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Decarbonizing Industrial Steam Generation Using Solar and Wind Power in a Constrained Electricity Network

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Abstract: Australia aims to achieve net zero emissions by 2050, with an interim target of reducing emissions to 43% below 2005 levels by 2030. Electrification of industry processes currently reliant on fossil fuels is a necessary step to achieve these emission reduction goals. This study investigates electrification of steam generation relevant to major industrial operations in the southwest of Western Australia using different renewable energy input levels. The designed system incorporates thermal storage to ensure continuous steam generation. The optimized technology mix, including wind, PV, and concentrated solar thermal (CST) systems for each renewable energy input target, is presented. The optimization process also identifies optimal locations for new renewable energy plants. In summary, the optimization tends towards favouring the development of large CST plants near a demand point. This avoids the use of the transmission network by direct use of the CST system for heating of the storage media, to address the costs and efficiency reductions arising from electrical heating, but the scope of CST use is expected to be limited by site constraints. The levelized cost of heat (LCOH) for the studied renewable energy input targets (i.e., 30–90%) ranges from 15.34 to 36.92 AUD/GJ. This is promising for the 30% renewable energy target, as future natural gas prices in Western Australia are likely to match or exceed the expected LCOH. Cost reductions for renewable generation and storage technologies with further implementation at a large scale in the future may result in more competitive LCOH at higher decarbonization levels, but it is likely that additional technologies will be required for cost competitiveness at very high decarbonization levels.

Keywords: CST; PV; thermal storage; wind; decarbonatization; network modeling

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1. Introduction

Australia aims to reach net zero emissions by 2050. Australian annual greenhouse gas emissions have decreased by 29% since June 2005. However, Australian emissions per capita are higher than those of other developed countries, and significant further progress across all of the economy's sectors needs to be made to achieve Australia's legislated commitment to reduce emissions by 43% by 2030 [1]. Although the contribution of industrial processes to Australia's total emissions is around 6% [2], substantial emission cuts are necessary to meet the reduction targets. In addition, the emissions from the production of exported materials are increasingly being considered by international customers. Therefore, Australian industry is actively aspiring to introduce new technologies to decarbonize industrial processes.

A comprehensive review of Australian industries and their energy needs with a focus on the application of solar thermal systems was conducted and presented in the authors' previous works [3–5]. Lovegrove et al. [6] undertook a study on the potential opportunities for renewable energy integration into industrial process heat applications. The Australian industrial sector accounts for 44% of the country's total energy consumption, of which 52% is used to supply process heat. Currently, heat is mainly provided by gas consumption, followed by coal. Over 1500 industrial sites across Australia use process heat, with most utilizing below 0.1 PJ/year. However, the largest proportion of heat consumption, i.e., more than 5 PJ/year, occurs in a limited number of large sites, including alumina refineries and iron and steel production facilities. Their findings also highlighted the fact that all current industrial uses of process heat have options to use renewable sources, including bioenergy, geothermal, renewable electricity, renewable hydrogen and solar thermal.

Decarbonization of Australian electricity networks has been the subject of study in recent years. The electrification of industrial processes has been included in a limited number of studies; however, these provide a high-level analysis, and the detailed investigation of industrial processes has not been addressed. Lu et al. [7] modelled a fully decarbonized electricity network with complete electrification of heating, transport, and industry, resulting in an 80% greenhouse gas emissions reduction. Their findings indicated that a synergistic combination of flexible energy sources, interconnection of electricity grids, demand-side response participation, and widespread energy storage can achieve high levels of reliability and affordability in the energy system. Laslett [8] examined the cost-effectiveness of utilizing high levels of distributed renewable energy and battery storage technology for meeting the energy demands of the South West Interconnected System (SWIS) electricity network in the southwest of Western Australia. The results highlighted the cost competitiveness of the investigated approach compared to the conventional fossil fuel business-as-usual approach, even without a carbon price or cost improvements, up to a break-even point of 70% renewable energy. With a carbon price or cost improvements in renewable energy technologies, the break-even point could increase and could potentially exceed 99%.

Lu et al. [9] modelled various scenarios with high renewable penetration (90% and 100%) for the SWIS network, incorporating wind and PV sources supplemented by a small proportion of biogas. Additionally, in certain scenarios, short-term closed cycle pumped hydro energy storage was considered as a large-scale conventional storage technology. Their findings indicated that high penetration levels of renewable energy can be achieved in the SWIS, which is of significance given the network's relatively small size without interconnection to the other networks. The results also demonstrated that achieving penetration levels of 90% or higher is economically viable by incorporating natural gas or biogas peaking to address medium-term (a few days) shortages. Integrating off-river pumped hydro for short-term (hours to days) energy shifts allows for a substantial cost reduction in the system. Transgrid [10] in partnership with several organizations and independent experts, developed and modelled six possible futures scenarios for Australia's energy system through the year 2050. In all scenarios, renewable energy will supply the majority of electricity needs in the National Electricity Market (NEM). In five out of the six scenarios, including the current trend (i.e., business-as-usual), over 70% of the NEM's annual energy needs will be supplied by renewable energy by 2035 and this percentage will exceed 90% by 2050. Under the scenario where the Australian economic growth slumps due to a global economic downturn, the renewable energy share will be over 50% by 2035 and 80% by 2050.

Lasslett et al. [11] developed a web-based interactive tool to model scenarios aiming for a 100% renewable electricity supply in the SWIS network. Due to the urgency of climate change mitigation measures, a swift completion schedule by 2030 was established, deviating from the conventional target of 2050. Various scenarios were explored, including high wind generation and different levels of solar power, wind power, distributed battery storage, energy efficiency enhancements, and power-to-gas systems. Simulation results demonstrated the feasibility of meeting the entire electrical demand of the SWIS on an hourly basis, projected out to the year 2030, under typical weather conditions. This was achieved using a combination of energy-efficient measures, residential and commercial rooftop photovoltaic systems, solar thermal power stations with heat storage, wind power, and distributed battery storage systems.

The Western Australian government established the Energy Transformation Taskforce in 2019 to deliver the government's energy transformation strategy. This taskforce prepared the Whole of System Plan (WOSP) report in 2020 [12]. The WOSP report outlines four prospective scenarios depicting the potential evolution of the SWIS up to the year 2040. Each scenario is underpinned by a range of assumptions regarding electricity demand growth, derived from considerations such as economic conditions, demographic changes, and uptake of distributed energy resources. Using an exhaustive modelling and analysis approach, the WOSP study, regarded as the most comprehensive undertaken on the SWIS, utilizes these scenario inputs to generate optimal combinations of cost-effective solutions for meeting demand. This encompasses the required capacities for transmission, generation, and storage, tailored to the unique conditions posed by each scenario. In all four scenarios, rooftop PV deployment is expected to rise, albeit at varying rates. Lower demand scenarios indicate minimal additional generation capacity needed before 2030, with sufficient rooftop PV and existing large-scale generation meeting demand. Higher demand scenarios require a cost-effective solution involving substantial large-scale renewable generation and some new flexible gas-fired facilities. Transmission capacity remains stable in lower demand scenarios, with minimal increases in the first decade of higher demand scenarios. Significant transmission capacity increases occur only when operational demand doubles in the SWIS. Energy storage is integral in all scenarios, varying in scale, while emission intensity of electricity production decreases across the board.

The present work focuses on the electrification of steam generation using varying renewable energy inputs in southwest Western Australia, where significant steam demand in major industrial operations exists. The optimized technology mix encompassing wind, PV, and CST (i.e., conventional molten salt tower) systems is presented for each renewable energy input target. An onsite thermal storage system is also incorporated to ensure a continuous steam supply. The optimization also involves identifying prospective locations to construct new renewable energy projects. This study leverages extensive experience in optimizing and simulating renewable energy technologies, especially molten salt solar tower systems. This work also draws upon the insights from the WOSP study's network modelling.

2. Materials and Methods

Production of steam is a major energy consumer in large industrial operations in southwest Western Australia, which is currently performed using fossil fuels. Steam provision technologies vary between industrial sites, with coal and natural gas-fired boilers being common, as well as heat recovery steam generators using waste heat from gas turbines. The challenge in achieving decarbonization of steam production is primarily that many processes require very consistent supply during operation. Steam generation is a very conventional industrial operation, but it is difficult to guarantee that renewable energy from sources such as solar and wind will be consistent with the standards required by these processes. Therefore, it is necessary to consider how diversity of supply and storage buffering can be used to achieve higher renewable input. This is particularly challenging in the southwest of Western Australia where there is a relatively small-capacity electricity network currently based heavily on fossil energy, and there is limited opportunity to install the large pumped hydro systems that are used in other areas to ensure reliability in electricity supplies. The scale of the energy demand in the region is also too large to expect that biomass will be able to provide a significant and economically viable contribution to energy input, so it is expected that solar and wind will be the most appropriate energy sources for the region.

2.1. Steam Supply System

As noted, the current energy supplies for steam generation are typically coal or natural gas. The systems for generating process steam vary, which affects the efficiency and emissions, but there is a target to decarbonize the process, and this requires a complete shift from fossil fuels to renewable input. There are several options for how this can be achieved, such as mechanical vapour recompression (MVR), electric boilers, improved heat recovery and alternative fuels, and it is possible that a combination of these will be used in practise. In this study, the assumption is that at least a significant portion of steam production will require electrical input in some form, and this will place additional demand on renewable energy supply from the transmission network. This requires that projections of the future supply of electricity in the network be used to estimate its availability. Given the scale of demand and the current condition of the SWIS network, it is extremely likely that additional generation capacity will be needed to secure sufficient electricity for the desired renewable energy input.

Consultation with the main industrial users in the region led to the conclusion that there is a requirement to produce 500 MW_t of steam continuously, using either renewable energy from external sources (local or network supply) or energy stored onsite. A preliminary assumption for the sizing of the storage requirements is that the system will be required to store 12 h of energy, i.e., 6 GWh. This assumption is tested and revised during the techno-economic assessment. A general plant configuration for thermal storage is provided in Figure 1, with the preferred option being the production of high-temperature steam (500 °C, 8 MPa) during periods when network electricity is expensive, and low-temperature steam (250 °C, 0.8 MPa) when network electricity is low-cost. In this configuration, steam is always produced using stored heat, and the storage will be charged by either a network or local sources of renewable energy. The options for this supply will be determined by the cost of supplying electricity, storing this thermally, and subsequent conversion to steam as required. The suitability of thermal storage technologies for these processes at the required scale is assessed, and appropriate methods are evaluated in the techno-economic analysis. Obvious criteria are the cost of the storage containment, and the energy transfer stages, but it is also notable that the efficiency of the overall system will have an influence on the requirement for electricity generation capacity that may have a significant impact on the overall economics. Evaluating this requires a comprehensive assessment of the performance of the overall supply network throughout a year of operations.

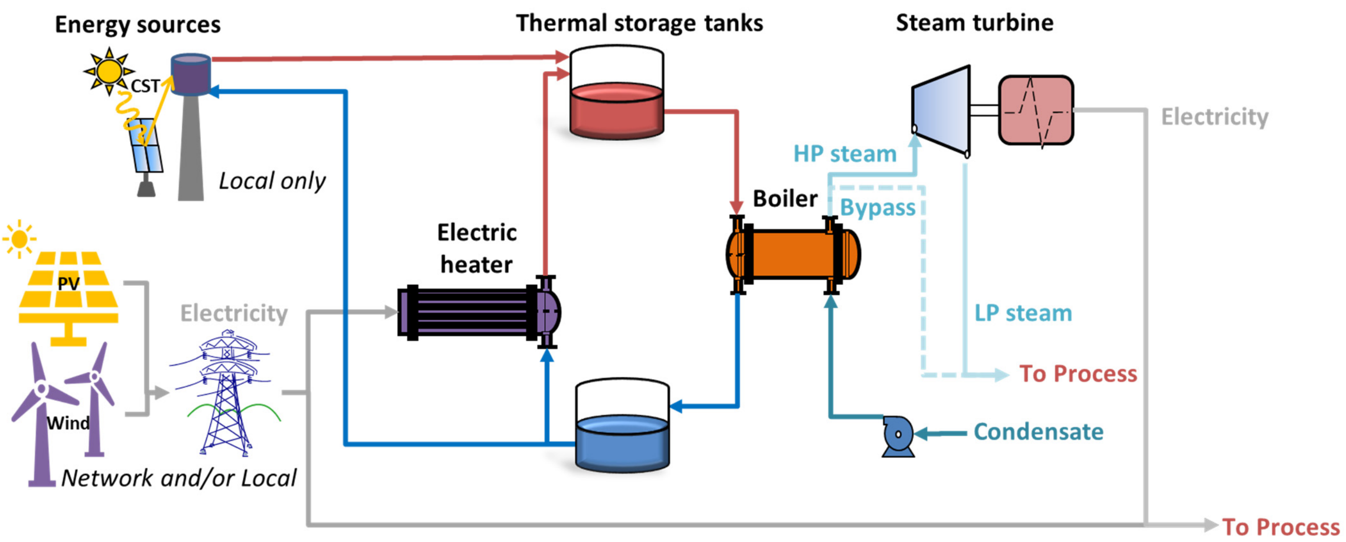


Figure 1. Schematic diagram of the steam generation system.

A broad review of thermal energy storage (TES) was undertaken that included a range of liquids and solids for sensible heat, phase change materials for latent heat, and thermochemical reaction systems. Despite the large number of systems that have been researched and increased recent commercial interest in marketing new designs, the only system with significant experience at this scale is the mixture of molten salts that are typically used in concentrated solar thermal power plants. While there are known issues with this technology, as it either freezes or breaks down when outside the safe temperature range, there are engineering solutions to limit the likelihood of this occurring, and it remains the preferred storage for steam generation at large scales. Liquid storage media are commonly heated using resistive heating elements in the form of immersion heaters. A protective sheath around the element can utilize a metal alloy of appropriate type to limit chemical or physical damage, and the elements may be bundled on a flanged fitting to allow removal for maintenance, hence a conveniently flexible system for many applications. This approach is used with molten salt in industrial heating applications and is therefore adopted in this study.

2.2. Capital Cost Estimates

As noted in a previously published study conducted by the authors [13], a comprehensive analysis of international as well as Australian studies [14–26] led to a detailed cost breakdown of a molten salt central receiver base-case plant (294 MW_t of thermal capacity with 4 h of two-tank thermal storage). The cost study also resulted in three cost values for the base-case plant items (most likely, maximum, and minimum) which were used to carry out probabilistic analyses. The cost values have been updated ever since to reflect cost reductions due to the molten salt system's maturity over years. A cost model was also prepared to estimate costs for other system sizes and provide a detailed system cost breakdown. This model used conventional engineering assessment techniques to estimate the cost of a plant component based on scale. The previously developed model was used to estimate the cost breakdown for four different molten salt storage system configurations: 1 pair, 2 pairs, 4 pairs, and 8 pairs, with a total capacity of 6 GWh. Figure 2 depicts the cost breakdown for different thermal storage configurations and the associated Steam Generation Systems (SGS). A review of the CST projects that are in operation or under construction around the world showed that 1 pair of storage tanks with a capacity of below 3 GWh is quite common for the new plants. Therefore, it appears that, given the current industry practise, an arrangement consisting of 4 pairs of storage tanks (1.5 GWh each) is more practical in comparison with the configurations with larger tanks.

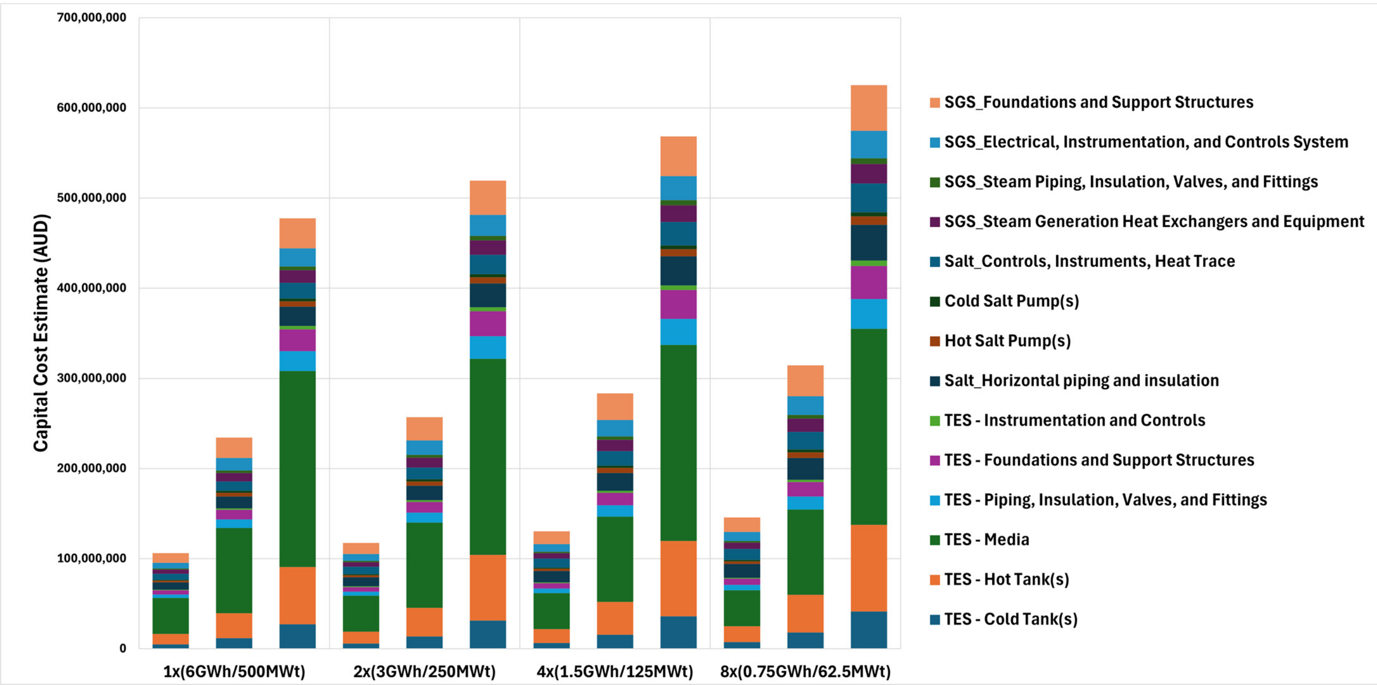


Figure 2. Estimated cost breakdown for different options for molten salt storage tanks.

The methodology outlined above has been used to estimate the capital cost breakdown for the solar collection subsystem of the conventional molten salt plant, including the solar field, tower, and receiver. Table 1 provides the cost breakdown for a system utilizing a 150 MW_t receiver (tower height of 103 m and a total reflective area of 270,414 m^2).

Table 1. Conventional molten salt system cost breakdown.

Item	Cost (AUD)
Site improvement	**6,232,864**
Site—Site Preparation	151,863
Site—Clearing and Grubbing	71,085
Site—Grading, Drainage, Remediation, Retention, and Detention	552,525
Site—Roads, Parking, Fencing	4,975,952
Site—Water Supply Infrastructure	481,440
Heliostat field	**44,232,215**
Field—Mirrors	8,504,399
Field—Drives	15,229,780
Field—Pedestal, Mirror Support, Foundation	14,055,234
Field—Controls and Wired Connections	1,459,582
Field—Wiring and Foundation Labour	2,634,128
Field—Installation and Checkout	2,349,092
Tower and Receiver	**26,328,261**
Tower—Tower	7,167,577
Tower—Riser and Downcomer Piping and Insulation	2,251,890
Receiver—Receiver	14,500,100
Receiver—Cold Salt Pump	2,025,221
Receiver—Spare Parts	383,474

Table 2 provides the total capital cost values for large-scale PV and wind plants. These values are based on the estimates provided in the GenCost 2022 study [27] under the current environmental policies.

Table 2. PV and wind capital cost estimates.

Item	Cost (AUD/kW)
Large scale PV	1441
Onshore wind	1960

2.3. Additional Costs

In addition to the basic costs for renewable technologies, any new plant built requires the addition of connection charges, and it is extremely likely that the transmission infrastructure will require upgrading. In the WOSP analysis, the upgrades to specific sections of the transmission network are considered as discrete items that are either installed or not installed, depending on decisions made in the optimization process. In this study, the scope is the delivery of electricity to a specific industrial user, and this will represent a fraction of any upgrade to the transmission system. The cost has been taken as an incremental component of future upgrades, depending on the power requirements of the refinery and the distance to the generation facility. Clearly, this is reliant on the SWIS network operator, Western Power, deciding that proposed developments are sufficient to warrant the capital outlay for the transmission upgrades, and the way this cost is transferred to industrial customers will be a decision made through the annual process of setting fees. It is important to recognize that costs will be incurred, but the additional complexity in determining exactly how the transmission upgrades will occur, and the financial processing of the costs, is outside the scope of this study.

Other additional components include the electrical heaters that are required to convert electrical inputs into heat in the storage media and steam piping for connection of any concentrated solar thermal-generated heat from outside the normal bounds of the plant to the steam supply system. Steam piping was selected as the transfer method based on the availability of cost data from distributed steam supply systems used in industry internationally, but costs and efficiency are affected by distances, and this has resulted in limitations on the quantity of CST systems that can be easily utilized, which will be discussed. Table 3 provides values for the base connection fee, transmission cost, as well as the steam piping cost. The base connection fee has been extracted from the data provided in the WOSP study. The connection cost for each of the SWIS zones, as depicted in Figure 3, is estimated by multiplying the base fee by the factors provided in Table 4 [12]. The transmission cost for different zones is then estimated using the Table 3 value and the approximate distance between zone representative sites, as listed in Table 3, and the nominal location of an industrial site located centrally within the region of major industrial operations in southwest Western Australia.

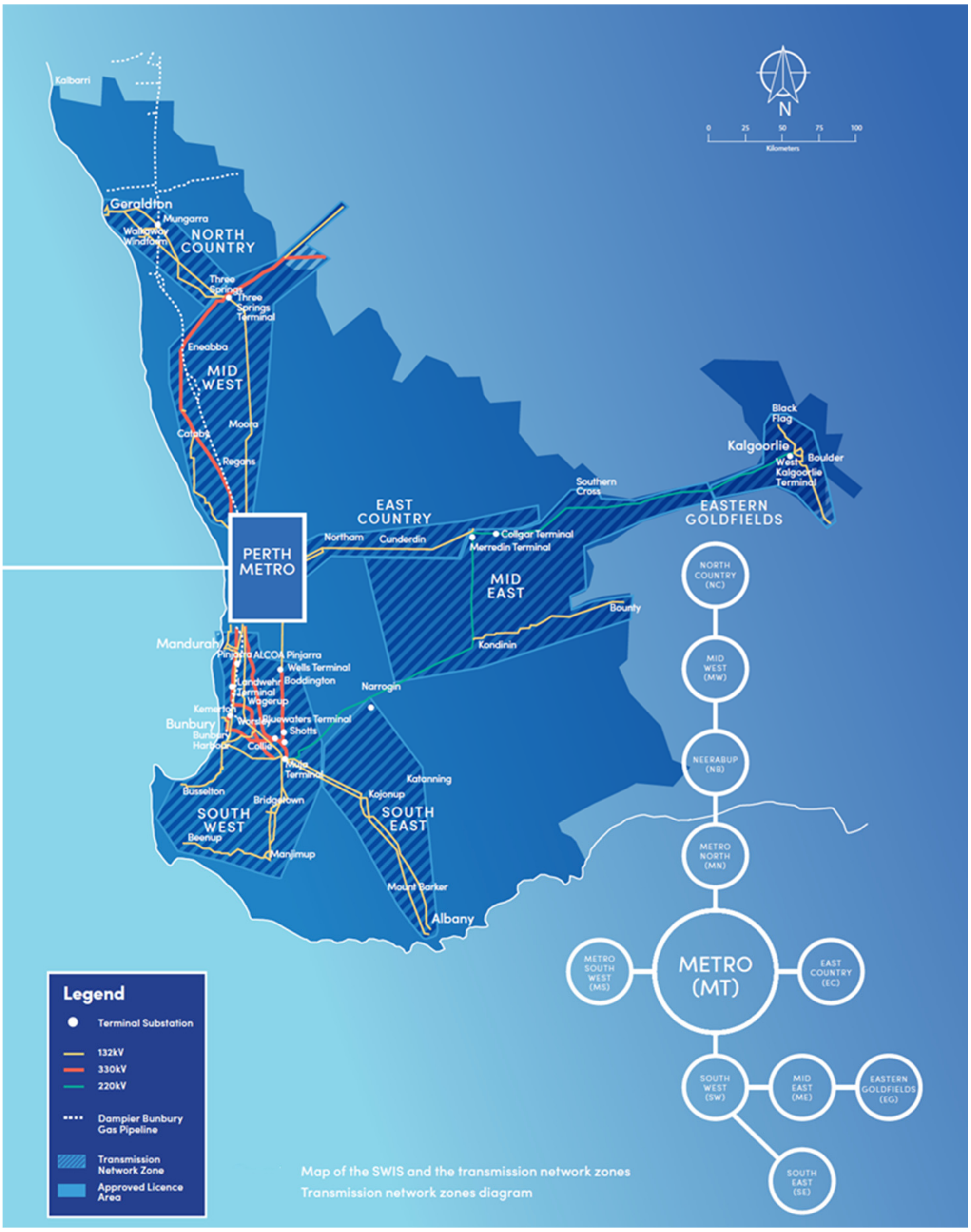


Figure 3. SWIS zones representation [12].

Where steam piping is required to link storages located in CST systems adjacent to the user, the cost has been estimated using the methodology outlined in [28] and the cost values provided by [29,30]. The resistive heater efficiency is assumed to be 99% [31], and the heater cost has been estimated using the values provided by [32,33]. An appropriate scaling factor is used to estimate the cost for other sizes.

Table 3. The estimated base connection fee, transmission fee, and steam piping and electric heater costs.

Cost Item	Value	Unit	Reference
Base connection fee	113,000	AUD/MW_e	[12]
Transmission fee	2500	AUD/MW_e/km	[34]
Steam piping	2,200,000	AUD/km	[28–30]
Electric heater	300	AUD/kW	[32,33] (based on the 500 MW_e heater)

Table 4. Whole of system plan zones specifications.

SWIS Zones	Connection Fee Factor	Representative Site	Approximate Distance (km)
North Country (NC)	1.1	Geraldton	600
Mid West (MW)	1.25	Eneabba	400
Neerabup (NB)	1.1	Neerabup	150
Metro North (MN)	1	Ballajura	140
Metro (MT)	1	Perth	120
Metro South West (MS)	1	Cockburn	100
Mid East (ME)	1.2	Kondinin	320
East Country (EC)	1.2	Merridin	380
Eastern Goldfields (EG)	1.35	Coolgardie	670
South West (SW)	1.07	Pemberton	210
South East (SE)	1.15	Albany	350

2.4. Assessment of Network Supply

A preliminary assessment of the projected network supplies of renewable energy has been undertaken to assist in scoping the requirements, which has indicated the significance of variability in renewable electricity supply. To aid this, the 2021 data for generation in the SWIS was extracted, with the source data being 30 min steps for each generating plant for the year [35]. This is presented in Figure 4 in terms of the total generation per technology type on each day of the year, with the price to retailers included for comparison. It is readily apparent that the total demand on the network can vary significantly, and that currently fossil fuel generation makes up the shortfall between variable renewable generation and the demand. There was no significant storage included in the network in 2021, but in future projections of the network's generation, renewable generation is expected to increase significantly, and there will be a need for significant network storage to maintain stable electricity supplies [12]. The electricity pricing data shown in Figure 4 is based on the 2021 generation mixture and, despite the variability shown, is unlikely to stay as stable if the renewable content of the generation becomes higher. The occasional negative pricing is caused by excess renewable generation, but is clearly erratic and too infrequent to be relied upon for routine filling of storage systems at low prices. It is likely that large-scale storage systems will be filled over annual cycles using electricity prices that are closer to the average in general and will require higher-priced electricity when there are shortfalls in renewable generation.

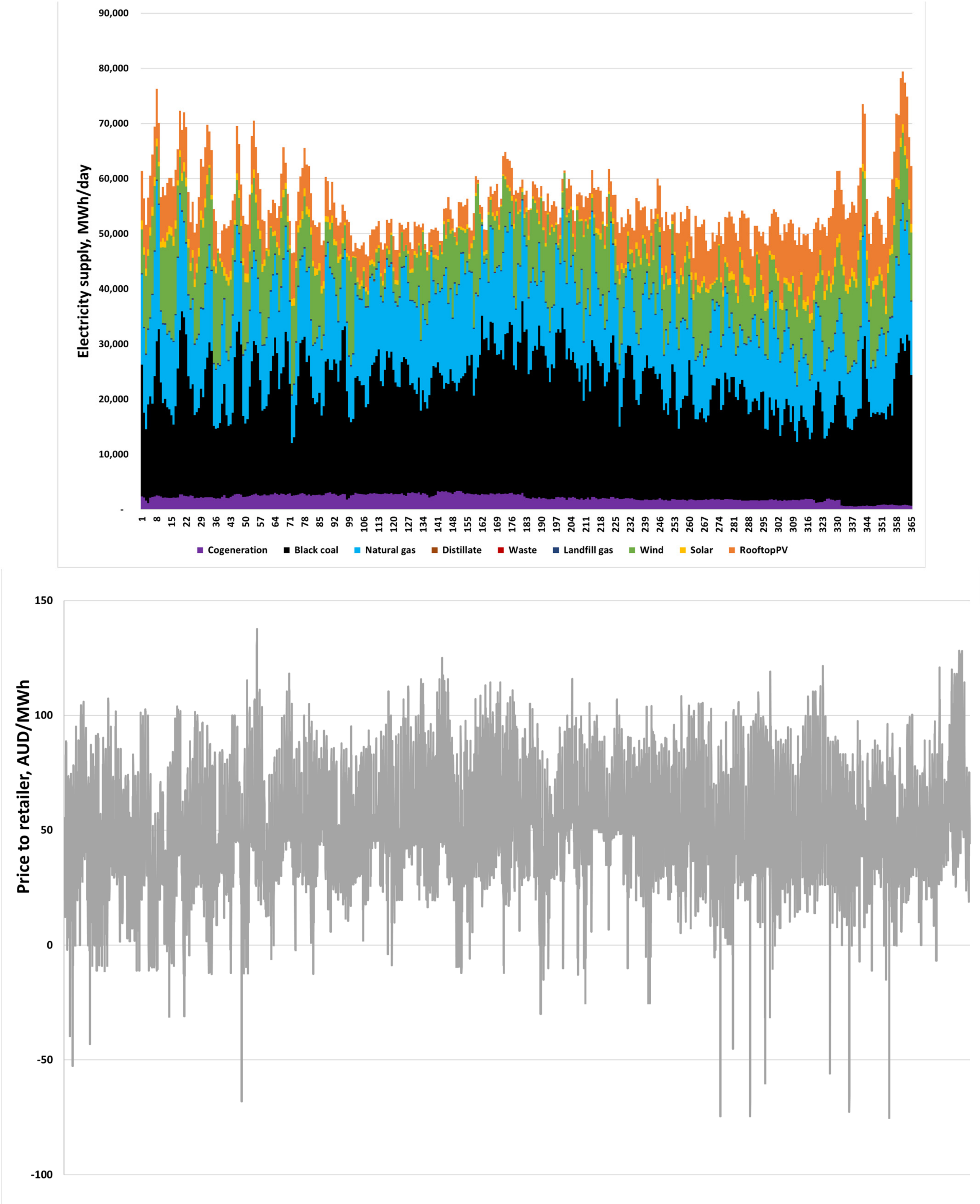


Figure 4. Generation data for different technologies on a daily basis for 2021 in the SWIS, with price variability.

The challenge in achieving the decarbonization of steam supply using renewable sources and the need for storage technologies is indicated in Figure 5, which shows only the renewable generation for 2021 and highlights the daily variability expected and multi-day periods with very low supply. For comparison, the modelled steam generation requires 12,000 kWh/day of electricity, and this highlights the impact on the network demands that direct electrification would have, as the entire 2021 supply for the SWIS does not achieve this level on a significant number of days. Clearly, more renewable generation is required to deliver sufficient supply and storage capacity to enable shifting of supply both within and between days will be required. It is noteworthy that generation is shown only as daily totals, so variations in generation within each day will require storage to allow for consistent steam production. In addition, a review of published studies on network modelling also suggests that it is necessary to consider the additional renewables required in the SWIS to meet the extra demand due to the electrification of steam generation in large industrial users.

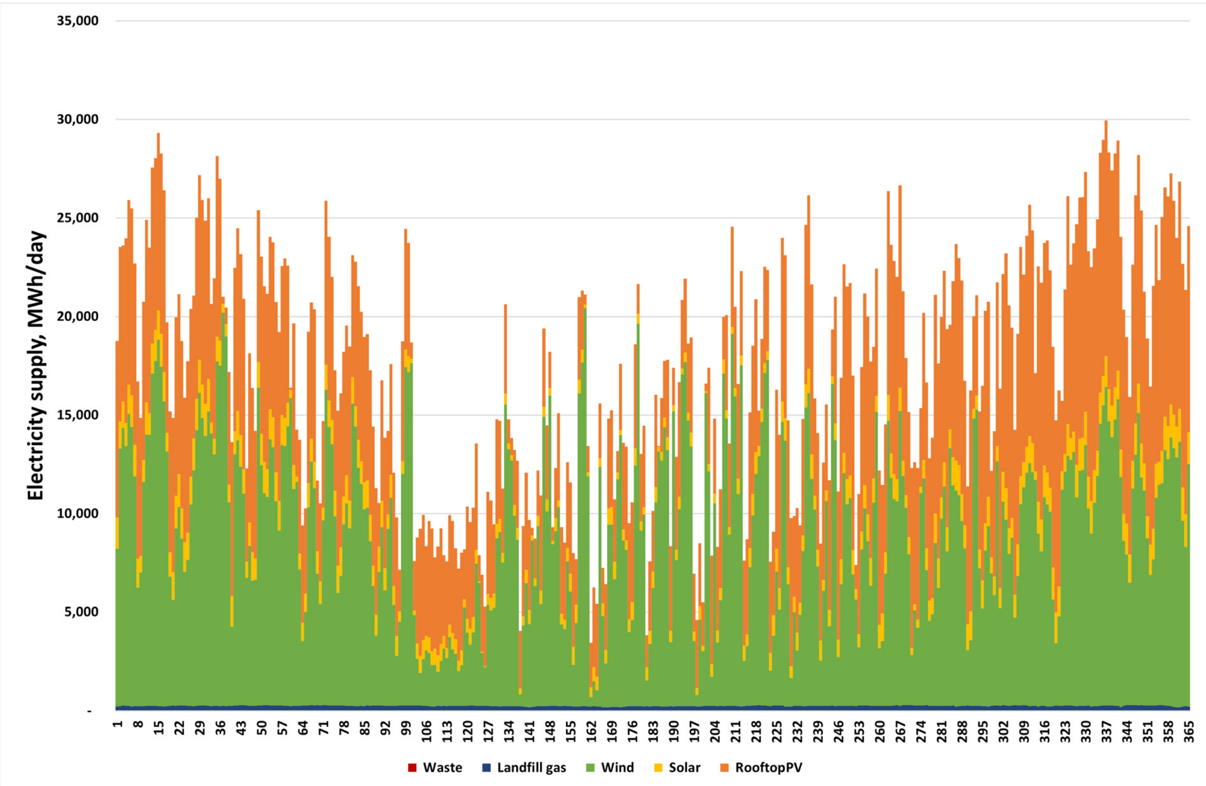


Figure 5. Generation data for renewable technologies as daily totals for 2021 in the SWIS.

2.5. Optimization Process

Based on the 11 zones defined in the WOSP and the potential for renewable generation from PV and wind in these, the approach taken in this study to network generation of renewables has been to model production on an hourly basis for commercial PV and wind generation technologies using an open-source software package, System Advisor Model (SAM), developed by the US National Renewable Energy Laboratory (NREL). The data on commercial technologies and methodologies used in this package are regularly updated, and are used in many published studies. To ensure that the output is relevant to Australia, the commercial systems selected for modelling and the assumed costs applied in the modelling were based on the annual GenCost review [27] conducted for the Australian Energy Market Operator (AEMO) assessments. Approximately 20 MW_{ac} modules of PV and wind plants were used in the modelling as a minimum commercial scale to determine performance data, but it is recognized that larger systems could have minor economies of scale. SAM was also used to develop performance data for a CST plant delivering thermal output, but only for a single zone in the region of the studied site that is described as local where the output can be directly coupled to the user. Modular design for CST plants was also considered, with each module size being 150 MW_t. This module size allows for better arrangement at the industrial sites whilst maintaining a reasonable economy of scale.

The other significant element of renewable energy supply is the input weather data, which supplies the solar, wind, and temperature data used in optimizing the system design and estimating the hourly generation over annual operations. Ideally, this would comprise 25 years of real, measured data for the specific sites where renewable generation would be applied, which is not possible for many sites in Australia. Numerous consultancies will supply data sites based on interpretation of satellite data, possibly in combination with interpolations of data from Bureau of Meteorology (BOM) weather stations. However, at the current level of assessment, the decision was made to use regional weather files supplied by NatHERS [36] to cover a typical meteorological year (TMY) of operations. While these files are intended for use in ensuring buildings meet the requirements of energy efficiency codes in the 83 different climate zones of Australia, they are produced using interpretation of the full range of historical BOM weather data in combination with satellite data and climate modelling tools for quality assurance. The solar data in the files are compiled using the standard methods appropriate for renewable energy predictions and the wind data are compatible with extrapolation to wind turbine hub heights using standard models based on terrain type to produce files suitable for wind generation predictions. This approach is suitable for predicting a typical (average) year of operations for standard renewable generation technologies on an hourly basis and can be used as a design basis for optimizing technologies, but any investigation of weather variability will recognize that not every year is the same. In sites exposed to coastal influences, there is typically a $+/-15\%$ variability between annual totals of renewable resource availability and far greater variability in individual months. By considering multiple regions in combination the overall variability is likely to reduce to something closer to $+/-10\%$ annually, and this needs to be considered in the impact on annual performance of renewable energy systems. Improvements in accuracy of the plant optimization are possible through more detailed assessments using specific sites and larger weather data sets, but that is beyond the scope of this study.

Figure 6 depicts the flowchart of the optimization process. Model components for storage and renewable generation have been developed semi-independently, which require integration into a model that adapts the sizing of equipment, zonal generation capacities, transmission requirements, and overall costing, applies any constraints, and optimizes the overall financial performance while meeting the renewable energy targets for a year of operation. This includes the needs for increased renewable generation from multiple zones of the SWIS, improvements to transmission infrastructure that are required to transfer electricity to the user, and then the optimization of the storage and steam systems within the industrial user to deliver renewably sourced steam at the required conditions to the process. Essentially, there is a "large system" that includes the entire expenditure required throughout the user systems and network, and then there is a "small system" that comprises the storage with charging–discharging components coupled to steam generation. These become integrated when the storage sizing, aligned with a specific mix of renewable supply options and a target annual renewable contribution, is combined with the goal of cost minimization. In simple terms, if the renewable energy supply is diverse in terms of time of delivery, then it reduces the capacity of the storage system required for constant delivery of output. So, the cost of diversifying renewable sources will be balanced against the cost of providing a larger storage system to produce an optimal cost of steam.

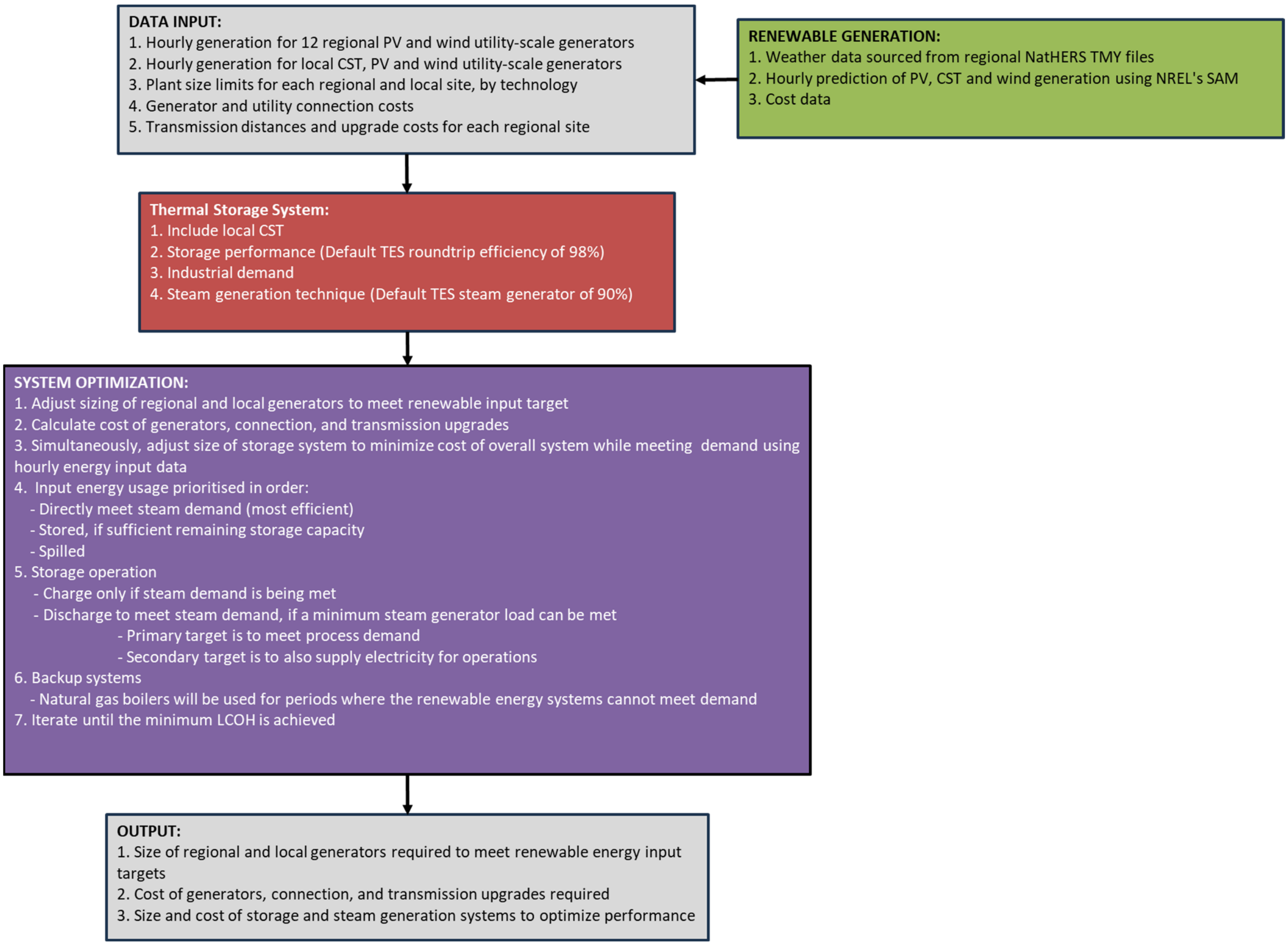


Figure 6. Flowchart of the optimization process.

In principle, this is a relatively simple optimization where the scale (cost) of each renewable generator is modified to achieve the quantity of input into the user system that will fill the storage sufficiently so that periods of low renewable availability can be bridged using steam generated by stored energy. The fluctuations in renewable supply then require a decision at each hour of the year if the renewable energy is best used in directly producing steam (most efficient use), stored for later use (if availability of energy is surplus to direct use needs), being spilled because the system cannot accept it (detrimental to LCOE for the renewable generator), or supplemented by fossil fuel backup to meet process requirements (resulting in a decline in renewable energy input). Storage capacity is modified hourly over the year of operation, so the integration of sources of energy for steam generation over the annual cycle provides a simple assessment of the share of renewables in the system. Iterative optimization of the scale of each renewable energy source and the storage capacity is used to identify the lowest-cost solution to achieving the renewable energy target.

An additional complexity that was added as the assessment progressed was adjustment of the thermal storage system to directly produce LP steam during periods where renewable electricity is available, with the lack of electricity generation being compensated by a larger import of electricity. Another complexity that was identified during the assessment was the desirability for local production of renewables in optimal situations, which was deemed to provide unrealistic systems that would be extremely likely to exceed the availability of land. The studied region of industrial operations does not have the best renewable resources in the SWIS, but the avoidance of transmission costs by direct connection of electrical output from PV and wind and avoidance of both transmission and electric heater costs for CST provides significant benefits. Constraints were made to the models to limit this behaviour. Each constraint can be independently varied, but the default approach taken was to limit CST to 5 × 150 MW_t systems adjacent to the users and a maximum of approximately 200 MW_e of each of wind and PV in any zone, including local. It will be apparent that at higher renewable targets, these constraints result in some dispersion of renewable generation to other zones, and the model has the capability of specifying if specific zones are desirable due to planned improvements to transmission infrastructure or knowledge of future surplus capacity in existing transmission lines (e.g., due to fossil fuel plant closures). As the overall system includes incremental costs for transmission line upgrades, this could significantly influence the optimization but would require additional information to be input. In addition, CST is a less mature technology option, and the decision on the incorporation of CST plants within the system or limiting the capacity to account for the suitability at specific sites can be modified in the model.

3. Results and Discussion

The major challenge has been the optimization of the supply of sufficient renewable energy and the required storage capacity, with the additional task of ensuring that charging and discharging are efficiently handled over a year of operations. The characteristics of the optimized systems for different renewable goals are summarized in Table 5. Cost data corresponding to the optimized cases is also shown in Figure 7. Some patterns to the changing system characteristics are evident, with both the renewable generation and the storage capacity increasing as the renewable goal rises. The heavy reliance on CST at low renewable targets was surprising and would also be the case for high renewable cases if a limit on CST capacity had not been set. In addition, there is a strong bias towards the other renewable generators being located either local to the site or in relatively close zones. This is not directly related to the renewable resources of the zones but appears more influenced by the model penalizing sites with long transmission distances and a preference for avoiding use of the transmission system entirely or, in the case of CST, using electrical heating systems. As the renewable energy goal increases, it is increasingly difficult to supply from the local and nearby zones, leading to higher transmission costs. This also translates to an increasing annual cost due to the large quantities of electricity being acquired through the network. It is difficult to precisely determine how the capital cost for new transmission infrastructure will be transferred to customers, and it may be possible to avoid some of the cost by selectively arranging new generation so that existing transmission infrastructure is used more aggressively, noting that this tends to have been arranged for large fossil fuel plants that may no longer be operational. In Figure 7, a second LCOH curve is shown, representing only the equipment located at the user site to highlight that the storage system with associated charge and discharge equipment is a relatively small component of the total cost. It is also noteworthy that the costs of other components may not be directly paid by the user.

Table 5. Summary of system specifications for thermal storage at varying renewable targets.

	Renewable Goal	30%	50%	70%	90%	Units
PV generators	Local	0.0	20.5	21.0	18.4	MW_e
	North Country (NC)	0.0	4.2	4.8	6.3	MW_e
	Mid West (MW)	0.0	10.4	13.2	25.7	MW_e
	Neerabup (NB)	0.0	12.2	14.0	16.3	MW_e
	Metro North (MN)	0.0	0.0	0.0	0.0	MW_e
	Metro (MT)	0.0	0.0	0.0	0.0	MW_e
	Metro South West (MS)	0.0	48.3	68.5	57.8	MW_e
	Mid East (ME)	0.0	12.4	16.1	22.6	MW_e
	East Country (EC)	0.0	0.0	0.0	0.0	MW_e
	Eastern Goldfields (EG)	0.0	1.2	1.3	1.4	MW_e
	South West (SW)	0.0	6.2	6.9	8.1	MW_e
	South East (SE)	0.0	0.0	0.0	0.0	MW_e
	Sub-Total (PV)	0.0	115.3	145.7	156.6	MW_e

Table 5. *Cont.*

	Renewable Goal	30%	50%	70%	90%	Units
Wind generators	Local	33.8	200.0	200.0	200.0	MW_e
	North Country (NC)	0.0	8.8	11.0	16.8	MW_e
	Mid West (MW)	0.0	12.7	200.0	200.0	MW_e
	Neerabup (NB)	0.0	0.0	0.0	0.0	MW_e
	Metro North (MN)	0.0	0.0	0.0	0.0	MW_e
	Metro (MT)	0.0	0.0	0.0	0.0	MW_e
	Metro South West (MS)	0.0	0.0	0.0	0.0	MW_e
	Mid East (ME)	0.0	18.4	28.3	42.3	MW_e
	East Country (EC)	0.0	1.8	1.8	200.0	MW_e
	Eastern Goldfields (EG)	0.0	1.1	1.1	1.1	MW_e
	South West (SW)	0.0	0.0	87.2	171.0	MW_e
	South East (SE)	0.0	0.0	0.0	200.0	MW_e
	Sub-total (Wind)	33.8	242.7	529.5	1031.3	MW_e
CST generators	Local only	750.0	750.0	750.0	750.0	MW_t
Capacity breakdown	PV	0.0%	10.4%	10.2%	8.1%	
	Wind	4.3%	21.9%	37.2%	53.2%	
	CST	95.7%	67.7%	52.6%	38.7%	
Supply breakdown	PV	-	276,439	349,548	378,023	MWh/y
	Wind	97,084	712,382	1,656,457	3,144,737	MWh/y
	CST	1,276,793	1,276,793	1,276,793	1,276,793	MWh/y
	Spillage	48,581	42,839	225,975	930,154	MWh/y
	Make-up	3,047,556	2,188,944	1,342,768	520,842	MWh/y
Storage capacity		1,482,944	3,506,631	4,676,883	6,927,108	kWh
		2.97	7.01	9.35	13.85	hours
LCOH		0.055	0.080	0.099	0.133	AUD/kWh
		15.34	22.27	27.55	36.92	AUD/GJ

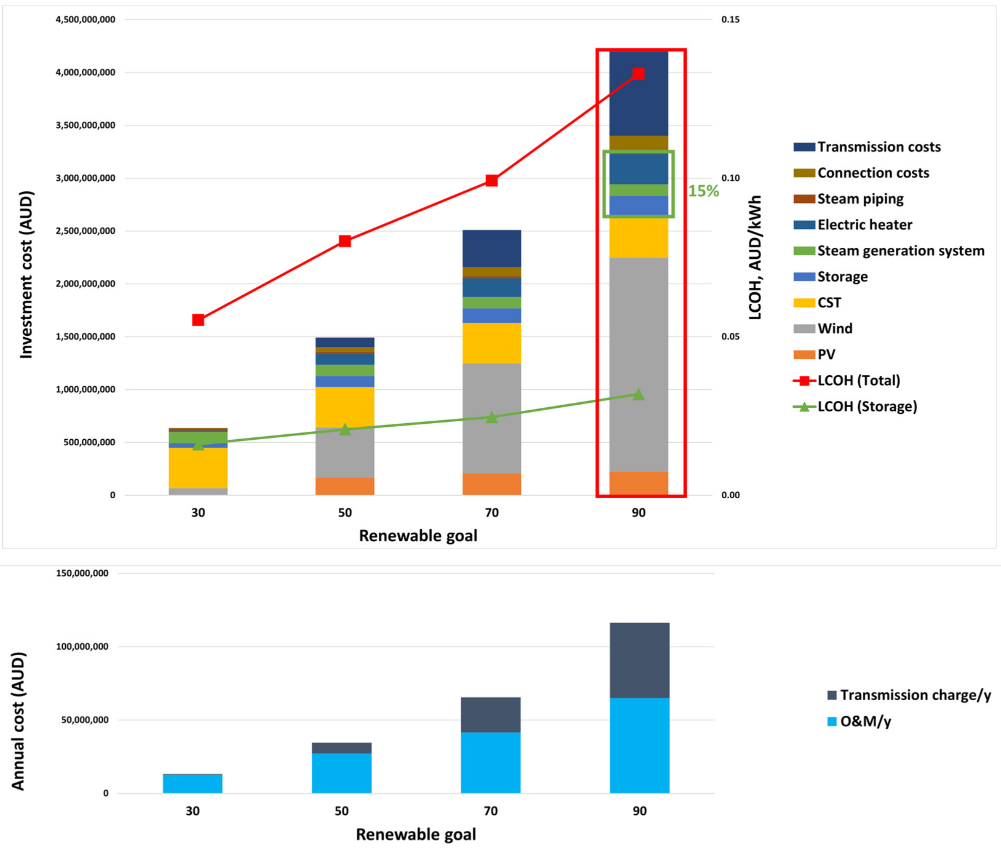


Figure 7. Cost breakdown for optimized systems for differing renewable goals.

Operational modelling tends to be hidden within the overall data; therefore, Figures 8 and 9 show the hourly transfers of energy for days in summer and winter for renewable steam provision of 90% and 50%, respectively. The two stacked columns for each hour show firstly the sources of incoming energy and secondly the disposal of this, with the superimposed storage level changing with charging and discharging. Two items to note are the spilled energy where surplus that the system cannot handle is available for the renewable generators, and shortfall, where additional supplies are required.

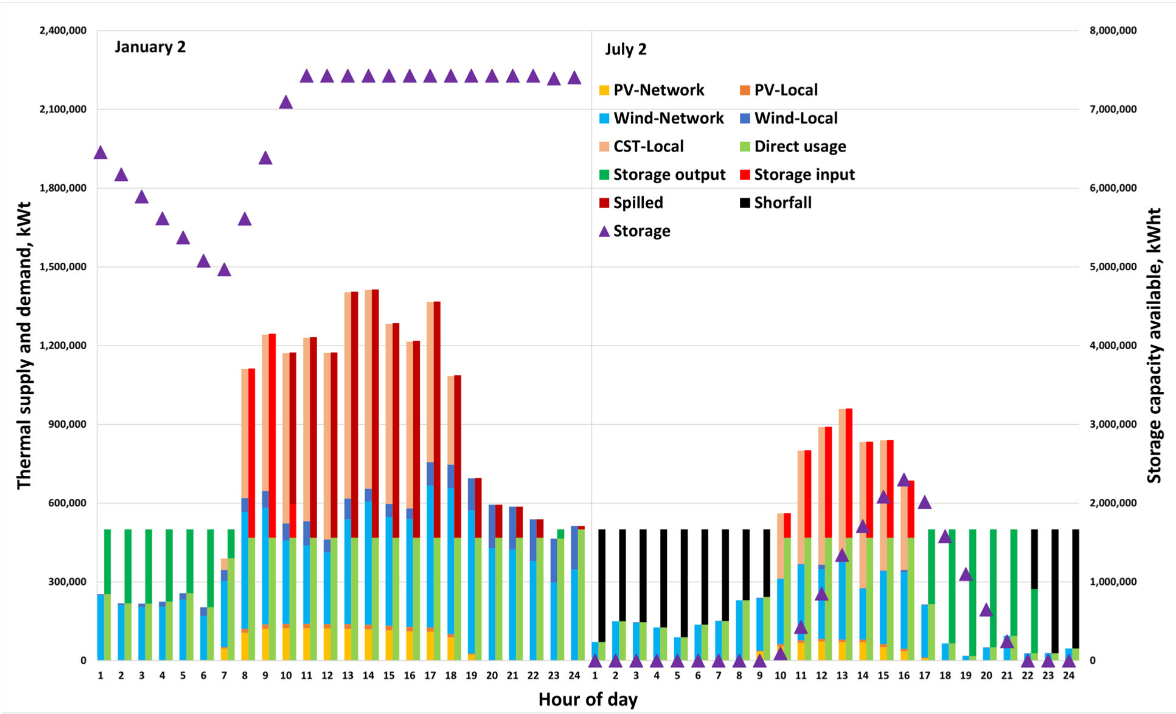


Figure 8. Hourly operations of the thermal storage for 90% renewable steam provision on two days.

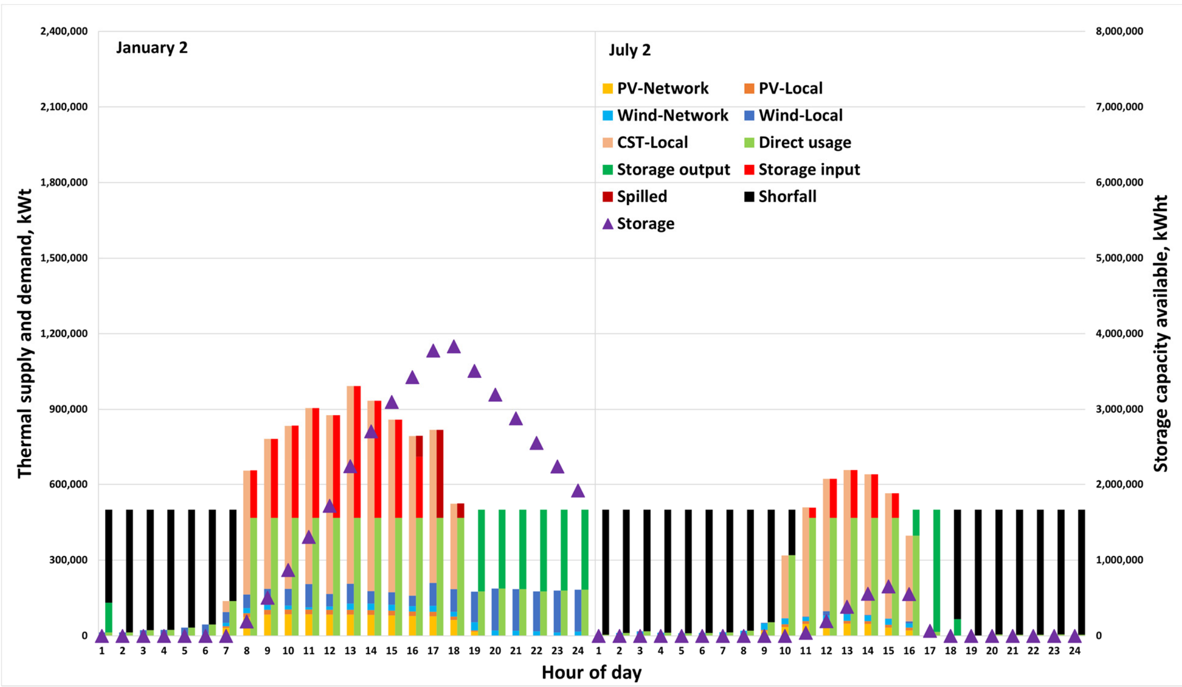
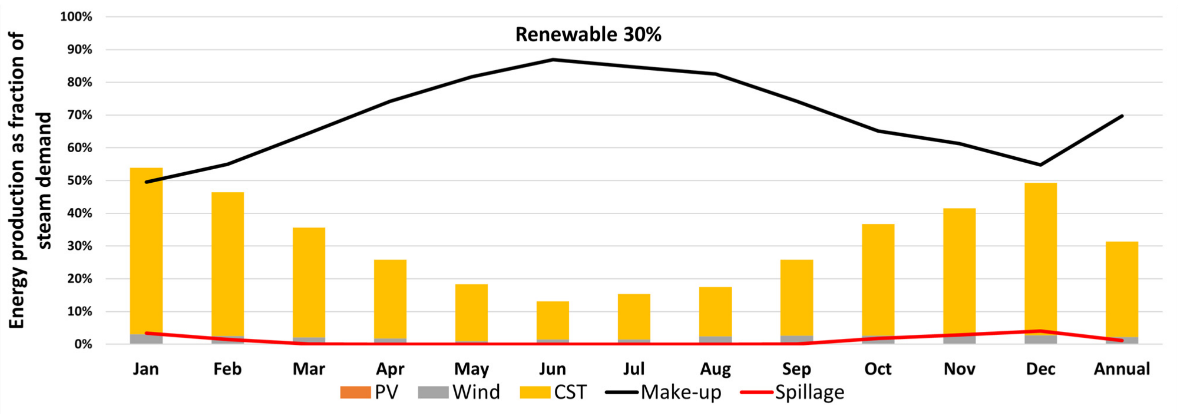


Figure 9. Hourly operations of the thermal storage for 50% renewable steam provision on two days.

A small anomaly in the model is the shift from HP steam to LP steam when electricity generation is not required due to surplus availability in the network, shown as slightly reduced power in the steam production columns. During daylight hours, direct usage of energy in LP steam production is slightly more efficient than production of HP steam from storage, and this results in a small reduction in energy use for the same steam demand. During other periods this will be supplemented by either storage output or the shortfall that requires other energy input, and during those periods HP steam is generated, and electricity is produced from the system for the use.

There are notable differences in how the system operations change with renewable target and time of year. The 50% renewable case has both lower storage capacity and uses a smaller renewable generator network, resulting in a need for additional energy input even in summer. Note that by late daytime, the storage has been filled and spillage has occurred, but the capacity starts to rapidly decline, and it would be expected that it will empty again overnight. Winter performance is dominated by the large quantity of additional energy that is required with the storage only providing a small capacity of output. In contrast, the 90% renewable case has a significant surplus in storage capacity and renewable input in summer, with 100% of the steam supply being met by renewables and a large fraction of the renewable energy input being spilled. In winter, the additional spread of renewable generators is evident by the increased supplies, but the storage is still not filled and additional energy sources are needed in many hours of the day. Another view of the overall performance of the systems is presented in the four graphs of Figure 10 for varying renewable targets. The trend associated with increasing renewable targets is relatively straightforward. By designing to minimize the need for large quantities of make-up steam supply in winter, it is likely that the summer months will experience a significant surplus supply that is spilled from the system. Whilst wind is the favoured technology to obtain more uniform generation in winter, it still accounts for only approximately half of the generation in the summer months.



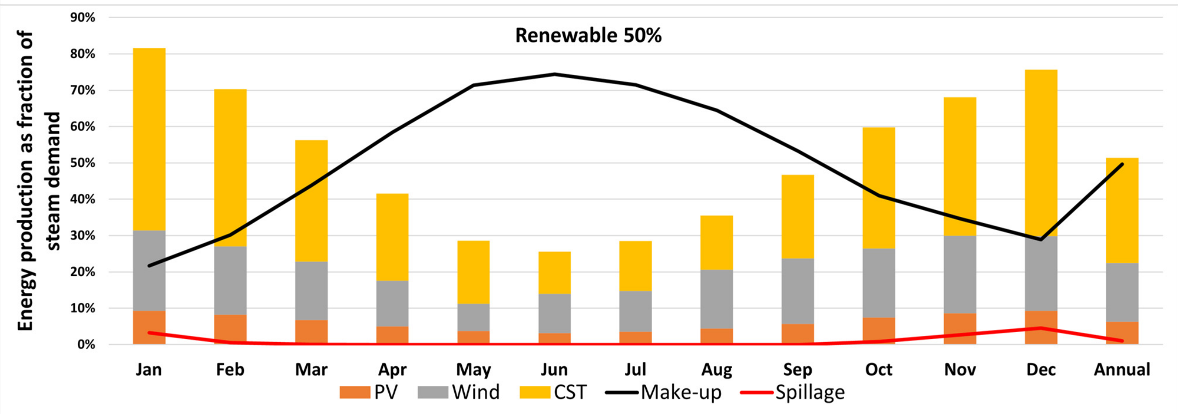


Figure 10. *Cont.*

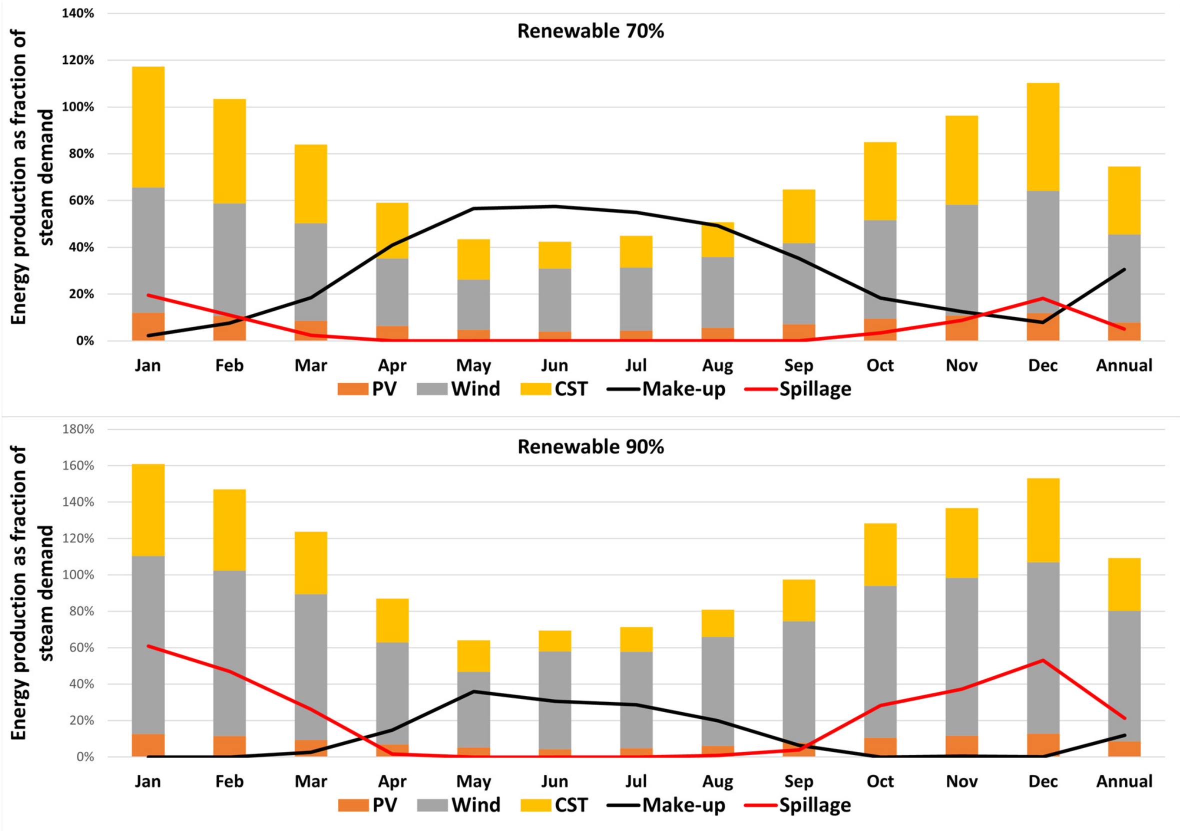


Figure 10. Monthly and annual system energy balances for four renewables targets.

The local CST system has the worst summer–winter differential in generation of the technologies chosen, but it is still the preferred technology in the optimization and would have a larger system installation if it was not capped by constraints. This is an unusual feature of the technology selection and arises from the avoidance of conversion to electricity. For example, a PV panel may be 24% efficient at conversion to electricity with minor losses possibly amounting to a few percent through to conversion to steam, but a heliostat field is likely to achieve 45–55% efficiency in capturing and storing heat, with only a few percent losses in subsequent steam generation. When the costs of the other required components are included, this provides considerable leeway in the cost of CST compared to PV systems, so it appears that this efficiency advantage is transferred to CST being a preferred technology despite the poor solar location. It is, however, a less mature technology that has considerable uncertainty in cost and reliability that needs to be addressed in more detailed engineering design studies.

4. Conclusions

This study took a holistic techno-economic approach to investigate the electrification of steam generation for large industrial users in southwest Western Australia. It was identified in the assessment that the cost of the system required for continuous steam production from variable renewable inputs can vary significantly, ranging from the equipment on the industrial site to the transmission network upgrades and the renewable energy systems. The scale of energy input required to shift industrial users from fossil fuel-based steam generation to variable renewables is considerable, especially for the relatively small network (i.e., SWIS) in southern Western Australia, where few large users are located. Complete electrification of users in the region would require at least a doubling, and more likely a tripling or more, of the existing generation capacity and major upgrades to many transmission lines. Given this context, the analysis assumed that the costs of the new renewable generation plants and the required transmission upgrades to supply a user were part of an overall project in addition to the new storage and steam supply systems at the industrial site. The simulation then optimized the cost and performance of the entire system, aiming to minimize expenses while meeting a specified renewable energy target on an annual basis.

Some findings around the influence of technology costs and performance are relatively obvious, but there is a clear indication that a major component of the costs will result from the provision and transmission of renewable energy rather than from the storage systems. This places emphasis on the delivery of high-efficiency storage to reduce the scale of renewable energy supply, rather than overly aggressive reductions in the cost of the storage system. However, bulk storage options where cost scaling applies to large volume storages are always expected to be considerably more appropriate than modular systems that lack the cost reductions in large installations and are likely to result in excessively complex piping networks for heat transfer.

The TES system is highly efficient, and larger storage capacities are predicted to be optimal, so the supply of renewables targets local resources with low transmission costs due to the time of delivery being less significant. Essentially, the system relies on a total amount of energy being delivered into the storage over a day of operation rather than uniform supply rates, and delivery from storage is instead the consistent aspect of system operations. This extended to favouring the use of a local CST system to avoid the need for transfer via transmission lines and incurring costs there and in electric heating.

One of the major findings was that local generation of all types was favoured, to the extent where limits had to be imposed on the capacities allowed in the different regions. It is likely that each specific user would need to use a customized set of constraints depending on the accessibility of renewable resources from the site, so the predictions presented should be considered as indicative. It is also highlighted that the convergence of the simulation to optimal designs is affected by the complexity of the range of potential solutions, so repeat analysis using different starting conditions should be performed for specific cases or the constraints on variables (such as the feasible capacities of renewable generation by individual regions) should be tightened to ensure that the output is realistic.

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