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Full-length article

Power system decarbonisation with Global Energy Interconnection – a case study on the economic viability of international transmission network in Australasia

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Abstract: The electric energy system in Indonesia is undergoing with the challenges of fast-increasing electricity demand, carbon constraints, and rising costs. Using our model of the Australian and Indonesian electrical grids (either separately or interconnected) that incorporates operational flexibility in capacity expansion planning, we first show that meeting the projected demand for Java and Bali—the main Indonesian grid, with 100% locally integrated renewables by 2050 would be challenging. However, a submarine high-voltage DC (HVDC) link connecting Indonesia's Java-Bali power grid to the Australian National Electricity Market (NEM) grid through the Northern Territory would help alleviate this situation, given Australia's abundant renewable energy resources. Then, our model reveals that the Australian NEM could also profit from additional renewables if connected to the Northern Territory through a ground HVDC transmission line to gather intermittent wind and solar generation, which would be curtailed otherwise if unused by Indonesia through the submarine link. Despite the expensiveness of long HVDC links, the wholesale electricity cost of the integrated 100% renewable Australasia power system could be reduced by over 16%, from $AUD177/MWh with only local renewables to $AUD148/MWh with integrated HVDC transmission. The model retrieved the optimal international HVDC link with capacity of 43.8 GW, and the optimal regional HVDC transmission line with a capacity of 5.5 GW. To the best of our knowledge, this is the first detailed model on power system decarbonisation planning for both Australian NEM and Indonesian Java-Bali power grid considering HVDC interconnections.

Keywords: Decarbonisation, Climate change mitigation, HVDC, Grid interconnection.

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1 Introduction

In this paper, Australian dollars are used and an exchange rate of AUD$1.00 = USD$0.74 is assumed.

Concerns over climate change and related environmental issues continues to grow. According to the IPCC AR5 [2], if GHG emissions continue along "business as usual" trends, the world will overshoot its carbon budget (the volume of greenhouse gases that can be emitted while maintaining a likely chance of keeping the global average temperature increase to 2 °C) in around 30 years. This is likely to expose global communities to increasing sea level rise, extreme weather, forest fires, drought, and other global warming induced consequences [2]. The IPCC AR5's Working Group III [3] report on climate change mitigation suggests that to avoid a global temperature increase of more than 2 °C, ambitious global greenhouse gas emission cuts are needed in the order of 40% to 70% below 2010 levels by 2050. Both the IPCC AR5 Working Group III [3] and the International Energy Agency's World Energy Outlook [4] highlight the fact that decarbonizing electricity generation is key for cost-effective climate change mitigation.

The electric power system the world over must undergo a fundamental transformation to achieve decarbonisation. In Australia, multiple studies [5-8] have demonstrated the feasibility of 100% renewable generation replacing the conventional fossil-fuel power plants serving regional or national electricity demand. For instance, the Australian Energy Market Operator (AEMO) conducted a 100% renewables modeling study for 2030 and 2050, showing the feasibility for the National Electricity Market (NEM) to operate entirely on renewable energy sources while satisfying its current reliability constraints [8]. Whereas for Indonesia, operating with a 100% renewable system would be challenging [9, 10] due to the limitations on resources availability and the required land areas for installations.

Australia has abundant solar and wind resources, but their best locations are usually remote, far away from the major demand centers. To use these abundant resources, a very long transmission extension and system upgrade will be necessary. However, whether this approach is cost-effective against using lesser resources closer to demand centers remains an open question. Consequently, a system-wide co-optimization is desirable for simultaneously assessing the generation and transmission systems within one planning framework to achieve power system decarbonization. Although such approach is usually studied within regional and national boundaries, in this study we considered extending the Australian power grid to Indonesia to test the feasibility of this international HVDC interconnection.

Power generation in Australia and Indonesia is currently dominated by coal. According to the Perusahaan Listrik Negara (PLN, the only state owned electric company in Indonesia) Statistics 2015 [11], the total installed generation capacity in Indonesia is approximate 53 GW with 36.9 GW (70%) corresponding to the interconnected Java-Bali system. In addition, most of the generation capacity is fossil-fuel based, whereas the installed renewable capacity represents only 7.4% of the generation. As for Australia, the NEM has similar size with its Indonesian counterpart in generation capacity but with about 14% of the annual generation from renewable sources [12]. The NEM interconnects five regional market jurisdictions – Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA), and Tasmania (TAS).

In this paper we present a set of scenarios for the future Australian and Indonesian electricity sectors with a particular focus on interconnections between the NEM and Java-Bali grids (shown by the red dashed lines in Fig. 1) as the first stage of our study on a series of possible interconnection routes (shown by the black dashed lines in Fig. 1) in the Australasian area.

We use models of the two systems separately with a business as usual (BAU) and high-emission abatement target for Indonesia. Then, we consider an HVDC interconnection between the two countries. The models include the cost of the HVDC link to determine economic feasibility. We found that when a 100% emission abatement target is applied to Indonesia, the HVDC link is justified and reduces the cost of electricity compared to the scenario without the link.

2 Methods

2.1 Problem statement

We formulate the power system model as a least-cost optimization aiming to investigate the lower bound of the required electricity infrastructure for Australia and Indonesia in one planning framework. The model minimizes the total present costs of electricity generation from 2015 to 2050 subject to reliability, operational, and emission constraints, etc. The major mathematical formulations are shown in Appendix A; the rest operational and capacity transitioning constraints, etc. can be found from [6]. Both power systems are envisaged to be interconnected with two HVDC links, a submarine HVDC cable connecting the Java–Bali grid to Northern Territory to exploit the abundant Australia's inland wind and solar resources, and a ground HVDC cable connecting Northern Territory to Queensland, where the nearest NEM grid is located. We conducted the capacity expansion study for this Australasian power system considering a 23-node transmission network comprising the Australian NEM grid (modelled in 21 nodes by ROAM Consulting), one Central Northern Territory (CNT) node and one Java-Bali node (JVA) illustrated in Fig. 1. To be specific, the ROAM network model is a 21-node, 27-line model of the NEM, described in the ROAM report to the Australian Energy Market Commission transmission frameworks review [13], contains details of the validation of the model with respect to more detailed models, and the calculation of the line flow limits, which are chosen to represent thermal and security constraint limits. This network model is based on the 16 nodal zones in the National Transmission Network Development Planning (NTNDP) report [14] by the Australian Energy Market Operator. In this study we have extended the model to include another two nodes representing Central Northern Territory and Java-Bali respectively with HVDC interconnector options. We modelled CNT as one node since there are no existing transmission facilities. For Java-Bali, the geographic span is relatively small, so we treated it as a single demand node as well.

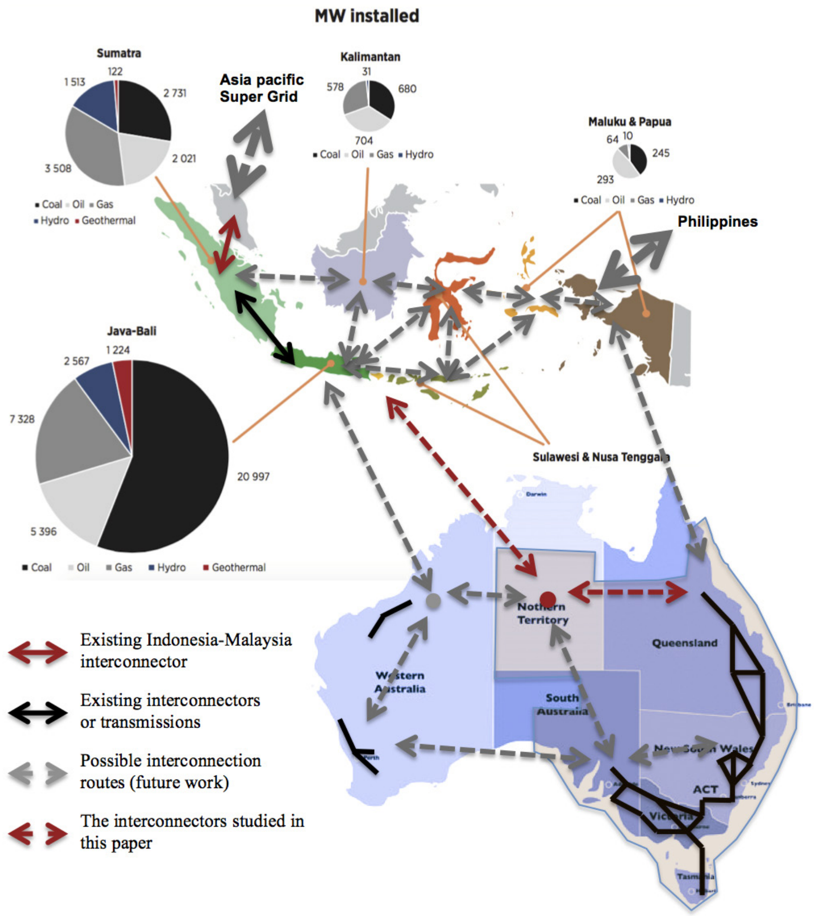

Fig. 1 Schematic of the Australian National Energy Market (NEM) transmission network (solid black lines in the eastern states).

The dashed lines in red show the interconnectors studied in this paper as the first stage of our study on a series of possible interconnection routes (shown by the dashed lines in black) in the Australasian area.

Pie charts show the current installed capacity in Indonesia (MW).

The Schematic for the Indonesian power system is taken from [1] with modifications to accommodate Australia's NEM grid modeled in 21 nodes. The potential power generation by the renewable resources in the shaded areas (55 locations) covering the eastern continent on the Australian map are assessed in this project. For Java-Bali, 6 locations are assessed.

In addition, we define linear carbon emission abatement trajectories to achieve 100% reduction for both NEM and Java-Bali system as shown in Fig. 2. For the NEM, we always consider the 100% emission abatement target but vary the emission target for Indonesia between the BAU case and 100% emission abatement target in different scenarios. Future work will be devoted to investigate the sensitivity of a broader range of targets for Indonesia (i.e., no abatement, 50% abatement, and emission intensity targets).

The 100% abatement for the NEM is reasonable because Australia should commit to at least 80% of the total emission abatement by 2050 following the policy adopted by the major political parties.Then, as a deep abatement will be less expensive in the electricity sector than in the

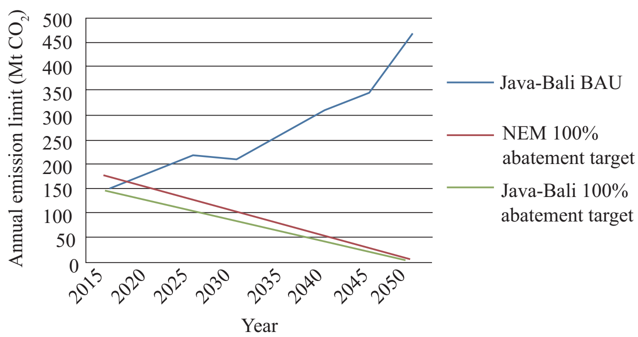

Fig. 2 Emission trajectories for the two emission abatement targets

The blue line shows the business as usual scenario of Indonesia, while the green line shows the trajectory for a 100% emission abatement target by 2050. In all scenarios, we use a 100% emission abatement target for Australia (red).

transportation, industrial, and agricultural sectors, a larger share of abatement is expected to be taken up by the electricity sector.

Summary of the scenarios simulated:

- NEM 100% abatement target and Java–Bali BAU case
  - with (**scenario 1**) and
  - without HVDC connections (**scenario 2**)
- NEM and Java–Bali 100% abatement target
  - with (**scenario 3)** and
  - without HVDC connections (**scenario 4**)

2.2 Demand forecast for NEM and Java-Bali power systems

Demand forecast for the NEM up to 2050 are calculated using the mean forecasted annual growth rate from 2015 to 2030 (data for 2030 – 2050 is unavailable) published in the National Energy Forecasting Report (NEFR) [15, 16] by the Australian Energy Market Operator (AEMO) for both the maximum demand and the annual energy generation. These yearly forecasts are translated into hourly values to the 21 NEM demand nodes for each future year using historical demand data from the reference year 2013.

For Java-Bali, according to the RUPTL estimates [17], the annual demand growth rate from 2016 to 2030 will be 6.8–7.5%. Based on this trend, the total demand increase will be tenfold by 2050. If we assume strict emission constraints, it is reasonable to expect that the energy intensity of the economy will improve, and the growth in energy demand will be curtailed. Therefore, we have empirically set an annual energy demand growth rate of 5%. Even under this limited growth, meeting this demand only with renewables (and without the HVDC connection to Australia) would be cost prohibitive for Indonesia.

2.3 Technical information on generating plants

The information for the existing NEM generation units such as capacity, emission factors, expected decommissioning dates, etc. shown Table B1 and B2 in Appendix B are obtained from AEMO's annual NTNDP report [14]. For all newly built thermal plants, we consider the thermal efficiency and combustion emission intensity provided by the Australian Energy Technology Assessment (AETA) [16].

We used the Black and Veatch report [18] for estimating each thermal plant's minimum stable generation level. For simplicity, all dispatchable plants are assumed to have a 5% forced outage rate, and planned outages are not explicitly modelled. Detailed assumptions can be found from our previous modelling formulation paper [6].

For Java-Bali, the current generation capacities and types are obtained from the PLN Statistics report [11]. Given the unavailability of information on existing generators, we assumed all the current existing coal and gas generators will reach their service lifetime and be decommissioned by 2040. Our assumption for the existing gas generators is fair as they are unlikely to keep operating after the next 20 years (given a typical service lifetime of 20-25 years) beyond 2040. As for the coal generators, because of the high demand projection and a zero-emission constraint, existing coal generators will play a diminishing role in the high renewable scenario and become negligible approaching to 2050 with 0 emissions as can be seen from Fig. 5 – the generation from exiting coal generators even becomes negligible after 2030 (before they are fully decommissioned by 2040). In addition, we modelled the unit commitment and ramping features of the coal generators; the inability of load following in a system with high renewable penetrations will put them in a jeopardised position to keep operating.

2.4 Transmission costs

Table C1 in Appendix C shows the costs of HVDC transmission cables used in this modelling exercise, taken from [19]. The distance between Central Northern Territory (CNT) and Java via Darwin is around 2900 km. The table shows that a 2000 km HVDC submarine line plus a 900 km on-ground HVDC line would cost around $AUD4.0B/GW of capacity. The model retrieves an approximate capacity of 43 GW for the HVDC link, and consequently the line would cost approximately $AUD170B. We have applied an arbitrary limit of adding 20 GW of HVDC per 5-year period, and the model fully utilises this limit in both 2045 and 2050 for scenario 4. Future work will consider the impacts of relaxing this constraint.

2.5 Financial information on generating plant and fuel costs

The AETA [16] provides data on the capital costs (capex), fixed and variable operating and maintenance costs (FOM and VOM) (shown in Table B1 and B2) and fuel costs for various new build utility-scale electricity generation technologies from now to 2050 in the Australian context. This includes estimates of learning rates for the capex of each generating technology considered, and escalation rates for the FOM and the VOM for each 5-year period. The value of lost load was set to be $13,100/MWh in accordance with the current NEM price cap [14]. In contrast, for Indonesia, those generating plant financial assumptions (i.e. capex, FOM and VOM shown in Table B1 and B2) and fuel cost projections (shown in Table C2) are obtained from the Indonesia Energy Outlook 2016 [20] by Indonesia's National Energy Board. All the costs were converted into Australian dollars.

2.6 Renewable resource estimates

In the AEMO's 100% renewables study [8], the eastern region of Australia was segmented into 42 zones. We used the same zonal configurations for this study. In each renewable zone, hour-by-hour time series for hypothetical 1 MW capacity wind, CSP (concentrating solar power) and solar photovoltaic (solar PV) power plants were calculated based on the weather model data from the Australian Federal Government's Bureau of Meteorology.

For CNT, we considered 12 locations covering all the possible weather patterns of the Northern Territory of Australia, the wind and solar potential generation data for these locations are obtained from [21, 22], which convert the NASA MERRA 2 weather data into wind and PV power traces. For Java-Bali, we divided the Java Island into 6 regions with each region the weather converted power traces for wind and solar PV were obtained from the same source.

The renewable resource potential for geothermal, biomass and hydropower in Java-Bali area (shown in Table 1) was obtained from the Indonesian Ministry of Energy and Mineral Resources [23] and set as capacity caps in the optimisation model.

Table 1 Estimated renewable energy potential in Java and Bali regions [23]

Resource	Potential (MW)
Geothermal	10,149
Biomass	9,215
Hydro (incl. mini hydro)	12,272

We deliberately did not put a constraint on the maximum capacity that can be built for solar PV, wind, CSP, and off-river PHES for both Java-Bali and Australia. For Java-Bali, this results in deployment of PV that is probably unfeasibly large given the land area required. However, the unlimited PV potential is required to find a feasible solution to the optimisation problem of how to meet demand without the HVDC interconnector. When the interconnector options are switched on, whether or not to build the expensive submarine HVDC link is purely based on resource quality (not availability) and economic competitiveness of renewables between the two countries. Still, further research is required to estimate realistic limits of wind and PV generation in Indonesia.

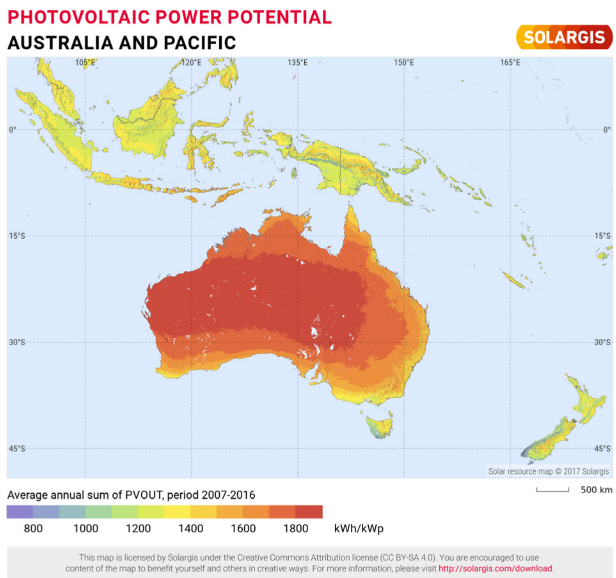

Fig. 3 Photovoltaic power potential for Australia and Indonesia from SOLARGIS

Comparing renewable resources in other Indonesian islands, as shown in Fig. 3, the solar resources in Kalimantan, Sumatra, and Sulawesi, etc. are even inferior to that in Java-Bali. Similar situations apply to the wind resources. However, in this paper we did not take into account the import/export options between Java-Bali and the other Indonesian islands. This clearly constitutes the second stage of our study on the series of possible interconnection routes in the future work.

2.7 Off-river PHES

Pumped hydro energy storage (PHES) is the most cost effective way of storing large amounts of energy for an electricity grid, and is currently the dominant form of energy storage used globally, with around 96% of the market share [24]. With the support of the Australia-Indonesia Centre, researchers from the Australian National University have identified 657 potential sites across Bali for off-river pumped hydro energy storage, with a combined potential storage capacity of 2 TWh [25]. They argue this is more than enough to support a 100% renewable electricity system for the whole Indonesia [25]. We have included this off-river PHES technology into the capacity expansion study for Java-Bali. The capital cost of PHES in our model is assumed to be $AUD3726 from the Indonesia Energy outlook [10, 20] based on estimates specifically for Indonesia. Other estimates suggest the costs could be lower [5]. Future work will consider the sensitivity of the results to these cost assumptions.

2.8 Implementation of optimisation

The optimisation is run over 35 years from the 1st of January 2015 to the 31st of December 2050. In order to make the simulation computationally manageable, the model has a 5-year time step for each periodic decision to be made, and each year is comprised of 28 representative days modelled at hourly resolution, i.e. 672 hours per annum. These representative days always include the summer and winter days of peak demand, with the other days sampled from different months reflecting the seasonal variability from the 2013 reference year. Hourly data for both the potential output from wind and solar (based on meteorologically data) and demand in a given year are used, with the demand scaled by the projected annual growth rate. The optimisation then expects that each modelled year is repeated for all 5 years of a given time step. For the end-of-horizon handling, the final year is assumed to repeat indefinitely, i.e. perpetuity is applied to all costs in that year. Detailed explanation on the implantation of optimisation can be found from our modelling formulation paper [6].

The linear program is implemented in Python using Gurobi – the state-of-the-art commercial solver with the barrier algorithm. There are multiple millions of variables and constraints. The model is solved on a 24-core, 80 GB memory machine running Linux, with each run taking 5-8 h.

3 Results

The results from the modelling scenarios show that for both scenarios one and two, when the emission abatement target for Indonesia is BAU, the cheapest option is to provide all demand in Java-Bali with domestic fossil fuel, primarily coal and gas. No HVDC interconnectors are built. The model optimisation selects a mix of coal, open cycle (OCGT) and combined cycle gas turbines (CCGT), with the mix determined by the ramping requirements of the three technologies (Fig. 5 - JVA 2050) in addition to the capital and operational costs.

For the NEM, with the abatement target of 100%, all fossil fuel generation is retired by the end of the simulation. The bulk of the electricity generation is provided by wind turbines as shown in Fig. 4. The model finds that with strategic placement of the wind farms throughout the NEM, the variability in aggregate output is minimised. Solar PV are also generously deployed, and to help balance the load; PHES is used to store a significant portion of the solar power generated during the day and dispatches it in the evening (Fig. 5) to ensure demand is always met. Note that the inertia constraints are met through both the generation and storage modes of the pumped hydro system. The wholesale electricity cost for scenarios 1 (and 2) ranges from $AUD 50-80 from 2020 to 2050.

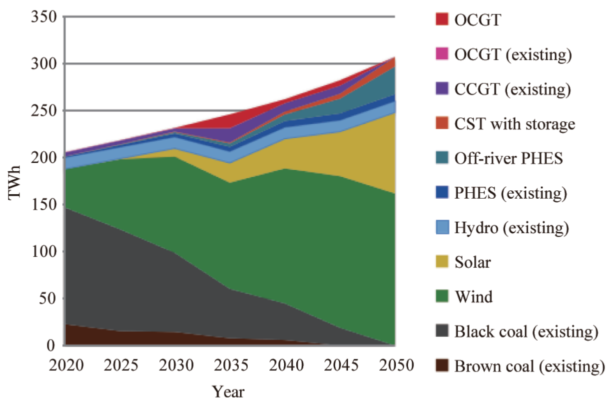

Fig. 4 Time evolution of electricity generation (TWh) for Australian NEM with 100% abatement target

For scenarios 3 and 4, the emission abatement target for Indonesia was also set to 100%, and we first simulated the systems separately, and secondly with a submarine HVDC interconnection (the option for the on-ground HVDC line connecting the NEM to CNT in Australia was always active). The capacity of the HVDC interconnection was also determined by the optimisation. The results show that for the case of no submarine interconnection and 100% abatement for Indonesia (Fig. 6), there are significant challenges for Java-Bali to meet its domestic demand. Large amounts of wind and solar power should be built to meet demand, but a large amount of power would be curtailed during low demand periods. The lack of high quality resources and a broad geographic range to smooth the output of the variable renewables makes the 100% abatement exercise very costly, with the levelized cost of energy (LCOE) in 2050 for this pre-defined Australasia power system (as two disconnected systems in scenario 3) calculated at $AUD177/MWh. This cost of electricity is unlikely to be acceptable. The construction of the on-ground HVDC (connecting NEM to CNT) in the Scenario 3 settings was also found to be economically unattractive and more costly than the locally integrated renewables from the 42 NEM zones.

In scenario 4, with the interconnection option switched on, the results change dramatically. The model selects to build a large interconnection between Java and CNT after 2035 enabling the flow of renewables from CNT; the model selects to build the maximum interconnector capacity allowable (20GW per 5 years) by 2045 and 2050 as shown in Fig. 7. The model also selects the interconnector between CNT and the NEM at the same time that it builds the interconnector from Java to CNT (and the generation capacity) so that the NEM can also take advantage of the high quality renewables in this region. The provision of power from CNT (and from the rest of the NEM) reduces the overall systems costs from $AUD496B (billion) (discounted, $AUD2015) to $398B. The combined system LCOE is $AUD148/MWh.

The energy dispatch graph in Fig. 8 shows that with the submarine interconnector available, in 2050 a large amount of electricity is imported into Java-Bali, especially in the evening after the sun has set and the PV in Java-Bali stop generating. The generation mix in CNT is dominated by wind and concentrating solar thermal, as these technologies are able to dispatch power at night. At this stage, we have not considered PHES in CNT, as to date the capacity for PHES in the region has not been published. However, if past work is a guide, we would expect significant capacity for PHES in the area. If PHES we allowed in the model for CNT, we might expect a larger portion of PV, and less wind and CST.

When comparing Fig. 6 to Fig. 9, we can see that the magnitude of generation in Java-Bali has been greatly reduced, and that the amount of energy curtailed from wind and solar PV has been reduced to negligible levels. Generation from CNT grows rapidly from 2035 when the first HVDC capacity is installed.

Table 2 shows the emission abatement targets, and the costs of the generation and transmission deployment in each 5 years increment. The values presented are prior to discounting. The final column shows the total system cost with the discounting applied. It is clear that the highest costs are incurred towards the end of the simulation period. This is partly because of the discounting providing incentive to delay investment as long as possible, and because the emission reduction targets get progressively tighter as the simulation progresses. The discount rate used here is 10%, which could be argued is conservative on the high side. Lower discount rate would most likely result in earlier deployment of the renewable technologies.

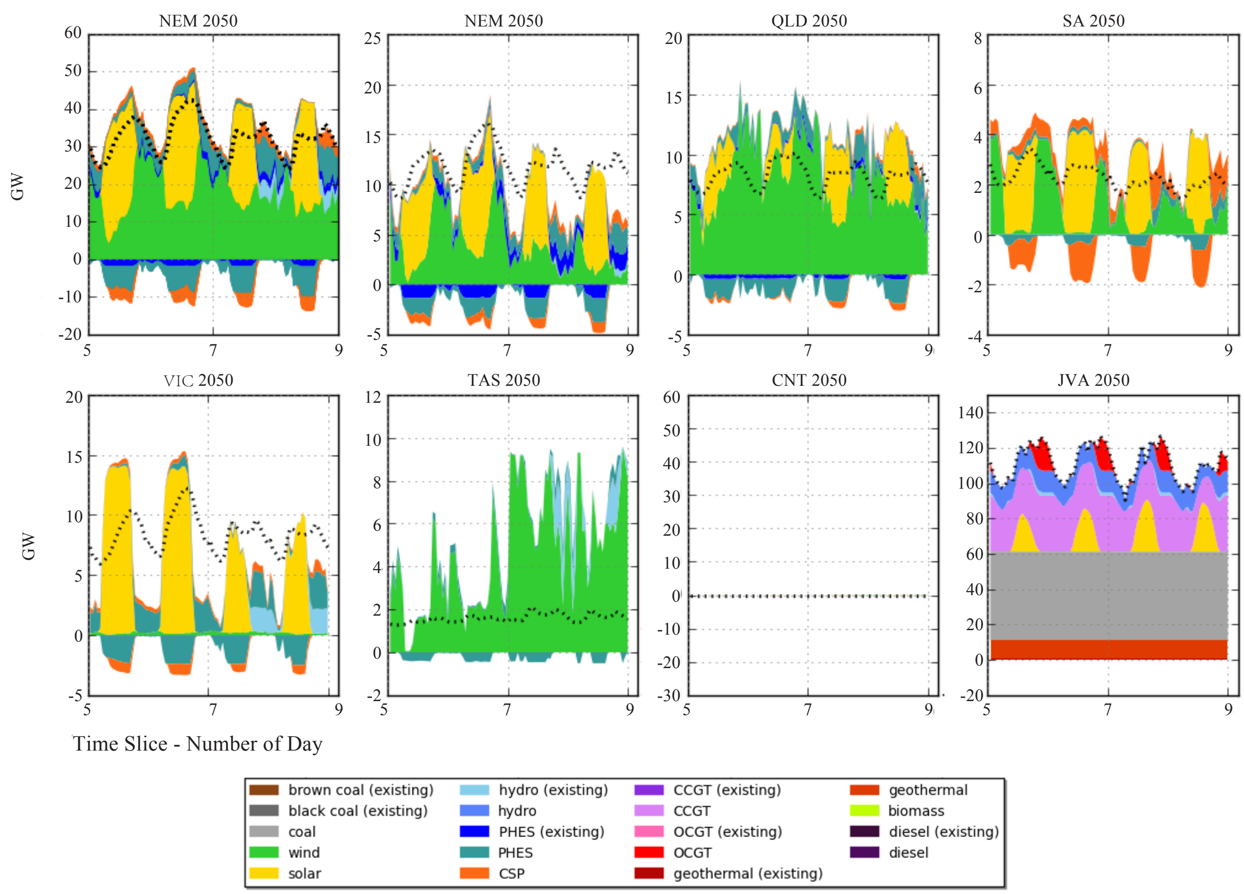

Fig. 5 Time series snapshot of the hourly dispatch (GW) for each of the states/regions in scenarios one and two. Figures show 4 days out of the total of 28 days used in the optimisation. The dot line shows the state energy demand

Table 2 Emissions in the 100% abatement scenarios for the NEM and Java-Bali power systems, and costs of generation capacity deployed in each 5-year step for the scenario with no HVDC link between Australia and Java, and with the HVDC link option switched on

Year	2020	2025	2030	2035	2040	2045	2050	Total system cost with perpetuity at present value (billion $AUD)
NEM Annual Emission ($MtCO_2$)	149	124	99	75	50	25	0	
Java-Bali Annual Emission ($MtCO_2$)	137	114	91	69	46	23	0	
5-year Period System Cost without HVDC (billion $AUD)	89	124	147	219	447	697	1082	496
5-year Period System Cost with HVDC (billion $AUD)	88	123	145	215	464	697	911	398

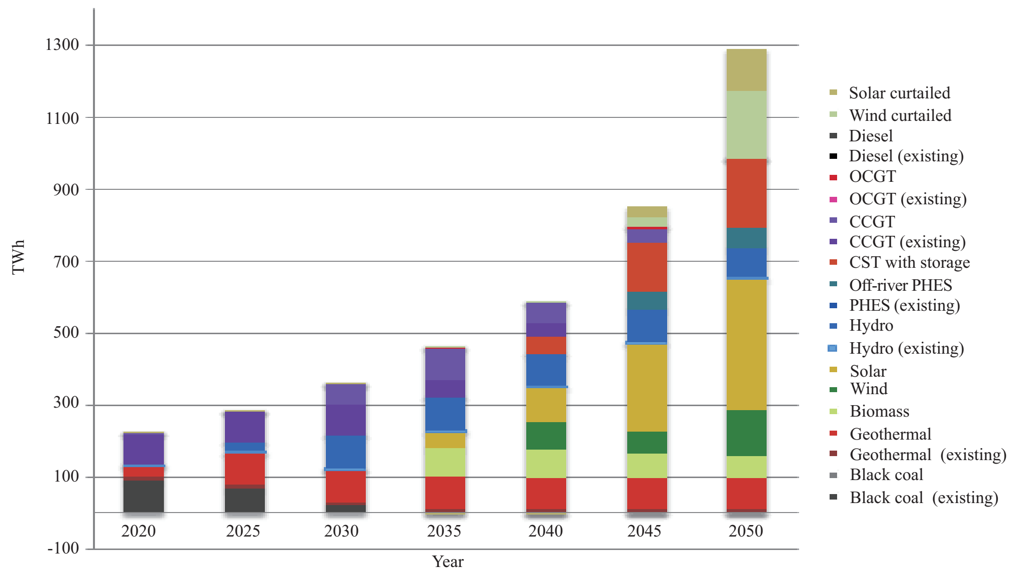

Fig. 6 Scenario 3, energy generation for Java-Bali with the 100% emission abatement with all demand met with domestic capacity. Note the high levels of curtailment of wind and solar PV

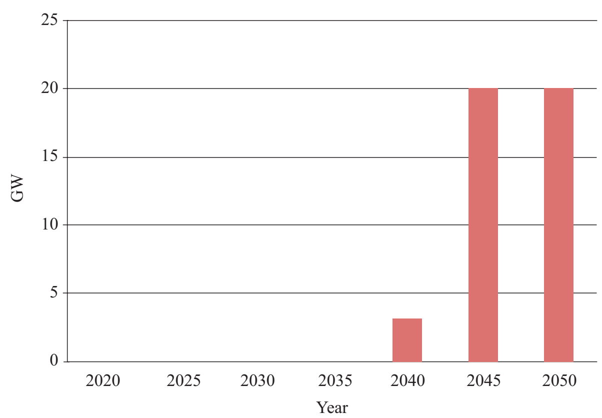

Fig. 7 HVDC capacity addition in the 100% Re scenario

4 Discussion and conclusions

This paper presents the result from the first stage of our study on a series of possible interconnection routes in the Australasian area. The scope of this paper is mainly confined to interconnection possibilities between Australia's NEM and the Indonesia's Java-Bali grid via the Northern Territory of Australia with a focus of comparing wind and solar resource qualities and their economic competitiveness between the two countries. The modelling work here presents a fairly strong case for building an HVDC interconnector between Australia and Indonesia to facilitate a 100% abatement target for both Australia and Indonesia.

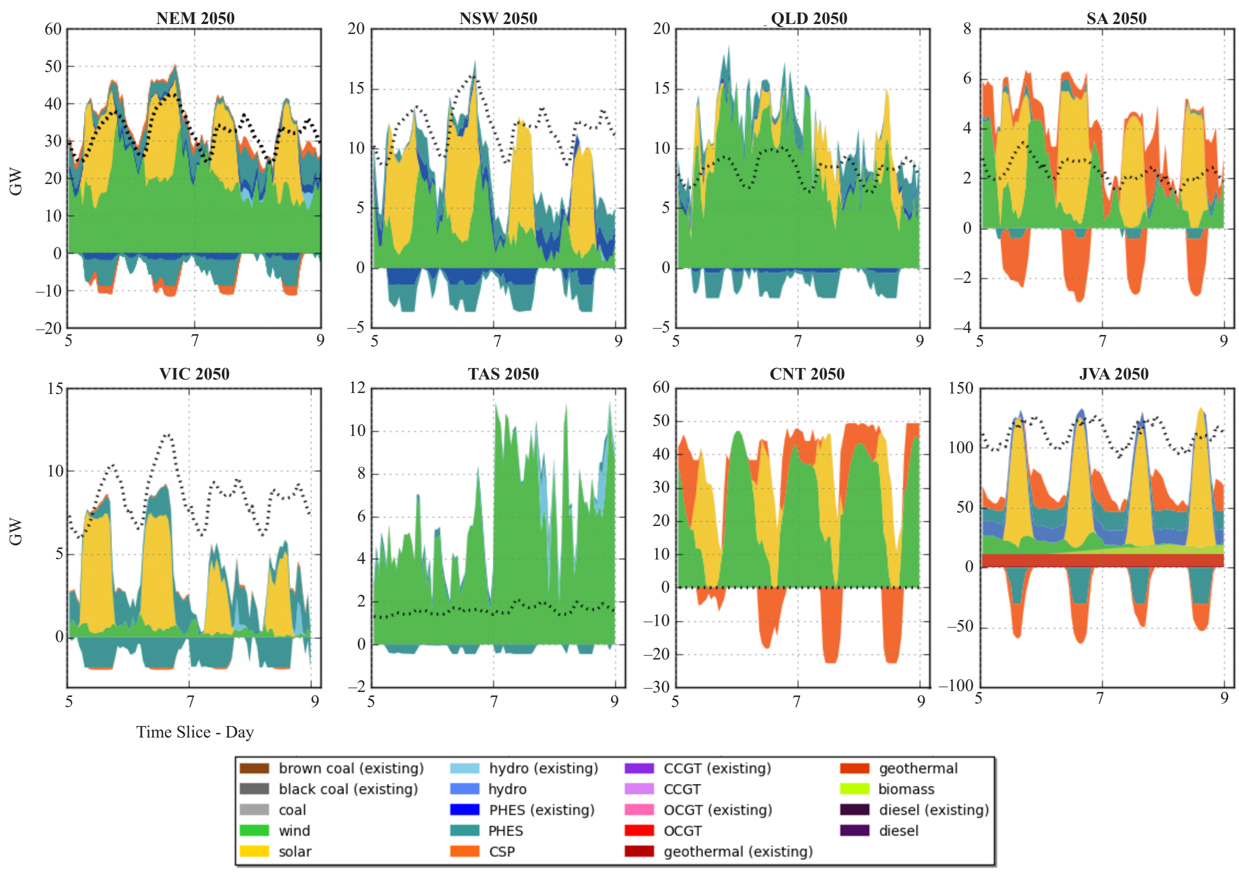

Fig. 8 100% renewables, 2050, with interconnector options switched on

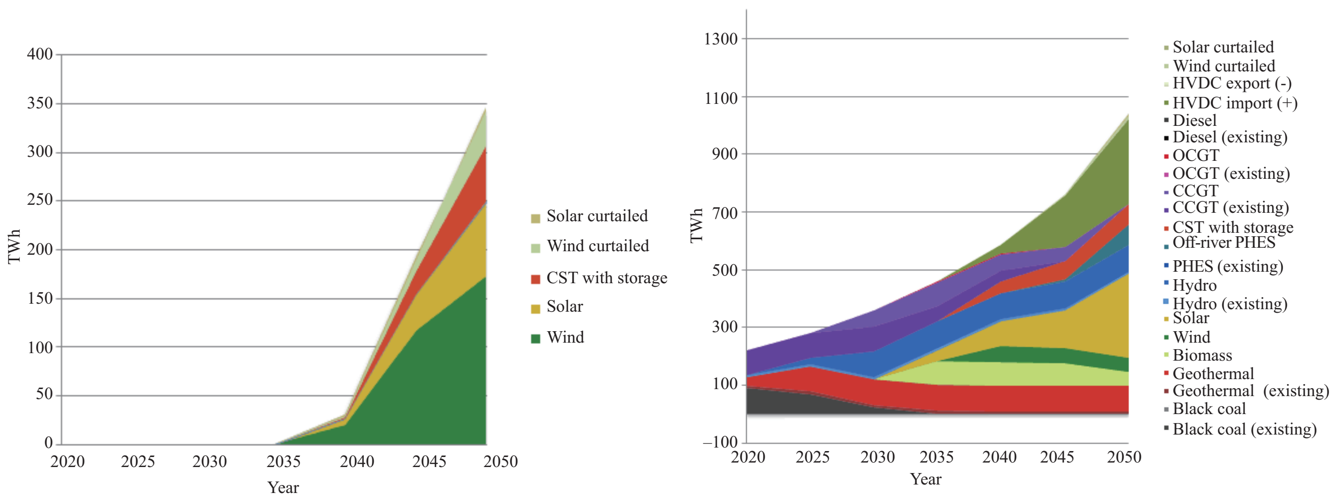

Fig. 9 Energy generation (and imports) for CNT (left) and Java-Bali for scenario 4 (HVDC switched on)

It would be considerably difficult for Java-Bali to meet its extraordinary electricity demand growth with domestic renewables alone, as the quality of resources and access to geographic diversity is limited. But with a connection into Australia, Java-Bali gains access to sunnier and windier locations and plus the large geographic distribution of resources in Australia that allows for a smoothing of the aggregate output of power.

Several assumptions from this study should be further scrutinized, and extensive future research should test the sensitivity of the results to these assumptions. For example, we have only used one set of values for the future costs of each technology (generation and transmission), and assumed that transmission costs in the future will be the same as today, however with increased demand for HVDC these costs could decrease. The generation technology costs come from the BREE AETA report, which is already out of date. We persist with using the AETA values as it is important to use consistent methodology for the broad range of technologies involved. If we were to use updated values (in particular for photovoltaics) the results will be impacted. Likewise, there is significant uncertainty on the future costs of both pumped hydro energy storage and concentrating solar thermal technology - it will be important to conduct a range of simulations with different ranges of costs for these technologies. In addition, economic viability of the HVDC interconnections with other abatement trajectories, e.g. the Intended Nationally Determined Contributions (INDCs) to meet the Paris Agreement needs to be studied in any future work.

Again, later work will expand the scope of the current study by incorporating options from other domestic and international interconnection routes i.e. the interconnection between the NEM, SWIS (the South West Interconnected System) and NWIS (the North West Interconnected System) across the major industrial load centers, and the interconnection between Java-Bali and other Indonesia islands, interconnection between Indonesia and other Southeast neighbouring countries to form a larger Australasian super grid.

Appendix A Optimisation mathematical formulations

The major mathematical formulations of the problem solved in this paper is described below; the rest operational constraints such as unit commitment, storage, security constraints, the capacity transition constraints, etc. and the nomenclature can be found from [6]. The objective function shown as follow is to minimise the plant capital expenditure, operating and maintenance costs, fuel costs, operating costs when recharging PHES and CSP, cost of transmission network augmentation (including the international submarine HVDC link) and the costs of unmet energy for both Australia and Indonesia as a conjoined system.

$$\begin{aligned}\min_{\mathrm{NEM,JVA}}\Bigg[&\sum_{p,r,y} X^{+}_{\mathrm{pry}} C^{\mathrm{b}}_{\mathrm{py}} D^{\mathrm{b}}_{\mathrm{py}} \\ &+\sum_{p,r,y}\left(X_{\mathrm{pry}} C^{\mathrm{f}}_{\mathrm{pry}} + E^{\mathrm{a}}_{\mathrm{pry}} C^{\mathrm{v}}_{\mathrm{pry}}\right) D^{0}_{\mathrm{y}} \\ &+\sum_{p\in,F,r,y} E^{\mathrm{fuel}}_{\mathrm{pry}} C^{\mathrm{fuel}}_{\mathrm{pry}} D^{0}_{\mathrm{y}} \\ &+\sum_{p\in,PHES,r,y,t}\left(1/\eta^{S}\right) S^{+}_{\mathrm{pryt}} C^{\mathrm{v}}_{\mathrm{pry}} \omega_{\mathrm{t}} D^{0}_{\mathrm{y}} \\ &+\sum_{l,y} T^{+}_{\mathrm{ly}} C^{\mathrm{l}}_{\mathrm{l}} D^{\mathrm{b}}_{\mathrm{ly}} + \sum_{r,y,t} E^{\mathrm{u}}_{\mathrm{ryt}} C^{\mathrm{u}} \omega_{\mathrm{t}} D^{0}_{\mathrm{y}}\Bigg]\end{aligned} \tag{A1}$$

The main constraints are as follows.

In all regions, generation and consumption must be balanced at all time for both the NEM and the Java-Bali grids, considering transmission flows and pumping of PHES.

$$\begin{aligned}&\sum_{p} E_{\mathrm{pryt}} + E^{\mathrm{u}}_{\mathrm{ryt}} + \sum_{N(l,r,r')} (1-\lambda_{l}) F_{\mathrm{lyt}} - \sum_{N(l,r,r')} F_{\mathrm{lyt}} \\ &= E^{\mathrm{d}}_{\mathrm{ryt}} + \sum_{p\in PHES} S^{+}_{\mathrm{p^{s}ryt}} / \eta^{\mathrm{s}}\end{aligned} \tag{A2}$$

Annual carbon emissions must be less than or equal to that of a specified abatement trajectory for Australia and Indonesia, respectively.

$$\sum_{pr} E^{\mathrm{fuel}}_{\mathrm{pryt}} \left(\left(1-G_{\mathrm{p}}\right) I^{\mathrm{c}}_{\mathrm{pr}} + I^{\mathrm{f}}_{\mathrm{pr}}\right) \leqslant M_{\mathrm{y}} \tag{A3}$$

To model the grid service, in all regions, synchronous generation capacity must be at least 30% of current demand.

$$\sum_{p\in U} Y_{\mathrm{pryt}} + \sum_{p\in D\notin U} E_{\mathrm{pryt}} \geqslant 0.3 E^{\mathrm{d}}_{\mathrm{ryt}} \tag{A4}$$

Transmission flows must be within line capacities. The line capacity in each year is equal to the existing line capacity plus the sum of the line capacity constructed in that year.

$$\begin{aligned}&T^{\min}_{\mathrm{ly}} \leqslant F_{\mathrm{lyt}} \leqslant T^{\max}_{\mathrm{ly}} \\ &T^{\min}_{\mathrm{ly}} = T^{\min}_{\mathrm{ly_0}} - T^{+}_{\mathrm{ly'}} \\ &T^{\max}_{\mathrm{ly}} = T^{\max}_{\mathrm{ly_0}} + T^{+}_{\mathrm{ly'}}\end{aligned} \tag{A5}$$

Appendix B Technology cost projections [6, 16, 20]

Table B1 Estimates of current financial and technical parameters for new plants

Plant	Build cost ($/kW)	Fixed O&M cost ($/MW/year)	Variable O&M cost ($/MWh sent out)	Thermal efficiency (%)	Emissions intensity (t CO_2 / MWh)	Minimum up time (hours)
Biomass (IND)	3,007	105,300	8.0	0.27	n/a	12
Combined cycle gas turbine	1,092	10,000	4.0	0.51	0.46	4
IGCC - Black coal	5,493	79,600	7.0	0.39	1.03	4
IGCC - Brown coal	6,196	99,500	9.0	0.34	1.12	4

continue

Plant	Build cost ($/kW)	Fixed O&M cost ($/MW/year)	Variable O&M cost ($/MWh sent out)	Thermal efficiency (%)	Emissions intensity (t CO_2 / MWh)	Minimum up time (hours)
Open cycle gas turbine	737	4,000	10.0	0.36	0.65	12
Pumped hydro	1,860	5,600	0.3	n/a	n/a	n/a
Geothermal (IND)	3,611	71,550	0.95	n/a	n/a	n/a
Solar Thermal CR with storage	7,095	71,312	5.7	n/a	n/a	n/a
Solar Thermal PT with storage	7,642	72,381	11.4	n/a	n/a	n/a
Supercritical PC - Black coal	3,136	50,500	7.0	0.43	0.82	12
Supercritical PC - Brown coal	3,786	60,500	8.0	0.33	0.99	12
Utility PV	3,301	30,000	0.0	n/a	n/a	n/a
Wind	2,276	32,500	10.0	n/a	n/a	n/a

Table B2 Estimates of 2050 financial and technical parameters for new plants

Plant	Build cost ($/kW)	Fixed O&M cost ($/MW/year)	Variable O&M cost ($/MWh sent out)	Thermal efficiency (%)	Emissions intensity (t CO_2 / MWh)	Minimum up time (hours)
Biomass (IND)	3,007	105,300	8.8	0.27	n/a	12
Combined cycle gas turbine	1,160	14,872	5.9	0.63	0.37	4
IGCC - Black coal	5,782	118,384	10.4	0.49	0.81	4
IGCC - Brown coal	6,411	147,980	13.4	0.45	0.86	4
Open cycle gas turbine	782	5,949	14.9	0.46	0.50	12
Pumped hydro	1,860	8,329	0.4	n/a	n/a	n/a
Geothermal (IND)	3,611	71,550	0.95	n/a	n/a	n/a
Solar Thermal CR with storage	4,399	44,215	3.5	n/a	n/a	n/a
Solar Thermal PT with storage	4,739	44,878	7.1	n/a	n/a	n/a
Supercritical PC - Black coal	2,934	75,105	10.4	0.53	0.66	12
Supercritical PC - Brown coal	3,762	89,978	11.9	0.44	0.75	12
Utility PV	1,063	18,601	0.0	n/a	n/a	n/a
Wind	1,848	48,335	14.9	n/a	n/a	n/a

Appendix C

Table C1 Cost assumptions for HVDC cables in AUD [19]

	Capex	Opex fix annual $\$/kW_{NTC}/km/a$	Opex Var $\$/kWh_{NTC}$	Lifetime years
HVDC line on the ground	$0.955 / kW_{NTC}/km	0.0117	0	50
HVDC line submarine	$1.548 / kW_{NTC}/km	0.00156	0	50
HVDC converter pair	$281 /$kW_{NTC}$	2.808	0	50

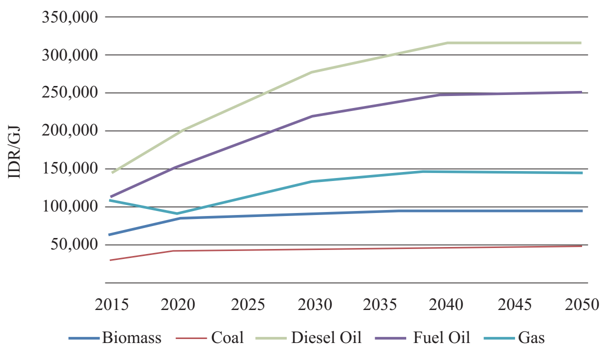

Table C2 Java-Bali Fuel Costs projections in IDR [20]

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(Editor Chenyang Liu)