Abstract—The majority of renewable energy sources are non-dispatchable, meaning that it is not possible to control when and how much power they produce. For non-dispatchable renewable energy sources to meet a greater proportion of global electricity demand, the industry must develop and implement strategies that directly address the intermittency challenge. This paper considers electrical storage and transmission assets as alternative means of matching non-dispatchable generation with non-deferrable demand. It seeks an optimal combination of storage and transmission assets for a simplified representation of Australian population centres, assuming that demand is met entirely with solar PV generation. This problem is solved using a Mixed Integer Linear Program. Under the baseline assumptions it is found that the optimal (lowest cost) solution has significant quantities of storage in all load centres, as well as transmission assets installed over large distances. The storage selected was 10-15% Li-ion batteries by energy; with the remainder being pumped hydro storage.

Keywords—Renewable energy sources; integration; optimisation; power transmission; energy storage.

I. INTRODUCTION

A. Background

Conventionally the majority of electricity supply systems have maintained the balance between supply and demand primarily by controlling the power output of dispatchable generating units. In the context of the storage/transmission trade-off considered in this paper, this conventional model could be viewed as an almost “transmission only” solution.

Most existing dispatchable generating assets are fossil fuel powered thermal generators. In Australia, for example, in 2012-2013, 86.9% of electrical energy was generated from burning fossil fuels [1]. Global reserves of economically recoverable fossil fuels are limited, and severely so if the environmental costs of climate change are factored into the cost of their extraction and use. As a result the electricity supply systems of the world need to transition to a greater proportion of Renewable Energy Sources (RES), many of which are non-dispatchable, i.e. it is not possible to control when and how much power they produce.

In [2] the US National Renewable Energy Laboratory summarise the challenges resulting from the non-dispatchable nature of many RES. A number of approaches have been proposed to deal with the uncontrolled variability introduced by non-dispatchable RES. The three main strategies are: (i) increase the amount of dispatchable spinning reserve; (ii) replace the loss of supply dispatch-ability by making a proportion of demand dispatchable (or at least deferrable); and (iii) incorporate larger amounts of energy storage into the electricity supply system. In this paper we only consider energy storage.

Recently in Australia, and elsewhere, there has been interest in the concept of individual homes installing and managing their own electricity supply systems, usually in the form of rooftop PV generation supplemented with battery storage. A CSIRO report looking at future pathways of the Australian electricity supply system suggests that this may be an economically viable option for many households by 2030 [3]. Others have speculated this may lead to the “utility death spiral”: where grid fixed costs need to be divided amongst fewer remaining grid-connected customers, causing an increase in per-unit energy prices and making it cost effective for more people to leave the grid. If the majority of electrical consumers decided to leave the grid in favour of a small scale supply system, with local battery storage, this would represent a “storage only” solution.

If a large proportion of electricity demand is to be met from non-dispatchable RES, it is likely that a large quantity of energy storage will be required; especially under the assumption of non-deferrable demand. The question addressed in this paper is what is the lowest cost combination of storage and transmission assets; in other words, do the potential benefits of reduced overall storage requirements and increased energy efficiency justify the cost of building and maintaining a transmission system?

B. Literature Review

Much research has been dedicated to the optimal planning and operation of electricity supply systems. [4] gives a review of multi-objective optimisation for planning Distributed Energy Resources (DER); it is interesting to note how many alternative (and sometimes conflicting) objectives can be optimised for. In this paper we consider the minimisation of total CAPEX (Capital Expenditure) only.

In [5] the ability of increasing quantities of storage capacity to enable the integration of a greater proportion of intermittent
RES is analysed. It concludes that relatively modest levels (10min) of quick responding storage can allow a modest increase in wind energy absorption (10%) and may be economical, but extending this to longer time-scales was not (with cost figures at the time of its writing). Finally [6]–[8] present capacity planning optimisation problems with very high levels of RES integration, focussing respectively on: Power-to-Gas energy storage systems in Germany; RES and storage systems globally; and RES, storage, and transmission systems in Europe. These studies, in particular [8], conclude that generating 100% of electricity from RES can be achieved at a competitive cost, provided the technologies, location and sizing of storage, generation and transmission assets are appropriately selected. Bussar et al. have presented a similar study for Europe as this paper carries out for Australia; except here we make additional assumptions regarding the type and location of RES to allow focus on the trade-off between storage and transmission.

The novelty of the present paper is in directly comparing storage and transmission assets as alternative means of balancing non-dispatchable supply with non-deferrable demand. We further consider what implications this has for the optimal interconnectionedness of future electricity supply systems.

The remainder of this paper is structured as follows: Section II formalises the problem and describes the Mixed Integer Linear Program (MILP) formulated to solve it; Section III describes the simplified instance of this problem tackled; and Sections IV and V present the results for this instance of the problem, and draw some conclusions.

II. METHOD

A. Basic Idea

Assuming an electricity supply system in which all generation is non-dispatchable and all demand is non-deferrable, and whose spatial and temporal distributions of supply and demand are known, the optimisation problem considered can be stated as: “what is the lowest cost combination of transmission and storage assets which allow demand to be satisfied in all locations and at all times?” To simplify this question a number of assumptions are made; it is assumed that the assets can be operated in an optimal manner, which requires assuming that the temporal patterns in demand and supply are known for the full planning period.

B. Baseline Model

The following primary decision variables are defined:

- $S_{ij}$ the amount of storage capacity of type $i$, installed in region $j$, [MWh];
- $X_{jk}$ the amount of transmission capacity (if any) installed from region $j$, to region $k$, [MWh/time-step];
- $x_{jk}$ a binary variable representing whether any link is installed between region $j$, and region $k$, [].

The following additional variables are defined:

- $s_{ijt}$, $w_{ijt}$ the amount of energy sent to (respectively withdrawn from) storage type $i$, in region $j$, during period $t$, [MWh];
- $s_{ijt}$ the amount of energy stored in storage type $i$, in region $j$, at the start of period $t$, [MWh];
- $e_{jkt}$ the amount of energy sent from region $j$, to region $k$, during period $t$, [MWh];
- $D_{jkt}$ the amount of Demand Response (DR), i.e. unmet demand, in region $j$, during period $t$, [MWh];
- $E_{jkt}$ the amount of energy dissipated (or generation curtailment) in region $j$, during period $t$, [MWh].

And the following model parameters are defined:

- $d_{jkt}$ the electrical energy demand in region $j$, during period $t$, [MWh];
- $P_{jkt}$ the solar PV electrical output\(^1\) in region $j$, during period $t$, [MWh];
- $S_{ij}$ the installed cost of a unit of storage type $i$, [AU$/MWh]$;
- $S_{ij}^s$ the fraction of energy stored, in storage type $i$, which is lost (due to ‘self-discharge’) in one period, [];
- $S_{ij}^x$ the fraction of energy lost, when energy is transferred to (or from) storage type $i$, [];
- $S_{ij}^{\max}$ the maximum energy [MWh] that can be sent to (or taken from) storage type $i$, in one time-step, per unit installed capacity, [];
- $x_{jkt}^c$ the installation cost of a 0MWh/time-step capacity link from region $j$, to region $k$. Represents the installed cost of poles (or cable conduit) [AU$]$;
- $X_{jkt}^c$ the incremental cost of adding 1MWh/time-step capacity between regions $j$ and $k$. Represents the per-unit capacity cost of conductors, power converters etc. [AU$/MWh$/time-step];
- $X_{jkt}^l$ the fraction of energy lost in transferring energy between regions $j$ and $k$, [];
- $D_{jkt}^c$ the cost per MWh of DR; this is set high, and the model iterated with larger values of $\gamma$ till $D_{jkt} = 0 \forall j, t$, [AU$/MWh]$;
- $M_d$ the sum of the maximum demand in each region [MWh], ($M_d = \sum_\forall_j \max(d_{jkt})$);
- $\gamma$ a model-tuning parameter; used as a multiplier of PV output. The model is iterated, increasing $\gamma$ till DR is no longer necessary. Iteration is required because losses are not known a priori;

$I, J, T$ sets of storage types, regions and time periods respectively, 1 is the first time period, $T_{\text{max}}$ is the final time period.

The model is then formulated as: Minimise:

$$\sum_{i \in I, j \in J} S_{ij} S_i^c + \sum_{j,k \in J, j < k} (x_{jkt} x_{jkt}^c + X_{jkt} X_{jkt}^c) + \sum_{j \in J, t \in T} D_{jkt} D_{jkt}^c$$

Subject to:

1. $e_{jkt} \leq X_{jkt} + X_{kjt}, \quad \forall j, k \in J, t \in T$

2. $X_{jkt} \leq x_{jkt} M_d, \quad \forall j, k \in J$

\(^1\)A unit PV output time series is scaled up such that $\sum_{t \in T} P_{jkt} = \sum_{t \in T} d_{jkt} \forall j \in J$
capacity factors (along with additional transmission assets); and secondly, it means the model does not need to be run iteratively (as PV capacity installed can be selected such that all demand and losses are satisfied).

To implement this extension the PV output multiplier, $\gamma$, is removed and the PV output parameter, $P_{jt}$, is replaced with the following parameters:

\[
\hat{P}_{jt} \quad \text{the PV output in each region } j, \text{ in each time-step } t, \text{ per unit (MWh/time-step) of PV installed capacity [time-step];}
\]

\[
\hat{P}_c \quad \text{the cost of installing a unit capacity of PV [SAU/MWh/time-step].}
\]

And we introduce the additional investment decision variable:

\[
\hat{P}_j \quad \text{the capacity of PV installed in region } j \text{ [MWh/time-step]}
\]

This changes the model formulation as follows: A cost for installing the selected amount of PV capacity is added to the objective function;

\[
\sum_{i \in I} S_{ij} \hat{S}_i + \sum_{j,k \in J | k < j} (x_{jk} x_{jk}^j + X_{jk} X_{jk}^j)
\]

\[
\sum_{j \in J} \hat{P}_j \hat{P}_c
\]

And the region energy balance equation (8) becomes:

\[
\sum_{k \in J} e_{kjt} (1 - X_{kj}^l) + \sum_{i \in I} w_{ijt} (1 - S_i^l) + \gamma P_{jt} + D_{jt}
\]

\[
= \sum_{k \in J} e_{kjt} + \sum_{i \in I} s_{ijt} + d_{jt} + E_{jt} \quad \forall j \in J, t \in T
\]

\[
\tilde{s}_{ij(t+1)} = \tilde{s}_{ijt} (1 - S_i^l) - w_{ijt} + s_{ijt} (1 - S_i^l)
\]

\[
\tilde{s}_{ij(t+1)} \geq \tilde{s}_{ij1} \quad \forall i \in I, j \in J
\]

\[
D_{jt}, E_{jt}, S_{ij}, X_{jk}, e_{kjt}, s_{ijt}, \tilde{s}_{ijt}, w_{ijt} \geq 0, \quad \forall j, k \in J, i \in I, t \in T
\]

\[
x_{jk} \in \{0, 1\}, \quad \forall j, k \in J
\]

C. Extension to Include PV Capacity as a Decision Variable

An extension is made to this model to include the capacity of PV installed in each region as a decision variable. In the baseline model representative PV generation profiles are used to determine the average capacity factor across the year, in each region. The PV capacities were then selected so that, over a year, each region could supply its own demand. The capacity was then scaled using the factor $\gamma$, until DR was zero at all time-steps, in all regions. In the extended model PV capacity installed in each region are additional decision variables. This has two potential benefits: firstly, it allows the preferential installation of PV generation in regions with high

Fig. 1. Graphical Representation of Region Energy Balance Constraint, (8)

Fig. 2. Graphical Representation of Storage Energy Balance Constraint, (9)
transmission assets (if any) to install between these demand centres and the capacity of different types of storage to install at each location. It is recognised that this approach is not sufficiently realistic to produce implementable recommendations, but it is used as an idealised case study of the trade-off between storage and transmission, with realistic cost and performance assumptions. It is further noted that 100% electricity supply from PV generation across Australia is not a realistic proposition and would require large quantities of storage which would likely be uneconomic. This simplifying assumption is made to provide a defined spatial and temporal pattern of demand which needs to be matched with the spatial and temporal pattern of demand, through some combination of storage and transmission assets.

A. Load Data

The load data used to populate $d_{jk}$ is half-hourly real power demand for the calendar year 2013 [9], [10].

B. PV Generation Profiles

To populate $P_{kt}$, PV generation profiles have been synthesised using NASA data for global monthly averages of solar radiation on a horizontal plane [11] and the solarR toolbox [12] to calculate the daily and seasonal variation of PV power output. The following assumptions were made:

- Monthly averages for radiation and temperature at the load centres are found using bi-linear interpolation of the NASA data-set;
- Melbourne average solar time is assumed to be exactly AEST, and other locations have time shifted, relative to this, linearly with longitude;
- The solarR package includes stochastic variation, due to fluctuation in clearness index etc., the default settings were assumed for all parameters.

C. Storage Cost & Technical Parameters

Five storage technologies were considered: Pumped Hydro Energy Storage (PHES), Compressed Air Energy Storage (CAES), Lead-Acid Batteries (PbAB), Flywheel Energy Storage (FWES) and Li-Ion Batteries (LiIB). The technical and economic parameters assumed for each of these are summarised in Table I; these were taken directly from, or calculated using data within [13]–[15]. Details of how each was derived is omitted for brevity.

D. Transmission Cost & Technical Parameters

For each pair of load centres $j$ and $k$, we require the cost parameters $x_{jk}^{c}$ and $X_{jk}^{c}$ which represent the cost of a zero-capacity HVDC link between the two locations, and the incremental cost of adding 2MW (1MWh/0.5hr time-step) capacity. We also require the expected fractional loss in moving energy between the two locations, i.e. $X_{jk}^{l}$. These values will depend on the distance of the power line route between the pair of cities. The optimal route for connecting each pair of cities is not known, but as a proxy we consider straight line distances.

Well-designed HVDC links have losses of 3% for every 1000km [16]; losses between pairs of locations are calculated as $1 - (1 - 0.03)^{\text{dist}}$. This value is computed for each pair of cities and added to a 1% [17] power converter loss at each end, to give the total loss between each pair of locations, $X_{jk}^{l}$, see Table II.

The cost of an HVDC transmission link of capacity “cap”, and distance “dist” is assumed to be approximated by:

$$\text{Cost}_{\text{HVDC}} = A \times \text{dist} + B \times \text{cap} + C \times \text{dist} \times \text{cap}$$

(15)

Where $\text{Cost}_{\text{HVDC}}$ is the cost of the project, and $A$, $B$, and $C$, are cost coefficients with units of AUS million/km, AUS million/MW, and AUS million/km/MW respectively. There are only three HVDC projects which have been completed in Australia and their parameters are presented in Table III. This data was used to solve for the coefficients $A$, $B$, and $C$, which were calculated as 0.143, 0.187 and 0.0053 respectively. These coefficients were used to calculate the model parameters $x_{jk}^{c}$ and $X_{jk}^{c}$. Defining the distance matrix between cities as $\lambda_{jk}$, these are calculated as $X_{jk}^{c} = A\lambda_{jk}$, and $x_{jk}^{c} = 2C\lambda_{jk} + 2B$, $\forall j, k \in J$. The resulting model parameters are given in Tables V and IV.

IV. RESULTS & DISCUSSION

To allow the model to be solved in a reasonable time, instead of considering a full year of half-hourly time-steps,
### TABLE III. EXISTING AUSTRALIAN HVDC LINKS, AND THEIR COSTS

<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td>Terranora</td>
<td>59</td>
<td>180</td>
<td>91</td>
</tr>
<tr>
<td>Murraylink</td>
<td>176</td>
<td>200</td>
<td>230</td>
</tr>
<tr>
<td>Basslink</td>
<td>370</td>
<td>500</td>
<td>1040</td>
</tr>
</tbody>
</table>

### TABLE IV. \( x_{jk}^{C} \cdot \text{AU$2014 million} \)

<table>
<thead>
<tr>
<th>From / To</th>
<th>WA</th>
<th>SA</th>
<th>VIC</th>
<th>TAS</th>
<th>NSW</th>
<th>QLD</th>
</tr>
</thead>
<tbody>
<tr>
<td>WA</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>SA</td>
<td>304</td>
<td>93</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VIC</td>
<td>188</td>
<td>93</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TAS</td>
<td>430</td>
<td>166</td>
<td>85</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>NSW</td>
<td>470</td>
<td>166</td>
<td>102</td>
<td>151</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>QLD</td>
<td>515</td>
<td>228</td>
<td>196</td>
<td>255</td>
<td>104</td>
<td>0</td>
</tr>
</tbody>
</table>

### TABLE V. \( X_{jk}^{C} \cdot \text{AU$2014 million/MWh/30min} \)

<table>
<thead>
<tr>
<th>From / To</th>
<th>WA</th>
<th>SA</th>
<th>VIC</th>
<th>TAS</th>
<th>NSW</th>
<th>QLD</th>
</tr>
</thead>
<tbody>
<tr>
<td>WA</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>SA</td>
<td>22.8</td>
<td>7.3</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>VIC</td>
<td>29.0</td>
<td>7.3</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>TAS</td>
<td>32.1</td>
<td>12.6</td>
<td>6.7</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>NSW</td>
<td>35.0</td>
<td>12.6</td>
<td>7.9</td>
<td>11.5</td>
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<td>0.0</td>
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<tr>
<td>QLD</td>
<td>38.3</td>
<td>17.2</td>
<td>14.8</td>
<td>19.2</td>
<td>8.1</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Four representative weeks are selected from throughout the year, and the model solved for those weeks as if they occurred consecutively. We would expect this to under-estimate the amount of storage required, but comparative results are likely to still be appropriate.

Figure 4 shows the results of the baseline model, showing significant storage assets in all locations. Of the five available storage technologies, only LiIB and PHES are used; serving the requirement for short term and long-term storage respectively. The largest transmission capacities are built between the three largest demand centres of QLD, NSW, and VIC, and all locations have a similar proportion of LiIB and PHES, with the exception of NSW which has a larger proportion of LiIB reflecting its higher di-urnal load variation. The total CAPEX for storage, transmission and PV assets in this baseline model is AU$2,143 billion.

To assess the impact of including transmission on the quantities of storage required, the baseline model was run whilst constraining all transmission capacities to zero; this resulted in the solution presented in Fig. 5. The storage capacities required are larger in all locations and the CAPEX has increased by 22% to $2,607 billion.

In the baseline model, Fig. 4, the most PHES was placed in VIC, with a capacity of 380GWh. No consideration has yet been given to the available sites for PHES. In [18] the sites assessed indicate that a total PHES capacity of approximately 300GWh could be available in the NEM regions (SA, VIC, TAS, NSW, QLD) at or below the $680,000/MWh cost considered here. To consider this additional constraint the capacity of PHES is constrained to 100GWh per location. This produced the solution presented in Fig. 6; in which all six regions are using the maximum available PHES capacity. Use is also made of CAES to make up for the short-fall in PHES capacity, increasing the CAPEX by 5% from the baseline to $2,254 billion.

Figure 7 shows the results of the model in which PV capacity installed in each region is a decision variable. Here we see larger PV capacities are installed in most regions, the preferred storage types have changed to CAES and PHES, and in the time-series results a significant amount of generation curtailment (\( E_{ji} \)) is seen. These differences are caused by...
that a more interconnected system may offer such as the greater CAPEX. This is without considering the additional benefits of transmission assets selected show a short-coming of the model formulation, in that it does not allow direct flow of energy from one region to another via intermediate regions. Were this allowed it is likely that some of the additional ‘direct’ links would not have been selected.

V. Conclusion

We have presented a Mixed Integer Linear Program for finding the lowest cost combination of storage and transmission assets that allow an electricity system with 100% non-dispatchable supply to meet non-deferrable demands in all locations and at all times. This model has been solved for a simplified representation of Australian electricity demand being served entirely by PV generation; and the solution suggests that whilst large storage assets are required, including transmission is worthwhile as it gives the lowest overall CAPEX. This is without considering the additional benefits that a more interconnected system may offer such as the greater efficiencies and economies of scale that may be available when generating, storing and managing electricity at larger scales.

This suggests that whilst it may be cost-effective, in the short-term, for individuals to disconnect from the grid and set-up their own electricity supply system, it is likely that this will not result in the lowest over-all cost solution.

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