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90–100% renewable electricity for the South West Interconnected System of Western Australia

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ABSTRACT

Rapidly increasing penetration of renewables, primarily wind and photovoltaics (PV), is causing a move away from fossil fuel in the Australian electric power industry. This study focuses on the South West Interconnected System in Western Australia. Several high (90% and 100%) renewables penetration scenarios have been modelled, comprising wind and PV supplemented with a small amount of biogas, and compared with a “like-for-like” fossil-fuel replacement scenario. Short-term off-river (closed cycle) pumped hydro energy storage (PHES) is utilised in some simulations as a large-scale conventional storage technology. The scenarios are examined by using a chronological dispatch model. An important feature of the modelling is that only technologies that have been already deployed on a large scale (>150 gigawatts) are utilised. This includes wind, PV and PHES. The modelling results demonstrate that 90–100% penetration by wind and PV electricity is compatible with a balanced grid. With the integration of off-river PHES, 90% renewables penetration is able to provide low-carbon electricity at competitive prices. Pumped hydro also facilitates a 100% renewables scenario which produces zero greenhouse gas emissions with attractive electricity prices. A sensitivity analysis shows the most important factors in the system cost are discount rate and wind turbine cost.

1. Introduction

1.1. Decarbonisation of Australian energy sector

Australia announced its 2030 Emission Reduction Target at the historic Paris Agreement on climate change, namely to reduce greenhouse gas (GHG) emissions by 26–28% below 2005 levels by 2030 [1]. This translates to emission reductions of 50–52% per capita, although these figures are considerably smaller if a different baseline year is selected. Australia's annual GHG emissions have averaged 570 Mt CO2-e over the last decade with around two thirds produced by energy-related sectors including stationary energy, transport and fugitive emissions [2]. Electricity generation, currently dominated by fossil-fuel power stations, is the largest source of emissions accounting for around one third of the total.

Low carbon electricity has the greatest potential for rapid decarbonisation of the energy sector [3]. This is the approach adopted by the Australian Capital Territory (ACT) Government to achieve its early GHG target of 100% renewable electricity by 2020 [4]. Wind and photovoltaics (PV) systems constitute virtually all new generation systems in Australia now and for the foreseeable future. Over the last decade, wind power has grown at an annual average rate of 22% with a total installed capacity of about 4 GW at the end of 2015. Solar PV has seen even stronger growth, dominated by residential solar installations, rising from around 4 MW to 5 GW. Wind and PV contributed about 18 TWh in Australia in 2015, compared with hydroelectricity (14 TWh) and biomass electricity (3 TWh) [5].

New capacity installations in the worldwide renewable electricity industry is heavily dominated by wind and PV, which are unconstrained by resource availability or water requirements or material supply or security issues. Together, wind and PV constituted about half of new generation capacity installed in 2015 (Fig. 1). Hydro power is unable to expand considerably due to lack of rivers to dam, and bioenergy is severely limited by biomass availability [6]. Heroic growth rates are required for other renewable or low emission technologies (nuclear, carbon capture & storage, concentrating solar thermal, ocean, geothermal) to span the 20 to 1000-fold difference in scale to catch up with wind and PV

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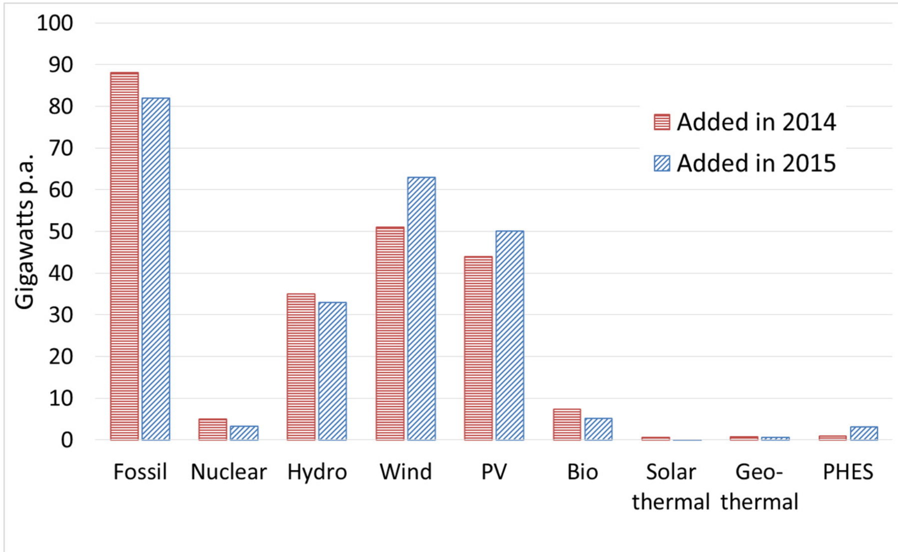

Fig. 1. New generation capacity installed worldwide in 2014 and 2015. Virtually all new Australian capacity is PV and wind [49–51].

– which are moving targets since both industries are themselves growing rapidly and both access large economies of scale.

In this paper wind and PV are assumed to continue their absolute dominance of new energy generation systems in Australia. As Australia's existing coal power stations reach the end of their working lives they are being replaced by wind and PV generators. For example, the last coal generator in the state of South Australia was recently closed, and from 2017 that state will procure about half of its annual electricity from windfarms and rooftop PV [7].

1.2. High wind and PV penetration

High penetration (50–100%) of variable wind and PV electricity in power systems requires technical adaptation, particularly relating to balancing variable wind and solar power supply and varying demand for electricity in real time [8]. Mitigation of this problem is as follows:

- Prediction: Solar and wind forecasting skill is already very good, and continues to improve. The combined output of thousands of wind and PV systems can be predicted on every time scale from seconds to years, which allows supporting measures to be taken [9–11];
- The use of PV and wind energy systems distributed over thousands or millions of square kilometres greatly reduces the effect of local weather [11,12]; a future study of the Australian National Electricity Market will quantify this reduction;
- In some interconnected regions the output of wind and PV systems is counter-correlated – for example, cloudy weather is often windy;
- Active load management allows interruptible loads to accommodate fluctuating wind, PV and demand, and also allows loads such as water heating or battery charging to be moved from night time to daytime [13].
- Controllable and quick-response peaking power plants such as hydro and natural gas or biogas-fuelled gas turbines, operated for only a small fraction of the year, can fill shortfalls in supply; and
- High power energy storage can shift excess energy produced by wind and PV to match the loads during periods of electricity shortage [14].

The purpose of this study is to simulate supply and demand for high renewables penetration scenarios for the South West Interconnected System (SWIS) of Western Australia (WA) centred on Perth. A "no heroic assumptions" policy is applied throughout the study, which means that only those commercially available technologies currently deployed on a large scale (more than 150 GW of worldwide deployment) and that have a sufficient resource base in WA are included in the simulation. This restricts the simulation to PV and wind for renewable energy generation, and pumped hydro energy storage (PHES) for storage, with a small amount of gas or biomass supplementation.

1.3. Off-river pumped hydro energy storage

Pumped hydro energy storage is simulated through the use of closed loop, off-river systems. Closed loop PHES comprises pairs of small reservoirs (1–100 ha), placed close together in steep hilly country outside national parks and other sensitive areas, separated by an altitude difference of 200–900 m, and connected by a pipe or tunnel containing a pump and a turbine. The small size of the reservoirs relative to conventional on-river PHES reflects the fact that off-river PHES provides storage for hours or a day rather than for weeks or a season. The reservoirs are essentially "oversized farm dams". The reservoirs are 10–20 m deep, and the walls are created from earth and rock scooped from the centre. Lining of the base and evaporation control suppresses the annual water consumption (evaporation minus rainfall). Construction costs are low because of the absence of flood control and the small size of the reservoirs. A previous Geographic Information System (GIS)-based screening study [15] demonstrated the substantial potential for off-river PHES to be deployed in the southwest of WA especially along the Darling Range escarpment.

1.4. Innovation

Large-scale energy storage is recognised as an effective approach to integrate intermittent solar and wind electricity into power systems through the mitigation of electricity supply fluctuations and load levelling. It is able to shift energy from times of excess generation to periods of low solar and wind availability and hence helps to maintain energy supply and consumption balance.

However, in many analyses of energy systems deployment of bulk energy storage is considered to be restricted by the availability of river-based hydro resources (pumped hydro energy storage); the requirement of special geologic structures (compressed air energy storage, CAES); limited deployment of the primary technology (molten salt storage); or low technology maturity associated with high capital expenditures such as batteries in electric vehicles.

For example in Australia, the Australian Energy Market Operator (AEMO) modelled four 100% renewables scenarios through the generation mix of thermal generation technologies such as geothermal, biomass and concentrating solar thermal (CST) [16]. The penetration of fluctuating wind energy was under 10% of the total generation although it was one of the lowest-cost generation technologies in Australia. Elliston et al. [17] utilised fast-ramping biogas-fuelled gas turbines to solve energy balancing problems and thus increased the wind integration to 46%. Lenzen et al. [18] mainly used CST with molten salt storage to conduct day-night shifting of solar energy which constitutes half of the energy generation and nearly 40% of the total installed capacity in the system. However, geothermal, wave, biomass and CST have not been technically and/or economically feasible to be deployed at gigawatts to dozens of gigawatts scale as PV and wind can do in Australia. Additionally, only existing PHES was included in these studies.

Globally, wind-PHES hybrid systems have been included in numerous studies but restricted to small-scale applications in existing power systems or in isolated islands. There are a few studies that have focused on using large-scale energy storage as a primary solution to achieve 50–100% wind integration in large-scale power systems such as in Denmark, Ireland and Portugal. Lund and Salgi [19] identified that an optimal 59% wind integration can be achieved via the deployment of CAES in the Danish energy sector and undertook a system-economic and a business-economic analyses for a 360 MW CAES plants to be operated in the system. Alternatives such as combined heat and power (CHP), industrial electric heat pumps and electric boilers were also analysed in the study. Connolly et al. [20] examined the role of PHES in wind energy penetration from 0 to 100% in the Irish power system and explored the economic viability of a 2.5 GW/25 GWh PHES plant in the 2020 scenario which was also compared with CHP and domestic electric heat pumps. Krajacic et al. [21] modelled the Portuguese power system to achieve 100% renewables penetration through the addition of 2 GW PHES.

Although the grid scale of SWIS can be comparable to those of the European countries, it has no interconnection with other electricity systems which brings a significant issue of energy balancing as well as grid stabilisation. Also, there are no river-based hydro resources that can be exploited at a large scale to support peak loads or contribute frequency control services in the south-west of WA. In addition, significant heating loads, which makes CHP even more attractive than PHES as discussed in the Danish and Irish grids, are not applicable in the SWIS region.

This study utilises closed loop (off-river) PHES as a primary approach to achieve 90–100% renewables penetration in a large-scale, self-contained power system. It features a “no heroic assumptions” policy which only includes those commercially available technologies currently deployed on a large scale and that have a sufficient resource base in WA. This study establishes a benchmark for the cost of an isolated GW-scale power system with 90–100% renewables penetration using existing mature generation and storage technologies and cost estimates for 2016. In future, more sustainable energy options can be integrated in the modelling once their economics and technology status can compete with PV and wind, although this seems to be unlikely in the foreseeable future.

2. The South West Interconnected System (SWIS)

2.1. Transmission and distribution network

The Transmission and distribution (T&D) network in the SWIS covers an area of 261,000 km^2 in the southwest of WA. It is not connected to Australia's eastern states, and has more than 7000 km of high-voltage transmission lines extending to Kalbarri in the north (132 kV), Kalgoorlie in the east (220 kV) and Albany in the south (66 kV) as showed in Fig. 2. Major mining fields in the region such as the Kalgoorlie gold mines and the Karara Iron Ore mines are connected to the coal-fired power stations located around the Collie Coalfield by 220 kV and 330 kV transmission infrastructure. This T&D network currently operated by the Western Power supports over 1 million electricity customers [22].

2.2. Electricity generation

SWIS generating facilities comprise: a) black coal power stations (Muja, Collie and Bluewater) with a total installed capacity of 1.9 GW; b) natural gas and distillate-fuelled combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) operated as load following and peaking plants contributing 4 GW of installed capacity to the system and c) renewable generators such as wind turbines, solar panels and biomass which produced over 2.3 TWh of electricity in 2015 constituting around 12% of the state's total annual energy generation [5,23].

Currently about 20% of the households in the state have rooftop PV panels, which contributes more than 0.5 GW of generating capacity connected to the SWIS. This is expected to increase [24].

2.3. The Wholesale electricity market

The operation of the Wholesale Electricity Market (WEM) for the SWIS commenced in 2006. The vast majority of energy is traded through bilateral contracts between generators and retailers due to the dominance of a state-owned generation and retail business. A small fraction of energy is traded in a day-ahead Short Term Energy Market for 30-min trading intervals on the following trading days.

Unlike the National Electricity Market (NEM) in the eastern states, which operates a market for frequency control ancillary

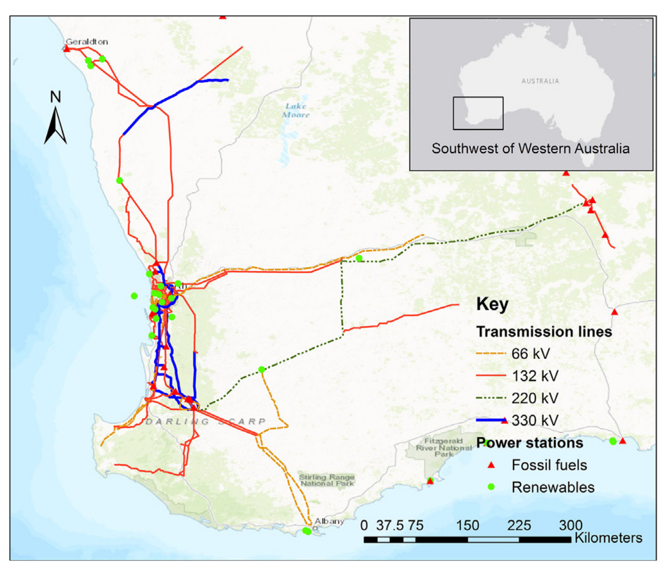

Fig. 2. Transmission lines and power stations in the SWIS [52].

Table 1
Thermal efficiencies and emission intensities.

Technology	Thermal efficiency (%)	Emission intensity (t/MWh)
Subcritical black coal	36	0.88
Natural gas-fuelled CCGT	50	0.37
Natural gas-fuelled OCGT	34	0.55
Biogas-fuelled OCGT	31	0

Note. Biogas-fuelled OCGT only used in the renewables scenarios.

services, WEM operates a Reserve Capacity Mechanism for the allocation of adequate capacity credits to the reserve capacity suppliers (which includes generators and demand-side management) [25].

At present, electricity valued at around $1 billion is annually traded in the WEM, and there is a subsidy of over $500 million per year provided by the WA Government to maintain lower market retail electricity prices for the end-users [26].

3. Hypothetical scenarios

As mentioned above, a “no heroic assumptions” policy is applied in the modelling. Mature power generation technologies are included: subcritical black coal units, CCGT, OCGT, wind turbines, PV panels (fixed and 1-axis tracking) and PHES. Emerging technologies for power generation from renewable sources that remain at early stage of development are not integrated into the modelling, such as CST, geothermal and wave technology. Carbon capture and storage for the mitigation of GHG emissions from fossil-fuel power stations is also excluded because of lack of commercial deployment.

3.1. “Like-for-like” fossil-fuel replacement scenario

A “like-for-like” baseline fossil-fuel replacement scenario is modelled whereby all the current generating fleet of fossil-fuel power stations is replaced with new power generation technology utilising coal and natural gas. This is on the basis that most existing coal and natural gas power plants in the SWIS will reach the end of their technical life by 2030 [23]. New-for-old replacement allows access to the higher thermal efficiencies and lower GHG emissions of modern units. However, because of the modest size of the SWIS, where the maximum demand is approximately 3.9 GW and the residual demand through nights is as low as 1.5 GW, smaller subcritical coal units are modelled rather than larger supercritical coal units, even though they have lower thermal efficiency [27].

Table 1 shows the assumed thermal efficiencies and emission intensities for new-built subcritical black coal plants, CCGT and OCGT in the scenario [17,28].

2015-16 average international prices for Australian thermal coal and the Japan liquefied natural gas (LNG) import price [29] are used in the scenario. There has been substantial volatility in fossil fuel prices, and it is beyond the scope of the study to project future prices of coal and gas.

3.2. 90–100% renewables penetration scenarios

For comparison, two high renewable energy penetration scenarios are developed whereby the vast majority (90%) or all (100%) of annual electricity comes from wind turbines, PV panels and biogas. Biogas use is limited to 10% of annual electricity production, primarily for cold, wet, windless weeks in winter. For the 90% renewable energy scenario, natural gas-fuelled OCGTs are utilised as a supplement to biogas.

In both the 90% and 100% scenarios, off-river PHES is available to improve the balance between demand and wind/PV generation by shifting excess energy generated by wind and PV to periods of electricity shortfall which could not be met with a 10% biogas limit. One 90% renewable energy scenario is also considered with no PHES for comparison.

Natural gas-fuelled OCGTs rather than CCGT technologies or coal power generation are used in the 90% renewables scenarios due to the likely need for peaking response rather than constant generation. OCGT has relatively fast ramp rates, typically 8%/min and 22%/min for spin and quick start (which is much faster than coal plant), and has low capital cost (1/3 of the coal units and 2/3 of the CCGTs) [30].

While fossil-fuel power stations are mature technology with no significant variations expected in their capital costs, wind and PV are likely to experience reductions from current construction and operation costs. Consequently, two cost assumptions are considered: current cost estimates for 2016, and future projected costs for 2030. There is a range of price reduction factors as shown in Table 2 displaying the cost projections derived from the reports published by the Australian Energy Technology Assessment (AETA) in 2012, CO2CRC in 2015 and the International Technology Roadmap for Photovoltaic (ITRPV) in 2016 also included for comparison [28,31,32]. In this study we assume reductions by 2030 of 22% and 35% in the cost of wind and PV systems respectively.

Current costs for the construction and operation of the plants are estimated from recently commissioned or proposed wind and solar projects. Hornsdale Wind Farm signed a 20-year contract with ACT at a price of $77/MWh in December 2015 [33]. This price had no allowance for inflation, and is equivalent to $65/MWh after allowing for an inflation rate of 2.5%/year. By using its announced capacity factor 49% [34] with an assumption of the operation and maintenance (O&M) cost (3%) and a discount rate of 6.5%, the capital cost of $2300/kW for the wind farm can be derived from this price.

Information about large-scale solar farms to be funded by the Australian Renewable Energy Agency (ARENA, data released in September 2016) [35] shows an average capital cost of $1.8/W-DC and $20/MWh for the average operating expenditure of single axis tracking systems. In view of the recent rapid fall in PV module prices, a figure of $1.7/W-DC is used in our modelling.

Table 2
Percentage reductions of capital costs for power generation technologies.

Technology	Capital cost reduction (%)				
	Modelling input	AETA 2012	CO2CRC 2015	CSIRO GALLM[a]	ITRPV 2016
Wind turbines	22	24–33	20	22–24	
PV systems	35	34–48	50	51–52	30–32

Note. Projections for capital cost reductions in the years 2030 (AETA, CO2CRC, CSIRO) and 2026 (ITRPV) compared with the costs in the years 2015 (CO2CRC, CSIRO, ITRPV) and 2012 (AETA).
[a] Also from the report released by CO2CRC in 2015.

4. Modelling input and assumptions

The SWIS was divided into 14 square "activity cells", each with a side length of one degree of latitude/longitude (Fig. 3). Representative wind and solar data was obtained for each cell. The amount of wind, PV and PHES systems assigned to each cell was optimised, depending mainly upon the solar and wind resources available within the activity cell.

4.1. Solar PV

Solar resources are available using the Australian hourly Direct Normal Irradiance (DNI) and Global Horizontal Irradiance (GHI) gridded data produced by the Bureau of Meteorology (BoM) for the last decade. NREL's (National Renewable Energy Laboratory) modelling software, System Advisor Model (SAM) [36], was used to determine energy production for rooftop and 1-axis tracking of PV. Assumptions were 97–98% for the inverter efficiency, 15% for the 1-axis tracked system loss (including soiling, mismatch, DC and AC wiring, diodes and connections, nameplate degradation and availability losses and additional 3% of shading loss for rooftop PV) and 0.3 for the ground coverage ratio (1.0 for rooftop PV). The assessment points to a preferred location of large-scale solar farms in four activity cells north of Perth, where the capacity factors can exceed 23% (Fig. 3, above the lines), and also east of Perth in order to create a wide geographical distribution of PV panels to mitigate the impact of local weather events. Solar farms can be located in close proximity to the existing transmission network.

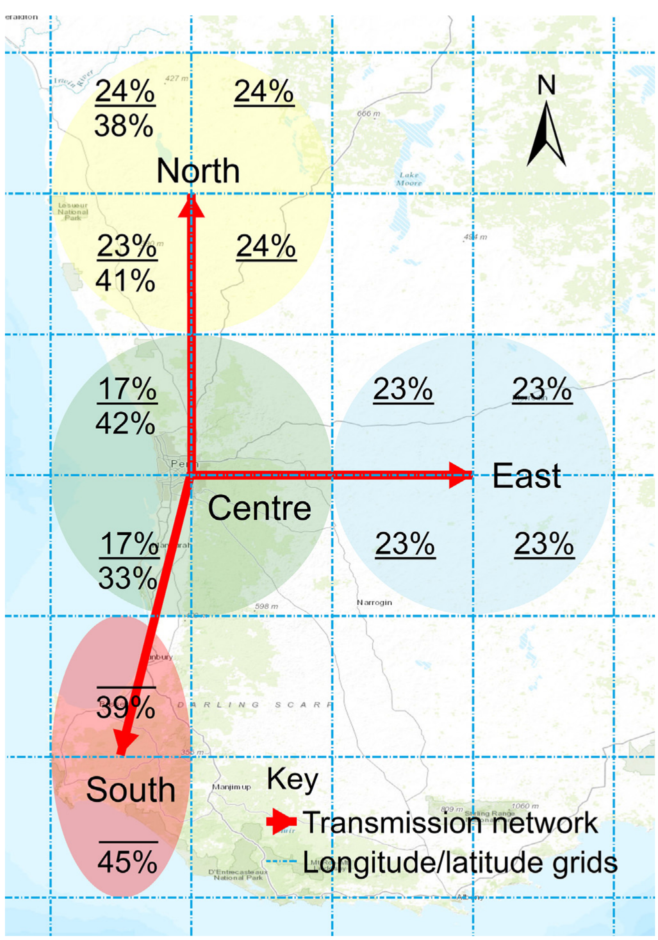

Fig. 3. Capacity factors for PV (upper figure) and wind (lower figure) in each activity cell.

All of the scenarios, including the high fossil fuel scenario, recognise the continuing substantial growth in rooftop PV systems. The scenarios incorporate 2.8 GW of rooftop PV capacity. This level of penetration assumes half of the residential houses and townhouses in the SWIS are mounted with a non-tracking 5 kW PV system (1.4 GW) [37]. The same capacity of solar panels (1.4 GW) is assumed on commercial building roofs. These PV systems are distributed across the two cells that contain the Perth/Fremantle population centres. The cost of these systems is absorbed by the building owners, and does not directly affect calculated electricity costs under this model. The output of these PV systems is assumed to be preferentially consumed before contributions from any other generator.

4.2. Wind farms

Historical half-hourly wind speed data is available from BoM for the last decade. The wind speed was originally derived from the weather stations and scaled up to the average figures at hub heights. It's then converted to power output by using the 3 MW turbine model in SAM. This data was used to determine the energy produced by the wind farms in each time period. The coastal regions from the north of Perth to the south-west corner of WA are particularly prospective, with potential capacity factors (CFs) ranging from 33% to 45% (Fig. 3, below the lines) [36]. Six activity cells distributed along the west coast hosted the simulated wind farms, which comprise 3 MW turbines. A preliminary assessment of land availability for the construction of wind farms was undertaken, demonstrating sufficient potential for each cell to deploy wind turbines at the hundreds of MW scale.

4.3. Pumped hydro

Opportunities for conventional on-river PHES such as the Tumut-3 and Shoalhaven projects in New South Wales and the Wivenhoe project in Queensland don't exist in WA. A GIS-based screening study [15] over the southwest of WA demonstrated numerous potential sites for off-river pumped hydro with a potential hydraulic head of 200–220 m, especially in the Darling Range area. The capacity of these sites far exceeds that required in this study. Moreover, some mining fields such as the Kalgoorlie Super Pit are expected to be closed in the near future which creates an opportunity to be converted into off-river pumped hydro facilities similar to that proposed for the Kidston PHES project (250 MW with 6 h of storage) in Queensland located on the site of the historical Kidston Gold Mine [38].

4.4. Biomass

Currently bioenergy constitutes 1% of the total electricity production in Australia's energy markets, and mainly comprises bagasse and landfill gas [39]. It is expected that stationary bioenergy generation in Australia is able to provide terawatt-hours of electricity to the power grids [39,40]. In this modelling, electricity production from biomass is limited to less than 10% (approximately 1.8 TWh per year) of the total consumption for the 90% and 100% renewables scenarios, and is assumed to be reserved for quick-response biogas-fuelled OCGTs.

4.5. Electricity loads

The historical demand of the SWIS is recorded by the system operator AEMO Western Australia (previously the Independent

Market Operator) showing a slow growth of the annual energy consumptions since the last decade as well as an undulating trend of the peak demand (Fig. 4). In order to model the interaction of wind and PV with demand in each hour interval over many years, demand in previous years is inflated to bring the annual total for each year up to that of 2014 (18.4 TWh).

4.6. Cost assumptions

Cost assumptions for baseline cases are listed in Table 3 [23,28,29,31].

4.7. Discount rates

A nominal discount rate of 6.5% is assumed for the baseline assumption to reflect the integrated rates for the returns on investment (30% of the capital with a 10% internal rate of return) and the interest rates from banks (70% of the capital with a loan interest rate of 5%). The baseline assumption reflects a decreasing interest rate environment in Australia and low risk and equity margins for renewable energy business once entering the era of high renewables penetration. This translates to a real discount rate of 5% by factoring in an inflation rate of 1.5%. The Australian Reserve Bank rate is currently 1.5% per year [41]. This is further discussed in the sensitivity analysis.

4.8. Modelling

This study undertakes an hourly energy balance analysis on the basis of historical solar, wind and demand data throughout the years 2007-14 in the SWIS. The supply of electricity was balanced against historical demand (uprated as discussed in section 4.5) for each hour period of each year by utilising PV, wind, coal, gas, biogas and PHES generators [17]. If supply was less than demand in any period, then additional capacity was included in the next modelling iteration. Thousands of iterations were performed, and for each iteration the cost of energy was calculated. In this way, optimised configurations of the various generating units could be determined. The modelling assumed 0.002% unserved energy.

The energy balancing model used in this study is modified and extended from the National Electricity Market Optimiser (NEMO) which was developed by Elliston et al. [42]. NEMO is a chronological dispatch model aiming to explore lowest-cost solutions for the Australian energy markets and has been used in a series of high renewables studies [17,43,44].

In this study, several adjustments to the NEMO model have been made in order to better utilise the capability of synchronous, fast-ramping PHES to integrate fluctuating solar and wind energy.

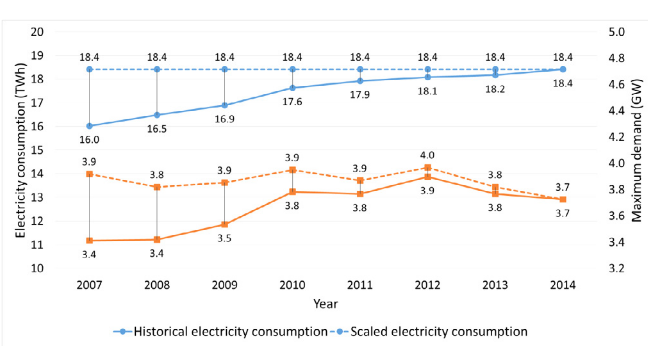

Fig. 4. Electricity consumptions and maximum demands in the SWIS.

This includes a range of operation strategies: a) pre-charging PHES facilities from existing bio and hydro plants to help ride through critical periods based on advanced weather forecasting; b) changing the merit order of existing hydro ahead of PHES in critical periods to ensure PHES not to be exhausted before the most difficult moments arrive; c) PHES co-operation to maintain maximum power and storage capacities for pumping and generation.

As with AEMO [16], Elliston et al. [17] and Lenzen et al. [18], the optimisation objective of this modelling is to find the lowest-cost generation mix while ensuring the current NEM reliability standard (<0.002% of the total demand) can be met. This is different from the studies of Connolly et al. [20] and Lund and Salgi [19] where a maximum energy spillage figure was set as a constraint when increasing wind penetration levels in the systems.

Moreover, Connolly et al. [20] and Lund and Salgi [19] modelled the entire energy sectors in Ireland and Denmark, including electricity, heating, industry processes and transportation while this study only focuses on the electricity industry. However, we note that transport and urban heat can be electrified through large-scale deployment of electric vehicles and heat pumps respectively in high renewables penetration systems. These devices have large-scale storage in the form of batteries in vehicles and heat/cool in water stores and the building fabric. This storage may substantially reduce system costs in the future.

In addition, the grid stabilisation measures applied in this study are much different from these previous studies. This is described in section 5.6. Stochastic modelling for power generation, fuel costs and electricity demand is not included while the historical meteorological data and loads are used in this study.

5. Modelling results

5.1. GHG emissions

By replacing the existing fleet of coal and natural gas generators burning low grade coal with modern generators burning higher grade coal and gas, the associated annual GHG emissions (23 Mt CO2-e in 2013 [45]) can be halved to 11 Mt CO2-e per year (Fig. 5). In the 90% renewables scenarios, about 95% of the current GHG emissions are eliminated.

5.2. Levelised cost of electricity (LCOE)

The system LCOE calculated for the “like-for-like” fossil-fuel replacement scenario is $94/MWh while the 90% renewables scenario without pumped hydro costs $126/MWh under the cost estimates for 2016, and $110/MWh under the cost projects for 2030. Under this scenario a significant gap of LCOE between fossil-fuel power generation and renewables exists.

Pumped hydro makes a significant improvement to the LCOE of the high renewable scenarios. For example, with the integration of pumped hydro, the system LCOE for the 90% renewables scenario reduces from $126/MWh to $116/MWh under 2016 cost estimates and from $110/MWh to $103/MWh under the projected costs for 2030, which mitigates the difference with the fossil-fuel scenario from $32/MWh to $22/MWh under current capital and O&M costs and $9/MWh in 2030 costs.

By integrating pumped hydro into high renewables penetration scenarios, reductions in installed capacities of wind turbines (from 4.5 GW to 3.5 GW) and OCGTs (from 3 GW to 2 GW) are achieved. Wind energy that would otherwise be spilled can be stored to produce electricity during critical periods of electricity shortfall when solar and/or wind availability is low. Fig. 7 illustrates load profiles and generation mix for a typical week under the 90% renewables scenarios without (a) and with (b) pumped hydro.

Table 3
Baseline cost assumptions for power generation technologies (2016 AU$).

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Technical lifetime (years)
Subcritical black coal	2900	45	2.5	3.1	40
CCGT	1450	20	1.5	11	30
OCGT	1000	8	12	11	30
Wind turbines	2300	35	10	0	25
1-axis tracking PV	1700	0	20	0	25
Pumped hydro	1180/200[a]	10	0	0	50
Biogas-fuelled OCGT	1000	8	12	12	30

Note. Cost estimates for 2016.
[a] $1180/kW for power components including turbines, generators, pipes and transformers, $200/kWh for storage components such as dams, reservoirs and water. A 200 m head for PHES systems is assumed.

Pumped hydro only accounts for a small fraction of the system LCOE (Fig. 6). This is because: a) rather than long-term energy storage with a duration of weeks, short-term pumped hydro (hours) is preferred by the model; b) unlike conventional on-river pumped hydro, off-river PHES needs no construction of dams on existing river systems and hence avoids high construction and operation costs related to environment protection and flood control issues.

Although biomass contributes only 10% of annual energy, it contributes more than 20% of the LCOE because of its relatively high fuel cost.

5.3. A pure renewable system

Pumped hydro storage is necessary to enable the 100% renewables scenario due to the constraint imposed on biomass of 10% of annual energy. This constraint is imposed to avoid a “heroic” increase in the quantity of biogas produced each year. The quantity of energy unable to be serviced by wind and PV is more than 10% due to the amount of time with both low wind and insolation. Short term storage is beneficial to this system, shifting energy from times when it would otherwise have been shed to periods of low solar and/or wind resource. This reduces the need for biomass support in the 100% renewables scenario to less than 10% for the simulated years.

It is noted that this pure renewable system costs $129/MWh under current costs which is close to the 90% renewables scenario without pumped hydro integrated ($126/MWh), and costs $109/MWh under 2030 cost estimates. The 100% scenario is able to compete with the fossil-fuel replacement scenario ($112/MWh) if a carbon price of $25/tonne of CO_{2e} is factored into the system LCOE. Significantly, no GHG-emissions are produced from this 100% renewables scenario.

5.4. Wind and solar penetration

Rooftop PV, which peaks each sunny day, contributes about a quarter of the total annual electricity generation (Fig. 5) in both the fossil-fuel and the renewables scenarios.

Large-scale solar PV is not included in the least-cost portfolio of generation mix under the cost estimates for 2016 (90% renewables) but contributes to the generation portfolio under the cost projections for 2030 where its capital cost decreases by 35% from current levels. This indicates a significant cost reduction of large-scale solar PV is needed for it to become more attractive in the WA system. This is due to the much higher capacity factors for wind in southwest WA, and insufficiently strong anti-correlation between wind and PV generation profiles in the SWIS. In other locations PV and wind may have more complementary generation profiles, and their combined use would reduce spillage of wind and PV electricity (equivalently they would have a higher combined capacity factor).

In the high renewable energy penetration scenarios, wind farms produce the largest proportions of electricity to the system accounting for 51% (with pumped hydro) and 57% (without pumped hydro) for the 90% renewables scenarios and 44% for the 100% renewables scenario (Table 4). Additionally, a further 5% of the total electricity that is contributed by pumped hydro in the 90% renewables scenario is mainly derived from the excess generation of wind turbines, and this figure increases to 10% in the 100% renewables scenario. Wind energy plays a key role in the high SWIS renewable power scenarios due to the very high capacity factors along the coastal regions of the southwest WA (33%–45%). This

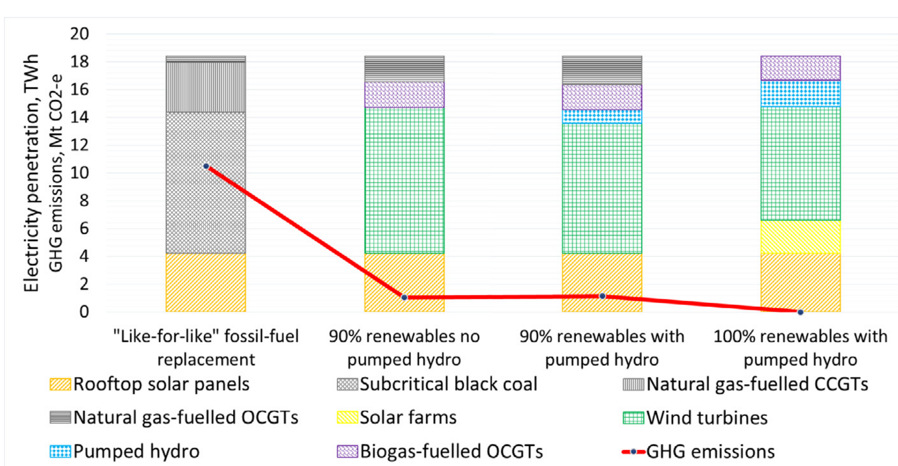

Fig. 5. Electricity penetration and GHG emissions of each scenario.

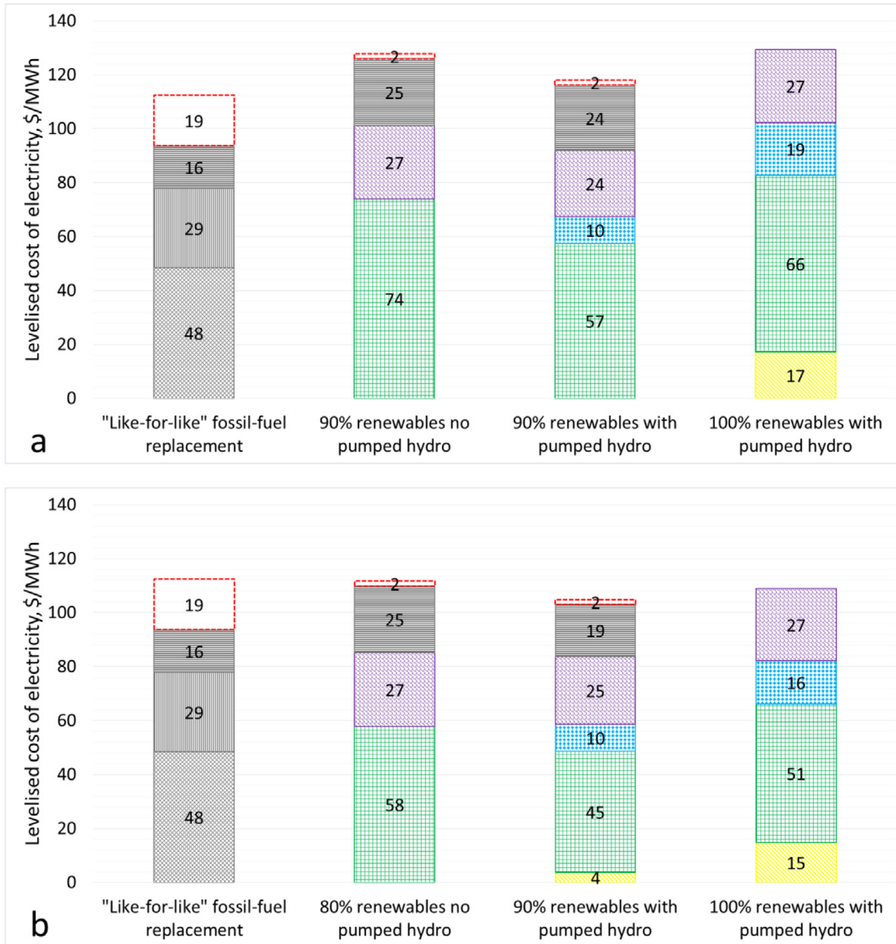

Fig. 6. LCOE breakdown for each scenario in (a) 2016 and (b) 2030. Colour scheme is the same as Fig. 5 with the top red dashed lines denoting carbon prices.

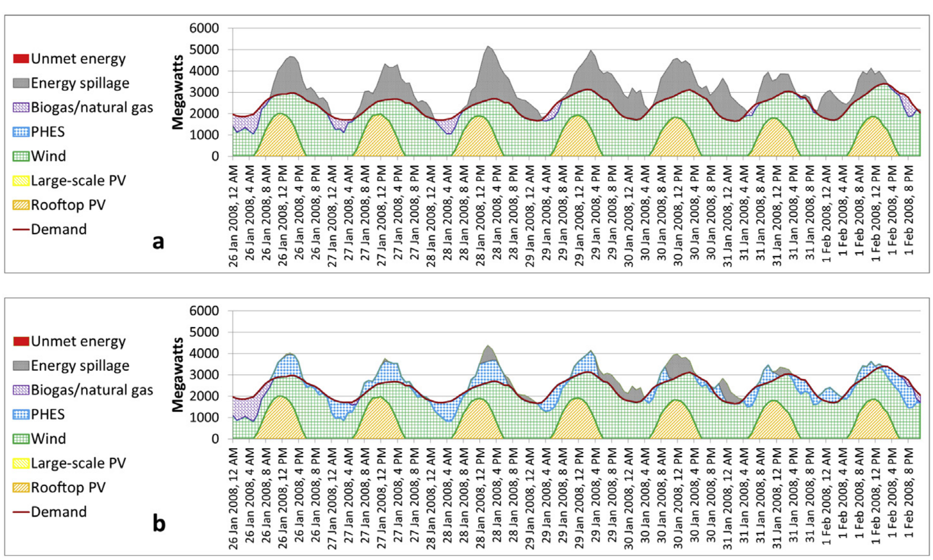

Fig. 7. Load profiles and generation mix for a typical week under the 90% renewables scenarios without (a) and with (b) pumped hydro.

compares favourably to the capacity factors for large-scale solar farms made up of 1-axis tracking PV panels of 23%–24%.

In addition, thanks to rapid ramp rates of PHES, which is typically 50%/min for spin and quick start, PHES is able to rapidly respond to short-term fluctuations in the system which comes from the imbalance between power supply and demand. This facilitates high penetration of intermittent and also less controllable wind and solar electricity in the electricity market.

Table 4
Generating capacity and electricity penetration for each scenario (2016 costs).

Technology	Capacity (GW)/Annual electricity penetration (TWh)			
	Fossil-fuel replacement	90% renewables without PHES	90% renewables with PHES	100% renewables
Subcritical black coal	1.6/10.1	–	–	–
Natural gas-fuelled CCGTs	1.1/3.6	–	–	–
Natural gas-fuelled OCGTs	2.2/0.5	1.5/1.9	1.1/2.0	–
Rooftop PV	2.8/4.2	2.8/4.2	2.8/4.2	2.8/4.2
Wind turbines	–	4.5/10.5	3.5/9.4	4.0/8.2
Large-scale solar farms	–	0.0/0.0	0.0/0.0	1.5/2.3
Pumped hydro	–	–	1.0[a]/1.0	1.5[b]/1.9
Biogas-fuelled OCGTs	–	1.5/1.8	0.9/1.8	1.5/1.7

Note. Electricity penetration (TWh) for a simulated year.
[a] 1.0 GW pumped hydro with 6 h of storage for the 90% renewables scenario.
[b] 1.5 GW pumped hydro with 10 h of storage for the 100% renewables scenario.

5.5. Reserve capacity

In the existing fossil fuels-dominated power industry of the SWIS, a large quantity of generating facilities (over 1 GW) needs to be operated as reserve capacity to ensure an adequate generation capacity available in case of emergency and during the peaking periods.

The nature of a distributed renewable energy system comprised of thousands of individual wind and PV systems avoids a significant impact on system reliability and security resulting from a sudden loss of a single large power generator. The use of thousands of PV and wind energy systems greatly reduces the effect of unexpected individual generator failure compared with an electricity system comprising a small number of large fossil or nuclear power stations, due to statistical reasons. In addition, pumped hydro is also suitable for demand-side participation programs as it is able to quickly suspend the consumption of electricity (pumping) if the system requires help in maintaining frequency stability.

The intermittency of power supply due to weather events is mitigated by wide dispersion of renewable generating facilities and by using advanced weather forecasting techniques. However, the relatively small geographical size of the SWIS compared with the eastern states grid substantially limits the ability to widely disperse the wind and PV generators. System robustness under high penetration of wind and solar energy scenarios and the behaviours of pumped hydro in power systems in case of emergency will be further investigated in future work.

5.6. Grid stability

Although the dynamical behaviour (on time scales of sub-seconds to minutes) of a 90–100% renewable energy grid is outside the scope of the present study, we note that PHES provides significant inertia, spinning reserve and rapid response capability to help maintain a high level of dynamical grid stability.

Connolly et al. [20] applied a non-synchronous penetration (NSP) limit of 70% in each hour's generation mix as a grid stabilisation measure while this limit was released to 75–80% in the studies of Krajacic et al. [21] and Elliston et al. [17]. AEMO [16] integrated a significant proportion of thermal generation technologies such as geothermal, biomass and CST to ensure the modelled 100% renewables system ensembles current structures of fossil fuels-dominated system (baseload – intermediate – peaking units).

By contrast, this study does not incorporate a NSP limit nor integrate geothermal or CST technologies while utilising the synchronous and fast-ramping characteristics of PHES generators/pumps to maintain the grid stability. As an initial estimate, 1.5 GW PHES when operated as generators or spinning reserve in the 100% renewables scenario is capable of providing 3000–6000 MW.s of inertial energy. While pumping or operated in electric motor mode, it is also able to contribute significant inertial energy required by the system stability. Also, the 1.5 GW biogas-fuelled OCGTs in that scenario can play an important role in the grid stabilisation. Detailed analyses of dynamical stability will be undertaken in future study.

In addition, we also note that interconnections with neighbouring electricity systems can be another approach to strengthen the grid stability. Future work will examine the possibility of connecting the SWIS network with the National Electricity Market (Perth to Port Augusta 2500 km or Kalgoorlie to Eyre Peninsula 2000 km) by utilising high voltage DC which can transmit gigawatts of power over thousands of kilometres [46].

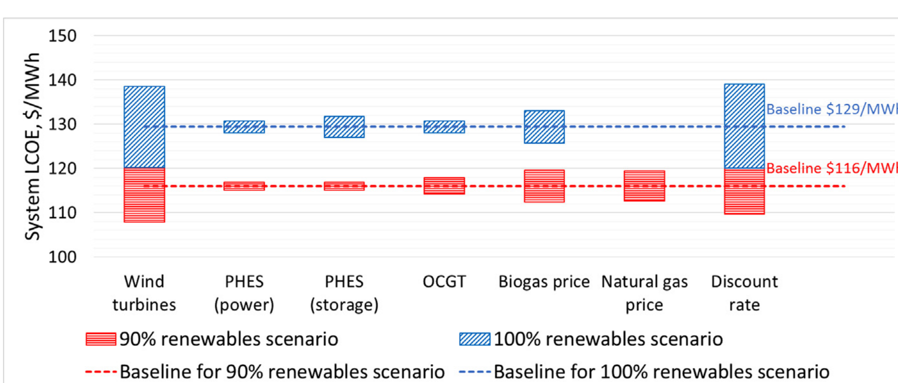

Fig. 8. Sensitivity analysis of the system cost components (Baseline 2016 costs).

6. Sensitivity analysis

Each critical cost component of the renewable system LCOE is analysed by varying the values between −20% and 20% to examine its significance in the overall cost of the system.

6.1. Discount rate

As illustrated in Fig. 8, a 20% change of real discount rates causes \$6–7/MWh of cost variations for the 90% renewables scenario (with pumped hydro and without carbon price) and \$9–10/MWh for the 100% renewables scenario under the cost estimates for 2016.

This demonstrates renewable energy systems, which are mainly driven by capital costs rather than fuel prices, are sensitive to the change of discount rates. Under an environment of low discount rates, the 90% renewables scenario is fully competitive with the fossil-fuel scenario especially when a carbon price included.

This indicates financial incentives such as low interest loans or a committed renewable energy target from government (in order to attract low risk/cost finance) are critical to the capital-intensive renewable industry, especially in the context of existing fossil-fuel power industry in WA receiving a subsidy of approximately \$500 million per year.

6.2. Capital cost

A 20% decrease of the capital cost for wind turbines from the baseline \$2300/kW to \$1840/kW also cause a significant reduction of the system LCOE from \$116/MWh to \$108/MWh for the 90% renewables scenario (with pumped hydro and without carbon price) and from \$129/MWh to \$120/MWh for the 100% renewables scenario. The capital cost of OCGT and the prices for biogas and natural gas can affect the system LCOE to some degree, although the small amount of fossil fuel used mitigates the effect. In other words, a high renewables scenario insulates the SWIS from future fossil fuel price variability.

It is noted that off-river pumped hydro cost has a minor effect on system LCOE. Variation in the cost of PHES has only a small influence on the system LCOE because the cost of pumped hydro only accounts for a small proportion of the system LCOE.

7. Conclusion

This work has demonstrated that very high penetrations of renewable energy can be delivered in the SWIS electricity network through the use of proven renewable technologies that are already in large scale (>150 GW) deployment. This is particularly significant given the relatively small, closed nature of the SWIS with no interconnection to neighbouring regions. Levels of 90% penetration or more can be managed at reasonable cost with the use of natural gas or biogas peaking to manage medium term (a few days) shortages. The cost of the system can be significantly reduced through the use of off-river pumped hydro to manage short term (hours-day) energy shifts.

A second important conclusion is that there is a \$22/MWh of difference in cost between a fossil fuel scenario in 2016 (\$94/MWh) and a 90% renewable energy scenario (\$116/MWh). This difference is highly likely to decline over time, and is immediately reduced to \$6/MWh if the moderate carbon price that prevailed until 2014 [47] (\$23–25/tonne of emitted CO_2) were to be reinstated. Construction of fossil fuel generators is inhibited by the current small economic advantage, when account is taken of the risk of a future carbon price.

Through the transition of the existing fossil fuels-dominated power industry to a high renewables penetration system such as the 90% renewables scenarios hypothesised for the SWIS, the vast majority of GHG emissions from electricity production can be eliminated. This would result in a removal of nearly one third of the state's GHG emissions which helps achieve the 2030 Emission Reduction Target of Australia.

Australia's current Renewable Energy Target is effectively 33 TWh of electricity generated from large-scale non-hydro renewable power stations by 2020, which is equivalent to PV, wind, hydro and biomass contributing about 24% of total electrical energy. This plays an important role in achieving Australia's 2020 emissions reduction target [47]. Similarly, a renewable energy target (or equivalent) for the post-2020 period is critical for further reducing GHG emissions to ensure the 2030 emissions reduction target is met. Legislated targets facilitate long-term supply contracts between electricity retailers and renewable project developers and provide future renewable investments with greater certainty and lower cost of capital.

With the integration of off-river pumped hydro, the costs for a renewable system substantially reduces while the system operation can still satisfy the reliability standard and security requirements, which helps high renewables penetration systems become more competitive with the existing fossil fuels-dominated power industry. Significantly, a pure renewables system where all the demands are powered by mature technologies of power generation from renewable sources become realistic in a cost-effective way by the deployment of off-river pumped hydro in the system.

Discount rates and the capital cost of wind turbines are the most significant factors that influence the system LCOE while construction costs for off-river pumped hydro has a moderate influence on the system LCOE though it plays significant roles in reducing the system LCOE as a whole and facilitating high penetration of intermittent wind and PV electricity in power system.

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Appendix

A1. Water requirement for off-river pumped hydro

An off-river pumped hydro plant is one in which water is cycled in a closed loop between upper and lower reservoirs. A moderate volume of water is needed to initialise the facilities. Ongoing top-up is required to offset the losses from evaporation and leakage during the operation, minus water delivered by rainfall. In the least-cost 90% renewables scenario, the required energy storage from pumped hydro is 1 GW of power capacity and 6 h of storage capacity. This translates to 2 GL of water consumed every year on average (evaporation minus rainfall). By contrast, existing fossil-fuel power stations in the SWIS consume around 18 GL of water per year accounting for 1.4% of the state's annual water consumption (Fig. 9) [48].

In other words, compared with conventional fossil-fuel power industry which consumes respectively 1.5 L and 0.56 L of water for a kWh of electricity production in coal and natural gas power stations, the 90% renewables scenario with short-term off-river energy storage from pumped hydro merely requires 0.11 L/kWh for the power generation.

This moderate amount of water can be transported from nearby water sources by pipelines, channels or water trucks depending on which is the most economical approach. Alternatively, it can be harvested by creating natural or artificial catchments to collect

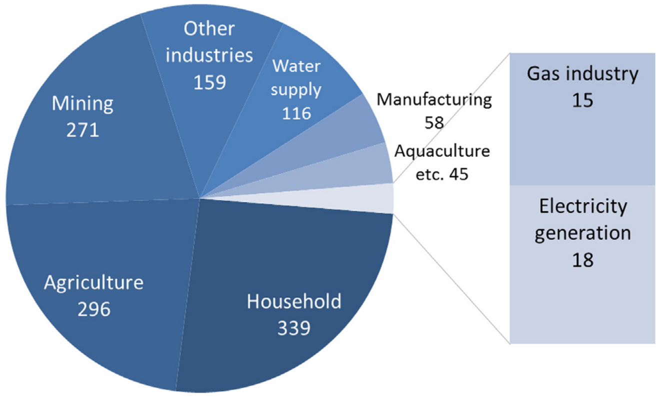

Fig. 9. Water consumptions (GL) in Western Australia 2013–14.

rainwater as a supplement or by utilising evaporation and leakage reduction measures to balance the water losses with gains during the operation. Further, although the cost of water is site-specific and decided by the approaches for water transportation, the total capital expenditure of storage components for a medium-sized pumped hydro which includes water cost is calculated to have only a small impact on the system LCOE in the sensitivity analysis.

A2. Residential battery storage system

Residential batteries mounted behind-the-meter such as the Tesla Powerwall and Panasonic LJ-SK84A are able to change the load profiles allowing more electricity from rooftop PV consumed by end-users and mitigating demands in the periods of evening peaks. A residential battery system with 8 kWh of storage capacity (2 kW × 4 h) is integrated into the 90% and 100% renewables scenarios in the WA households where there is a rooftop PV installed, which can contribute 2 GWh of energy storage capacity to the system for day-night load shifting. These batteries are assumed to be charging from 10 a.m. to 3 p.m. (peaking at 12 p.m. and 1 p.m.) to store surplus renewable energy and powering the evening demands between 5 p.m. and 10 p.m. (peaking at 6 p.m. and 7 p.m.). A slight reduction in the system LCOE ($2/MWh, compared with $10/MWh reduction from the integration of PHES for the 90% renewables scenario) is demonstrated in the modelling.

However, future development of residential battery storage systems in Australia's households remains uncertain and is driven by a range of factors such as price decreases and financial incentive programs offered by the utilities. The operation of residential batteries in the system as well as the role in the amelioration of system reliability needs further investigation.

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