized costs of each transmission technology are compared here. Therefore, lifetime costs are broken down over the expected lifetime of transmission lines. The lifetime of transmission lines is 30 years, and the capital recovery factor for this lifetime is calculated by considering 12% discount rate. The costs of the total annual energy losses during transmission are computed using the average estimated levelized O&M cost, which is 35.34 USD/MWh for this case (Chang and Li, 2015; Huber et al., 2015; IEA, 2015b; NREL, 2016; Short et al., 1995).

The comparison of annual costs for the cross-border interconnections for HVAC and HVDC transmission technologies is shown in Fig. 2. From Fig. 2, it is observed that the HVDC transmission systems are feasible for Myanmar-Thailand, Thailand-Laos, Thailand-Cambodia, Laos-Vietnam, P. Malaysia-Sumatra, P. Malaysia-Sarawak.
(Malaysia), Singapore-Sumatra, Sarawak (Malaysia)-W. Kalimantan, and Sabah (Malaysia)-Luzon (Philippines) due to low operation and maintenance costs for long-distance bulk power transmission. In addition, reactive compensation is needed for the HVAC, which requires more capital cost for long-distance power transmission. For the remaining interconnections, the HVAC option is more beneficial than the HVDC because of the small transmission distance involved in those interconnections, in which capital costs are higher for HVDC than HVAC. The comparison of annual costs due to energy losses during transmission is presented in Fig. 3. From Fig. 3, it can be seen that the HVDC transmission technology has smaller annual costs due to lower transmission loss and no reactive power, as well as minor reactive power compensation loss than the HVAC transmission technology. The annual cost for the HVAC transmission systems is US $1024 million more compared to the HVDC in the selected interconnections of APG. And, this is mainly due to the energy losses associated with the HVAC system. Therefore, in terms of energy efficiency, HVAC options are more suitable than the HVAC for those APG interconnections.

The breakdown of the total annual equivalent costs associated with the interconnection between Myanmar and Thailand for both HVAC and HVDC is shown in Fig. 4. From the results given in Fig. 4, it can be realized that the cost due to losses along transmission lines has the largest contribution to the total cost for the HVAC, while the cost due to HVDC converter investment is the largest for the HVDC; these costs are annual equivalent to US$330.12 million and US$ 323.57 million, respectively. Transmission line losses of HVAC account for 51.58%, and HVDC converter investment costs account for 55.41% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively (as presented in Table 8). From the table, it can be seen that the HVAC transmission line investment costs and the HVDC transmission line loss costs, which are 21.82% and 21.65%, respectively, are the second-largest contributor to the total costs. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC, which are 11.64% and 5.82%, respectively. The HVDC converter loss and the HVDC transmission line investment costs which are 10.13% and 9.53%, respectively, have a significant contribution in the HVDC case. The reduction of HVDC converter investment cost and HVDC converter loss can have a notable effect on the HVDC transmission. Future VSC-HVDC technology can achieve this by, for example, using multilevel VSCs instead of two-level converters to reduce converter loss (Elliott et al., 2016).

### 3.3 Sensitivity analysis

The results obtained in this paper are greatly dependent on system design, input assumptions, and requirements of the ASEAN countries. A different set of design and input assumptions could provide different results. For example, HVAC options are suitable for short distances and low power transfer because of their significantly low capital cost. However, HVAC systems have a higher loss than HVDC. Besides, if the HVDC converter cost could be reduced to an acceptable level, then the HVDC transmission option could economically compete with the HVAC for short distance. Another important variable that can significantly influence the final results is the actual distance of the power transmission. Only the distance of the interconnections between asynchronous grids is considered for calculating the annual cost for either HVAC or HVDC transmission option. Nevertheless, practical situations could be quite different. Sometimes, the generated power

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**Fig. 2.** Comparison of total annual costs of HVAC and HVDC of the interconnections.

**Fig. 3.** Comparison of total annual costs due to energy loss during transmission of HVAC and HVDC of the interconnections.
from one country to the load centers of another country is necessary to transfer by using neighboring countries’ power transmission infrastructure. In this case, power transmission distances are not only limited to the interconnections’ distances. For example, the OPF simulation result in Fig. 1 shows that the generated power from Myanmar, Lao PDR, and Cambodia needs to transfer to the high-demand load centers in Malaysia and Singapore through the transmission infrastructure of Thailand and Malaysia. Presently, the same types of multilateral cross-border power trade from Lao PDR to Singapore through the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project (LTMS-PIP) are being implemented in the ASEAN (APGCC, 2015). As a result, analyzing the feasibility of the transmission options for the interconnections among the asynchronous grids by varying the actual power transmission distances rather than using only the fixed interconnection distances is necessary. Thus, sensitivity analysis of the transmission options for the interconnections by varying the distances was conducted here for Myanmar–Thailand (01–02), Thailand–Cambodia (02–04), Thailand–Lao PDR (02–03), Cambodia–Vietnam (04–05), Thailand–P. Malaysia (02–06), and Sarawak–Sabah (10–14), and illustrated in Fig. 5.

From Fig. 5(a), and (b) it can be observed that the HVAC transmission systems initially have less annual costs compared to the HVDC transmission systems for the selected interconnections (i.e. Myanmar–Thailand (01–02), Thailand–Cambodia (02–04), Thailand–Lao PDR (02–03), Cambodia–Vietnam (04–05), Thailand–P. Malaysia (02–06), and Sarawak–Sabah (10–14). This is primarily due to the proportionally higher capital costs associated with HVDC systems and small transmission losses associated with HVAC system. In addition, from Fig. 5(a) and (b), it is evident that the total annual costs of HVAC transmission systems are increased higher than that of HVDC transmission systems with the increment of transmission distances. This is because of the higher operational and maintenance costs (especially costs of HVAC transmission losses and reactive compensation losses) associated with long distance HVAC transmission systems. Besides, capital costs also increased with the increment of length due to the reactive compensation requirement of HVAC system after certain distances. As a result, HVDC transmission systems are becoming preferable than HVAC systems with the increment of distances. Additionally, it can be observed that the cross-over distance at which HVDC connection is cheaper than HVAC occurs depending upon the amount of power transmission through the interconnections. Fig. 5(a) shows that the cross-over occurs roughly between 185 to 200 km
distance for the interconnections of Myanmar–Thailand, Thailand–Cambodia, and Thailand–Lao PDR. Moreover, Fig. 5(a) shows that the annual costs of HVAC systems are increased significantly after the cross-over distance. Annual costs of HVAC become nearly double than HVDC at a distance 500 km. From Fig. 5(b), it can also be seen that the cross-over occurs approximately between 170 to 190 km distance for the interconnections of Cambodia–Vietnam, Thailand–P. Malaysia, and Sarawak–Sabah and likewise, annual costs of HVAC become approximately double than HVDC at a distance 500 km. The aforementioned discussion shows that the HVDC transmission option becomes less expensive with increasing distance, especially in bulk power transmission. The sensitivity studies for other links have been conducted, however, not presented here due to the brevity.

In conclusion, the HVAC transmission costs are more sensitive to operational costs than the HVDC transmission system, especially to transmission losses. A number of additional factors can be considered in analyzing the sensitivity, such as omitting the metallic earth return for the HVDC transmission case and costs of STATCOM for controlling the voltage for the HVAC case. Considering these values can reduce the crossover or break-even distances at which HVDC becomes less expensive than HVAC.

4. Conclusions and policy implications

The economic characteristics of HVAC and HVDC transmission technologies are investigated in this study for ASEAN region. The results of this study can be utilized for cross-border transmission interconnection during the establishment of the APG. The minimum-cost power generation model is developed by considering the proposed APG network for the ASEAN region to calculate the optimal cross-border electricity flows among 15 nodes of 10 countries in the ASEAN for the 2030 power generation and demand.

Energy market simulation results show that the electricity demand of ASEAN countries can be supplied from minimum-cost power generators through the APG to promote renewable power generation in the ASEAN region. Case studies indicate that the nodes with abundant renewable potentials (especially hydropower and geothermal) in Myanmar, Lao PDR, Cambodia, Sumatra (Indonesia), Batam (Indonesia), and Sarawak (Malaysia) can significantly contribute to the cross-border power export through the APG. In addition, countries such as Vietnam, Thailand, P. Malaysia, Singapore, Sabah (Malaysia), and Luzon (Philippines), which have a high demand with a small low-cost and renewable generation potential, can become importing and exporting hubs in the ASEAN region.

Apart from the OPF model development, analysis of economic characteristics using either technology (i.e. HVAC and HVDC) to interconnect the individual power systems of ASEAN countries is conducted. In the economic analysis, the cost of necessary equipment of either technology is considered according to relevant standards, such as reactive compensation for HVAC transmissions. Capital and operational costs are considered for both technologies to show a comparison. The analysis shows that HVDC options have significant capital costs for the VSCs, while the HVAC options have subsequently higher costs due to energy losses in transmission. These two aspects are combined to

Fig. 5. Total annual costs of HVAC and HVDC technology for different transmission distances, (a) Myanmar – Thailand, Thailand – Cambodia, and Thailand – Lao PDR, (b) Cambodia – Vietnam, Thailand – P. Malaysia, and Sarawak – Sabah.
compare the annual costs for the specified interconnection distances. The low cost HVDC transmission options is found for Myanmar–Thailand, Thailand–Laos, Thailand–Cambodia, Laos–Vietnam, P. Malaysia–Sumatra, P. Malaysia–Sarawak (Malaysia), Singapore–Sumatra, Sarawak (Malaysia)–W. Kalimantan, and Sabah (Malaysia)–Luzon (Philippines).

Furthermore, transmission distance greatly affects the annual costs of the two transmission options. Sensitivity analysis of the annual costs is conducted by varying the transmission distances to find the cross-over distance, where the annual costs of HVDC become less expensive than those of the HVAC options for some power importing and exporting hub interconnections). Sensitivity analysis shows that the cross-over between the annual costs of using HVAC and HVDC occurs when the distance is greater than 160 km. Thus, the more the capacity utilization of the HVDC transmission link is, the lesser the VSC cost, which in turns shortens the cross-over distances of HVDC than HVAC. In addition, the utilization of multi-level VSCs for the HVDC converter station and removing the metallic earth return conductor for the HVDC transmission can also shorten cross-over distances. The approximate cost of 150 million USD/GW/location for the AC–DC converter or 20 million USD/GW/location for the substation is considered in this study because of the lack of cost terms for the ASEAN context. Specific cost consideration of individual elements rather than approximate cost considerations can give more accurate results and enable the reporting of the cross-over of HVDC in short distances.

This study gives a preliminary outcome that needs to be analyzed for in-depth techno-economic assessments. This result can help policy makers, investors and transmission system planners in designing the APG in the ASEAN region. Key policy implications that can be drawn from this study are follows:

1. From an environmental perspective, the optimal power flow result shows that APG is expected to promote renewable power generation in the ASEAN region. Free movement of electricity through APG could expedite the electricity generation from hydro resources in Myanmar, Lao PDR, Cambodia, Batam (Indonesia), and Sarawak (Malaysia) and additional geothermal resources in Sumatra (Indonesia). This in turns can promote an environment friendly generation mix in the ASEAN.

2. Abundant renewable (especially hydropower and geothermal) potential regions like Myanmar, Lao PDR, Cambodia, Sumatra (Indonesia), Batam (Indonesia), and Sarawak (Malaysia) could become the net exporter of electricity in the region. Conversely, high electricity demand region like Vietnam, Thailand, P. Malaysia, Singapore, Sabah (Malaysia), and Luzon (Philippines) could be net importer in meeting their electricity demand. In addition, Thailand, P. Malaysia, Sarawak (Malaysia), and Sabah (Malaysia) could act like power transportation hubs in the ASEAN region.

3. Economic comparison results between HVAC and HVDC transmission technology demonstrate that HVDC transmission options are feasible for transferring bulk power for 2030 generation and demand scenarios. HVDC transmission technology have more economic benefit in the form of total annual cost reductions, especially, for interconnections of Myanmar–Thailand, Thailand–Laos, Thailand–Cambodia, Laos–Vietnam, P. Malaysia–Sumatra, P. Malaysia–Sarawak (Malaysia), Singapore–Sumatra, Sarawak (Malaysia)–W. Kalimantan, and Sabah (Malaysia)–Luzon (Philippines). In addition, the results show that HVDC transmission technology exhibits less transmission losses than HVAC technology. Therefore, HVDC options are more suitable over HVAC for these APG interconnections in terms of energy efficiency for 2030 scenarios. APG may need to go a long way to reach the level of bulk power transferring of 2030 scenarios in the study, however, this study shows that HVDC is more beneficial than HVAC during establishing APG. Therefore, the stakeholders of ASEAN Power Utilities / Authorities (HAPUA) should investigate more to select the transmission options during integrating regional electricity market through APG.

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