Doctoral thesis

Clean. Reliable. Affordable. The role of nuclear technology in meeting the challenge of low greenhouse gas electricity supply in the 21st century.

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Contents

In memoriam

- **Sir David J. McKay.** You taught us all to do the numbers.

- **Stephen Tindale.** You cut the path I walked.

- **Juan Alberto Gonzalez Garrido**. I had a terrific feeling we would be friends for life. I am still hurting that Life had other plans.

Gentlemen, this is my best effort, and I dedicate it to you.

Abstract

Climate change is broadly acknowledged as one of the greatest challenges facing humankind this century. The emission of greenhouse gases from human activity is driving warming of the atmosphere. The extent of the forecast warming has the potential to seriously and irreversibly alter global environments, with consequently serious impacts for humankind in our occupation of this planet. The energy sector is one of the largest sources of anthropogenic greenhouse gas emissions, being based nearly entirely on the combustion of fossil-carbon fuels, including for the generation of electricity. This energy consumption raises standards of living and is central to the development processes that alleviate poverty and reduce population growth rates. Non-fossil options for the generation of electricity include renewable energy sources (covering hydro, wind, solar, geothermal, wave, ocean, tidal and biomass) and nuclear fission in power-generating nuclear reactors. While nuclear power, along with hydroelectricity, has historically proven to be an effective and scalable replacement for fossil fuels in electricity generation, this technology lacks broad support, is actively opposed by the great majority of environmental groups and has grown little in recent decades. The exclusive use of non-hydro renewable technologies to generate electricity lacks historic evidence of scalability and cost-effectiveness, however these technologies enjoy popular support and the amount of electricity they supply is growing rapidly. This thesis examines how to provide electricity supply that is free from fossil carbon fuels at relevant global scale in the 21st century by examining the benefits and drawbacks of both nuclear and renewable technologies and considering their potential role in forming workable, cost-effective portfolios of solutions. I examine in detail the rapid transition towards wind and solar power in South Australia (Chapter 1), and critically review literature purporting to provide evidence that only renewable technologies are required for reliable, cost effective, clean electricity supply (Chapter 2). I undertake modelling of Australia's National Electricity Market using varying combinations of nuclear and renewable technologies to identify cost-optimal

supply combinations at varying carbon prices (Chapter 3), and re-model the potential for nuclear to meet a supply gap that is greatly modified by the uptake of variable renewable generation (Chapter 4). The potential role of advanced nuclear technologies is examined in a business case for storing used nuclear fuel and re-investing revenue in the development of fuel recycling facilities and advanced reactors (Chapter 5). I demonstrate that nuclear technology is an essential solution for the challenge of displacing fossil fuels from electricity supply, and that this role is robust against a range of assumptions and projections relating to greater use of renewable technologies. I conclude with a brief consideration of the little-studied challenge of providing industrial heat including to manufacture chemical feedstocks, a segment of energy consumption where advanced, high-temperature nuclear reactors may have a nearly unfettered role in the displacement of fossil fuels.

Statements of originality and authorship

I certify that this work contains no material which has been accepted for the award of any other degree or diploma in my name in any university or other tertiary institution and, to the best of my knowledge and belief, contains no material previously published or written by another person, except where due reference has been made in the text. In addition, I certify that no part of this work will, in the future, be used in a submission in my name for any other degree or diploma in any university or other tertiary institution without the prior approval of the University of Adelaide and where applicable, any partner institution responsible for the joint award of this degree. I give consent to this copy of my thesis when deposited in the University Library, being made available for loan and photocopying, subject to the provisions of the Copyright Act 1968. The author acknowledges that copyright of published works contained within this thesis resides with the copyright holder(s) of those works. I also give permission for the digital version of my thesis to be made available on the web, via the University's digital research repository, the Library Search and also through web search engines, unless permission has been granted by the University to restrict access for a period of time.

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Benjamin P. Heard

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'It is better to be roughly right than precisely wrong'.
- John Maynard Keynes.

'Please don't get me wrong. I'm not trying to be pro-nuclear or anti-wind. I'm just pro-arithmetic'.
- Sir David J. McKay

'I spent twenty years campaigning against nuclear power and then I realised I was wrong. Because I am not a politician, I said so'.
- Stephen Tindale

'No reason to get excited,'
The thief, he kindly spoke,
'There are many here among us now
Who feel that life is but a joke,
But you and I, we've been through that
And this is not our fate
So let us not talk falsely now.
The hour is getting late'.
- *All Along the Watchtower*, Bob Dylan (1967)

INTRODUCTION

Energy underpins human civilisation. It is "… the only universal currency"[1] and "… the master enabler"[2]. For everything from our basic survival to our grandest and most complex enterprise, we exploit and deploy energy in myriad forms. Sociologist Johan Goudsblom acknowledged that civilisation, as an observable phenomenon and process, has been a transitional process of energy exploitation: from using sticks and stones as tools and weapons to the point where "… today, there are none living without the products of agriculture and large-scale industry"[3].

This transitional process of increasing energy exploitation (Table 1) has been 'good' for humans. Since around 1800, average life expectancy has risen from 30-40 years to 71.5 years in 2015[4,5]. The world is now less violent than at any other point in our history[6], global vaccination coverage of newborn children is now 86 %[7], and the global rate of population growth is now 1.1 % and has been in steep decline since peaks of approximately 2 – 2.3 % around 1963-1970[8]. These historical trends point to energy as an enabler of peace, technological advancement and human longevity. However, our energy consumption has externalised costs. The price of modern civilisation could prove dear indeed if our energy consumption seriously disrupts the vital natural systems on which our well-being also depends.

Table 1 Evolution of power outputs of machines available to humans. Source: Modified from Hall (2017)[2]

machine	kilowatt
man pushing a lever	0.04
ox pulling a load	0.4
water wheels 300–	0.4–3.7
Versailles water works (1600)	56
Newcomen steam engine	4.1
Watt's steam engine	30
marine steam engine (1850)	746
marine steam engine (1900)	6,000
steam turbine (1940s)	224,000
nuclear power plant (1970)	1,120,000

Such disruption is well underway. The energy consumption that has raised human longevity and standards of living to unprecedented heights has also contributed to rapid changes in the Earth's climate. Our energy consumption, based almost entirely on the combustion of fossil-carbon fuels, results in the emission of the long-lived greenhouse gas, carbon dioxide. Emissions of carbon dioxide from the combustion of oil, coal, and gas exceed 33 million metric tonnes per year[9], and global average temperature is estimated to be 0.99 °C above the 1950-1981 average[10]. If we continue to use fossil fuels as our dominant source of energy, best-estimate modelling suggests that temperatures could rise to between 2.6 and 4.8 °C above the 1986-2005 average by the end of this century[11], with associated increases in the acidity of oceans through the absorption of additional carbon dioxide[11]. Such increases in global average temperature and changes in ocean chemistry might be well-beyond our adaptive capabilities, potentially impacting our settlements and food production systems at a scale that may be comparable to the deindustrialisation of civilisation[12].

As a consequence, humanity faces a paradox. Our historic conditions tell us that departure from an energised civilisation will lead to catastrophic outcomes for humanity. Yet our energy consumption drives us toward risks of climate disruption on a catastrophic scale. How can we break this paradox not only to continue to enjoy the benefits of our energised civilisation, but also extend it to eliminate poverty? How can we subsequently enhance our civilisation using energy — the universal currency and master enabler — to protect, conserve, and then enhance and restore our natural world? How can we do these things without fatally undermining that most vital of all our natural support systems — a stable, dependable and hospitable climate? The search for answers to these questions is the motivational underpinning of my PhD thesis. I begin by examining how energy consumption has changed in the era of global awareness of climate change.

From 1990 to today — energy in the age of climate change awareness

In 1990, the Intergovernmental Panel on Climate Change handed down its first assessment report[13]. From then to now (2018) represents nearly three decades of increasing scientific understanding of, and policy focus on, anthropogenic impacts on the climate. But the energy-and-climate paradox remains unbroken. In the age of climate change awareness, our consumption of energy has appreciably altered in one major way: it has grown (Figure 1), along with increasing human population and rising standards of living. Human population growth once led to cries of alarm in environmentalist literature[14]. This moderated in subsequent generations as the process of demographic transition became more broadly acknowledged[15-18]. The large growth in population that was witnessed from the dawn of industrialisation to the last quarter of the 20th century was a result of greater *survival*. The subsequent prosperity that has resulted in greater resource consumption is strongly correlated with lower population growth rates, enabling humanity to move toward population stability. That process that might be additionally accelerated with targeted, anthropocentric policies:

extension of family planning services and healthcare, greater provision of education, extending economic opportunities (i.e. jobs and income) that delay the age of primagravida etc.[18-22]. These realities of human development only heighten the paradox. A larger number of consumptive, prosperous humans assuredly, numerically, increases pressure on the natural environment and increases the challenge of achieving something that might be reasonably called 'sustainability'[19,20,23]. Yet constraining human population is most effectively achieved through the energy-intensive process of development and poverty alleviation; two outcomes where impressive progress *has* been made since 1990[24]. Unfortunately our dependence on fossil fuels across this period was has been virtually unaltered (Figure 1). There has been no transition away from fossil fuels of sufficient size to offset overall growth.

Figure 1 Global consumption of primary energy, coal, oil and gas, and global emissions of carbon

dioxide from fossil fuel combustion in 1990 and 2016. Source: Adapted from BP[9].
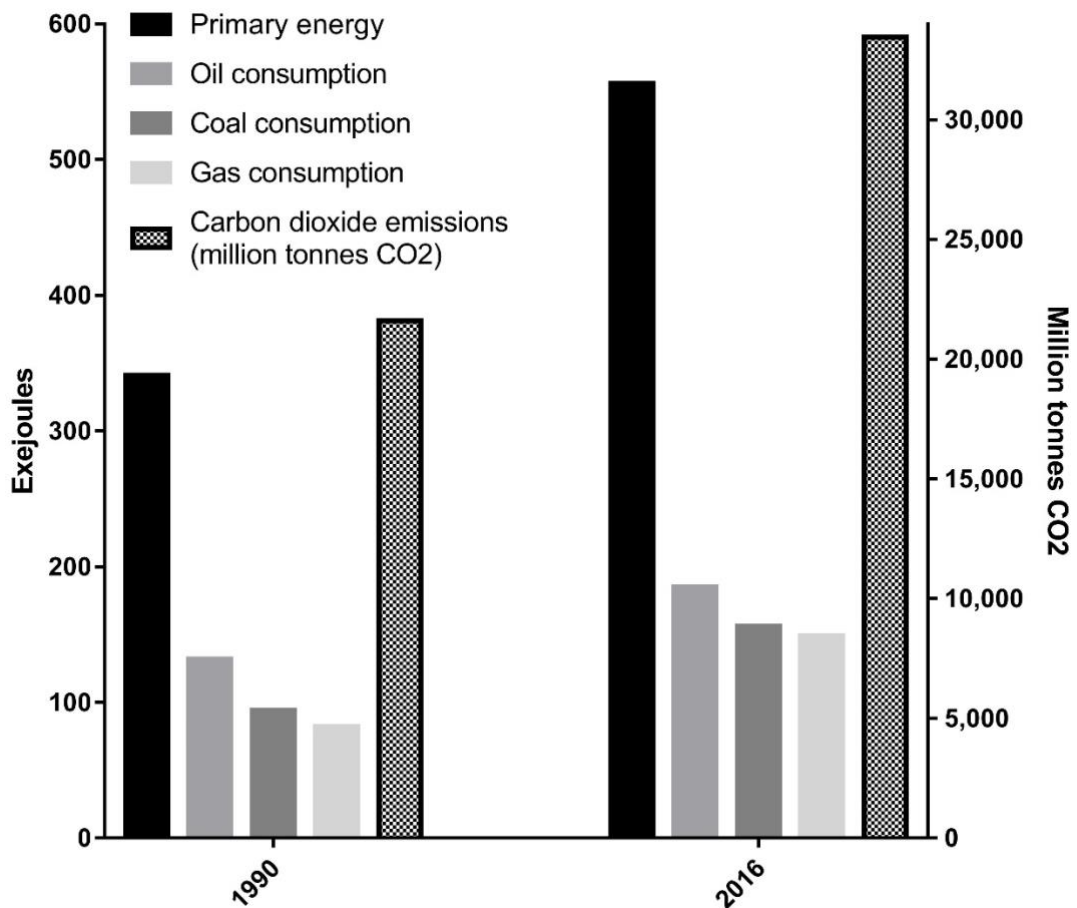
Much recent commentary has highlighted rapid growth in installed capacity and generation of

electricity from non-hydro renewables[25-27] (principally onshore wind and solar photo-voltaics), with

suggestions that these technologies might break the paradox. While this rapid growth is inarguable, it

also needs to be placed in appropriate context to establish the overall impact in reducing

dependence on fossil fuels. Globally, growth in electricity generation from non-hydro renewables was

just over 16 % year[-1] for the ten years to 2015[9]. In 1990, non-hydro renewables (solar, wind,

geothermal, biomass and waste) generated 121 terrawatt-hours (TWh) of electricity. By 2016, the

non-hydro renewable contribution to electricity generation had grown fifteen times (1,854 TWh)[9]. In

2016, global investment in renewable generation was larger than global investment in fossil fuel

generation for the fifth year in a row[26]. New electricity generation in 2016 from all renewables (approximately 353 TWh) was greater than new electricity generation from fossil fuels (approximately 247 TWh), with non-hydro renewables adding approximately the same amount of new electricity generation (234 TWh) as fossil fuels[9].

Conversely, from 1990-2016, total global electricity consumption more than doubled (11,914 to 24,816 TWh). New hydro-electric generation contributed 1,730 TWh of that increase, while nuclear generation increased output by around 615 TWh[9]. Compared with 1990, in 2016 the *additional* electricity generated from fossil sources (8,686 TWh year^{-1}) was slightly higher than the *total* electricity generated from non-fossil sources (8,494 TWh year^{-1}). All other non-electrical energy (principally heat and transportation) remained dominated by fossil fuels.

In markets that have adopted non-hydro renewable electricity generation early and fast, there are challenges in exceeding certain amounts of penetration and supply[28,29]. Meanwhile the use of fossil fuels shows minimal signs of abatement. In 2016, 79 GWe of new coal capacity was added globally[30]. While that is a notable decline from a record 104 GWe (2015) it is only slightly below the 10-year average (2006-2016) of 84 GWe[30]. China might be reducing the energy intensity of its economic growth, leading to a downturn in growth in coal consumption[31], but 1.2 billion people globally had no access to electricity in 2016[32]. The global human population is expected to continue to grow to the end of this century[20,33] and total energy consumption is expected to grow with it[34]. It could be that optimism regarding a meaningful overall 'transition' to renewable energy is at best premature, and at worst, altogether misguided. Growth in consumption of non-hydro renewables has not halted growth in consumption of fossil fuels, let alone led to a net reduction in greenhouse-gas emissions from overall energy use. This sobering reality is generally not appreciated by the general public or even non-specialist scientists, nor is it commonly discussed in the major media.

One the limits to the public discourse relating to the recent rapid growth in renewable electricity generation is a tendency to focus primarily on cost of electricity generation, rather than focus on the overall value provided to a system by different technologies. This is prevalent in discussions of the Australian National Electricity Market[35], which I examined in detail in this thesis. The National Electricity Market operates as an 'energy only' market, where generators price bids at five-minute intervals, with dispatch to market based on the price of these bids determined each half-hour[36]. In the case of renewable electricity-generating technologies that are now being added to a mature grid (most notably, wind turbines and solar photovoltaic cells), the levelised cost of electricity generation has fallen sharply in recent years[37,38]. This provides such technologies with a distinct advantage energy-only markets. However, the energy-only approach overlooks several valuable characteristics of electricity-generating assets that are required to create and maintain a reliable and affordable electricity system. These include the amount of firm generating capacity that is added to the system (being the capacity that will reliably be available during periods of highest demand); any effects on constraining transmission and distribution asset costs, and maximising the benefits of existing assets; energy security benefits; environmental benefits; and reliability benefits such as the provision of essential ancillary services like frequency control.

What appears 'cheap' in electricity generation might be of low value to the system overall, and what appears costly in electricity generation might be of high value to the system overall. However, as this thesis examines in more detail (Chapter 1 and Chapter 2), this broader value might be obscured in the early stages of an energy transition where new energy sources are added to a mature, functional system. However, they must eventually be accounted for in full. Thus, the transition from electricity grids based on centralised, synchronous generation (fossil fuels, nuclear and large hydro-electricity) to distributed, variable (e.g., solar thermal) and asynchronous generation (e.g., solar photovoltaic and wind) is likely more difficult, and costly, than many realise.

Nuclear technology — can it break the paradox?

There is another non-carbon energy source available to us alongside hydroelectricity and non-hydro renewables: nuclear power. In nuclear technology, humanity developed the first, and still only, fuel-based energy source that does not rely on the process of combustion (rapid oxidation) of carbon-based fuels, but rather the wholly different physical process of fission. In fission, chemically combining oxygen and carbon plays no role whatsoever. In other words, *it is the only form of greenhouse-gas free energy production that has been proven and demonstrated beyond doubt as reliable, fully transferable and completely scalable to the demands of developed nation economies.*

The difference is not merely qualitative, but also quantitative. Human civilisation advanced with the exploitation of fuels of higher energy density[39]. Where dry firewood holds ~ 16 MJ kg^{-1}, good-quality coal has nearly double the density (30 MJ kg^{-1}) and crude oil approximately triple the density (45-46 MJ kg^{-1})[40]. Natural uranium, deployed in a typical light-water reactor, offers ~ 500,000 MJ kg^{-1} — an energy density *five orders of magnitude higher than crude oil*[40], therefore potentially opening avenues for unexpected and beneficial progress in human civilisation. As shown in Table 1, the process of nuclear fission represents a major departure in energy density that Hall casually refers to as "… much more intense than we are used to."[2]

With these compelling characteristics, it might appear self-evident to the empirical mind that nuclear technologies must play a crucial role in meeting humanity's interrelated challenges of poverty alleviation and climate stability in the 21st Century. Yet, as we near the completion of the first 20 years of that century, the role and reputation of nuclear technology remains highly contested, controversial, and contradictory. In nations where nuclear has been deployed in decades past, it has proven potent in displacing fossil fuels from electricity supply[41]. Yet, during the era of climate-change awareness (1990-2016), the world increased nuclear electricity generation by only 600 TWh year[-1] (less than 5 % of the new total new generation added), and growth in the ten years to 2015 was -0.7 % (i.e., it shrank in absolute terms)[9]. Despite being demonstrably the safest energy source in the choice of coal, oil, gas, hydroelectricity, or biomass[42-44] (Figure 1), it carries a perception of great risk[45,46]. Where it has been deployed, electricity costs are generally low and stable[47-49] to the extent that in Sweden a tax on nuclear electricity made up one-third of the operating cost[50]. However, today one hears from nearly anyone who cares to comment that it is too expensive to play a meaningful role in dealing with climate change[51-54], somehow it is "… too costly to matter"[55].

Figure 2 Comparison of mortality and morbidity, normalised to units TWh-1, between brown coal, black coal, oil, gas and nuclear power. Source: Adapted from Markandya and Wilkinson (2007)[43]
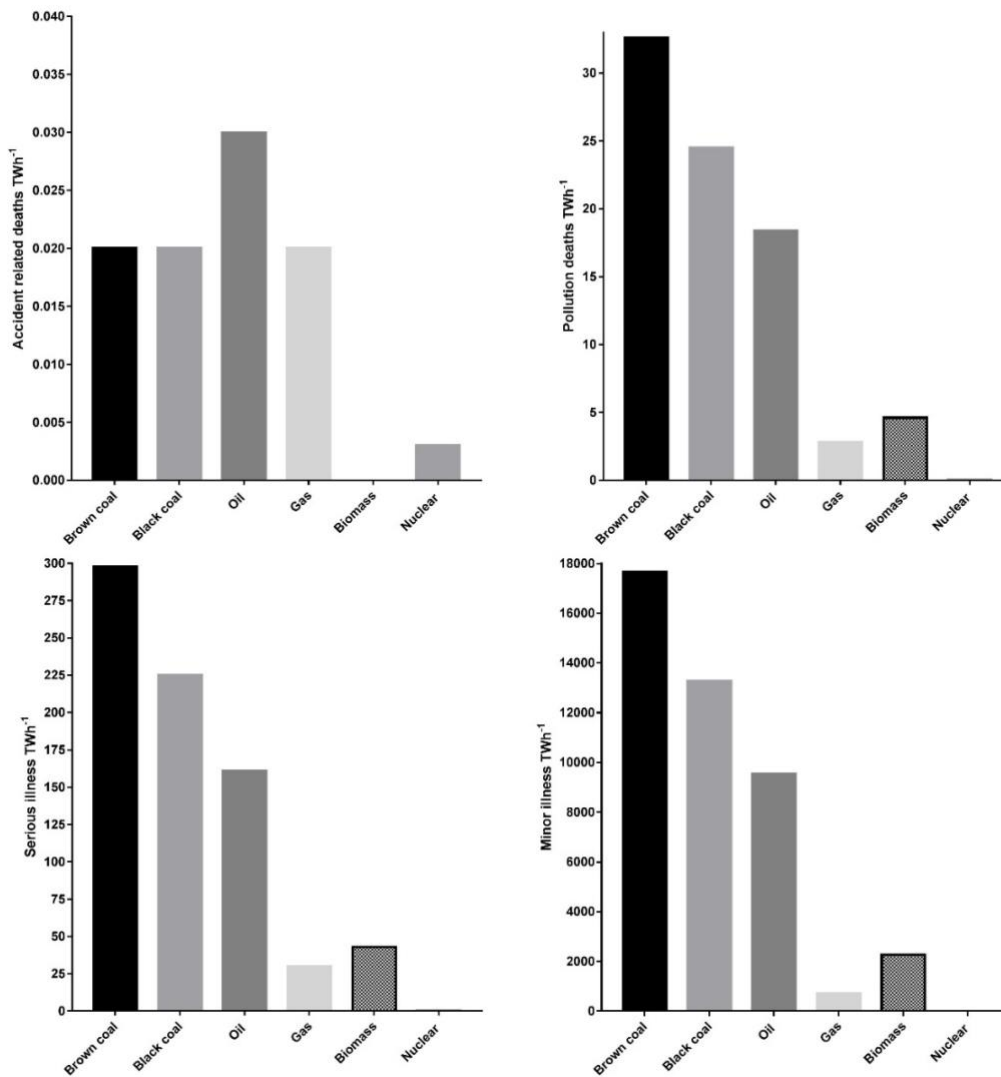
Nuclear technology has the singular distinction among fuel-based energy sources of capturing its operational waste as well as planning and funding responsible disposal as a matter of normal operations; this distinction is presented as a flaw when eventual solutions are delayed, unpopular or otherwise problematic[56]. Without exception, it is rejected by the oldest major environmental groups[57-59], with Greenpeace International declaring it "… has always fought — and will continue to fight — vigorously against nuclear power". Yet a growing number of new environmental groups[60-62], joined by climate and conservation scientists, are vocally speaking out in favour of nuclear power as not merely important, but an essential component for addressing climate change[63-68]. The Intergovernmental Panel on Climate Change includes growth in nuclear power as a necessary

component in scenarios that achieve lower greenhouse-gas emissions, while simultaneously focusing on "… a variety of barriers and risks"[69]. There seems to be little consensus on the likely, possible, or the essential role of nuclear power in global electricity supply this century.

What is the role of nuclear power in combatting climate change?

My thesis explores this as-yet unbroken climate and energy paradox, to examine the possibility that nuclear technologies can be the foundation of a portfolio of solutions that can help humanity to move rapidly beyond the carbon-fuelled, climate-disrupting externality of our civilisation. In Chapter 1, I explore the potential role of variable renewable energy by examining the energy transition in my home state of South Australia[70]. This jurisdiction has had one of the deepest, most rapid uptakes of non-hydro renewable energy in the world. I identify the beneficial outcomes of this transition as well as emergent risks to energy costs and reliability. I argue that South Australia will eventually need to move away from variable renewable energy sources to eliminate fossil fuels fully from its electricity supply. I argue that nuclear technology will be an appropriate candidate for this task and that early adoption of advanced nuclear technologies could provide a socially and economically achievable pathway to nuclear technology deployment.

In Chapter 2, I turn my attention globally to examine the possibility that nuclear power is *not* required in the task of decarbonising electricity supplies. I review the evidence for the proposition of 100 % renewable electricity supply across twenty-four published studies, and assess their feasibility using a novel scoring framework[71]. I identify gaps in evidence for the basic feasibility of these proposals, as well as the likely serious environmental and social consequences that could arise from their implementation.

In Chapter 3, I examine the Australian National Electricity Market in 2030, and via hourly modelling of supply and demand, identify firm directions for establishing reliable, cost-optimal, low emissions-intensity electricity supply using combinations of nuclear fission, solar photo-voltaics, onshore wind hydro-electricity, and open-cycle gas. Here, I seek to understand whether nuclear power can contribute to a cost-optimal electricity supply system given the emergent marginal cost differences between variable renewable (on-shore wind and solar photo-voltaics) and nuclear electricity. In this process, I identify a cost-effective range for penetration of variable renewable-energy sources. I also identify a size range for a nuclear power sector in Australia that could underpin a cost-effective transition away from fossil fuels, were nuclear technologies legally permitted to be included in planning from this point forward.

In Chapter 4, I assume nuclear is *not* included in planning, and instead determine the electricity supply gap in Australia that must be filled to achieve a clean supply, if intermittent-electricity supply continues to increase in line with current projections to 2035-2036[29]. With this supply gap, I examine afresh (*i*) whether nuclear power is needed for the decarbonisation challenge of electricity supply in the Australian National Electricity Market, and if so, (*ii*) whether it could be viably deployed to such a highly modified supply system.

In Chapter 5, I examine the controversial issue of used nuclear fuel, which is euphemistically and, I argue, erroneously referred to as 'nuclear waste'[72]. I examine the potential of an advanced nuclear technology (sodium-cooled integral fast reactor paired with full-fuel pyroprocess recycling), appended to an international service in used-nuclear fuel custody as a means of (*i*) boosting the prospects for accelerated investment in currently commercially available technology in fast-growing economies, and (*ii*) bringing forward the commercialisation of newer and better reactors. I identify and recommend a pathway where revenues from accepting used nuclear fuel are committed to the

development of advanced nuclear technologies that decrease the volume and longevity of the nuclear-waste stream.

I conclude my thesis with a review of the changes and upheaval that have beset the nuclear-power sector in the years over which I prepared my thesis, paired with an initial consideration of the vital role of advanced nuclear technologies in providing not just electricity, but heat. Heat is required to power industrial processes and generate the synthetic fuels and feedstock that might be required to complete the non-electrical energy decarbonisation challenge.

Having written this thesis, my hope is a decidedly immodest one: to influence what it means to be an environmentalist. I hope this thesis will serve as one of many forces that can unify the notion of environmentalism with humanism, being the right and responsibility to give meaning and shape to our own lives in an ethical and fulfilling way and based on reason, scientific methodology, and solid evidence. For when I fight for the environment, I do it principally for my *human* children. Might we be so fortunate as to one day live lives of prosperity as a civilisation that has transitioned its relationship with the natural world from exploitative to restorative? We might. But only humans can make that happen, and we can only make it happen with abundant, affordable, and low-carbon energy.

CHAPTER 1: Beyond wind: Furthering development of clean energy in South Australia

Abstract

The deep and rapid decarbonisation of electricity supply systems is an essential component of mitigating the impacts of climate change. Despite a high penetration of wind-generated electricity (27 %), South Australia remains connected to, and reliant on, one of the most coal-intensive electricity grids in the world – Australia's National Electricity Market. Here we explore the changes to South Australia electricity generation in the context of the recent, large expansion of wind-generated electricity, the impacts of this expansion, and the potential for alternative, low-emissions technologies to help the State complete the decarbonisation task. We find that although the expansion of the wind-generation sector in South Australia has delivered meaningful reductions in greenhouse-gas emissions in just over ten years, the limitations of strongly correlated and variable electricity supply that is decoupled from electricity demand place upper limits on the plausible future contribution from wind. System costs arise from integrating these sources, both from managing uncorrelated supply and the declining availability of ancillary services such as the frequency control provided by synchronous generators. These costs have been minimal to date, largely due to the connection to the National Electricity Market and already available, open-cycle gas turbines as reserve margins. However, evidence of large-scale integration costs is emerging and expected to increase should wind continue to grow in penetration. Development of the South Australian hot dry-rock geothermal resource has confirmed the well-documented challenges in developing this energy source, with still no operating power supply after more than 30 years of development. Solar-thermal technology remains uneconomic in the absence of either substantial subsidies or high carbon pricing. Given these inherent constraints, the deployment of nuclear energy technology provides the pathway of greatest technical and economic certainty for the permanent displacement of fossil-fuelled baseload

electricity generation in South Australia. Nuclear power is, however, hampered by legislative barriers and requirements for the development of legal and regulatory frameworks. Support for the nuclear option is broadening within South Australia, and innovative economic development strategies based on the deployment of generation IV 'integral fast reactors' could spur the necessary bi-partisan political support to transition the State's electricity supply entirely to low-emissions sources.

Authors note: This paper was researched and written in 2014-2015 and published in 2015. As such, many updates to figures referred to in this paper are available at the time of thesis publication (2018). In this chapter, I have preserved the paper in its originally published form. I reflect on subsequent events in CHAPTER 6 – Discussion.

Statement of Authorship – Chapter 1

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Publication Status	☑ Published ☐ Accepted for Publication ☐ Submitted for Publication ☐ Unpublished and Unsubmitted work written in manuscript style
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Name of Principal Author (Candidate)	Benjamin P. Heard
Contribution to the Paper	Led the research, drafting and finalisation of this paper including all figures and tables.
Overall percentage (%)	80
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.

Signature		Date	29 August 2017

By signing the Statement of Authorship, each author certifies that:

i.   the candidate's stated contribution to the publication is accurate (as detailed above);

ii.   permission is granted for the candidate in include the publication in the thesis; and

iii.   the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	Professor Corey J.A. Bradshaw		
Contribution to the Paper	Reviewed the earliest paper drafts, provided guidance on paper style, structure, content and preparation of tables and figures.		
Signature		Date	13 September 2017

Name of Co-Author	Professor Barry Brook		
Contribution to the Paper	Reviewed later stage drafts and provided guidance on paper style, structure, content and preparation of tables and figures.		
Signature		Date	29 August 2017

Introduction

The recent report from the Intergovernmental Panel on Climate Change (IPCC) has reinforced the now unequivocal finding[73] of the warming of Earth's climate and the progressive acceleration in the rate of greenhouse-gas emissions since 1970 (IPCC 2013). The IPCC states that substantial cuts are required in anthropogenic greenhouse-gas emissions, achieved largely through large-scale changes in energy systems. Delaying further mitigation efforts beyond those in place today through to 2030 is estimated to increase substantially the difficulty of maintaining temperature change less than 2 °C relative to pre-industrial averages[11]. This growth in greenhouse-gas emissions from the energy sector has occurred simultaneously with increases in output from low-carbon energy sources. In electricity generation, the average annual growth rate of global production from wind and solar power sources was greater than 26 and greater than 50 %, respectively for the ten years to 2012, whereas global nuclear output recorded a slight decline over the same period of 0.8 % year^{-1}, although the total energy supplied by nuclear (2463.5 TWh) was over four times greater than by wind (534.3 TWh) and over 23 times than by solar (104.5 TWh) due to a large existing capacity[74].

Despite a strong focus on the deployment of renewable energy technologies, Australia has maintained one of the highest per capita rates of greenhouse-gas emissions from the consumption of energy in the world (18 tCO_2-e capita^{-1} in 2001[75] and in particular, one of the most coal-and-gas-dependent electricity supplies (electricity generation in 2011/2012 was 69 % coal and 20 % gas)[76]. Ironically, given current policy goals, production from renewables as a share of total electricity produced in Australia was greater in 1960 (19 %) compared to today (less than 10 %), while the use of coal (in terms of total energy output) has grown approximately 10-fold over the same period[77]. The use of nuclear energy is prohibited federally under Section 140 A of the *Environmental Protection and Biodiversity Conservation Act 1999*[78].

The State of South Australia has taken a proactive approach to the development of its wind resources and has achieved the highest penetration of wind generation of any Australian state, at 27 % of electricity consumption for the 12 months to 30 June 2014. But is this enough? Will a focus on wind and other renewable technologies ensure South Australia delivers substantially greater cuts in emissions from the energy sector, and how logistically and economically feasible is the ongoing expansion of these non-fossil-fuel power-generation sources? The old age of and the high emissions from South Australia's electricity-generating assets combine to present a compelling case for alternative-energy planning. In this analytical paper we examine the relevant historical data, discuss some of the intractable barriers to full reliance on renewable energy sources for this transition, and then present an alternative vision for the future of low-carbon electricity generation for the State.

South Australia's electricity profile

The underpinning infrastructure of the South Australia grid is getting old. Twenty-five per cent of South Australia's baseload generating capacity was commissioned before 1970, and 56 % before 1980 (Figure 3). Gas dominates the baseload generation, followed by coal. Most of the State's greenhouse-gas emissions are produced from the coal-power stations located at Port Augusta at a rate of greater than 1,000 g CO_2-e kWh^{-1}, followed by the burning of gas in the inefficient 'open cycle' plant at Torrens Island A and B at a rate of 580 g CO_2-e kWh^{-1} (Figure 4)[79]. By comparison, the more advanced and cleaner-burning combined-cycle gas plant at Pelican Point commissioned in 2001 delivers electricity at 400 g CO_2-e kWh^{-1} (Figure 4).

Figure 3: Commissioning period for currently operational South Australian baseload electricity generators expressed as peak installed capacity in successive decadal blocks. Source: data from Geoscience Australia[80].
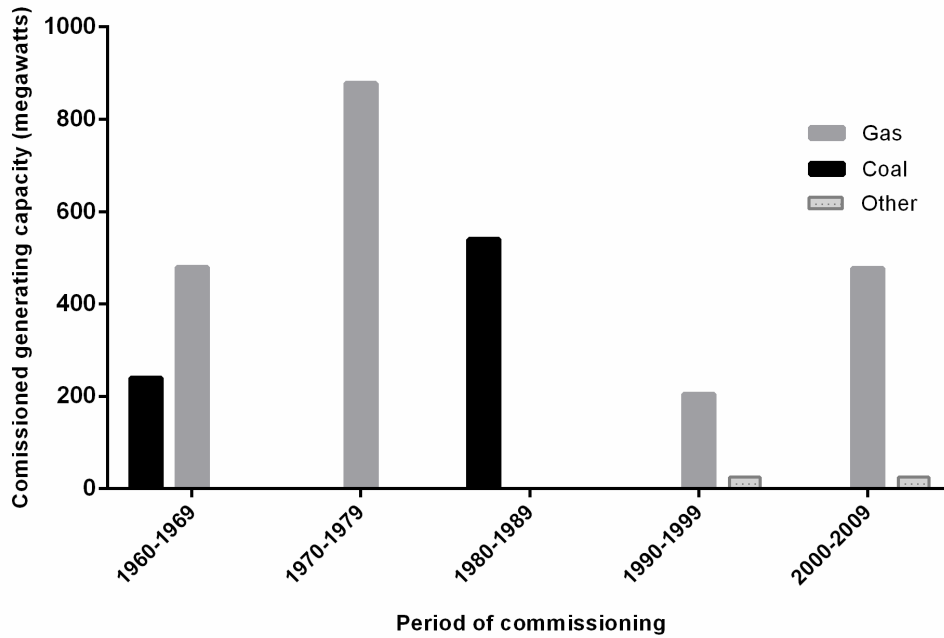
Figure 4: Greenhouse-gas emissions and electricity generated from South Australian baseload generators during the financial year 2012-13. Source: data from Clean Energy Regulator[79].
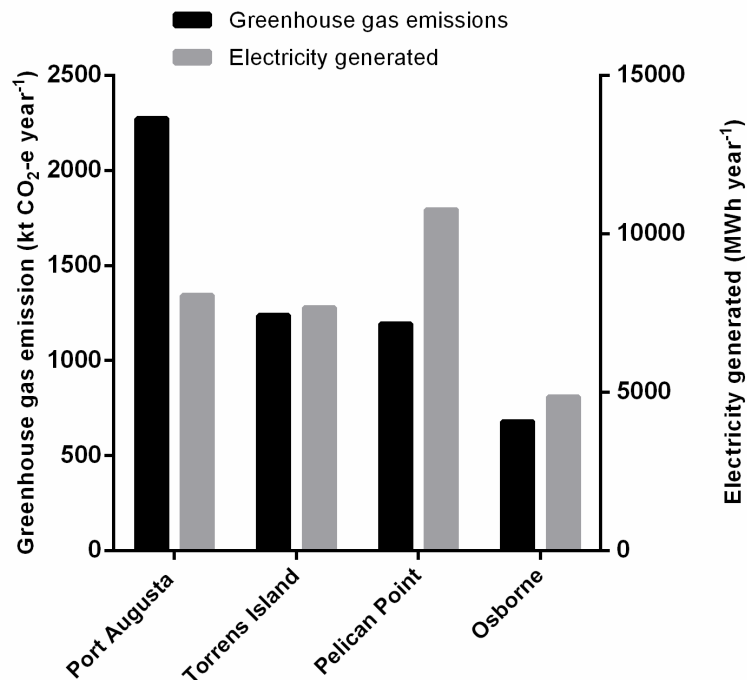
Figure 5 Map of South Australian energy infrastructure and regions
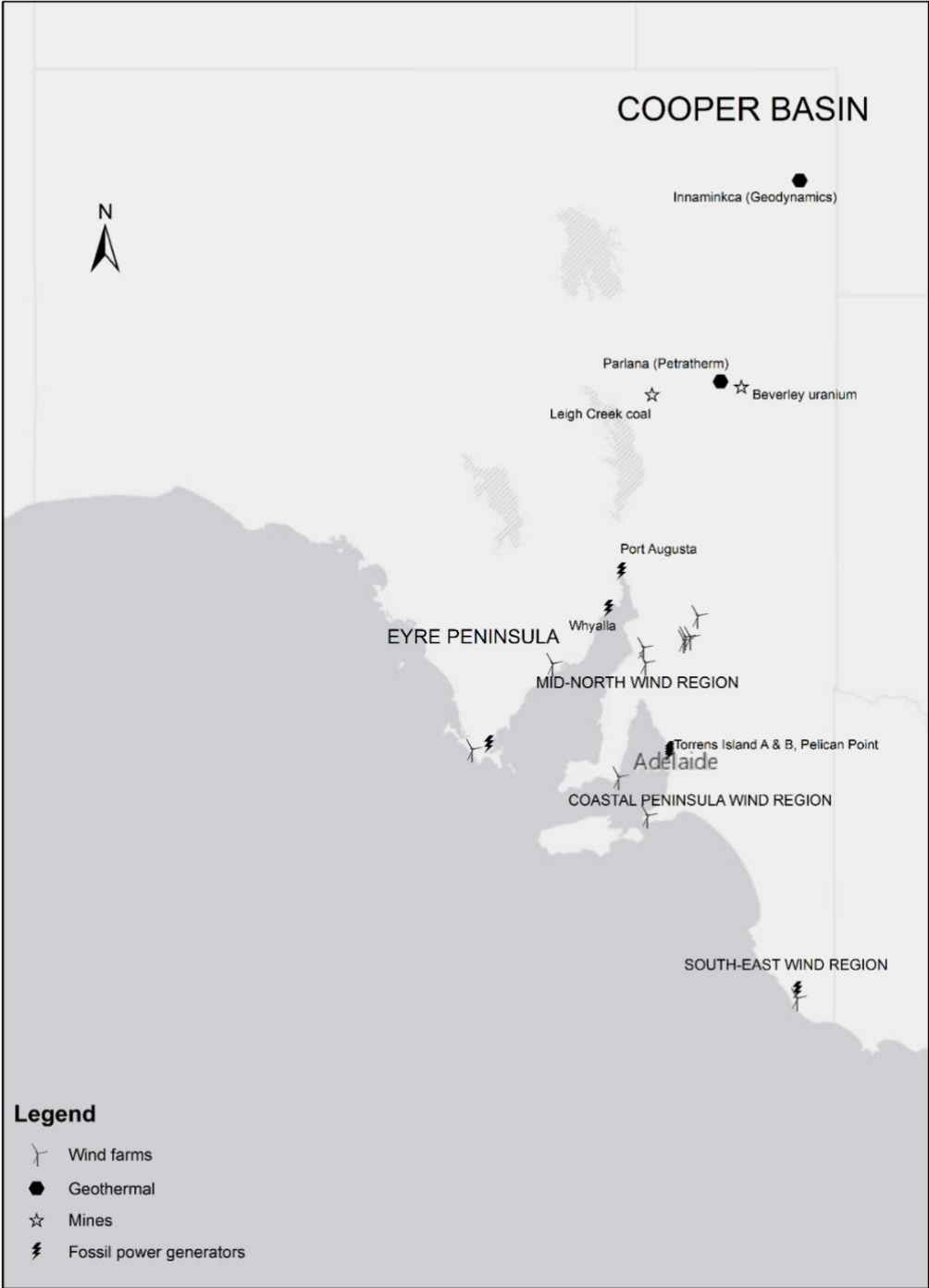
This appraisal suggests that a rational approach to cutting greenhouse-gas emissions would focus

on direct replacement of the Port Augusta coal and Torrens Island gas power stations. Instead,

South Australian electricity has been getting cleaner through the incremental addition of new generation in the form of wind, with little attention to substitution of the baseload generators.

Reliance on the National Electricity Market

Since 2003, the contribution of wind power to electricity generation in South Australia has grown to around 27 % of total annual electricity supplied to the State[81]. This increased wind generation has come mainly at the expense of generation from existing coal and gas generators which are now run less frequently[81]. Yet despite the rapid increase in wind-generated electricity in the State, South Australia still depends on participation in the National Electricity Market for a reliable supply of electricity.

The National Energy Market is spatially the largest electricity grid in the world and serves approximately 9.5 million end-use customers[82]. It is a wholesale market for the supply of electricity to retailers and end users in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia. Exchange of electricity is facilitated through a pool where the output from all generators in the network is aggregated and scheduled at short (5-minute) intervals, to meet demand across the network. Within the National Electricity Market, electricity is indistinguishable from one generator to another, but network stability concerns mean that there is a need to have generators operating across a wide geographical spread of network nodes. The purpose of the market is to provide efficient and above all, secure electricity supply to meet a dynamically changing electricity demand efficiently[83].

South Australia's connection with the National Electricity Market supports both reliability of supply and the efficient use of the wind resource, typically exporting power when the output is high and demand is low (as commonly occurs around 04:00)[84]. Over the entire National Electricity Market,

wind contributed 4.4 % of total electricity generation output in 2013-2014, with 74 % coming from

coal, and 12 % from gas[82]. Despite the ability to sell low-emissions power from wind, South

Australia imported 2010 GWh in 2013-2014, six times the quantity exported (338 GWh)[81].

Trading between adjacent National Energy Market regions relies on high-voltage transmission

lines called 'interconnectors', which are used to import electricity into a region when demand is

higher than can be met by local generators, or when the price of electricity in an adjoining region

is low enough to displace the local supply[83]. The efficient use of South Australia's wind generators

relies on two interconnectors to Victoria, as well as substantial transmission infrastructure within

South Australia. South Australia's larger Heywood Interconnector (460 megawatts-electric (MWe))

was used at 100 % capacity for 8.7 % of the time in financial year 2012-2013[85]. A $108-million

upgrade of Heywood, to be commissioned in July 2016, aims to accommodate the increase in

wind generation that has occurred over the last few years[86]. The recently approved development

of Australia's largest wind farm (199 turbines for 600 MWe at a cost of ~ $1.3 billion), to be located

on the Yorke Peninsula, includes investment in 60 km of undersea cables to transmit the power to

load centres, as well as two converter stations[87]. In another study, capital costs of greater than

$900 million were identified for the additional transmission requirements to support development

of the extensive Eyre Peninsula wind resource, with annual operational and maintenance costs of

greater than $18 million year^{-1} [88].

With the benefit of the National Electricity Market ensuring security of supply and efficient export

of surplus generation, the wind sector has driven total greenhouse-gas emissions from South

Australia's electricity sector down by one quarter over the last ten years: from just over 8

megatonnes (Mt) CO_2-e year^{-1} to just over 6 Mt CO_2-e year^{-1} [89]. South Australian electricity now

has the second-lowest emissions intensity (approximately 0.6 kg CO_2-e kWh^{-1}) of the Australian

states and territories (Figure 6), having diverged sharply from approximate parity with

Queensland, New South Wales and the South West Interconnected System from 2005 until today (the South West Interconnected System is a smaller electricity grid that serves the south-west of Western Australia; it is not part of the National Electricity Market). Until recent connection with the National Electricity Market, Tasmanian electricity generation had nearly zero emissions due to a predominant supply from hydro-electric generation. It has retained the lowest-emission electricity of any National Electricity Market region (0.2 kg CO_2-e kWh^{-1}), but its relative emissions intensity has risen sharply following the interconnection. Victorian electricity releases approximately 1.2 kg CO_2-e kWh^{-1} due to a dependence on combustion of lignite (brown coal) for electricity supply.

Electricity from wind generation brings challenges related to its variable and intermittent supply. As installed capacity grows, the frequency of sudden changes in wind farm output also increases, rendering the management of power systems and transmissions networks more challenging[85]. A review of the aggregated wind output across three defined geographical regions in South Australia (Mid-North, South-East and Costal Peninsula regions) has found that spatial dispersion of wind generation helps to reduce overall variation in supply, but cannot substantially mitigate it[85].

The relationship between wind generation and consumer electricity demand shows "little correlation… between the aggregate wind output and demand in any region"[90]. At times wind supply can be negatively correlated with demand during heat waves[91]. So while the geographic distribution of wind provides some smoothing, the combined variability of wind and consumer demand means that other generation sources are required to respond to rapid changes of supply during periods of low output from wind[85]. For example the largest five-minute change in supply from wind in South Australia was a decrease of 294 MWe[85]. To manage this variation, capacity in excess of an entire, large generating unit (280 MWe of coal generation from Northern power station) had to be sourced at short notice[85]. Such challenges will increase in size and frequency,

and therefore potential economic cost, as wind power supply increases, notwithstanding improving prediction of the availability of electricity from wind[92].

Figure 6 Emissions intensity of electricity for New South Wales (N), Victoria (V), Queensland (Q), South Australia (S), Tasmania (T), Northern Territory (n) and South West Interconnected System (W). Sources: [82,]Commonwealth of Australia (2013)[93,]Commonwealth of Australia (2010)[94,]Commonwealth of Australia (2012)[95,]Commonwealth of Australia (2011)[96,]Commonwealth of Australia (2006)[97,]Commonwealth of Australia (2009)[98,]Commonwealth of Australia (2008)[99]
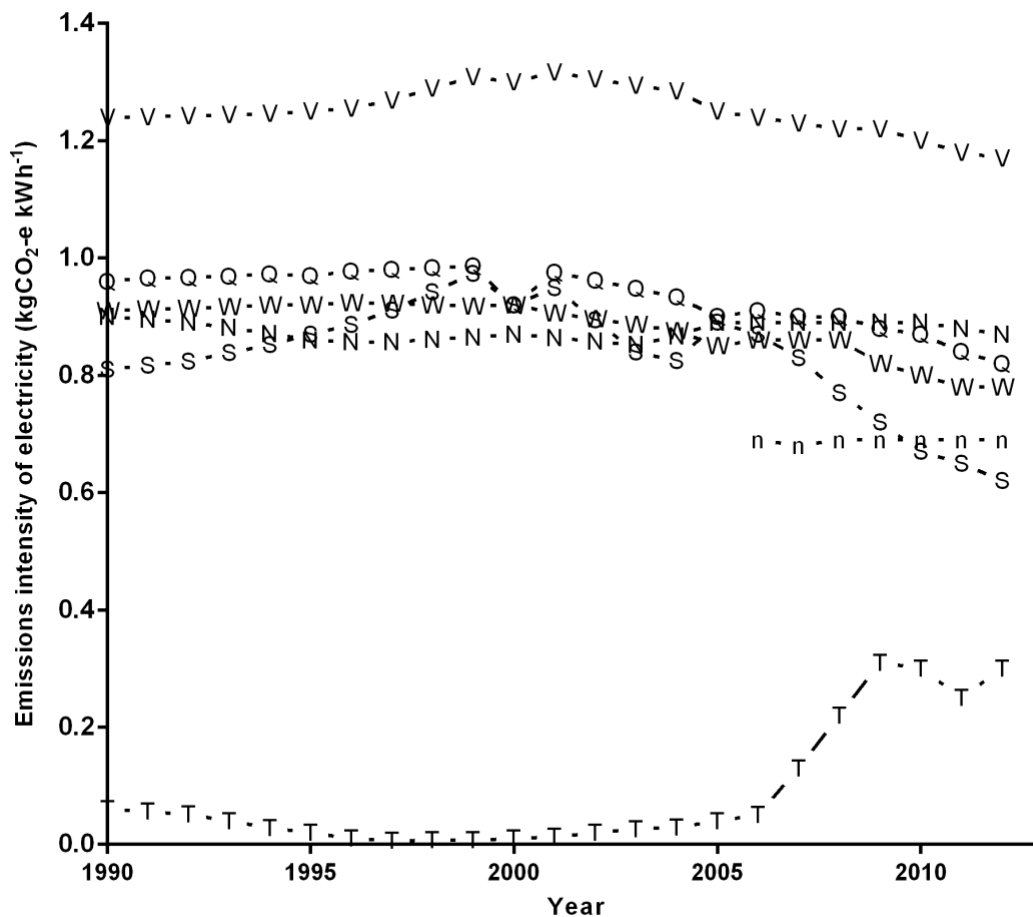
The lack of correlation between electricity demand and supply from wind has another long-term impact on overall system costs: the constrained ability to retire other 'baseload' (in reality, 'dispatchable' *sensu*[100], generators from service. This is best illustrated by the poor correlation

between supply and peak demand. During periods of peak demand, only a small amount of the total installed wind capacity can be relied on firmly to be providing electricity; the Australian Energy Market Operator currently assumes only 8.6 % for summer and 7.9 % for winter peak demand in South Australia (more precisely, for every MWe of wind-generating capacity installed, the Market Operator can only rely on a statistically 'firm' 8.6 % of that capacity being available during 85 % of the top 10 % highest demand periods of the year)[101]. During periods of low wind generation, the cost impact is minimal. Pre-existing margins of reserve supply, which insure against the sudden loss of fossil-fuel generators, can also cover the wind variability. As wind-power penetration increases, however, the cost implications become ever more daunting. These subsidised, variable generators supply electricity at low marginal costs (e.g., no fuel requirements, no need for permanent staff at the power plant, etc.). This removes potential generating hours for other (baseload) generators with higher marginal costs to sell power and raise revenue. However, little of this dispatchable generation can permanently exit the market. Most of it must be retained to cover periods of peak demand when wind is generating little electricity. South Australia has 1,473 MWe of existing and committed registered generation capacity from wind, but the maximum 'firm' contribution is only 93 MWe[102]. Just 60 MWe of coal has been taken out of service[103] and the market operator has not been advised of any plant retirements within the 10-year planning outlook[102]. In the eleven years since wind first entered the South Australian market, registered generation capacity increased 62 % while peak demand grew only 13 % (Figure 7). South Australia has been through a period of system overbuilding[104], exemplifying Tainter's "complexity spiral" whereby societies become more complex as they attempt to solve problems, with increasing costs and diminishing returns as the complexity increases (Tainter, cited in Palmer (2014)[105]). Perversely therefore, the addition of variable, low marginal-cost generators gradually places upward pressure on overall system costs, in order to keep all necessary generators in the market[106]. There is already evidence of this effect in South Australia (see below).

Figure 7 Comparison of registered generation capacity by energy source, expressed as peak installed capacity, with peak demand, 2003 and 2014. Data sources: Australian Energy Market Operator (2014)[101,]Electricity Supply Industry Planning Council (2003)[107].
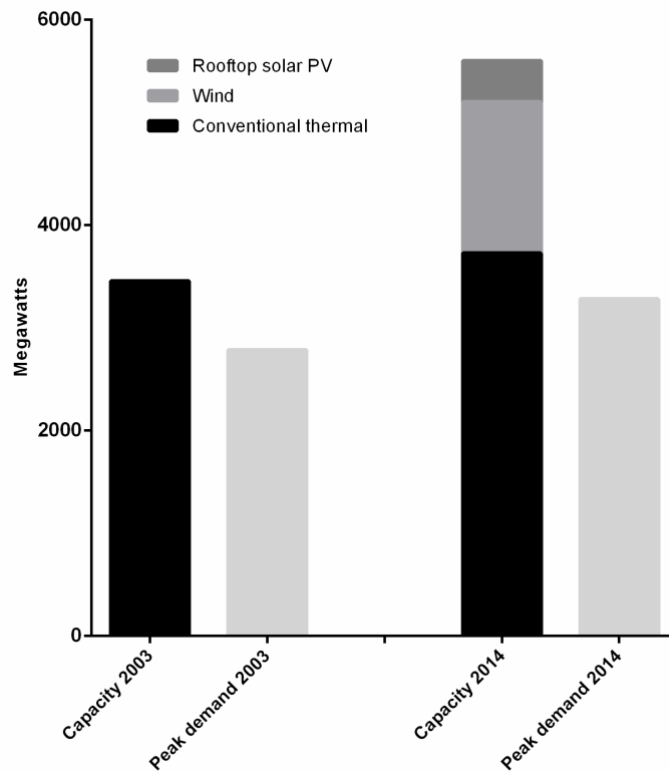
Initially, the average wholesale price of electricity in South Australia declined from a spot price of over \$80 MWh[-1] in 2009-2010, to \$42 MWh[-1] in 2010-2011[108]. The decline in wholesale price was due in part to wind generators sometimes bidding at negative prices because of their ability to earn and sell renewable energy certificates to cover their costs[109]. However in 2012-2013, the South Australian wholesale electricity spot price rose by over 70 %[108]. The main driver of this rise was a price spike in autumn. This was unusual; autumn is a period of typically subdued demand, and the event occurred against a backdrop of generally lower demand in the National Electricity Market[108]. The Australian Energy Regulator attributed the price spike to commercial decisions (i.e., cost control) from non-wind suppliers to take some generating capacity offline, which increased the wholesale price of electricity[108]. The Australian Energy Regulator highlighted that the State's reliance on wind-generated electricity had driven down spot prices, thereby eroding the

returns for other generators. During this event, South Australia's electricity imports were at their highest for six years[108]. This illustrates system costs rising perversely from increasing reliance on subsidised, variable renewable energy generators whose output is uncorrelated with demand.

Another reliability issue is the provision of necessary ancillary services to the network to ensure systems stability and power quality, such as frequency-control capability and reactive support[110]. These services are provided by 'synchronous' generators, typically traditional coal and gas generation or hydro (in some states), where electricity is generated through turbines spinning in synch at close to 50 Hz. Ancillary services are a physical requirement of any electrical system and have been necessary since the development of reticulated power[111]. However as shown, increased wind participation displaces traditional (non-hydro) synchronous generators from the market. The associated ancillary services reduce or disappear[110].

The rapid influx of wind generation, combined with proposals for over 3,000 MWe of additional wind generation[101] spurred the Australian Energy Market Operator and transmission network operator Electranet to "identify existing limits to secure SA power system operation with high levels of installed wind generation and PV relative to SA electricity demand"[110]. The report stipulates that the asynchronous generation of wind and solar PV "by themselves, are not able to provide the required controls to ensure system security"[110]. The report finds that South Australia is able to operate securely with high generation from these sources, even more than 100 % of demand, provided at least one of the following two conditions are met: (a) the Heywood Interconnector linking South Australia and Victoria is operational; and (b) sufficient synchronous generation, such as coal or gas thermal generators, is connected and operating on the South Australia power system[110].

AEMO and Electranet examined the credible event that future market conditions could push the number of synchronous generators in South Australia to zero at any given time, and this coincided with a loss of interconnection. They found:

> "Where SA has zero synchronous generation online, and is separated from the rest of the NEM, AEMO is unable to maintain frequency in the islanded SA power system. This would result in state-wide power outage".[110]

This finding provides insight into how South Australia needs to view variable renewable energy. In electricity terms, South Australia is not, in normal circumstances, an island. The current and future success of integrating variable renewable energy in South Australia hinges on the reliability provided by the rest of the NEM network. In that context, pursuing high penetrations of variable renewables in South Australia, as an end itself, becomes a parochial pursuit more so than a meaningful contribution to decarbonising the National Electricity Market. Proposed solutions to mitigate this risk include payments for minimum synchronous generation to remain online, development of a new market in ancillary services, network augmentation and even curtailing supply from wind and photo-voltaics[110]. This again points to system costs that are not represented by technology-specific metrics such as capital cost or levelised cost of electricity of the renewable generator. Such costs would spread nation-wide were other states to follow South Australia's lead, with each new addition of variable renewable energy eroding the buffer of reliability on which the overall system depends and increasing their implicit operating subsidy.

These phenomena argue strongly that South Australia should plan both for more wind integration, but also on how to move beyond a sole focus on maximising wind capacity. Other forms of low-emissions generation must finish the decarbonisation job that wind has begun, and ultimately meet the role of largest provider. There are no credible plans for decarbonisation of Australian

electricity that rely on variable supply alone, so this cannot come from merely a wind-plus-solar photo-voltaic combination. Studies that have sought to address this challenge have applied varying combinations of energy storage and dispatchable, synchronous 'clean' energy (e.g., burning biomass) to support the variable renewable generators[112-115]. The only real question is just what these constant, dispatchable and synchronous sources of supply should be. In the absence of a large hydro-electric resource, options such as geothermal and large-scale solar-thermal have been the subjects of considerable attention, research and development in South Australia. At a national level, the capture and storage of carbon dioxide from coal combustion has also been the subject of ongoing research. In the subsequent sections, we discuss the progress, realism and prospects of each.

Carbon Capture and Storage

The capture and permanent storage of carbon dioxide from power plants offer the potential for continued exploitation of coal resources and existing power-generating infrastructure with reductions of greenhouse gas emissions of 80-90 %[100]. With the high dependence on coal both globally and in Australia, carbon capture and storage therefore merits consideration.

A globally important carbon capture and storage project is the US$1.35 billion Boundary Dam in Saskatchewan, Canada. This 110 MWe redevelopment of an existing coal-fired generator has the economic advantage of using the captured CO_2 for enhanced oil recovery in a nearby oil field[116]. In Australia, carbon capture and storage is at various stages of research, development and piloting[117]. The most advanced Australian pilot project involved a one-off storage of 65,000 t CO_2-e in Victoria's Otway Basin[117]. Against annual emissions from Australia's electricity sector of around 2 million t CO_2-e[118], there remains a large gulf between existing development and a meaningful contribution to reducing greenhouse gas emissions.

The unavoidable energy and cost penalties of carbon capture and storage at the plant, as well as the need for substantial new pipeline infrastructure, will pose a barrier to deployment. Hammond, Akwe and Williams (2011)[119] estimate an energy penalty of between 14 and 30 % compared to reference plants without capture, and an increase in the cost of electricity of between 27 and 142 %. Commercial deployment would therefore require a carbon price at which alternative clean energy sources, particularly nuclear energy, would likely have clear commercial advantage[100]. An analysis based on an existing 425 MWe facility in Australia assumed geo-sequestration 500 km from the site[120]. A carbon price of US$75 would be required before the plant operator could justify a retrofit of the plant. Herzog[121] estimated a required carbon price of US$65 per tonne for an nth plant (in the range of the 5th - 10th plant constructed). Based on existing developments, uncertainty of successful deployment and high cost, carbon capture and storage is a poor candidate for meaningful decarbonisation of South Australia's electricity sector.

Geothermal

Geothermal power used for electricity generation in many parts of the world is based on near-surface hydrothermal resources. These resources make use of steam derived from natural aquifers associated with volcanic systems. Unfortunately, Australia lacks this type of easily developed resource[122]. However, Australia has extensive, deep geothermal resources in the form of hot sedimentary aquifers and hot-dry rocks, reported at over 2.5 million petajoules (1 PJ = 10^{15} J), against total primary energy consumption of around 6,000 PJ year^{-1} [122]. Of these resources, South Australia has a smaller endowment of hot sedimentary aquifers in the south-east of the State and one of the world's best hot-dry rock resources in the far north of the State. This hot-dry rock resource has been the focus of considerable development and investment[122].

The challenge of tapping South Australia's hot-dry rock resource in an economically efficient way has been a slow and fraught process. Geothermal drilling has high engineering, financing and non-discovery risks [123], particularly in Australia where geothermal exploration is in its infancy[124]. The necessary temperatures are found at depths of ≥ 5 km[125] in solid, impermeable granites. Circulation of fluids through the heat-bearing rock requires deep drilling and precise directional fracturing to allow fluid to be pumped through the heat source and then recovered via another well, and the use of specialised methods to prevent localised over-cooling and mineralisation of fractures[126]. Compared to most oil and gas exploration, geothermal formations are hot, hard, abrasive, highly fractured and often contain corrosive fluids[126]. Drilling is usually difficult, with slow rates of penetration and low lifespan for drill bits[125], and frequent challenges such as loss of circulation of drilling fluid or instability of the well bore itself. Such problems might often cause drilling to take twice as long as conventional drilling, and effectively double the costs[123]. Compared to oil and gas drilling, engineered geothermal projects suffer higher risks for a lower value product (hot water), and therefore an inferior ratio of investment to return[127]. Increased research and development is required, both in exploration and development, but there is "no panacea"[124].

The practical outcome is that geothermal exploration and development has delivered little financial return for South Australia. After listing to the Australia Stock Exchange in 2002, the company *Geodynamics* successfully commissioned a 1 MWe demonstration geothermal plant in 2013, which has now ceased operations. The major joint venture partner, *Origin Energy*, departed in 2013[128]. *Geodynamics* is now seeking funding to develop a 5-10 MWe facility selling electricity to gas producers in the Cooper Basin[129]. Against a baseload electricity supply of around 3,000 MWe in South Australia alone, the shortfall of much greater than two orders of magnitude is obvious. *Geodynamics* acknowledges that the development of geothermal resources remains a long-term challenge in South Australia[128]. Another lead developer, *Petratherm*, is now targeting a 3.5 MWe development to supply the off-grid Beverley uranium mine. Further development plans comprise

300 MWe of gas and wind generation, followed by another 300 MWe of large-scale geothermal and solar[130]. The project is designed to enable the financing of the geothermal resource[130]. Investment, research and development in geothermal will likely continue in South Australia, and globally. Based on progress to date it remains unclear whether geothermal will proceed to play the medium-term decarbonisation role touted by the Australian Government over the last five to ten years[131,132], but its prospects for being a major solution to displacement of coal- and gas-fired electricity seem a distant hope at best.

Solar-thermal with storage

The growth rate of solar power over the last few years, both globally and in Australia, has been substantial. In 2013, slightly more peak global capacity (i.e., 'nameplate' capacity, which does not account for average output or 'capacity factor') was installed in solar (36.5 GWe) than in wind (35.5 GWe)[133] with annual average growth for the ten years to 2012 of greater than 50 %[74]. In the global context, solar has grown from a tiny initial base of 0.01 % to a more substantive 0.5 % (i.e., greater than 50-fold increase) of global electricity supply from 2002 to 2012[74]. With over a million solar photo-voltaic installations in Australia alone, solar now provides more than 4 GWh of electricity year[-1 134], or approximately 1-2 % of Australia's current annual electricity consumption.

In South Australia, the proportional uptake of solar photo-voltaic is greater than the national average, with 560 MWe of registered capacity providing over 5 % of electricity annually[89] from over 20 % of registered residential customers. The rate of photo-voltaic installation has, historically, risen and fallen with the availability, and periodic withdrawal, of subsidies including direct financial assistance, renewable energy certificates with multipliers, and generous feed-in tariffs (Figure 8). With the removal of the multiplied value of the renewable energy certificates and more recently, the feed-in tariffs, the month-to-month installation rate of solar photo-voltaic has

fallen to a mean of approximately 5,600 kW for the ten months to November 2014. This is against a mean monthly installation rate of approximately 12,600 kW for the 36 months to January 2014[135-137] (Figure 8).

Nonetheless, further reductions in the price of photo-voltaic systems in the medium to long term, with the potential addition of cost-effective distributed storage, could support continued expansion of solar photo-voltaics in South Australia. The potential disruption of the electricity retail market from high photo-voltaic penetration has been explored in detail by a collaboration of industry experts[138] and modelled to devise a 100 % renewable-energy system for Australia[115]. In both cases, the need for large, dispatchable, utility-scale electricity generation is reduced, but remains.

Figure 8 Monthly solar photo-voltaic installation in South Australia (kW month[-1]) from February 2011 to November 2014 showing reduction and withdrawal Renewable Energy Certificate (REC) multipliers and Feed in Tariff (FiT). Sources: Clean Energy Regulator (2012)[135,]Clean Energy Regulator (2014)[137]
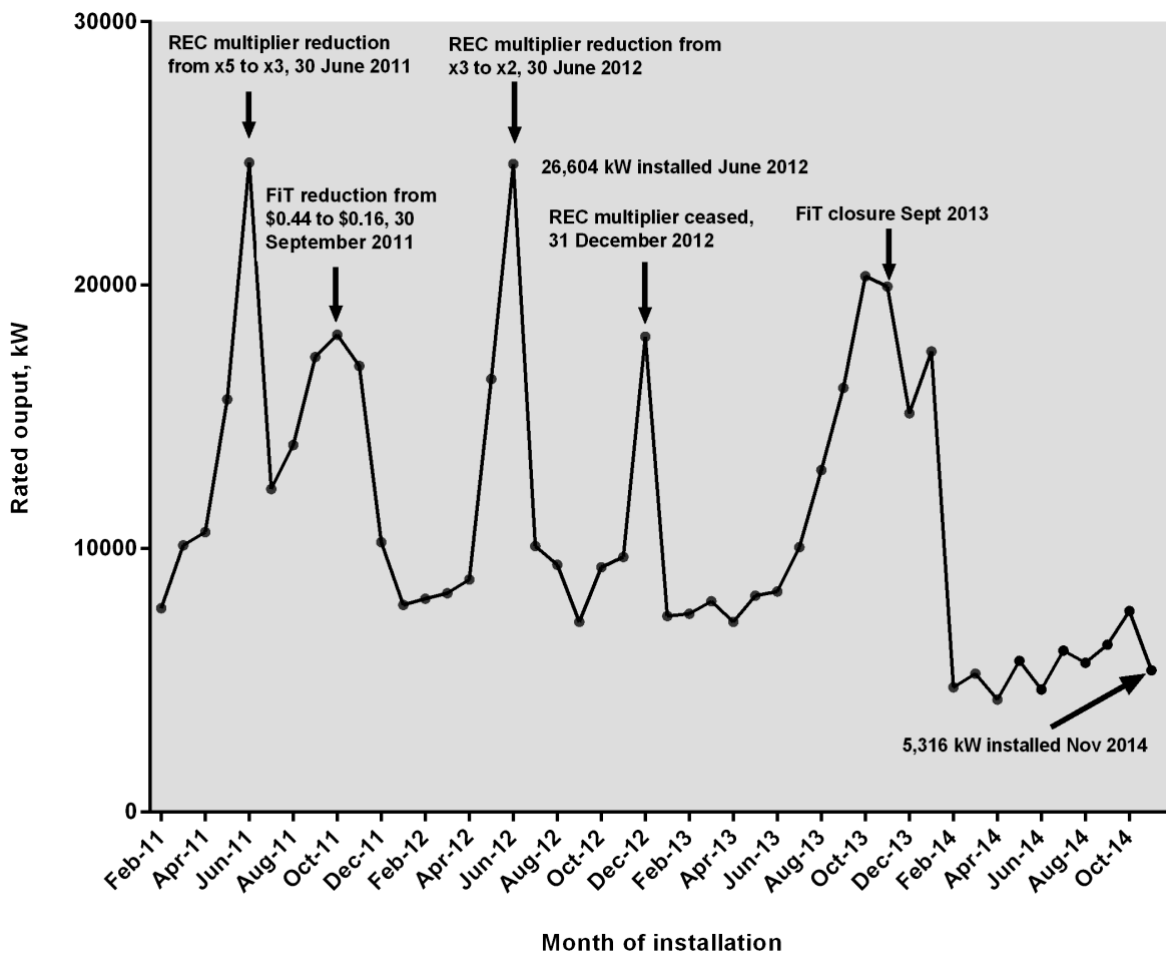
The long lead times to these outcomes reinforces the need to hasten action to replace fossil-fuel baseload, not delay it. Detailed recent analysis by Palmer (2014)[105] also suggests that the broadly unappreciated limitation and difficulties presented by high penetrations of solar photo-voltaics to networks, along with questionable energy return on investment, might work against such high penetration scenarios.

It is certain that distributed solar photo-voltaics will play an increasing role in South Australia, and it is equally certain that utility-scale, dispatchable, clean electricity will remain a requirement in the long term. Such a service might be conceivably provided by concentrating solar power (used interchangeably here with 'solar-thermal') with the addition of large, external energy storage. Globally, concentrating solar power has experienced a much lower rate of uptake than photo-voltaics. Progress has been intermittent since the early 1980s, with growth tied directly to strong incentives, particularly in the USA and Spain[139]. With the highest average direct solar radiation of any continent[122], Australia has the greatest solar resource potential in the world. In raw terms, the annual solar radiation reaching Australia is 10,000 times our total primary energy consumption[122], but such figures can be misleading. Areas with the necessary technical characteristics for large-scale solar power must be overlaid with other relevant limitations of site suitability such as proximity to load, high-capacity transmission lines, and auxiliary fuel, as well as exclusions based on existing land use. When accounting for these real-world limitations, the size of the area in Australia that is suitable for potential development of utility-scale solar could be reduced by as much 99 %[140].

Even taking such constraints into account, Australia has many potentially suitable sites for developing utility-scale solar energy[122,140], including in South Australia's Port Augusta region[141] (Figure 3). Home to the State's most polluting coal-fired power stations (emissions less than 2.2 million t CO2-e in 2012-2013[79]), it is unsurprising that Port Augusta has become the focus of lobbying in favour of solar-thermal development. A 2012 report from the not-for-profit lobby group *Beyond Zero Emissions*[142] proposed the replacement of the coal-fired power plants in Port Augusta with a hybrid renewable solution combining wind and solar-thermal with storage technology. A select committee of the South Australian Parliament was formed to investigate the replacement of the Port Augusta coal-powered stations by a concentrated solar-thermal power station[143]. The interim report states that high and uncertain costs remain the major barriers to

solar-thermal technology[143]. The costs provided were on the basis of a proposal including only 5 hours of energy storage under the assumption that capacity factor of 50 % is sufficient[142]. This would represent a diminished capability in reliable electricity generation in South Australia compared to the existing coal plants.

The challenge for utility solar power with on-site energy storage (cf. the now widespread rooftop solar photo-voltaic units with output that is both cyclical and variable) is that replacing coal-fired generation is likely to be cost-prohibitive under anything but a policy of high carbon pricing[141]. Previous professional economic and engineering assessments provided little support for the development of solar-thermal in South Australia[141]. Lovegrove *et al.*[144] indicated that for utility-scale solar, the lowest-risk technology at the most favourable site (i.e., parabolic trough at Longreach in Queensland) would have a levelised cost of electricity of $252 MWh^{-1}, compared to a volume-weighted average price of $74 MWh^{-1} for South Australia in 2012-2013[108]. Initial assessments by Alinta Energy were similar, stating that subsidies of $200-400 MWh^{-1}, or capital contribution of at least 65 % of construction costs, would be required[145].

A $2.3 million feasibility study, co-funded by Alinta and the Australian Renewable Energy Agency, has considered exclusive solar-thermal generation and a coal-solar hybrid option for Port Augusta[145,146]. Based on the findings of the early study's preliminary cost estimates for a 50 MWe, stand-alone solar-thermal plant of $15,926 kW^{-1} installed, and a levelised cost of electricity of $258 MWh^{-1}[147], commercial development would require long-term offtake agreements with ≥ 1 customers to purchase the electricity generated from the concentrated solar power facility[147]. According to the potential proponent, these costs are currently prohibitive[148].

The commercial feasibility of this option will be studied further "with the due diligence it warrants" to provide information for potential investors "should the cost of technology or regulatory

environment change"[148]. This detailed consideration might provide a more positive assessment of the economic case for stand-alone solar-thermal. Some assessments suggest that solar technologies will become cost-competitive by 2020 and beyond[139,149-151] and others identify the many specific avenues of research, development and learning that might be the actual drivers of this reduced cost[144,152-154].

In Australia, there is evidence that the outlook for solar has been overly optimistic. In 1994, an analysis suggested that the price and availability of solar-thermal in Australia could make it highly competitive, possibly before the year 2000[155]. More recently, the 2012 report prepared for the Australian Solar Institute acknowledged that there has been some progress, but not as much as previously suggested[144]. The Australian Solar Institute recommends an early focus on smaller-scale deployment in market sectors where the cost-revenue gap for solar is smaller than in the market for grid-connected electricity supply. Suggested options include off-grid applications that compete with diesel generation and also hybrid applications with existing fossil-fuel technologies[144]. This suggests many smaller systems of around 50 MWe each to reduce the risk of individual projects failing, broaden the deployment and industry 'know how', and incrementally build relationships and experience with incumbent stakeholders in Australia's energy market. Clearly, it will be a slow and difficult path.

Nuclear power

Given the problems identified in the above review, we argue that a compelling case to close South Australia's aging fossil fuel-generated baseload can only be formed if the solution is a technology that matches the reliability of the incumbent generators (unlike wind or photo-voltaics), is more cost-competitive than solar-thermal, and more mature than engineered geothermal or exotic forms of chemical energy storage. This could call for the exploitation of one of South Australia's other

impressive energy resources; nuclear power might represent the technology that most effectively answers the challenge[156].

In terms of performance and reliability, nuclear power is not subject to the speculation and uncertainty associated with unconventional geothermal technology or solar-thermal with heat storage. A commercially mature technology with substantial global experience, there are over 437 nuclear reactors in operation in over 30 nations, today providing around 11 % of total global electricity supply and over 40 % for jurisdictions including Sweden, France and the Canadian province of Ontario[157]. Where the largest enhanced geothermal development worldwide is the 5 MWe proposal in South Australia, nearly 75,000 MWe (i.e., 15,000× more) of nuclear generation is currently under construction, mainly in China, Russia, India and South Korea[157]. Despite some well-documented miscalculations in terms of cost and delivery times at various points in the history of the nuclear power industry[158], nuclear deployment remains the only pathway, with the exception of geographically constrained, large hydroelectricity schemes, to have successfully demonstrated the decarbonisation of electricity supply for large, developed nations (Table 2). For example, the Canadian province of Ontario, with a population of nearly 14 million people, delivers electricity at a maximum of $0.135 kWh^{-1} to residential customers[159], with greenhouse gas emissions rarely exceeding 75 g CO_2-e kWh^{-1} [160]. This has been achieved with a supply mix of approximately 50 % nuclear, with the balance provided by hydro, gas and wind power; all coal has been retired.

Table 2: Comparison of electricity supply by greenhouse-gas intensity (kg CO_2-e kWh^{-1}) and price (AU\$ MWh^{-1}) in nations with varying percentage penetration of nuclear electricity. All data from the International Energy Agency[161] except Australian price from Australian Energy Market Commission[162]. Prices adjusted for purchasing power parity[163].

Nation	Emissions intensity (kg CO_2-e kWh^{-1})	% nuclear	Residential price (AU\$ MWh^{-1})	Industry price (AU\$ MWh^{-1})
Australia	847	0	271	-
Denmark	385	0	450	\$127
Germany	468	23	282	\$126
Switzerland	27	40	269	\$156
Sweden	22	40	241	\$101
France	77	76	157	\$102

Rapid Organisation for Economic Co-operation and Development (OECD) nuclear-build programs left a legacy of reliable, cheap and clean electricity. Between 1971 and 1993, Ontario commissioned nearly 13 GWe of new nuclear generating capacity[164]. Sweden commissioned 9.5 GWe in the twenty two years between 1972 and 1985[165] and France commissioned over 63 GWe in the twenty years to 2000[166]. It is therefore evident that the construction of nuclear technology itself poses no obstacle to the rapid retirement of fossil baseload.

It is somewhat perplexing then that among OECD nations and now many developing nations, Australia actively refuses the use and development of nuclear power[167]. This is despite Australia's involvement in mining and export of uranium fuel for foreign reactor programmes, as well as highly developed nuclear-research and nuclear-medicine sectors, and the presence of an established regulatory body. There have been several governmental and non-governmental processes for modelling, forecasting or proposing electricity generation mixes for Australia at different

milestones to 2050[112,114,115,131,168], but none to date has openly considered the potential contribution from nuclear power.

Wight and Hearps[112] rather dubiously justify the exclusion based on the 2020 timeframe of their energy plan and that nuclear power could not be implemented within 10 years. Another model commissioned by the Australian Government simply assumed that, beyond coal and gas, there was "no other viable thermal power alternative"[168]. Likewise, Elliston et al[114] specifically excluded large coal, gas and (arbitrarily) nuclear plants, and the Australian Energy Market Operator[115] explicitly excluded nuclear based on the terms of reference provided by the Department of Climate Change and Energy Efficiency. In an apex moment for circular reasoning, a report from the Climate Council explained that "Nuclear is not considered in this report because of the focus of future options for the Australian electricity sector vis-à-vis fossil fuels and renewables"; quite literally, nuclear is not being considered because nuclear is not being considered[169]. However, these exclusions run contrary to a 2006 bi-lateral Federal Parliamentary Committee report that found that nuclear power represents the only current reliable and proven technology to reduce emissions while supplying the world's high energy demand[170].

More recent considerations of nuclear power by the Australian Government have been sporadic. The Australian Energy Projections[171] duly references the highly competitive cost finding of the Australian Energy Technology Assessment[172], yet follow this solely with scenarios that have zero contribution from nuclear power generation to 2050, without justification. The Draft Australian Energy White Paper[173] expressly excluded nuclear and stated that the technology is not permitted under the *Commonwealth Environment Protection and Biodiversity Conservation Act 1999* (Section 140A: No approval for certain nuclear installations).

The Australian Energy Technology Assessment[172] included both gigawatt-scale nuclear and small modular nuclear power. Even though the 2013 update to this model included a "special emphasis" on operational and maintenance costs and improvement rates for all wind, solar-thermal and solar photo-voltaic technologies[174], no comparable data are modelled for understanding future costs for nuclear technologies despite the availability of recent, credible assessments[175-178]. This partial review instead generated a questionable output, in which small modular reactor technology (which is yet to be deployed and is intended to be factory manufactured), were projected with no decline in price to 2050[174], again without justification nor reconciliation against the fact that all other alternative-energy technologies were modelled to include sharp cost reductions over time.

Nuclear power in South Australia

To explore the potential role of nuclear power for South Australia, a 2012 report compared the hybrid wind-solar proposal for replacing the Port Augusta power station to a 'reference' nuclear solution, and then these options were evaluated against thirteen economic, environmental and social criteria[179]. This assessment found that for nearly half the capital cost, the nuclear option delivered more electricity with superior reliability and dispatchability (power on call), allowing more direct displacement of the most emissions-intensive coal power stations from South Australia's generation profile. The electricity provided was also cheaper than that provided by the solar-thermal generator by at least \$112 (to \$160) MWh^{-1} (competitive with estimates for newly commissioned modern coal power) and required 90 % less land and 340,000 tonnes less steel, with at least double the lifespan of the infrastructure[179].

Despite the demonstrated economic and sustainability superiority of nuclear power in large-scale decarbonisation[100,174,179,180], any economic advantage for nuclear in the Australian setting hinges on longer-term assessments of national interest. While the cost advantage against comparable

renewable generation is large, high up-front investment renders nuclear unpalatable compared to fossil fuels in liberalised energy markets that have come to prioritise short-term investor returns[181]. Deployment of nuclear energy in Australia is unlikely to thrive without a strong policy shift, either related to reduction of greenhouse-gas emissions, air pollution or simply planned renewal of energy infrastructure.

Since 2003, overall construction costs for nuclear build have escalated in line with all types of large-scale engineered projects including (but at a greater rate than) gas and coal plants[182]. Early indications from new build programs in OECD nations presents a mixed picture of cost, ranging from AU$5,200 kW^{-1} (AREVA European Pressurised Reactor in Flamanville, France)[183] to AU$7,650 kW^{-1} (AREVA European Pressurised Reactor in Olkiluoto, Finland)[184]. Delivery ranges from behind schedule and over budget (e.g., Westinghouse AP1000 in Georgia, USA)[185] to substantial time and cost overruns (e.g., Olkiluoto, Finland). These nascent OECD build programs are for new reactor designs with advanced safety features, expected capacity factor of more than 90 % and a design lifespan of 60 years, compared to 30-40-year design lifespans of earlier generations of nuclear reactors.

It is the rapidly developing Asian markets, particularly the substantial build program of China, that provide a more reliable indicator of the mature construction costs of nuclear new build[100]. Generation III reactors such as the AREVA European Pressurised Reactor under construction in Taishan, are scheduled to be brought online within 40 months[186], with reported costs of approximately $2,500 kW^{-1}. Construction of four AP1000 reactors at Sanmen is on schedule at an estimated cost of $2,615 kW^{-1} [187] and Korean vendor KEPCO have sold turn-key nuclear development to the United Arab Emirates at a competitive price of $3,643 kW^{-1} [100]. With seven reactors currently under construction and another 183 reactors on order or planned[157], Australia's

late entry to nuclear power may reap the benefit of a globally mature and competitive market in generation III reactor construction.

Despite the glacially slow progression in the future planning of South Australia's energy portfolio, many stakeholders in South Australia, and nationally, appear keen to increase serious consideration of nuclear energy. For example, *Business SA* recently favoured informed debate on the benefits, costs and risks of establishing a nuclear industry in the State[188]. Likewise, the Academy of Technological Sciences and Engineering concluded that nuclear is a viable candidate to replace coal-fired power stations and that there was no reason to omit its consideration in the generation mix[189]. Even academics are turning public opinion. University of Adelaide climate scientist Tom Wigley recently joined international colleagues in an open letter to environmental organisations calling for an embrace of nuclear power to tackle climate change[190]. An international group of 75 conservation scientists signed a similar letter in 2015, with a focus on the benefits of nuclear power for biodiversity preservation[65]. Professor Ove Hoegh-Guldberg, Director of the Global Change Institute at the University of Queensland, issued a public statement calling for the deployment of nuclear power as "the one real option to significantly reduce global carbon emissions"[191]. Random polling of more than 1,200 South Australians recently showed much higher support for nuclear power (48 %) than opposition (32.6 %), with strong support outweighing strong opposition (29 and 20 %, respectively)[192]. Such growth in visible support for the consideration of nuclear power might have been influential in the decision by South Australian premier Jay Weatherill in early 2015 to call a Royal Commission to investigate the potential for South Australia to expand activity in the nuclear-fuel cycle.

Barriers to nuclear deployment

The deployment of nuclear power in South Australia still faces many barriers. Unlike the technical, reliability and (relatively much higher) cost barriers faced by geothermal and solar-thermal, a nuclear power sector will need to develop the necessary licensing and regulatory arrangements, as well as obtain a skilled workforce and garner majority support by the public. A previous Government assessment suggested 10-20 years would be required between the establishment of a national strategy and the commencement of reactor operations[193]. Getting such a process underway requires open, Government-led public discussion to reach sufficient community consensus, especially regarding the management of spent nuclear fuel and understanding of risks and benefits.

Aside from depending on proactive political leadership, the pace at which a nuclear sector could develop likely depends on the extent of South Australia's international commitment to facilitate technology, knowledge, education and skills transfers into Australia[179]. International precedent set by the partnership between the United Arab Emirates and South Korea has once again demonstrated the rapid up-scaling of nuclear electricity-generation capacity, with 5,600 MWe contracted in 2009 to be staged into operation by 2020[194]. The World Nuclear Association recently reinforced that rapid deployment pathways might be open to South Australia because of its well-equipped political, legal and educational infrastructure[195]).

Opportunities for South Australia also lie in the most innovative end of nuclear technology. Development concepts based on generation IV fast-reactor technology, coupled with full fuel recycling (collectively called 'integral fast reactors'), could overcome traditional objections to both spent nuclear fuel storage and nuclear power generation[156], thereby economically bootstrapping the deployment of new clean energy generation.

Previously, proposals for economic development through the acceptance of spent fuel by Australia have been predicated on long-lived hazardous waste that requires isolation for hundreds of millennia[193,196]. Emphasis is placed on remote locations, favourable geology and political stability as key competitive advantages for Australia[188]. The emphasis on these competitive advantages arguably serves to reinforce perceptions of spent fuel acceptance as hazardous and with an essentially infinite timeline for management – a major point of objection and political and social opposition.

By contrast, integral fast-reactor technology recycles more than 99 % of spent nuclear fuel for zero-carbon electricity generation, providing 150 times more electricity from uranium fuel compared to the current generation of reactors[197]. The technology provides major improvements in safety related to the use of metal fuel and metal coolants, which make accidental meltdowns a physical impossibility, and ensure indefinite passive removal of decay heat in the event of emergency shutdown[197]. The small quantity of eventual waste produced by integral fast reactors has a half-life of approximately 30 years. Secure storage is thus required for about 10 half-lives (only 300 years) after which activity is reduced to the levels of natural uranium ore. The engineering requirements for safe storage are therefore considerably simpler, with existing United States Environmental Protection Agency standards met *a priori* at many sites[197].

With dry-cask storage now approved in the USA for up to 100 years[198], it would be possible to couple a committed integral fast reactor program with the establishment a multinational spent-fuel repository based on longer-term storage using rolling review and approval of established, above-ground storage technologies[199]. These characteristics could render integral fast-reactor development a game-changing economic concept for South Australia. South Australia could access the huge, already-established market in acceptance of spent nuclear fuel (valued in 1998 at $200 billion)[200] with a known, understood and beneficial end-use for the material. Using

recycling and establishing simpler engineered storage for a smaller quantity of shorter-lived waste would unblock the back end of the nuclear fuel cycle for international customers. That in turn would facilitate more rapid global growth in nuclear development with subsequent benefits to South Australia via growth in uranium exports.

Each integral fast reactor development (an installation of twin, compact power modules) would add 622 MWe of dispatchable, zero-carbon generation for either consumption or export to the National Energy Market. This could improve South Australia's role in meeting the 50 % projected increase in Australian electricity demand to 2050[171]. Sufficient integral fast-reactor units to displace all coal and gas generation in South Australia (3,500 MWe) would require a throughput of a mere 150 t year^{-1} of recycled spent fuel or depleted uranium tails, of which just 10 t year^{-1} would be fissioned for energy (based on figures in Carmack, Porter, Chang, Hayes, Meyer, Burkes, Lee, Mizuno, Delage and Somers (2009)[201]). Taking custody of even a modest quantity of spent nuclear fuel would secure South Australia's energy independence for many centuries. The small size of the generating units (311 MWe) means additional transmission and network requirements would be negligible.

Both the reactor and fuel-recycling technologies have been extensively and successfully demonstrated over 30 years of operation and development at the Argonne National Laboratories in the USA[197]. The integral fast reactor is commercially available as the PRISM reactor from GE-Hitachi[202]. The design, layout and operations of the PRISM reactor, including the various fuel configurations, have been described in detail[203] as has the coupled fuel-recycling technology (known as pyroprocessing)[197,204-206] and the characteristics of the different metal fuel options[201,207]. All technical characteristics of the technology have been summarised in non-specialist formats[208,209], and the requirements for eventual waste storage have been elaborated in persuasive technical detail[197].

Conclusions

South Australia will not meet its obligations for deep and permanent cuts in emissions from electricity through a continued, single-minded focus on the expansion of wind generation. The relative success of wind integration to date (27 % in South Australia, 3-4 % across the entire National Energy Market) is a credit to the proactive approach South Australia has taken, and the approach of seeking efficient market and regulatory solutions to the challenges posed by wind generation. This should continue. While further wind developments are likely to provide an efficient means of cutting emissions within South Australia and as an export to the National Electricity Market, there is no answer to the inherent limitation of strongly correlated and variable supply that is uncorrelated with demand. With further installation, wind penetration will run into ever-firmer upper limits of supply, at which point efficient market solutions to managing this limitation are exhausted, the costs to the overall system become too high, and the strongly correlated peak supply pushes prices down to the point where wind would cannibalise its own share of the market. The absence of vital ancillary services from the non-synchronous wind generation reinforce that this source of generation is basically unsuitable for high penetration. Therefore, a dispatchable, synchronous source of low-emissions electricity is required.

Exploration and development of the hot-dry rock geothermal resource has to date served only to reinforce the difficulty in converting this large, raw, but difficult-to-access energy resource into a large, reliable and cost-effective supply of electricity. Solar-thermal offers a possible solution, but has a nascent global record of successful delivery of dispatchable electricity, and many uncertainties remain about its capacity to compete at large scales. Australian industry advocates acknowledge the long road ahead to commercial competitiveness with fossil fuels and there is no answer to the increased consumption of land and materials this option demands, as well as the

potentially shorter lifespan. Solar-thermal offers a pathway of great uncertainty at a time where response to climate change demands greater certainty.

Contrasting these, nuclear power offers a mature technology from a competitive global market of suppliers with a solid track record of delivering deeply decarbonised and reliable electricity supply in concert with other technologies. Here we have argued that a commitment to the deployment of the most advanced nuclear technologies provides South Australia with a means to upscale low-emission baseload generation rapidly while earning revenue through the establishment of a new industry in the custody and recycling of spent nuclear fuel. Progress in the development of a nuclear-energy sector remains hampered by a lack of political will that seems increasingly out of step with South Australia's business, scientific and academic communities, as well as the public at large. South Australia needs to open the way for serious considerations of the deployment of nuclear energy and this must be led by government. Bi-partisan support should be achieved on the basis of the inarguable interest represented by a new, service-oriented industry that also provides future-proofing development of low-emission electricity generation while offering the ultimate in fuel security and energy density. These developments can take place alongside, not in place of, the further development of South Australia's wind resource.

For too long the perceived political risk of nuclear energy has been treated as less tractable to change that the technical and economic limitations of immature, low-emission alternatives. It is time for a reversal in approach. Continuing South Australia's response to the challenge of climate change and energy demands political leadership on the pathway of greater technical and economic certainty provided by nuclear technology. We contend this pathway can now be taken with the confidence that South Australia is ready to follow.

CHAPTER 2 – Burden of proof: A comprehensive review of the feasibility of 100 % renewable-electricity systems

Abstract

An effective response to climate change demands rapid replacement of fossil carbon energy sources. This must occur concurrently with an ongoing rise in total global energy consumption. While many modelled scenarios have been published claiming to show that a 100 % renewable electricity system is achievable, there is no empirical or historical evidence that demonstrates that such systems are in fact feasible. Of the studies published to date, 24 have forecast regional, national or global energy requirements at sufficient detail to be considered potentially credible. We critically review these studies using four novel feasibility criteria for reliable electricity systems needed to meet electricity demand this century. These criteria are: (1) consistency with mainstream energy-demand forecasts; (2) simulating supply to meet demand reliably at hourly, half-hourly, and five-minute timescales, with resilience to extreme climate events; (3) identifying necessary transmission and distribution requirements; and (4) maintaining the provision of essential ancillary services. Evaluated against these objective criteria, none of the 24 studies provides convincing evidence that these basic feasibility criteria can be met. Of a maximum possible unweighted feasibility score of seven, the highest score for any one study was four. Eight of 24 scenarios (33 %) provided no form of system simulation. Twelve (50 %) relied on unrealistic forecasts of energy demand. While four studies (17 %; all regional) articulated transmission requirements, only two scenarios—drawn from the same study—addressed ancillary-service requirements. In addition to feasibility issues, the heavy reliance on exploitation of hydroelectricity and biomass raises concerns regarding environmental sustainability and social justice. Strong empirical evidence of feasibility must be demonstrated for any study that attempts to construct or model a low-carbon energy future based on any combination of low-carbon technology. On the basis of this review, efforts to date seem to have substantially

underestimated the challenge and delayed the identification and implementation of effective and comprehensive decarbonisation pathways.

Statement of Authorship – Chapter 2

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Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.

Signature		Date	15 August 2017

By signing the Statement of Authorship, each author certifies that:

    i.   the candidate's stated contribution to the publication is accurate (as detailed above);

    ii.   permission is granted for the candidate in include the publication in the thesis; and

    iii.   the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	**Professor Corey J.A. Bradshaw**		
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Introduction

The recent warming of the Earth's climate is unequivocal[11,73]. Over the 20 years to 2015, atmospheric concentration of carbon dioxide has risen from around 360 parts per million (ppm) to over 400 ppm; emissions of carbon dioxide from fossil fuels have grown from approximately 6.4 Gt C year^{-1} in 1995 to around 9.8 Gt C year^{-1} in 2013[210]. Global average temperature rise has continued, with 2016 confirmed as the warmest year on record. Thermal coal production increased for 14 consecutive years to 2013 before recording a slight decline, with a net increase of approximately 3 billion tonnes of production per year since 1999[211].

Inexpensive and abundant energy remains crucial for economic development; the relationship between per-capita energy consumption and the United Nations Human Development Index is "undeniable"[24]. But there seems little prospect of decreasing energy consumption globally this century, especially with more than 10 % of the global population in extreme poverty[212]. With the fate of modern society and global environments at stake, effective action on climate change demands credible, evidence-based plans for energy systems that (*i*) almost wholly avoid the exploitation of fossil carbon sources, and (*ii*) are scalable to the growing energy demands of approximately nine to ten billion people by mid-century, and perhaps over 12 billion by the end of the century[213]. This process logically begins with displacing coal, gas and oil in electricity generation, but must eventually expand to eliminate nearly all fossil hydrocarbon used in industrial and residential heat, personal and commercial transportation, and most other energy-related services.

Much academic, governmental and non-governmental effort has focused on developing energy scenarios devoted exclusively to energy technologies classed as 'renewable' (mainly hydroelectricity, biomass, wind, solar, wave and geothermal), often with the explicit exclusion of nuclear power and fossil fuels with carbon capture and storage[113,115,214-232]. These imposed choices automatically

foreclose potentially essential technologies. In this paper, we argue that the burden of proof for such a consequential decision is high and lies with the proponents of such plans. If certain pathways are excluded *a priori*, then such exclusions should be fully justified, and the alternatives proven. This is rarely the case.

There is a near-total lack of historical evidence for the technical feasibility of 100 % renewable-electricity systems operating at regional or larger scales. The only developed-nation today with electricity from 100 % renewable sources is Iceland[161], thanks to a unique endowment of shallow geothermal aquifers, abundant hydropower, and a population of only 0.3 million people. Other European nations lauded for their efforts in renewable energy deployment produce greenhouse emissions from electricity at rates close to the EU-27 average (468, 365 and 442 g CO_2-e kWh^{-1} for Denmark, Germany and EU-27, respectively)[161].

Scenarios for 100 % renewable electricity (and energy) have nevertheless proven influential as a platform for advocacy on the development of energy policy[233-235]. Despite this, there has been only limited structured review of this literature to test for fundamental technical feasibility. A narrative review of 23 studies in 2012 provided a useful diagnosis of common features and gaps in the peer-reviewed literature on 100 % renewable systems[236]. That review identified extensive deficiencies in the evidence, highlighting in particular the lack of attention paid to the necessary transmission/distribution networks, and provisions of ancillary services. In assessing the feasibility of these studies however, feasibility itself was not defined, and no firm conclusions were drawn regarding the most basic questions that responsible policy making requires: (*i*) can such a system work? and (*ii*) what evidence is required to describe such a system in sufficient detail such that elements like time, cost, and environmental implications can be estimated accurately? IPCC Working Group III, in examining the potential contribution of renewable energy to future climate-change

mitigation, examined 164 scenarios from 16 different large-scale models[237]. However, the IPCC did not examine explicitly the feasibility of the various renewable-energy systems considered[237].

Repeated critiques of individual studies by Trainer[238-240] have highlighted feasibility deficiencies, including the reliance on only single years of data to determine the necessary generating capacity, and not accounting for worst-known meteorological conditions. A critique by Gilbraith, Jaramillo, Tong and Faria (2013)[241] identified insufficient analysis of the "technical, economic and social feasibility" of a 100 % renewables proposal focused on New York State[222]. Another recent assessment has highlighted serious and extensive methodological errors and deficiencies in a 100 %-renewable plan for the continental United States[242]. Loftus *et al.*[243] examined global decarbonisation scenarios (encompassing all energy use, not only electricity), including several 100 %-renewable analyses. Their review highlighted several deficiencies in the latter, including assumptions of unprecedented rates of decline in energy intensity. However, their review did not consider national- or regional-level studies, nor did it attend closely to issues of electricity reliability[238-242,244-246].

Policy makers are therefore handicapped regarding the credibility of this literature —there is no empirical basis to understand the evidence behind propositions of 100 %-renewable electricity (or energy) for global-, regional- or national-scale scenarios. Consequently, there is a risk that policy formation for climate-change mitigation will be based more on considerations of publicity and popular opinion than on evidence of effectiveness, impacts, or feasibility.

Here we provide a first step in remedying this problem. We present the results of a comprehensive review seeking evidence that the electricity requirements of modern economies can be met through 100 % renewable-energy sources. We describe the method we used to identify the relevant scenarios, define the concept of *feasibility*, and describe and justify our choice of assessment

criteria. We discuss the results of the assessment in terms of the strength of the evidence for technical feasibility of 100 % renewable-electricity systems, and outline some of the major environmental and human development implications of these proposed pathways. Our intention is to provide policy makers and researchers with a framework to make balanced and logical decisions on low-carbon electricity production.

Methods

We identified published scenarios that have attempted to address the challenge of providing electricity supply entirely from renewable sources. We applied the following screening criteria for this literature search: (*i*) Scenarios had to be published after 2006: we applied this cut-off date to weight selections towards literature that was representative of the current state of knowledge; (*ii*) Scenarios must propose electricity supply to be from at least 95 % renewable sources (through some combination of hydroelectricity, biomass, wind, solar, geothermal or wave energy); (*iii*) For spatial scale, scenarios must consider large-scale demand areas such as the whole globe, whole nations, or covering extensive regions within large nations (so excluding scenarios for single towns, small islands, counties, cantons and the like); (*iv*) Scenarios were required to forecast to the year 2050 or earlier. For the target year, if scenarios extended beyond 2050, but still allowed scores to be determined based on 2050 milestones, we included the scenario and scored it against the 2050 outcome.

We were principally concerned with evidence for the strict technical feasibility of proposed 100 %-renewable electricity systems. We were not seeking to establish the viability of the proposed systems. These terms are frequently used interchangeably. We use *viability* as a subordinate concept to *feasibility*. We define *feasible* as 'possible within the constraints of the physical universe', so a demonstration of feasibility requires that evidence is presented that a proposed system will work

with current or near-current technology at a specified reliability. Note that our use of *feasible* refers to the whole electricity system, not merely the individual items of technology, such as a solar panel or a wind turbine. *Viable* means that the system is not only feasible, but also realistic within the socio-economic constraints of society[243]. Thus, unless something is first established as feasible, there is no point in assessing its viability (*sensu* Dalton, Lockington and Baldock (2009)[247]).

Our definitions are not unique; *feasibility* has been used elsewhere to refer to technical characteristics of the energy system under assessment[248,249], and Dalton *et al.*[247] explicitly distinguished between solutions that are "technically feasible" but not considered "economically viable". This distinction is not applied universally. Several other studies confound these terms or have used them semi-interchangeably[250-253]. For example, while Loftus *et al.*[243] acknowledged the physical barriers of feasibility, their use of the term extended beyond what they called "hard physical constraints"[243]. Our study is based on the lower hurdle only. We require only evidence for feasibility, i.e., that the system will work.

Even so, our use of *feasible* requires four subsidiary criteria so that it can be workable when applied to a whole electricity network. Our goal is to distil many of the issues raised by previous critical examinations[236,241] into a well-defined set of criteria. Below we describe our four subsidiary feasibility criteria.

Criterion 1: The electricity demand to which supply will be matched must be projected realistically over the future time interval of interest.

Total global energy consumption, consisting of both electrical and non-electrical energy end-use, is projected to grow to at least 2100[34,254]. Population growth is expected to continue at least to the end of the century[33,213,255]. Nearly all of the expected population growth — around 2.4 billion people

relative to today (range 1.4-3.5 billion)[256] — will occur in Africa, Asia and the Middle East[213,255]. These growth trends contain such momentum that the range of possible mid-century outcomes is insensitive even to major interventions in fertility policy, or widespread catastrophe[22,213,256]. This population growth will occur at the same time as growth in per-capita income, which is strongly correlated with per-capita energy consumption in the early stages of modern development[257].

Growth is also anticipated specifically for electricity consumption. The International Energy Agency estimates that in 2016, more than 1.2 billion people had no access to electricity[32]. Electricity supplies an increasing share of the world's total energy demand and is the world's fastest growing form of delivered energy[258]. Projected 'electrification' of energy use in countries outside the Organisation for Economic Co-operation and Development (OECD) is higher (3.6 % year[-1]) than in OECD countries (1.1 % year[-1])[258], but different models make a wide range of forecasts.

An effective climate change response requires provision of electricity to avoid the exploitation of fossil fuels. Substitutes will also be required for non-electric energy services traditionally met by fossil fuels[112,215,220,231,259-263]. Today, fossil-fuel sources account for about 80 % of primary energy and two thirds of final energy[264]. This reflects not only the availability, but also the great utility of hydrocarbon fuels in a variety of services including transportation and industrial process heat[265,266]. To achieve deep climate-mitigation outcomes, these energy services must be provided in ways that minimise the use of fossil carbon sources. Electrification of energy services via non-carbon-based electricity generation offers one pathway towards that outcome[34]. However, other energy-intensive pathways, such as the production of synthetic hydrocarbons[266] or ammonia[267-269], are also likely to be required to achieve the required stabilisation of atmospheric carbon dioxide while meeting demand for versatile energy services.

Given these issues, any future global scenario that presents static or reduced demand in either primary energy or electricity is unrealistic, and is inconsistent with almost all other future energy projections. Such an outcome would be at odds with the increase in global population, ongoing economic development for the non-OECD majority, and the firmly established link between industrialisation and increased energy consumption. The inevitability of increased primary energy consumption holds, even after accounting for projected rates of decline in energy intensity (primary energy GDP^{-1}) — rates that are expected to be more than the average rate of change for the last 40 years (-0.8 % year^{-1})[243]. For example, the most extreme (Level 1) mitigation scenarios in the US Climate Change Science Program report show primary energy increases of 0.26, 0.62 and 0.85 % yr^{-1} over 2010 to 2050 for the IGSM, MERGE and MiniCAM models, respectively, compared with (and much less than) the corresponding rates of gross domestic product change (2.80, 2.35 and 2.28 % yr^{-1}, respectively). While the implied reductions in energy intensity are large, primary energy consumption will still increase. Electrification results (electric primary energy/total primary energy) show how complex this parameter is. For the IGSM from 2010 to 2050, electrification is predicted to decrease (from 0.43 to 0.37), while electrification increases in the other two models, from 0.38 to 0.54 in MERGE, and from 0.41 to 0.52 in MiniCAM. Scenarios that project electricity demand under the assumption of extreme increases in electrification might imply unrealistic energy transition pathways that are inconsistent with the mainstream literature[34].

So for scenarios to be feasible, they must be consistent with: (*i*) the range of primary energy projections in the mainstream literature for that region, and (*ii*) complementary projections in total electricity consumption. Electricity-demand scenarios that are inconsistent with the above represent low-probability outcomes. Effective climate-change mitigation under scenarios that diverge from the above would call for total reinvention of *both* supply *and* demand of energy. Proposed supply systems for such scenarios therefore represent policy pathways with a high potential for failure.

Criterion 2: The proposed supply of electricity must be simulated/calculated to be capable of meeting the real-time demand for electricity for any given year, together with an additional back-up margin, to within regulated reliability limits, in all plausible climatic conditions.

An electrical power system must provide reliable electricity to its customers as economically as possible[83,270]. Cepin[270] stated that power-system reliability depends on both adequacy and security. *Adequacy* refers to the existence of sufficient generation for the electric power system to satisfy consumer demand at any time, and *security* describes the ability of the system to respond to multiple types of disturbance in the quality of power supply[271]. These concepts together define a reliability standard, which prescribes the required service as a percentage of customer demand that must be served over a given period of time (e.g., 1 year). High reliability (greater than 99.9 %) is a common requirement of modern electricity supply (e.g., 99.98 % service of customer demand every year for the Pennsylvania, New Jersey, Maryland (PJM) network in the United States, and 99.998 % for the Australian National Electricity Market). Electricity supply must vary dynamically to ensure instantaneous matching with demand[83]. For this reason, generation that is constant (i.e., available at all times [baseload]) and/or fully dispatchable (able to be called-up or withdrawn at any time in response to demand changes) is deemed essential for system reliability.

The increasing penetration of variable, climate-dependent sources of generation that are largely uncorrelated with demand, such as wind and solar generation, provides additional challenges for managing system reliability[114,272-275]. Such generators can have high reliability in terms of being in working order, yet they have low and intermittent availability of the resource itself[270]. Furthermore, system-wide reliability cannot be determined based on 'typical' weather conditions[239], but must instead account for present and predicted variability in the resource over foreseeable time scales, from less than 1 minute to decadal. Atypical conditions that are extreme, yet credible (e.g., based on historical precedent or realistic future projections), must be identified, both for each generation type

in isolation and in combination (e.g., severely drought-impacted hydro-electric output in winter combined with coincident low solar and wind output).

Any proposed supply system must therefore demonstrate that the proposed supply will meet any foreseeable demand in real time at a defined reliability standard and with a sufficient reserve margin for unscheduled outages like breakdowns. It must do so in a way that fully accounts for the limited and intermittent availability of most renewable resources and the potential for extreme climate conditions that are outside the historical record. As per Criterion 1, this reliability must be demonstrated as achievable for the full range of plausible future energy demand.

Criterion 3: Any transmission requirements for newly installed capacity and/or growth in supply must be described and mapped to demonstrate delivery of generated electricity to the user network such that supply meets both projected demand and reliability standards.
Transmission networks transport electricity from generators to distribution networks[276], which in turn transport electricity to customers. To achieve high penetration of renewable energy, augmented transmission networks are vital[277-282]. Credible characterisation of the necessary enhanced transmission network is essential for establishing the feasibility of any high-penetration renewable electricity system.

Criterion 4: The proposed system must show how critical ancillary services will be provided to ensure power quality and the reliable operation of the network, including distribution requirements.
Ancillary services are a physical requirement of any electrical system and have been necessary since the development of reticulated power[111]. The availability of ancillary services can be compromised by high penetration of renewable energy sources. For example in Germany, the

determined implementation of the *Energiewende* strategy has triggered an examination of how ancillary services will be retained. Unresolved challenges, particularly in system-restart requirements, have been identified to 2033, even in a scenario that maintains 72 GWe (28 % of total installed capacity) of fossil-fuel-powered, synchronous generators, in a network that is connected to greater Europe[283]. Such challenges at 100 % penetration of renewables remain largely unexamined and unresolved. We discuss two examples of ancillary service requirements:

Frequency control ancillary services:

At any point in time, the frequency of the alternating-current electrical system must be maintained close to the prescribed standard (typically 50 or 60 cycles per second [Hz] within a normal operating band of ± 0.1 Hz). In practice, the frequency varies due to changes in electrical load on the system. Changes in frequency arise from the small, instantaneous and ongoing variation in load that occurs due to consumer behaviour (e.g., turning lights on and off), to larger changes in demand occurring in the normal course of a day. Instantaneous frequency control is typically provided by the inertia of 'synchronous' generators, where electricity is generated through turbines spinning in unison at close to the regulated standard. However, increased wind and solar penetration, with asynchronous generation of electricity, displaces traditional synchronous generators from the market[110].

For example, in the Australian National Electricity Market, the provision of all frequency-control ancillary services comes from bids to the market by 116 connected generating units (a mixture of coal, gas and hydro-electric power stations)[284]. No wind or solar generators are registered bidders for these services. The increase of intermittent renewable generation is already leading to a scarcity of support services in the network and an increasing risk of breaching reliability standards. Modelling the potential withdrawal of coal-fired generation to meet Australia's COP-21 commitments suggests this situation could be exacerbated in the future[285]. In September 2016, the loss of transmission lines in South Australia during a major storm caused disturbances triggering the departure of 445 MWe of wind generation. Without adequate synchronous generation, the rate of change of frequency

exceeded prescribed limits, resulting in total power loss to all 1.7 million residents, all business and all industry in the state[286]. The estimated economic impact of this event was AU$367 million[287].

Network control ancillary services: voltage control.

Voltage must be managed to within specified tolerances for insulation and safety equipment[111,288]. Voltage management is affected by the expansion of generation that is connected to an electrical-distribution network, known as 'embedded generation'[289]. The impact of embedded generation has been transformed by the rapid uptake of small-scale solar photo-voltaic systems[289]. As a consequence, voltage control at distribution level has become a concern in markets with high penetration of solar photo-voltaics[289-297].

Projected 100 %-renewable electricity systems are incomplete in the absence of evidence that essential, regulated ancillary services will be maintained. This is particularly relevant for 100 % renewable-supply systems that propose high reliance on asynchronous wind generation and embedded, asynchronous solar photo-voltaic generation.

Scoring

With our four feasibility criteria we can assign scores for each individual study. We assigned each of Criteria 1, 3 and 4 a maximum score of one. Studies fully meeting an individual criterion scored one and we combined scores for each of these three criteria without weighting. We gave studies not meeting a criterion a score of zero. If efforts to address a criterion stood out among studies, yet still did not address the criterion fully, we gave the study a score of 0.5.

We subdivided Criterion 2 into four parts because different scenarios simulate system reliability over different time scales. We gave a score of one to scenarios simulating supply to the hour; an

additional score of one to those simulating to the half-hour, and another score of one to scenarios simulating to the five-minute interval. Finally, we gave another score of one to scenarios that specifically attempted to account for, and adequately addressed, the impact of extreme climate events. Our emphasis on Criterion 2 (higher relative weighting, with a maximum score = 4) is justified based on the following: (*i*) demand-supply matching is one of the most challenging aspects of electricity provision[114,272-274]; (*ii*) the cost of meeting higher reliabilities is non-linear (i.e., increasing reliability toward 100 % imparts exponentially rising costs, with diminishing returns on loss-of-load probability reductions); and (*iii*) maintaining reliability under extreme climate conditions that have no historical precedent further exacerbates the challenge. Thus, the maximum possible score for any scenario was seven.

Results

Based on our criteria, none of the 100 % renewable-electricity studies we examined provided a convincing demonstration of feasibility. Of the 24 studies we assessed, the maximum score accrued was four out of a possible seven for Mason *et al.*[214,298]. Four scenarios scored zero (i.e., they did not meet even a single feasibility criterion). Eight of the 24 scenarios did not do any form of integrated simulation to verify the reliability of the proposed renewable electricity system. Twelve of the 24 relied on unrealistic energy-demand scenarios, either by assuming unrealistic reductions in total primary energy and/or by making assumptions of extreme increases in electrification. Only four of the studies articulated the necessary transmission requirements for the system to operate, and only two scenarios, from the same authors[115], partially addressed how ancillary services might be maintained in modified electricity-supply systems. No studies addressed the distribution-level infrastructure that would be required to accommodate increased embedded generation, leaving a gap in the evidence relating to ancillary services and overall system reliability.

Table 3 Summary of scoring against feasibility criteria for twenty-four 100 % renewable energy scenarios. 'Coverage' refers to the spatial/geographic area of each scenario. 'Total' means the aggregated score for the scenario across all criteria with a maximum possible score of 7. Criteria are defined in Methods. For concision, the 'Reliability' column aggregates all four potential scores for reliability into a single score. An expanded table is available in the Supplementary Material.

Study	Coverage	Criterion				
		I (Demand)	II (Reliability)	III (Transmission)	IV (Ancillary)	Total
Mason et al.[214,298]	New Zealand	1	2	1	0	4
Australian Energy Market Operator (1)[115]	Australia (NEM–only)	1	1	1	0.5	3.5
Australian Energy Market Operator (2)[115]	Australia (NEM–only)	1	1	1	0.5	3.5
Jacobson et al.[299]	Contiguous USA	0	3	0	0	3
Wright & Hearps[112]	Australia (total)	0	2	1	0	3
Fthenakis et al.[300]	USA	0	2	0	0	2
Allen et al.[231]	Britain	0	2	0	0	2
Connolly et al.[223]	Ireland	1	1	0	0	2
Fernandes and Ferreira[301]	Portugal	1	1	0	0	2
Krajacic et al.[224]	Portugal	1	1	0	0	2
Esteban et al.[221]	Japan	1	1	0	0	2
Budischak et al.[302]	PJM Interconnection	1	1	0	0	2
Elliston, MacGill and Diesendorf[226]	Australia (NEM–only)	0	1	0	0.5	1.5
Lund & Mathiesen[220]	Denmark	0	1	0	0	1
Cosic, Krajacic & Duic[215]	Macedonia	0	1	0	0	1
Elliston, Diesendorf and MacGill[114]	Australia (NEM–only)	0	1	0	0	1
Jacobsen et al.[222]	New York State	1	0	0	0	1
Price Waterhouse Coopers[216]	Europe and North Africa	1	0	0	0	1
European Renewable Energy Council[230]	European Union 27	1	0	0	0	1
ClimateWorks[303]	Australia	1	0	0	0	1
World Wildlife Fund[304]	Global	0	0	0	0	0
Jacobsen and Delucchi[228,229]	Global	0	0	0	0	0
Jacobson et al.[305]	California	0	0	0	0	0
Greenpeace (Teske et al.)[219]	Global	0	0	0	0	0

Energy demand

Our review revealed that among the 100 % renewable-energy studies examined, many assumed reductions in primary energy. This is conceptually unrealistic, and at odds with most of the literature. To show how widely each proposed global renewable energy scenario diverges from 'mainstream projections', we compared energy demand in the scenarios that considered the whole globe to the primary energy data from the following sources: the IPCC Special Report on Emission Scenarios[306], the US Climate Change Science Program (an inter-agency effort from the U.S. Government)[34], and the World Energy Technology Outlook of the European Commission[307]. We plotted 28 demand scenarios from these three organisations in 10-year steps from 2000 (where available) to 2050 (Figure 9). This set of 28 included scenarios with strong mitigation of greenhouse-gas emissions in response to climate change. We also plotted actual (observed) annual global primary energy data from 1990 from the BP Statistical Review of World Energy[9]. We calculated the median of all 28 scenarios in ten-year steps from 2000. Primary energy consumption in 2050 for the scenarios ranges from 535 EJ for the US Climate Change Science Program IGSM Level 1 scenario (1.2 % below the actual primary energy consumption figure for 2014) to 1431 EJ (165 % above 2014 actual primary energy). The median is 805 EJ (+ 49 % above 2014). Twenty-three of the 28 scenarios projected global primary energy to between 600 and 1,000 EJ in the year 2050. These 28 scenarios provide a reasonable spectrum of credible possibilities within which realistic 100 %-renewable scenarios should lie.

Figure 9 Comparison of scenarios for global primary energy from the Intergovernmental Panel on Climate Change (IPCC), the Climate Change Science Program (CCSP), the World Energy Technology Organisation (WETO), the BP Statistical Review, Greenpeace and the World Wildlife Fund (WWF). Sources: [258]; [304], [306], [219], [307], [308]. All WETO values are converted from million tonnes oil-equivalent. All EIA values are converted from quadrillion British Thermal Units. Greenpeace values are converted from petajoules. All WWF values were published as final energy only and are converted from final energy to primary energy based on the ratio of primary-to-final-energy provided in the Greenpeace scenario.
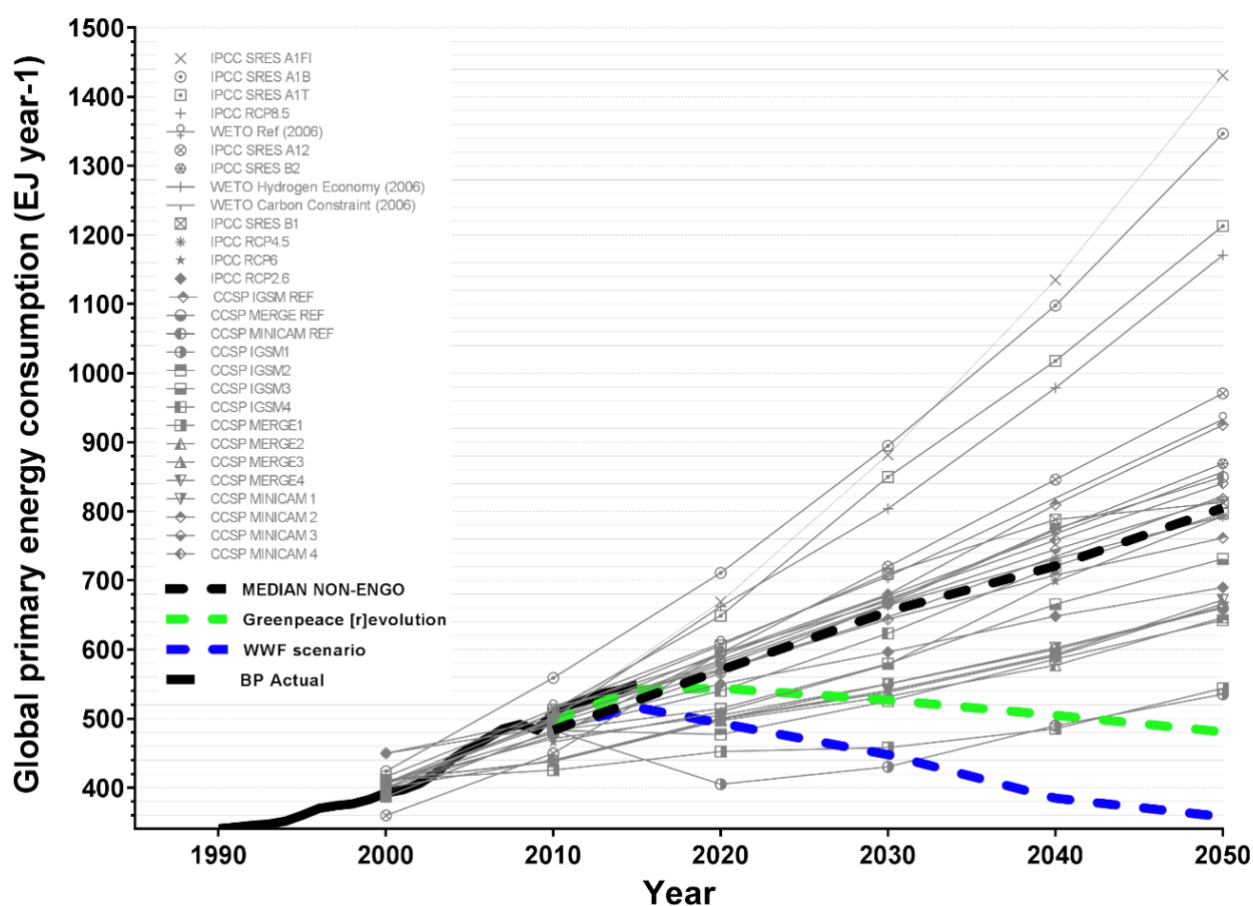
The two global scenarios from environmental non-governmental organisations (WWF and Greenpeace) assumed that total (global) primary energy consumption in 2050 would be less than primary energy consumption in their respective baseline years (481 EJ, or only 70 % of the 2009

baseline for the WWF scenario; and 358 EJ, or only 80 % of the 2010 baseline for the Greenpeace scenario) (Figure 9). These assumptions are clearly unrealistic. Human population will grow by about 3 billion compared with the baseline years. Even in the baseline years, approximately 2.4 billion people live in energy poverty[309]. To rely on contraction in total primary energy in 2050 compared to today, by as much as 30 % in the case of the WWF scenario, is therefore implausible. Several other national and regional scenarios were based on similarly unrealistic assumptions relating to steep reductions in primary energy (Figure 10). Additional analysis from Lund *et al*.[310] contends that the magnitude of energy demand must be adjusted to the realistic amount of supply from renewable sources. We contend the opposite is true; supply solutions must be scalable to realistic projections of future demand.

A few scenarios[112,231,299,305] attempted to maintain *final* energy demand at values consistent with the mainstream literature. These scenarios assumed up to 100 % transition of whole-of-economy energy to either direct electrification or electrolytic hydrogen production, with reliance on flexibility of demand and/or widespread storage of energy using a range of technologies (most of which— beyond pumped hydro—are unproven at large scales, either technologically and/or economically). The speculative storage assumptions used in these scenarios, as for the earlier primary energy assumptions, are inconsistent with the literature on future energy, so these scenarios represent low-probability outcomes. They also prematurely foreclose on the application of several potential technology pathways, such as synthetic fuels[266,311] or second-generation biofuels for transportation energy, and high-temperature nuclear reactors for industrial heat applications (or electricity generation)[312].

Figure 10 Summary of percentage changes in Total Primary Energy (TPE) from baseline years across nine scenarios of 100 % renewable energy. Baseline years vary among scenarios[215,220,223,228-232,241].

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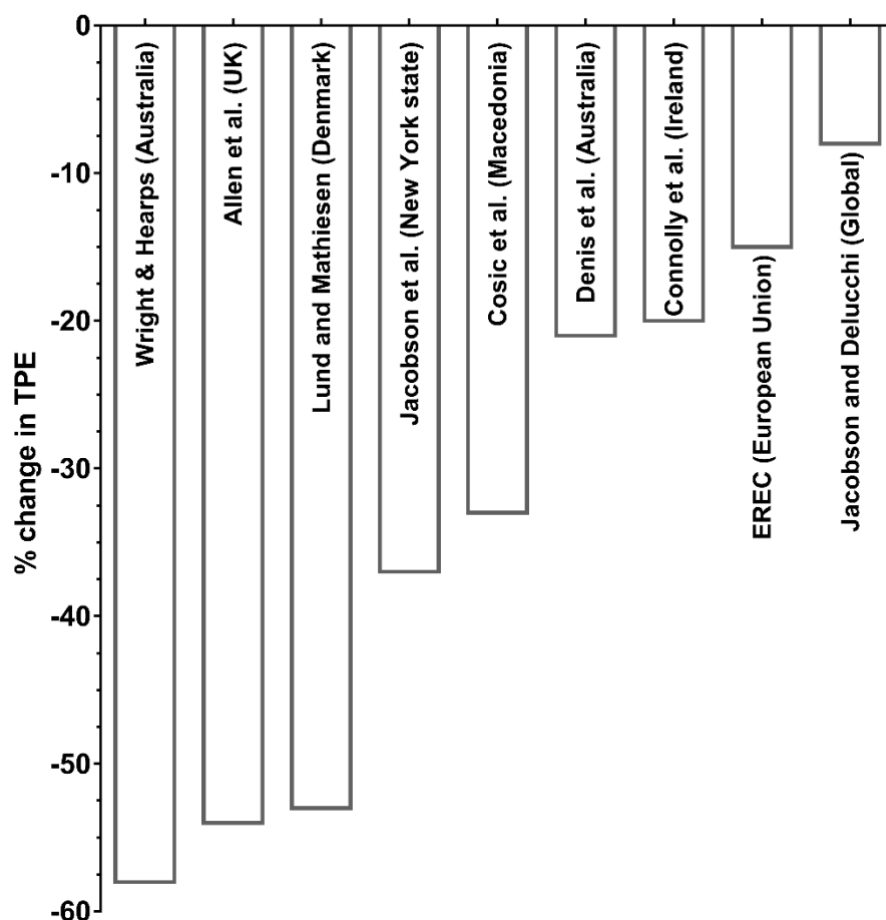
System simulations

The absence of whole-system simulations from nine of the reviewed studies suggests that many authors and organisations have either not grasped or not tackled explicitly the challenge of ensuring reliable supply from variable sources. For example, WWF assumes that by 2050 the share of energy from variable renewable sources could increase to 60 % via all of the following: (*i*) grid-capacity improvements, (*ii*) demand-side management, (*iii*) storage, and (*iv*) conversion of energy excesses into storable hydrogen[304]. This suite of assumptions for managing a system dominated by

supply-driven sources is largely repeated in the Greenpeace scenario ([219]). In neither case is evidence from system simulation provided for how this might occur.

Jacobson et al.[228,303,305] also proposed supply systems without doing simulations, instead referencing other studies to assert that system reliability is possible[115,138,302]. Jacobson et al.[228,303,305] did not apply simulation processes to their own, different proposed systems, nor did they address the uncertainties, challenges and limitations articulated in their supporting references or related critiques[238-241,245,246]. A recent critique highlights these and other errors in the methodologies of Jacobson and co-authors[242].

Of the 16 scenarios that provided simulations, only two simulated to intervals of less than 1 hour and only two tested against historically low renewable-energy conditions. Historical testing is useful in general, but such tests do not address the high variability of output from renewable resources, let alone the attendant uncertainties associated with future climatic changes. Because of these issues, the system-simulation approaches applied so far mostly cannot demonstrate the feasibility and reliability of 100 % renewable energy systems. Additionally, several of the simulations[115,224,231,301,303] assumed reliance on electricity-generation technologies, such as wave, tidal or enhanced dry rock geothermal, that are yet to be established on any comparable scale anywhere in the world, yet they are assumed to provide dispatchable and baseload roles in the simulations. Our framework applies no penalty against these technology assumptions; however, it further highlights the challenges that must be overcome to ensure reliability.

The only study we reviewed that simulated below half-hourly reliability (i.e., 30 minutes)[299] offers a system simulation for the continental United States. The results show a *perfect* match between supply and demand based on a renewable-energy scenario that assumed (*i*) expansion in the use of thermal stored energy (*ii*) total electrification of the United States' whole-of-economy energy

needs, (*iii*) nation-wide dependence on underground thermal-energy storage for space and water heating based on a system that has not yet been commissioned, and (*iv*) flexibility in demand ranging from 50-95 % across different energy sectors, including some industrial applications (see Supplementary Material for further discussion). As such, the scenario is unrealistic, violating the first criterion. Such work calls into question whether energy system simulations are valid when the system under simulation bears little resemblance to that in operation today, or one likely to be achieved in the foreseeable future.

Large, dispatchable supply

Most of the studies that did system simulations[112,114,115,218,220,223,224,231,298] included high proportions of dispatchable-generation sources for the provision of a reliable electricity system. Those scenarios exploited two intrinsically 'stored' resources in particular: hydroelectricity and biomass. Mason *et al.*[214,298] simulated 75–78 % of generated electricity coming from dispatchable sources of expanded, unconstrained hydroelectricity and geothermal. For New Zealand, with large endowments of hydro and geothermal resources and a small population (4.5 million people), a 100 %-renewable electricity system might be possible at reasonable cost, provided the consequences of unconstrained hydro ramping (i.e., the change in power flow from one time unit to the next) are deemed acceptable for the operations of the plant and the hydrology of the waterways[214,298].

The Mason and colleagues' studies reinforce the notion that integration of variable renewable energy sources into existing grids can be cost-effective up to penetrations of around 20 %, after which integration costs escalate rapidly[106,313]. An upper threshold to economically rational amounts of wind generation capacity is also found in simulations for the United Kingdom[231]. Any further installed wind-generating capacity makes little difference in meeting electricity demand in times of low wind supply. While the cost-effective threshold for integration of variable renewable electricity

will vary among grids, 100 %-renewable studies such as these reinforce that penetration thresholds exist and that alternative dispatchable generation supplies are required to meet the balance of supply[214,231,298].

In other scenarios where high penetration of hydro power was not possible, biomass typically filled the need for fully dispatchable supply[114,115,215,220,223,231,314]. Jacobson and Delucchi[228] excluded the use of biomass globally, citing irreconcilable concerns relating to air pollution, land use and water use. However, other studies have found biomass to be essential to ensure system reliability, providing between 2 and 70 % of the electricity supplied under 100 %-renewable scenarios (Figure 11).

Solar shows promise in Australia, but with limitations

Scenarios for Australia drew heavily on solar-thermal technologies with energy storage, and solar photo-voltaics. Elliston *et al.* (2012)[114] claimed to meet the high reliability standard of Australia's National Electricity Market of 99.998 % on a cost-optimised basis, with 46 % of generation from onshore wind and 20 % from solar photo-voltaic (with no storage). The scenario simulated hourly supply for a single year based on demand for the year 2010. That study did not consider demand variation on less than 1-hr time scales and in terms of representativeness, is limited by using a single simulation year (both common problems; see Table 3). There is ample evidence for conditions with sustained, coincident low output from both wind and solar resources in Australia[245]. Such conditions might converge with drought-constrained hydroelectric output in the future. Solar photo-voltaic output varies on timescales of minutes, with large changes in output occurring on sub-hourly timescales[315]. Simulation to the one-hour timescale only will therefore not account for these rapid fluctuations. Finally, an assessment based on a single year's current demand and meteorological record underestimates the system-wide reliability requirements in all years in a

nation where electricity demand is forecast to grow by 30 % to 2050[171]. The subsequent attempted costing of this system is therefore unrepresentative of the future range of possibilities.

Figure 11 Percentage of biomass in total primary energy (TPE) (for scenarios covering all energy) and to electricity production other selected scenarios[114,115,215,219,220,223,224,228,230,231,298,301,304].
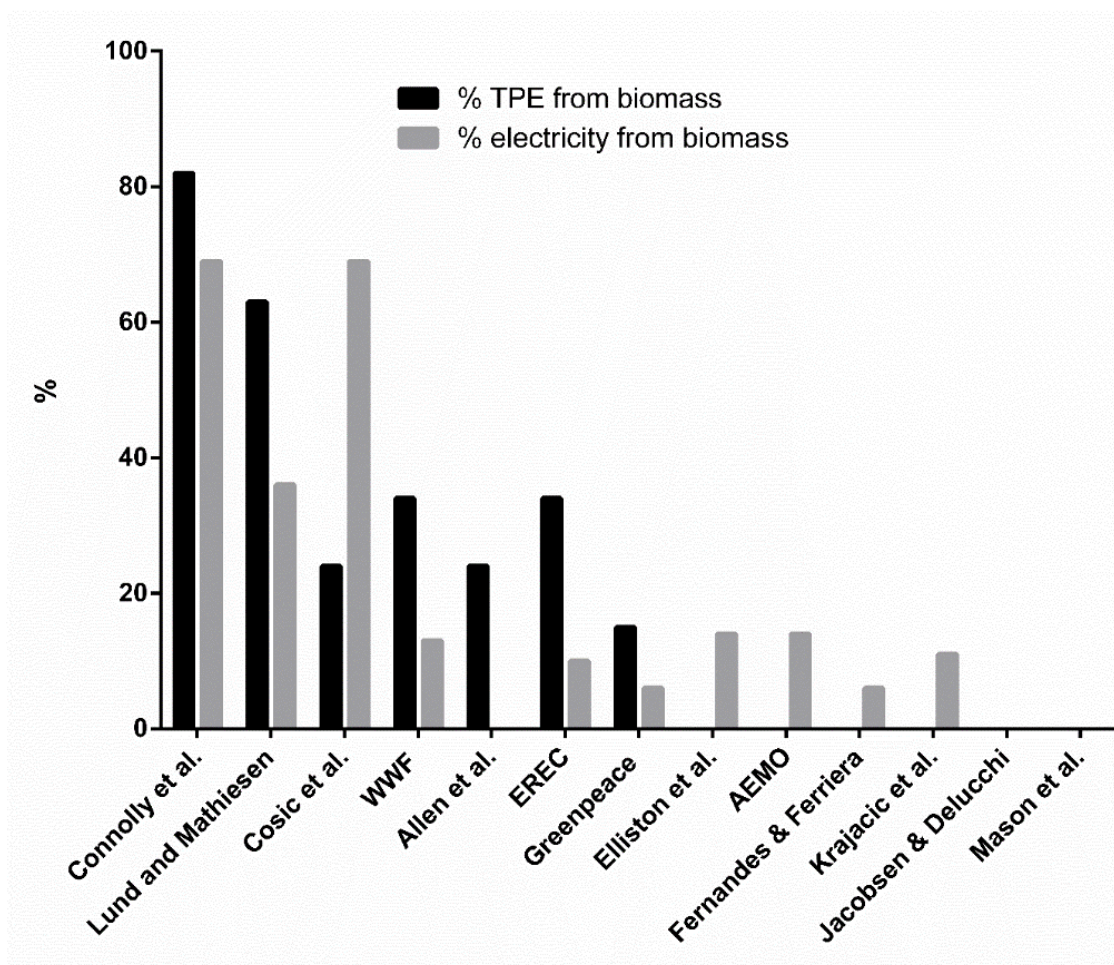
The Australian Energy Market Operator Ltd.[115] generated 2050-based supply-systems with conventional baseload profiles using biomass and geothermal energy as continually available sources of generation. Low-cost, inflexible solar photo-voltaics were deployed to reach between 22 and 37 % of installed capacity. We generously awarded these scenarios a mark as realistic in demand and a mark for simulation to the hourly timescale. To achieve reliability of supply,

Australian Energy Market Operator Ltd.[115] assumed that between 5 and 10 % of demand in any hour is "flexible". Unfortunately "flexible" was not defined, how the demand was to be controlled was not discussed, and achieving this flexibility was not costed. In the absence of this assumed "flexible" demand, and based on values shown in the cited report, the simulation would likely have unmet demand on every single day. The system would not, therefore, be feasible according to our minimum criteria.

Ancillary services largely ignored

The report from Australian Energy Market Operator Ltd.[115] is the only study in the published large-scale scenario literature to acknowledge the importance of maintaining ancillary services through the wholesale system redesign demanded by 100 % renewable electricity. The other 23 studies make no reference to these challenges. The review from Australian Energy Market Operator found that the operational issues should be manageable. However, they also cautioned that such a system is at or beyond globally known capabilities and this demands further assessment[115]. Furthermore, none of the studies we reviewed considered any of the challenges that will be faced in redesigning distribution networks to accommodate greater embedded generation, offering no robust way of assessing the associated costs.

Discussion

Our review of the 100 %-renewable-scenario literature raises substantial concerns. The widespread assumptions of deep cuts in primary energy consumption defy historical experience, are generally inconsistent with realistic projections, and would likely raise problems for developing countries in meeting goals of poverty alleviation. Loftus *et al.*[243] found that scenarios with a decline in total primary energy consumption from 2009 to 2050 required annual declines in energy intensity (primary energy consumption GDP^{-1}) of 3.4-3.7 % yr^{-1}, which is approximately twice the most rapid

rates observed at the global scale over the last four decades. The US Climate Change Science Program scenarios shed further light on energy-intensity requirements. If primary energy were not to increase, the energy intensities would have to decrease by 2.72, 2.29 and 2.06 % yr^{-1}, respectively, with even larger rates of increase if primary energy were to decrease from 2010 to 2050 (as in the WWF and Greenpeace scenarios).

Whether these estimated required rates of decline in energy intensity are possible is a complex question. Our view is that they are not. The large decline in the IGSM Level 1 case is atypical and depends on other assumptions made in that model. But this misses the essential point that economic growth and poverty reduction in developing countries is crucially dependent on energy availability. A reduction in primary energy is an unlikely pathway to achieve these humanitarian goals. To move beyond subsistence economies, developing nations must accumulate the necessary infrastructure materially concentrated around cement and steel. That energy-intensive process likely brings with it a minimum threshold of energy intensity for development[257]. Across a collation of 20 separately modelled scenarios of primary energy for both India and China, Blanford *et al.*[316] found a range of energy-growth pathways from approximately +50 to +200 % from 2005 to 2030. None of those scenarios analysed for these two countries — with a combined population of almost 2.5 billion people — suggested static or reduced primary energy consumption[316].

Many, or possibly all, of the changes assumed to decrease the energy intensity of economies in the scenarios that assumed falling primary energy demand might have individual elements of realism. However, in applying so many assumptions to deliver changes far beyond historical precedents, the failure in any or several of these assumptions regarding energy efficiency, electrification or flexible load would nullify the proposed supply system. As such, these systems present a fragile pathway, being conceived to power scenarios that do not exist and likely never will. The evidence from these

studies for the proposition of 100 % renewable electricity must therefore be heavily discounted, modified or discarded.

Our review also found that reliability is usually only simulated to the hour or half-hour in modelled scenarios. A common assumption is that advances in storage technologies will resolve issues of reliability both at sub-hourly timescales and in situations of low availability of renewable resources that can occur seasonally. Yet in the 24 scenarios we examined, 23 either already relied directly on expanded storage technology, or they described an implicit reliance on such technologies without simulation support (see Supplementary Material). Despite these storage assumptions, only five of the 24 studies demonstrated sub-hourly reliability. A high-penetration renewable scenario for California developed by Hart and Jacobson[317] suggested that moving to 100 % generation from renewables would require a lower bound storage capacity of 65 % of the peak demand to decouple most real-time generation from real-time demand. The authors describe this as a "significant paradigm shift in the electric power sector". Achieving such a paradigm shift is an unresolved challenge, one that Hart and Jacobson claim will require a willingness to transform not only a region's generating fleet, but also the controls, regulations and markets that dictate how that fleet is operated. It behoves policy makers to interrogate such pathways carefully and critically, and to ask the question of whether more mature, dispatchable clean energy technologies should be rejected *a priori* at the cost of uncertainty and upheaval required by 100 %-renewable systems.

It is reasonable to assume a larger range of cost-effective options in energy storage will be available in the future. Such solutions will undoubtedly assist in achieving reliability standards in systems with higher penetration of variable renewable generation. However, whether such breakthroughs will enable the (as yet unknown) scale of storage and associated paradigm shift required for 100 % renewable remains unknown and is largely unaddressed in the literature (see additional discussion in Supplementary Material). To bet the future on such breakthroughs is

arguably risky and it is pertinent for policy makers to recall that dependence on storage is entirely an artefact of deliberately constraining the options for dispatchable low-carbon generation[318,319]. In optimal systems for reliable, decarbonised electricity systems that have included generic, dispatchable zero-carbon generation as well as variable renewable generation, the supply provided by storage is just 2-10 %[319].

Not accounting for the full range of variability of renewable energy resources is another area of vulnerability. The year-to-year variability of inflows that ultimately determine hydro-electric output is well-known — the minimum annual US output over 1990-2010 was 23 % lower than mean output for the same period[320]. The range of capacity factors for Hydro Portugal varied from 11.8-43.2 % over 13 years to 2009[224]. Recent drought has reduced California's hydro-electric output by more than half[321]. Record-low dam levels in Tasmania coincided with the failure of network interconnection and triggered an energy crisis for that state in 2015-2016[322]. Extreme droughts are also projected to impact hydroelectric output negatively in the Zambezi River Basin[323]. Yet there has been limited or no effort, with the exception of studies by Mason *et al*.[214,298] and Fthenakis *et al*.[300], to identify and resolve renewable-energy conditions that are not 'typical', but are ultimately inevitable in a system that is relied on every year. Ensuring stable supply and reliability against all plausible outcomes in renewable energy availability, not only for hydroelectricity, but also for wind, solar and commercial biomass, will raise costs and complexity through the need for additional capacity that will be redundant in most years. Such costs are obscured unless the impacts of worst-case conditions are expressly identified and quantified.

Resource variability is not the only concern regarding hydroelectricity. The widespread potential disruption to rivers and associated habitats from hydro-electric dams are well documented, particularly for the rivers and forests of the Amazon[324-327]. Proposed hydro-electric developments in

the Amazon will be major drivers of disruption to connectivity of habitat and deforestation[328].

Proposed developments will also lead to displacement of indigenous populations[329].

Perhaps our most concerning finding relates to the dependence of 100 % renewable scenarios on biomass (see Figure 11). The British scenario[231] is a typical example; even with the assumption of a 64 % reduction in primary energy consumption, biomass requires 4.1 million ha of land to be committed to the growing of grasses, short-rotation forestry and coppice crops (17 % of UK land area)[231]. Lund and Mathiesen[220] described how Denmark would need to reorganise farming from wheat to corn to produce the requisite biomass, in a scenario of 53 % reduction in primary energy consumption from the baseline year. For Ireland, Connolly *et al.*[223] calculated a biomass requirement that was 60 % of the total potential biomass resource in Ireland. Crawford *et al.*[330] suggested that short-rotation and coppice crops, coupled to an extensive and logistically challenging fuel-distribution infrastructure, would be required to meet energy requirements. Turner *et al.*[225] proposed trucking and burning Australia's agricultural residue, and then trucking the residual ash back to avoid long-term nutrient depletion. The WWF scenario[304] demanded up to 250 million ha for biomass production for energy, along with another 4.5 billion m^3 of biomass from existing production forests to meet a scenario of an absolute reduction in primary energy from today.

The demand-reduction assumptions in most of the scenarios considered here, when combined with their dependence on hydroelectricity and biomass, suggest that 100 % renewable electricity is likely to be achievable only in a low-energy, high-environmental-impact future, where an increasing area of land is recruited into the service of providing energy from diffuse sources. The realisation of 100 % renewable electricity (and energy more broadly) appears diametrically opposed to other critical sustainability issues such as eradication of poverty, land conservation and reduced ecological

footprints, reduction in air pollution, preservation of biodiversity, and social justice for indigenous people[329,331-336].

The remaining feasibility gaps lie in the largely ignored, yet essential requirements for expanded transmission and enhanced distribution systems, both to transport electricity from more sources over longer distances, and to maintain stable system operations. Fürsch et al.[277] suggested that a cost-optimised transmission network to meet a target of 80 % renewables in Europe by 2050 would demand an additional 228,000 km of transmission grid extensions, a + 76 % addition compared to the base network. However, this is an underestimate because they applied a "typical day" approach to assess the availability of the renewable-energy resources instead of using full year or multi-year hourly or half-hourly data. Rodríguez et al.[279] concluded that to obtain 98 % of the potential benefit of grid integration for renewables would require long-distance interconnector capacities that are 5.7 times larger than current capacities. Becker et al.[337] found that an optimal four-fold increase in today's transmission capacity would need to be installed in the thirty years from 2020 to 2050. An expansion of that scale is no mere detail to be ignored, as it has been in Elliston et al.[114], all work led by Jacobson[222,228,229,235,299,305], the global proposals from major environmental NGOs[219,304] and many more of the studies we reviewed. Transmission lines are acknowledged as slow projects, taking 5-10 years on average to construct, projects that are vulnerable to social objection that may force even more delay[278]. In one case, a transnational interconnection took more than 30 years from planning to completion[338].

Recent work[339] demonstrates the importance of power-flow modelling done at the necessary scales. In that study, where the necessary transmission network was identified and the power flows were modelled, the system in question required 100 GWe of nuclear generation (delivering 16 % of supply) and 461 GWe of gas (delivering 21 % of supply). In the absence of such baseload and dispatchable contributions, the expanded transmission requirements will evidently present

technical, economic and social challenges that are largely unexamined in the 100 % renewables literature. Policy makers must be aware of this gap.

Nonetheless, of the four criteria we propose, transmission networks could arguably be regarded as more a matter of *viability* than *feasibility*; the individual requirement of long-distance interconnection is well-known and understood. Rescoring all the studies excluding this criterion (effectively granting all the assumptions of a copperplate network), feasibility is still not met completely by any study (see additional Table in Supplementary Material).

The same grace cannot be granted for maintaining sufficient synchronous generation, voltage requirements and ensuring robust system-restart capabilities in 100 % renewable systems with high production from variable and asynchronous sources. The state of research into how variable renewable sources such as wind can contribute actively to providing frequency control services is nascent[340-342]. There is a much research examining the role of batteries in frequency control, indicating growing understanding of the potential applications, prototype large grid-connected projects, and aggregation of distributed-storage systems via novel technology platforms[343-345]. However, we found nothing approaching a clear understanding of the scale of intervention that might be required for maintaining these services in 100 % renewable electricity systems in large markets[346]. As well as the direct use of batteries or modified wind turbines, maintaining stability could require interventions that include payments for minimum synchronous generation to remain online, development of new markets in ancillary services, network augmentation, and even the mandated curtailing of supply from wind and photo-voltaics in some supply situations[291,295-297]. Others have suggested that changes in market operations will be required to accommodate energy sources that are euphemistically described as "flexible"[347].

A practical portfolio of solutions to these challenge lies beyond current operational knowledge[115,283]. In Germany where penetration of solar photo-voltaic systems is the highest in the world, voltage overloading is leading to grid-reinforcement requirements expected to cost €21-27 billion (Ebridge consulting cited in Braun *et al.* (2012)[290]). Potential partial solutions include intelligent operation of distributed energy storage (i.e., batteries)[292,295,296], grid reinforcement[295], active power curtailment (i.e., preventing export from photo-voltaics to the feeder, representing a loss of income to the photo-voltaics owner)[295], and active and reactive power control from the photo-voltaic unit itself, demanding more advanced inverters[290,293,295]. It is axiomatic that these requirements add to the uncertainty surrounding 100 % renewable pathways as we depart from well-known and understood electricity systems into novel approaches that rely on reinvented networks with greater complexity. It seems likely that current research and applications will boost the potential role for variable renewable energy sources. However, compelling evidence for the feasibility of 100 % renewable electricity systems in relation to this criterion is absent.

Limitations of our framework

The scoring system we developed and applied emphasises the importance of simulating supply to meet demand. In turn, this underscores the issue of achieving reliability with electricity-generation systems that vary over time. With our simple scoring system, some specific item scores might be unjustified when assessed more holistically — specifically if there are major deficiencies in other areas. For example, some studies have done system simulations (earning a score of 1), but have made unrealistic assumptions in setting up the simulation. We did not penalise these cases. The work of Jacobson *et al.*[299] is an example of this because it depends strongly on extraordinary assumptions relating to electrification, energy storage and flexibility in demand. Although this work scored 3 for a fine-grained timescale simulation, the results of such a simulation are likely to be

meaningless because the underlying assumptions are unrealistic. There is potential for a more useful framework to be developed that reflects these interdependencies.

Under our framework, a study can achieve relatively low scores, which might suggest it lacks breadth of coverage of the feasibility criteria. Yet the study itself can be meritorious for its quality in areas it has specifically chosen to address. We highlight the work of Elliston *et al.*[114] as one such example, because it provides valuable insights in several areas and explores useful assessment methods. Finally, the criteria of ancillary services will be of varying importance depending on the proposed mix of technologies. For example, approximately 80 % of the proposed renewable generation for New Zealand comes from dispatchable, synchronous hydro and geothermal, with less than 20 % of supply from wind and no embedded solar generation[214,298]. Such a mix provides some certainty at the outset in terms of system reliability and power quality.

Conclusions

Our assessment of studies proposing 100 % renewable-electricity systems reveals that in all individual cases and across the aggregated evidence, the case for feasibility is inadequate for the formation of responsible policy directed at responding to climate change. Addressing the identified gaps will likely yield improved technologies and market structures that facilitate greater uptake of renewable energy, but they might also show even more strongly that a broader mix of carbon-free technologies is necessary. To date, efforts to assess the viability of 100 % renewable systems, taking into account aspects such as financial cost, social acceptance, pace of roll-out, land use, and materials consumption, have substantially underestimated the challenge of excising fossil fuels from our energy supplies. This desire to push the 100 %-renewable ideal without critical evaluation has ironically delayed the identification and implementation of effective and comprehensive

decarbonisation pathways. We argue that the early exclusion of other forms of technology from plans to decarbonise the global electricity supply is unsupportable, and arguably reckless.

For the developing world, important progress in human development would be threatened under scenarios applying unrealistic assumptions regarding the scale of energy demand, assumptions that lack historical precedent and fall outside all mainstream forecasts. Other outcomes in sustainability, social justice and social cohesion will also be threatened by pursuing maximal exploitation of high-impact sources like hydroelectricity and biomass, plus expanded transmission networks. The unsubstantiated premise that renewable energy systems alone can solve challenge of climate change risks a repeat of the failure of decades past. The climate change problem is so severe that we cannot afford to eliminate *a priori* any carbon-free technologies.

Our sobering results show that a 100 % renewable electricity supply would, at the very least, demand a reinvention of the entire electricity supply-and-demand system to enable renewable supplies to approach the reliability of current systems. This would move humanity away from known, understood and operationally successful systems into uncertain futures with many dependencies for success and unanswered challenges in basic feasibility.

Uniting the alleviation of poverty with a successful climate-change response in our energy and electricity systems should be an international goal. This is likely to require revolutionary changes in the way we grow food, manage land, occupy homes and buildings, demand electricity, and otherwise live our lives. Such changes will require more, not less energy. It would be irresponsible to restrict our options to renewable energy systems alone. The reality is that 100 % renewable electricity systems do not satisfy many of the characteristics of an urgent response to climate change: highest certainty and lowest risk-of-failure pathways, safeguarding human development

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outcomes, having the potential for high consensus and low resistance, and giving the most benefit at the lowest cost.

A change in approach by both researchers and policy makers is therefore required. It behoves all governments and institutions to seek optimised blends of all available low-carbon technologies, with each technology rationally exploited for its respective strengths to pursue clean, low-carbon electricity-generation systems that are scalable to the demands of 10 billion people or more. Only by doing so can we hope to break the energy paradox of the last twenty years and permit human development to continue apace while rapidly reducing greenhouse gas emissions from electricity generation and other demands for energy. Anything less is an abrogation of our responsibilities to both the present and the future.

CHAPTER 3: Cost optimised, low-carbon electricity-supply combinations for Australia

Abstract

Despite extensive natural energy resources, economic wealth, and decades of affirmative clean-energy policies, non-hydro renewable-energy sources made up only 6 % of the total electricity sold in Australia's National Electricity Market in 2015-2016. Furthermore, Australia has one of the most greenhouse gas-intensive and expensive electricity supplies in the world. A new approach is clearly needed if a meaningful transition from fossil-fuel dependence is to occur in Australia's electricity supply. Yet, there has been little investigation of the potential to combine intermittent supply from variable renewable energy with reliable baseload supply from nuclear. Here we address this gap by modelling supply to meet the hourly electricity demand projected for Australia in 2030, using different combinations of nuclear power, renewable energy sources (wind and solar photo-voltaic) and open-cycle gas, optimised for lowest average levelised cost of electricity at varying carbon prices. We selected on-shore wind due to the existing and projected future price advantage and recent research done for the federal government making it the lowest levelised cost of electricity of any new generation in Australia. We selected single-axis tracking photo-voltaic as the lowest-cost solar technology at utility scale, which is expected to equal the levelised cost of wind in 2020. Against the single-year demand profile, we applied eight years of hourly supply traces for on-shore wind power and single-axis-tracking solar photo-voltaics from across the Australian National Electricity Market. We modelled five approaches to meet the demand: (*i*) nuclear power and gas; (*ii*) nuclear power, wind, and gas (*iii*) nuclear power, utility solar photo-voltaics, and gas; (*iv*) nuclear, wind, photo-voltaics, and gas; and (*v*) wind, photo-voltaics, and gas. For model *iv*, we additionally modelled future price decreases in wind and solar photo-voltaics, and a scenario with increased nuclear price. We assumed perfect connectivity of

all supply. We found that the cost-optimal range of variable renewable energy supply in the Australian National Energy Market is between 40 and 53 % of the total quantity of electricity demanded, where transmission expansion is uncosted and even when accounting for steep decreases in capital costs of wind and solar. Using nuclear, wind, solar and gas, a reliable electricity supply with emissions intensity of ~ 88 g CO_2-e kWh^{-1} is possible with a $0 tonne CO_2-e^{-1} carbon price at a of AU$94 MWh^{-1} (2020 values), with a nuclear sector of ~ 15,500 providing 59 % of the total electricity sold. In all scenarios, the imposition of a carbon price increases the proportion of nuclear power, and decreases the proportions of both renewable energy and gas. The simple combination of nuclear and gas provided an average levelised cost of electricity of $97 MWh^{-1} and an average emissions intensity of 45 g kWh^{-1} at a $0 tonne CO_2- e^{-1}carbon price, bringing additional benefits of assured synchronous supply and minimal transmission expansion. The results strongly support the role for reliable nuclear power in seeking to achieve electricity supply that is low in greenhouse-gas emissions, reliable, and cost-optimal.

Statement of Authorship – Chapter 3

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Overall percentage (%)	70
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.
Signature		Date	29 August 2017

By signing the Statement of Authorship, each author certifies that:

i.   the candidate's stated contribution to the publication is accurate (as detailed above);

ii.   permission is granted for the candidate in include the publication in the thesis; and

iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

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Signature		Date	29 August 2017

Introduction

The Earth's climate is experiencing rapid changes due to human disruption of normal climate cycles[11], with a consensus that, in the absence of strong mitigation measures, the risks this poses are potentially severe, pervasive and irreversible[348]. The greatest contribution of the anthropogenic climate forcing comes from emissions of carbon dioxide[11], related substantially to the combustion of fossil fuels for energy services, with electricity and heat production from coal, oil and gas responsible for approximately 25 % of global greenhouse-gas emissions[69]. While reducing human impacts on the climate to limit temperature rise has served as a major driver of low-carbon energy investment over recent years, investment in electricity generation in general must increase from current amounts just to keep pace with growth in demand and the need to replace aging infrastructure[349].

Many technologies are capable of generating electricity without combusting fossil fuels. These include hydro-electric dams, combustion of processed plant material (biomass), wind turbines, a range of solar technologies (direct electricity production with photo-voltaic cells or thermal generation using captured heat), geothermal (based on either shallow, hot aquifers or deep, hot-dry rocks), or technologies seeking to exploit the movement of oceans (e.g., tidal movements, waves, or ocean currents). This diverse group is collectively referred to as 'renewables' because these resources return over timeframes relevant to human industry[350]. The other main way of providing electricity without the combustion of fossil fuels is from nuclear-fission heat to produce steam that powers turbines (in the same manner as coal, gas, solar thermal and biomass technologies). While nuclear technologies are also diverse, most operating commercial nuclear reactors for electricity production today are light-water reactors, operating with solid-fuel uranium oxide pellets, and moderated and cooled by normal (light) water[351].

Reliable, dispatchable electricity supply with greenhouse gas emissions of 100 g CO_2e kWh^{-1} has been achieved at large scale based mainly on two technologies, either individually or in partnership: hydroelectricity and nuclear fission[70]. Other renewable technologies, chiefly wind turbines and solar photo-voltaics (referred to here as non-hydro-renewables), are growing rapidly in many parts of the world. However, in no jurisdictions apart from a few small examples (e.g., Iceland), are non-hydro renewables alone providing large-scale, reliable electricity supply. A review of evidence has previously identified substantial challenges to meeting even a basic definition of feasibility in devising 100 % renewable electricity systems and that all existing plans all contain serious limitations in terms of physical feasibility[71,242]. Substantive displacement of fossil fuels amidst growing global electricity consumption will almost certainly require expansion of both non-hydro renewable and nuclear technologies.

Past research into 100 % renewable-electricity supply for Australia has focused on Australia's National Electricity Market[71]. This market arguably offers the best environment, globally, in which to explore non-hydro 100 % renewable-electricity options because it: (*i*) has a relatively small number of customers (~ 9 million) relative to most other comparable networks, (*ii*) spans a wide geographic distribution (latitude approximately 16° to 44° south, and longitude approximately 135° to 153° east), and (*iii*) includes areas with among the best solar, wind, and deep geothermal resources in the world[122]. Australia lacks potential for a major expansion of hydroelectricity[122], with an existing sector of 7,800 MWe installed providing approximately 7 % of the electricity sold in Australia[352], and output reduced in conditions of severe drought[353,354].

Due to historical biases, Australian research and policy investigations have, over the course of decades, consistently excluded from consideration the potential role of nuclear generation in partnership with renewables[37,38,112,114,115,218,225,226,355,356]. This institutional reticence relates to a standing prohibition on the approval of nuclear power technologies, which has been in place

since 1998[357]. The existing legislation has served as the principal justification for constrained terms of reference in government-funded work[37,38,115]. The decision not to consider nuclear technologies has also been a deliberate choice of research teams, based on stated technology 'preferences', alongside varying justifications[112,114,218,225,226,355]. Irrespective, even the hypothetical inclusion of nuclear technologies in energy research in Australia has been limited despite the documented challenges in feasibility of systems based largely on variable renewable sources[70,242,245,358] and the dearth of real-world examples of success.

The recent South Australian *Nuclear Fuel Cycle Royal Commission Final Report* identified several principles to consider when determining an appropriate electricity supply for Australia: (*i*) it is not a simple choice between renewables and nuclear; (*ii*) identifying whether a particular generation portfolio would deliver electricity at the lowest possible cost requires an analysis of the future cost of the system as a whole; (*iii*) there has yet to be any analysis of a future National Energy Market that examines total system costs based on a range of credible, low-carbon energy-generation options — such an analysis would be required before it could be asserted that any option would deliver reliable, low-carbon electricity at the lowest overall cost, with or without nuclear power; and (*iv*) a critical issue to be determined in a total systems cost analysis of a future National Energy Market is whether nuclear could lower the total costs of electricity generation and supply[359]. Here, we begin to address these gaps by merging nuclear generation with the lowest-cost renewable technologies to identify directions toward a clean-electricity pathway that are both technically feasible and available at the lowest average cost of supply.

Methods

We constructed five electricity-supply models to integrate three zero-carbon (at generation) technologies in varying combinations: on-shore wind, utility-scale solar photo-voltaics with single-

axis tracking, and generic nuclear generation (assuming gigawatt-scale light-water reactor technology). We selected on-shore wind due to the existing and projected future price advantage according to the Australian Energy Technology Assessment and recent research done for the Australian Commonwealth government[37,38], making it the lowest levelised cost of electricity of any new generation in Australia[174]. We selected single-axis tracking photo-voltaic as the lowest-cost solar technology at utility scale[174], which is expected to equal the levelised cost of wind in 2020[37,38]. We selected nuclear technology as the most reliable, dispatchable source of zero-carbon generation with the best evidence for providing nation-scale supply[41,70].

Based on prices for electricity generated and availability constraints published in the 2012 Australian Energy Technology Assessment[174], the 2017 Finkel Review[37,38] and research by Australian Energy Market Operator[115], we found no grounds for modelling the following renewable technologies: solar thermal with storage, geothermal, wave, ocean, or biomass (further justified in the Supplementary Information). The three low-carbon technologies that we explored in this modelling exercise have lifecycle greenhouse gas emissions of approximately 10 g kWh^{-1} (nuclear and wind) and ~ 50 g kWh^{-1} (solar photo-voltaic)[360]. However for simplicity, we excluded all 'embedded emissions' values from further analysis. We included a fourth technology, open-cycle gas turbines (unabated; i.e., assuming no capture of greenhouse-gas emissions resulting from combustion) to ensure 100 % of demand was met in all cases. As such, we deployed two climatically variable renewable energy suppliers (wind and solar) and two reliable, fuel-based suppliers (nuclear and gas).

For our demand trace, we used the hourly *Scenario 1 2030, with photo-voltaics, and 10 % probability of exceedance* from Australian Energy Market Operator[115]. This scenario is in keeping with more recent research by Gerardi and Galanis[38] that suggests peak demand and total quantity of electricity demanded in the National Electricity Market could stabilise between 2036

and 2050. The hourly demand profile represents the quantity of electricity 'sent out' that our modelled scenarios needed to provide after subtracting a projected contribution (22 TWh in total) from fixed, rooftop solar photo-voltaic capacity. The Australian Energy Market Operator [115] modelled demand-side participation of 5 or 10 % of demand in any hour being treated as curtailable load (i.e., load that can be reduced at a cost) or moveable demand (i.e., reduction in demand that must be consumed at an alternative time that day, at no additional cost). These assumptions reduce peak demand and allowed their model to match demand to the availability of variable renewable supply. Our modelling assumes no demand-side participation, broadly consistent with the current operation of the Australian National Electricity Market, although we note continuing pilot and proof-of-concept projects for demand management that are underway in the National Electricity Market[361]. The scenario has a total annual quantity of electricity demanded of 199 TWh (excluding the 22 TWh of supply provided by rooftop photo-voltaics), with peak demand of 38,611 MWe.

Over this scenario, we then allocated hydroelectric supply based on the constraints applied in the *National Transmission Network Development Plan*, where supply is assumed to return to starting values each year[29,362]. A peak capacity of 7,524 MWe is available, with a maximum supply of 16 TWh year^{-1}. Consistent with earlier examinations of 100 % renewable electricity for the National Electricity Market[103], we treated the hydroelectricity as dispatchable capacity to meet periods of high demand.

We dispatched the available hydroelectric capacity according to the following process. Using the hourly profile we calculated the mean value of load. We then sorted the values from largest to smallest. Beginning with the hourly load, we dispatched 6,500 MWe if the difference between that value and the mean supply gap was equal to or larger than 6,500 MWe. If the difference was less than 6,500 MWe, we dispatched the difference. We continued dispatching in order of hourly load

increments (largest to smallest) until the available supply (initially 16 TWh) became zero, or until there were no more periods of load above the mean. This process yielded an hourly demand profile for the Australian National Electricity Market which treats both existing hydroelectric supply and forecast rooftop solar photo-voltaic development as subtracted demand. We do not assume that these load profiles represent actual outcomes of future market dispatch. After allocating hydroelectric supply, the peak demand of the scenario was lowered from 38611 MWe to 36330 MWe.

Consistent with previous analysis relating to deployment of renewable technologies[115], we treat the demand profile in 2030 (net of projected uptake of rooftop solar photo-voltaic systems and existing hydro-electricity) as a 'snapshot' against which we attempt to find a cost optimal mix of supply. In this paper, we are not attempting to project a likely mix of supply in 2030 based on current assets, policies (such as subsidies for renewable generators), announcements or trends, nor are we attempting to model real-time market behaviour. We are attempting to find the optimal mix of four potential supplies to construct a low greenhouse-gas, reliable supply for the Australian National Electricity Market based on cost alone. Consideration of the role of nuclear power against currently projected uptake of renewable energy sources to 2035 is undertaken in Chapter 4.

For the installed nuclear-generating capacity, we assumed an energy-availability factor of 0.91 based on our analysis of operating data from the nuclear fleet of the United States for ten years to 2015[363] (discussed in Supplementary Information). The energy availability factor is defined as the ratio of the energy that the available capacity could have produced during this period, to the energy that the reference unit power could have produced during the same period. The energy availability factor is determined for each period as:

$$E_A\ (\ \%\ ) = 100(E_G - L_P - L_U - L_T)/E_G$$

Where E_G = reference energy generation for the period; L_P = total planned energy losses; L_U = total unplanned energy loss; and L_T = total external energy losses (beyond the plant management control).

Here, E_A is distinct from capacity factor, in that capacity factor must consider not only the production, but refers to the ratio of the amount of electricity dispatched to a market during a given period relative to the energy that the reference unit power could have produced during the same period if generating consistently at its full, rated output[172]. Capacity factor can therefore be lower than the energy availability factor, but not higher.

In our models, the available supply from on-shore wind and utility solar is represented by 1 MWe supply traces, modelled by the Australian Energy Market Operator, and covers 43 geographic polygons spread across the eastern part of the Australian continent (Figure 12). Of those, we selected 13 polygons for wind and 10 for solar identified by the Australian Energy Market Operator as providing the best resource availability with minimal seasonal variation, reasonable spread across the entire National Energy Market, and other advantages including siting reasonably close to existing transmission and load centres. We selected the supply traces determined from an eight-year energy-resource record (2004-2005 to 2010-2011)[115]. To represent the geographic spread of wind and solar resources, we created a single supply trace for each based on the mean supply of all polygons. This assumes that any megawatt of wind tested by the model is split evenly across the 13 optimal locations, and any megawatt of solar tested by the model is split evenly across the 10 optimal locations. As such, the wind and solar supply is not optimised based on the demand profile nor specific locations, but is representative of a broad geographic range of resources that are potentially available to future expansion of the

National Energy Market infrastructure. This simplifying assumption is useful given that expected cost, planning, transmission, and social-consent limitations would likely constrain the development of any distributed renewable sector below what might be operationally optimally.

To test the potential role of nuclear power in meeting demand in the National Electricity Market, we constructed five supply models to meet 100 % of the supply optimised for lowest average levelised cost of electricity: (1) nuclear/gas; (2) nuclear/wind/gas; (3) nuclear/solar/gas; (4) nuclear/wind/solar/gas (using a. 2020 prices; b. 2030 prices; c. 2050 prices; and d. 2050 prices weighted heavily against nuclear: ~ 67 % nuclear-cost inflation); and (5) wind/solar/gas.

In models 1 to 4, we begin with a quantity of installed nuclear supply capable of meeting 100 % of the hourly demand, i.e., installed nuclear = peak demand / E_A. The model progressively reduces the available nuclear capacity to zero in increments of 100 MWe. Based on the demand scenario with a peak of 38,611 MWe, our model explores 424 incremental reductions in nuclear capacity. Each increment of reduction leaves a supply gap, evaluated hourly over the full year of demand.

Figure 12 Polygons selected to provide supply traces for on-shore wind and utility-scale, single-axis tracking solar photo-voltaic. Modified from Australian Energy Market Operator [115]
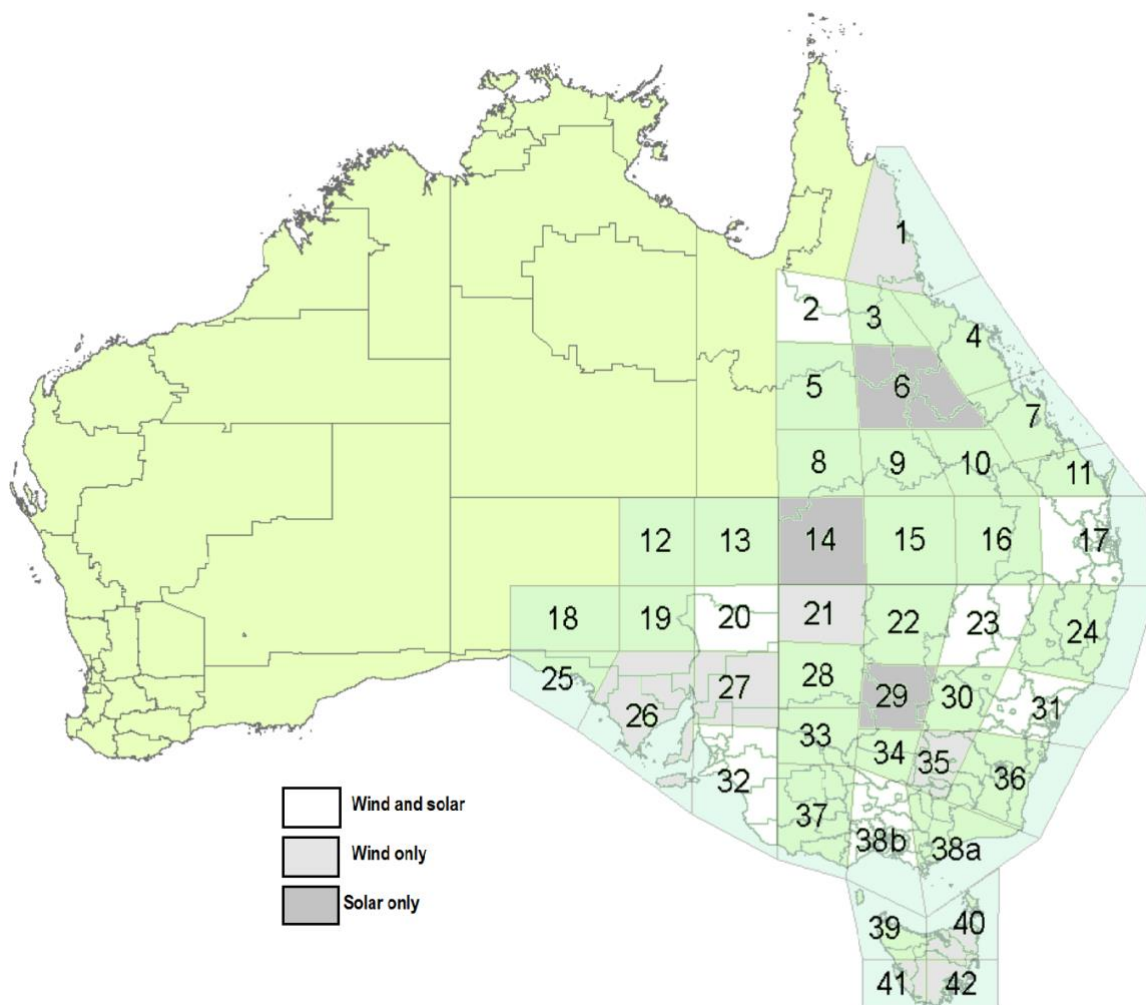
The models address the supply gap in the following ways:

Model 1: nuclear + gas: The supply gap is met by open-cycle gas (hereafter, simply 'gas'), which is assumed to ramp perfectly to meet demand without curtailment ('curtailment' refers to generated electricity that cannot be used or stored, and thus is not dispatched to the market[364]). The model finds the lowest cost combination across all increments of reduction of nuclear capacity.

Model 2: nuclear + wind + gas: For every increment of reduced nuclear capacity the model adds an equivalent in peak (nameplate) capacity of wind generation. All hours of wind supply matching the supply gap are 'sold', and all hours of in-excess supply are curtailed. Any remaining supply gaps are filled with gas. We added an equivalent in peak capacity from wind rather than beginning with overbuild to rationalise capital expenditure and minimise excess supply and curtailment. The model finds the lowest-cost combination across all increments of reduction of nuclear capacity.

Model 3: nuclear + solar + gas: As per model 2, with incremental additions in peak capacity of utility-scale, single-axis tracking photo-voltaic solar generation instead of wind generation. The model finds the lowest-cost combination across all increments of reduction of nuclear capacity.

Model 4: nuclear + wind/solar + gas: For every increment of reduced nuclear capacity, the model selects the cost-optimal proportion of wind and solar capacity to meet the supply gap. For the available amount of peak capacity to be added in wind and/or solar, the model tests all potential combinations ranging from 0.1 to 99.9 % of wind and solar, respectively. Any residual supply gap is filled with gas. The model finds the lowest-cost combination across all increments

of reduction of nuclear capacity. Using model 4, we did additional sensitivity testing for forecast prices of all four technologies in 2030 and 2050, plus additional testing in a scenario with 2050 forecast prices additionally weighted to make nuclear more expensive. We provide more detail on these assumptions below.

Model 5: wind + solar + gas: In model 5, we began with a substantial overbuild of wind, based on matching peak supply to the lowest quartile of the hourly wind-supply trace (0.3): starting wind capacity = peak demand/quartile. We reduced the wind supply in increments of 100 MWe peak capacity, and introduced solar photo-voltaics in equivalent increments. All hours of solar supply matching the supply gap are 'sold', and all hours of excess supply are curtailed. Any remaining gaps are filled with gas.

Previous modelling of the National Electricity Market to investigate 100 % renewable electricity supply has dispatched in order of price of generation, prioritising dispatch of wind and solar photovoltaic supply ahead of dispatchable supply from sources like geothermal, biomass, solar thermal with storage or hydroelectricity[114,115,365]. These studies excluded nuclear technology from consideration in the electricity generation mix, constraining reliable supply to more expensive, less-scalable forms of renewable generation. Our models dispatched available supply from the sources included in each model in the order of (*i*) nuclear fission, (*ii*) optimised wind and solar photo-voltaic, and (*iii*) gas. This order implicitly values the greater capacity value (or capacity credit) of nuclear technology. Johnson *et al.* (2016)[364] defined capacity value as a technology's contribution to the firm capacity requirement, being a technology's available capacity during peak load times. Whereas nuclear technologies can be assumed to contribute close to their full nameplate capacity to firm capacity, the capacity values of wind and solar photo-voltaics tend to decline with increasing market share[106,366,367]. Nonetheless variable renewable generators have been granted priority dispatch in several markets, and maintaining this priority dispatch is openly

declared as vital to the development of the renewable-energy industry[368]. However, in our model the firm supplier with high capacity value (nuclear fission) has lifetime carbon emissions similar to wind and below solar photo-voltaics[360]. Therefore, no climate-mitigation imperative exists to prioritise dispatch of variable renewables in a way that displaces the more reliable supplier. It would be difficult to conceive of a policy decision that led to a new (first-time) investment in nuclear generators in Australia without a concomitant goal of maximising its efficiency. The firm supplier also provides essential frequency control via synchronous generation, so there is a reliability imperative[37,38] to maintain dispatch of the nuclear generation.

Our models curtail excess generation from variable suppliers (wind and solar photo-voltaics), and also reduces output from firm suppliers (nuclear) when the potentially available supply exceeds demand. Alternately, generation can be reduced from reliable sources of supply either in response to changes in load or, more recently, to prioritise dispatch of electricity from variable renewable generation, now an observed phenomenon in many markets in response to higher penetrations of variable renewable-energy generation[369-373] . The economically optimal path for integrating higher penetrations of variable renewable-electricity generation remains unclear and is likely to vary between jurisdictions[373]. Budischak *et al.* (2013)[302] found that the lowest costs for high penetrations of renewables are achieved with diverse renewable generation, high curtailment, and low storage. This is the approach we explore in this model for the Australian National Electricity Market, assuming no storage of excess supply from either variable or firm generators. For further discussion of curtailment see the Supplementary Information.

All economic inputs for wind, solar, and gas were based as closely as possible on Gerardi and Galanis[38] for 2020 in support of the recent *Independent Review into the Future Security of the National Electricity Market*[37] (Table 4 and Table 6). Based on these published values and other published inputs (capital costs, variable operational and maintenance costs, fixed operational and

maintenance costs, fuel cost), we ascertained the assumed capacity factors for these three

technologies at these levelised costs. Using these inputs, our model adjusts the levelised cost of

electricity based on the actual capacity factor of each of technology (determined by the quantity

of electricity supply that matches demand and is 'sold') according to the following formula:

$$\text{LCOE}' = (\text{LCOE} - V)\frac{\text{cf}}{\text{cf}'} + V\frac{\text{cf}'}{\text{cf}}$$

where LCOE´ = levelised cost of electricity determined in the model, LCOE = starting assumed

levelised cost of electricity of the supplier; *V* = variable portion of the LCOE of the supplier being

the sum of fuel cost (gas, nuclear), and variable operations and maintenance costs (gas, nuclear,

wind and solar) MWh^{-1}; cf = starting assumed capacity factor of the supplier; cf´ = actual

(realised) capacity factor of the supplier determined in the model. Our models do not assume any

policy benefit to any technology. For example, the existing Renewable Energy Target rewards

generation from renewable sources with certificates currently valued at $85 MWh^{-1}. Our models

are cost models, not market models, and such policy-driven benefits are not considered in our

optimisation.

Gerardi and Galanis[38] and Finkel *et al.*[37] excluded nuclear-generation technologies in their

assessments. We calculated a levelised cost of electricity for nuclear power in Australia based on

capital and operational cost inputs from the 2013 update of the *Australian Energy Technology

Assessment*[174]. To compare with values published in Gerardi and Galanis[38], we inflated the

capital expenditure for nuclear to 2020 Australian dollars based on average annual inflation of 1.8

% for the period 2013-2020.

An important consideration in determining levelised cost of electricity is the appropriate discount rate to apply to the cost-benefit analysis. This is a critical parameter of analysis whenever costs and benefits differ in their distribution over time, and especially where they occur over long periods[374]. Our examination of the application of discount rates in energy system analyses (see Supplementary Information) suggests some important guidelines: (*i*) there is no single 'correct' discount rate readily identifiable across literature; therefore, (*ii*) it is important to test across a range of discount rates; (*iii*) consideration of environmental issues and intergenerational equity, exemplified by the challenge of responding to climate change, support the application of lower discount rates, perhaps as low as 3 % real and certainly 5 % real; (*iv*) higher discount rates are more indicative of commercial rates of return and shorter investment time horizons.

Gerardi and Galanis[38] applied a differentiated discount rate depending on the technology in question, recognising that "… more emissions-intensive generators face greater investment risks than low emissions generators". This would recommend a discount rate for nuclear in line with that applied for renewable investments. However, Gerardi and Galanis[38] also highlighted that projects can have higher finance costs due to project risks faced by size and complexity and a high proportion of upfront capital cost. This would recommend a higher discount rate for nuclear. However, as we discussed above, the long lifetime of a new nuclear power plant (potentially 80 years) compared to the assumed 20 and 25-year lives of wind and solar projects, respectively, recommends a lower discount rate to value appropriately a long-term contribution to matters of inter-generational social benefit like climate change.

For this first stage, we applied a real discount rate (i.e., not including inflation, as opposed to nominal discount rate) of 7 % in determining the levelised cost of electricity from nuclear power, consistent with rates applied throughout Gerardi and Galanis[38] and Finkel *et al.*[37]. We applied this in all models except model 4d. In model 4d, we assumed instead first-of-a-kind capital costs for

all nuclear build (i.e., no n^{th}-of-a-kind cost reductions) and applied a higher discount rate of 10 % to nuclear while leaving the renewable prices and assumptions unchanged (Table 5).

An important feature of these models is that the outcomes are not driven by levelised cost *per se* so much as the *difference between the levelised costs of the different generation sources*. Thus, while we have applied up-to-date references and assumptions in establishing the starting levelised cost of electricity for each source, these values can be reduced to a simple ratio without altering the cost-optimal generation mixes selected by the models. Readers can therefore infer changes in pricing for any of these technologies based on different assumptions, and consider the likely outcomes on the basis of these modelled outcomes. The ratios of starting levelised cost of electricity for the sources in each model are shown in Table 7.

Table 4 Inputs for determining levelised cost of electricity (LOCE) of wind and solar photo-voltaic. All dollars are 2020 AU$. MWh = megawatt-hour; MWe = megawatt electric; O&M = operational and maintenance; $m = millions of dollars. Source: All values from [38] except *Construction period* from Bureau of Resource and Energy Economics Bureau of Resource and Energy Economics (2012)[172]. Capacity factors determined independently based on published inputs.

Input	Onshore wind			Utility single axis tracking solar		
	2020	2030	2050	2020	2030	2050
capacity factor (base assumption)	33	33	33	32	32	32
LCOE ($ MWh^{-1} sent out) (base assumption)	92	79	70	91	61	49
fixed O&M ($ MWe^{-1})	40	40	40	35	35	35
variable O&M ($ MWh^{-1} sent out)	5	5	5	2	2	2
capital cost ($m MWe^{-1})	2.400	1.972	1.727	2.300	1.380	1.114
asset life (amortisation)(years)	25	25	25	20	20	20
discount rate (real, pre-tax weighted average cost of capital) (%)	7	7	7	7	7	7
construction period (years)	2	2	2	2	2	2

Table 5 Inputs for determining levelised cost of electricity of nuclear power. All dollars are 2020 AU$. MWe = megawatts-electric; MWh = megawatt-hour; O&M = operational and maintenance; $m = millions of dollars; GJ = gigajoule; HHV = higher heating value. Source: All inputs from [174] with *capital cost* adjusted to 2020 AU$ except *Asset life* from Nuclear Energy Institute Nuclear Energy Institute (2016)[375], d*iscount rate* from [38].

Nuclear levelised cost of electricity input	2020/2030/2050	2050 weighted
capital cost ($ m MWe^{-1})	5.558	6.740
asset life (Amortisation)(years)	40	40
discount rate (real, pre-tax weighted average cost of capital) (%)	7	10
construction period (years)	6	6
capacity factor (base assumption) (%)	91	91
fixed O&M ($m MWe)	0.344	0.344
variable O&M ($ MWh^{-1} sent out)	14.7	14.7
fuel cost ($ GJ HHV^{-1})	0.75	0.75
thermal efficiency (%)	34	34
energy conversion (GJ MWh^{-1})	3.6	3.6
levelised cost of electricity ($ MWh^{-1} sent out)	89.3	149

Table 6 Inputs for determining levelised cost of electricity and greenhouse gas emissions from open-cycle gas turbines. All dollars are 2020 AU$. MWe = megawatts-electric; MWh = megawatt-hour; O&M = operational and maintenance; $m = millions of dollars; GJ = gigajoule; CO_2-e = carbon dioxide equivalent. Source: All inputs from [38].

Open-cycle gas turbine levelised cost of electricity input	
capacity factor (base assumption)	20
LCOE ($ MWh^{-1} sent out) (base assumption)	129
gas price ($ GJ HHV^{-1})	6.4
fixed O&M ($m MWe^{-1})	0.013
variable O&M ($ MWh^{-1} sent out)	10
carbon intensity from fuel combustion (kg CO_2-e MWh^{-1})	620
construction period (years)	2
thermal efficiency (%)	35

Table 7 Ratio of starting levelised cost of electricity for each generation source in each model, relative to the starting levelised cost of electricity for nuclear generation, except model 5 where cost ratios are relative to gas.

Model	Nuclear	Gas	Wind	Solar PV
1 (nuclear + gas)	1.0	1.5	NA	NA
2 (nuclear + wind + gas)	1.0	1.5	1.0	NA
3 (nuclear + solar + gas)	1.0	1.5	NA	1.0
4a (nuclear + wind + solar + gas 2020)	1.0	1.5	1.0	1.0
4b (nuclear + wind + solar + gas 2030)	1.0	1.5	0.9	0.7
4c (nuclear + wind + solar + gas 2050)	1.0	1.5	0.8	0.6
4d (nuclear + wind + solar + gas 2050, weighted nuclear)	1.0	0.9	0.5	0.3
5 (wind + solar + gas)	NA	1	0.5	0.4

Results

In this section, the results for the cost optimal combinations from each model are discussed in order of ascending carbon price ($0 to $100 tonne CO_2-e^{-1}). Results are shown in detail in Sup. Table 5 in 'Supplementary material for *CHAPTER 3*'.

Table 8 Cost optimised combinations of nuclear, wind, solar photo-voltaic and open cycle gas turbine to meet 100 % of the demand of the Australian National Electricity Market in 2030 (net of contribution from projected increase in rooftop solar photo-voltaic). tCO$_2$-e = tonnes of carbon dioxide equivalent; IC = installed capacity; CF = capacity factor; Prop = proportion; VRE = variable renewable energy; LCOE = levelised cost of electricity; av = average; MWh = megawatt-hour
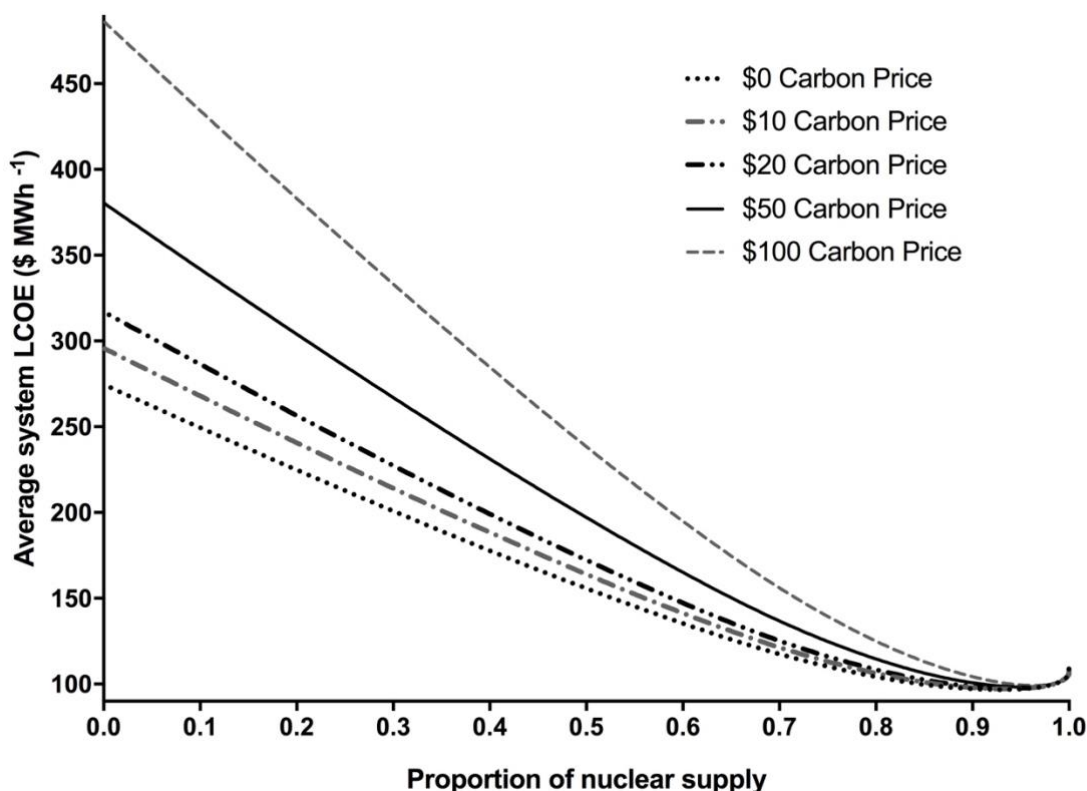
NUCLEAR AND GAS

Carbon price ($ tCO$_2$-e^{-1})	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO$_2$-e.MWh
0	26.8	NA	NA	9.5	82 %	NA	NA	19 %	0.93	NA	NA	0.07	0.00	1.00	$94	NA	NA	$128	$97	0.045
10	27.2	NA	NA	9.1	82 %	NA	NA	18 %	0.93	NA	NA	0.07	0.00	1.00	$95	NA	NA	$133	$97	0.041
20	27.5	NA	NA	8.8	81 %	NA	NA	17 %	0.94	NA	NA	0.06	0.00	1.00	$95	NA	NA	$138	$98	0.037
50	28.2	NA	NA	8.1	80 %	NA	NA	15 %	0.95	NA	NA	0.05	0.00	1.00	$96	NA	NA	$151	$98	0.030
100	29.0	NA	NA	7.3	79 %	NA	NA	12 %	0.96	NA	NA	0.04	0.00	1.00	$96	NA	NA	$172	$99	0.022

NUCLEAR WIND AND GAS

Carbon price ($ tCO$_2$-e^{-1})	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO$_2$-e.MWh
0	16.3	20.0	NA	17.2	91 %	30 %	NA	20%	0.63	0.23	NA	0.14	0.23	0.77	$89	$98	NA	$130	$97	0.088
10	17.4	18.9	NA	16.2	91 %	28 %	NA	19%	0.67	0.21	NA	0.13	0.21	0.79	$89	$104	NA	$135	$98	0.078
20	18.6	17.7	NA	15.1	90 %	27 %	NA	18%	0.71	0.18	NA	0.11	0.18	0.82	$90	$110	NA	$139	$99	0.067
50	21.1	15.2	NA	12.8	89 %	23 %	NA	15%	0.79	0.13	NA	0.08	0.13	0.87	$90	$127	NA	$151	$100	0.048
100	23.5	12.8	NA	10.6	86 %	19 %	NA	12 %	0.85	0.09	NA	0.05	0.09	0.91	$92	$150	NA	$172	$101	0.031

NUCLEAR SOLAR, AND GAS

Carbon price ($ tCO$_2$-e^{-1})	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO$_2$-e.MWh
0	19.5	NA	16.8	15.7	90 %	NA	25 %	16 %	0.74	NA	0.16	0.10	0.16	0.84	$90	NA	$118	$128	$98	0.061
10	20.0	NA	16.3	15.2	90 %	NA	24 %	15 %	0.76	NA	0.15	0.09	0.15	0.85	$90	NA	$120	$133	$98	0.056
20	20.4	NA	15.9	14.8	89 %	NA	24 %	14 %	0.77	NA	0.15	0.08	0.15	0.85	$90	NA	$122	$138	$99	0.052
50	21.5	NA	14.8	13.7	88 %	NA	23 %	13 %	0.80	NA	0.13	0.07	0.13	0.87	$91	NA	$129	$152	$100	0.043
100	22.8	NA	13.5	12.4	87 %	NA	21 %	11 %	0.84	NA	0.11	0.05	0.11	0.89	$91	NA	$139	$174	$101	0.033

NUCLEAR, WIND/SOLAR AND GAS 2020

Carbon price ($ tCO$_2$-e^{-1})	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO$_2$-e.MWh
0	15.5	12.5	8.3	18.6	91 %	35 %	30 %	19 %	0.59	0.17	0.10	0.14	0.26	0.74	$89	$82	$97	$128	$94	0.088
10	16.2	11.5	8.6	18.0	91 %	34 %	29 %	18 %	0.62	0.15	0.10	0.13	0.25	0.75	$89	$83	$99	$133	$95	0.081
20	17.0	10.4	8.9	17.3	91 %	33 %	29 %	17 %	0.65	0.13	0.10	0.12	0.23	0.77	$89	$86	$101	$138	$96	0.073
50	18.9	8.4	9.0	15.5	90 %	30 %	26 %	14 %	0.72	0.10	0.09	0.09	0.19	0.81	$90	$93	$109	$151	$97	0.055
100	20.7	7.0	8.6	13.8	89 %	28 %	24 %	12 %	0.78	0.08	0.08	0.07	0.16	0.84	$90	$101	$119	$172	$99	0.041

NUCLEAR, WIND/SOLAR AND GAS 2030

Carbon price ($ tCO$_2$-e^{-1})	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO$_2$-e.MWh
0	15.6	12.2	8.5	18.5	91 %	34 %	30 %	19 %	0.60	0.16	0.10	0.14	0.26	0.74	$89	$71	$63	$128	$89	0.087
10	15.8	11.9	8.6	18.4	91 %	34 %	30 %	19 %	0.61	0.16	0.10	0.14	0.26	0.74	$89	$71	$63	$134	$90	0.085

Carbon price ($ tCO₂-e⁻¹)	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO₂-e.MWh
20	16.5	10.9	8.9	17.7	91 %	34 %	29 %	18 %	0.63	0.14	0.10	0.13	0.24	0.76	$89	$73	$65	$138	$91	0.078
50	18.0	9.2	9.2	16.4	91 %	32 %	27 %	16 %	0.69	0.11	0.10	0.10	0.21	0.79	$89	$77	$69	$152	$92	0.063
100	19.6	7.7	9.0	14.9	90 %	30 %	26 %	13 %	0.74	0.09	0.09	0.08	0.18	0.82	$90	$83	$74	$172	$94	0.050

NUCLEAR, WIND/SOLAR AND GAS 2050

Carbon price ($ tCO₂-e⁻¹)	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO₂-e.MWh
0	15.1	12.9	8.3	19.0	91 %	35 %	30 %	20 %	0.58	0.17	0.10	0.15	0.27	0.73	$89	$61	$50	$129	$86	0.093
10	15.8	11.9	8.6	18.4	91 %	34 %	30 %	19 %	0.61	0.16	0.10	0.14	0.26	0.74	$89	$63	$51	$134	$87	0.085
20	16.3	11.2	8.8	17.9	91 %	34 %	29 %	18 %	0.63	0.15	0.10	0.13	0.25	0.75	$89	$64	$51	$139	$88	0.080
50	17.7	9.5	9.1	16.6	91 %	32 %	28 %	16 %	0.68	0.12	0.10	0.11	0.22	0.78	$89	$67	$54	$152	$90	0.066
100	19.6	7.7	9.0	14.9	90 %	30 %	26 %	13 %	0.74	0.09	0.09	0.08	0.18	0.82	$90	$73	$59	$172	$92	0.050

NUCLEAR, WIND/SOLAR AND GAS 2050 - WEIGHTED

Carbon price ($ tCO₂-e⁻¹)	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO₂-e.MWh
0	0.0	35.9	0.4	32.2	91 %	38 %	33 %	36 %	0.00	0.53	0.00	0.47	0.53	0.47	$149	$56	$46	$166	$108	0.289
10	2.7	33.3	0.3	29.7	91 %	38 %	33 %	34 %	0.10	0.49	0.00	0.40	0.49	0.51	$149	$57	$46	$170	$112	0.251
20	7.5	26.8	2.0	25.5	91 %	37 %	32 %	29 %	0.29	0.39	0.03	0.30	0.41	0.59	$149	$58	$46	$166	$116	0.186
50	10.9	20.1	5.3	22.6	91 %	37 %	32 %	25 %	0.42	0.29	0.07	0.23	0.35	0.65	$149	$58	$47	$177	$123	0.142
100	13.7	15.1	7.5	20.2	91 %	36 %	31 %	21 %	0.53	0.21	0.09	0.17	0.30	0.70	$149	$60	$48	$198	$130	0.108

WIND, SOLAR AND GAS

Carbon price ($ tCO₂-e⁻¹)	nuclear IC	wind IC	solar IC	gas IC	nuclear CF	wind CF	solar CF	gas CF	nuclear Prop	wind Prop	solar Prop	gas Prop	Prop.VRE	Prop.REL	nuclear LCOE	wind LCOE	solar LCOE	gas LCOE	av.lcoe	tCO₂-e.MWh
0	NA	119.3	1.8	25.6	NA	21 %	5 %	2 %	NA	0.97	0.00	0.02	0.98	0.02	NA	$137	$559	$482	$147	0.014
10	NA	119.3	1.8	25.6	NA	21 %	5 %	2 %	NA	0.97	0.00	0.02	0.98	0.02	NA	$137	$559	$483	$147	0.014
20	NA	119.3	1.8	25.6	NA	21 %	5 %	2 %	NA	0.97	0.00	0.02	0.98	0.02	NA	$137	$559	$484	$147	0.014
50	NA	119.3	1.8	25.6	NA	21 %	5 %	2 %	NA	0.97	0.00	0.02	0.98	0.02	NA	$137	$559	$486	$147	0.014
100	NA	119.3	1.8	25.6	NA	21 %	5 %	2 %	NA	0.97	0.00	0.02	0.98	0.02	NA	$137	$559	$489	$147	0.014

Model 1: nuclear/gas

In Model 1, nuclear generation meets 93-96 % of the cost-optimal total electricity supply, with a higher carbon price increasing the penetration of nuclear and displacing the contribution of open-cycle gas (Figure 13). Against all tested carbon prices, the average greenhouse gas intensity of the system-wide supply is less than 50 g kWh^{-1}, and with a carbon price of $20 tonne CO_2-e^{-1}, the average emissions intensity falls to 37 g kWh^{-1}. Average levelised cost of electricity varies by $2, from $97 MWh^{-1} at a $0 tonne CO_2-e^{-1} carbon price to $99 MWh^{-1} at a $100 tonne CO_2-e^{-1} carbon price. The model selects a nuclear capacity of ~ 26,800-29,000 MWe, operating at capacity factors of 82-79 %, paired with a gas sector of 9,500-7,300 MWe.

Figure 13 Cost-optimised average levelised cost of electricity for 100 % supply of the Australian National Electricity Market in 2030 using combinations of nuclear power and open cycle gas, by proportion of nuclear supply, at carbon prices of $0, $10, $20, $50 and $100 tonne CO_2-e^{-1} LCOE = levelised cost of electricity; MWh = megawatt-hour.

Model 2: nuclear/wind/gas

Model 2 optimised at a wind sector of 20,000-12,800 MWe to meet between 23-9 % of the total demand, depending on the carbon price. Higher carbon pricing resulted in lower wind penetration and increasing the nuclear penetration, as the use of wind relies on a back-up role for gas, which becomes more expensive as the carbon price rises. Hence the rising carbon price displaced both wind and gas in favour of nuclear (Figure 14). The model pairs this wind sector with a nuclear sector of between 16,300-23,500 MWe, with the nuclear sector operating from its peak output of 91 % to a minimum of 86 % (at carbon price of $100). Model 2 finds a similar range of optimised average costs ($97-101 MWh^{-1}) and range of greenhouse-gas emissions (88-31 g kWh^{-1}) as Model 1. A carbon price of $50 tonne CO_2-e^{-1} is required to bring emissions below 50 g kWh^{-1}.

Model 3: nuclear/solar/gas

Optimised results for Model 3 suggest a large-scale solar photo-voltaic sector of 16,800-13,500, MWe providing 13-7 % of the total quantity of electricity demanded. The model paired this solar sector with a nuclear sector of 19,500-22,800 MWe, with the nuclear sector operating at capacity factors of 90-87 %. A gas sector of 15,700-12,400 MWe provides 10-5 % of the supply. Raising the carbon price increased the penetration of nuclear and decreased the penetration of solar and gas as the use of solar relies on a back-up role for gas, which becomes more expensive as the carbon price rises. Hence the rising carbon price displaced both solar and gas in favour of nuclear. The range of optimised costs is $98-101 MWh^{-1}. Average emissions intensity of supply ranges from 61-33 g kWh^{-1}.

Figure 14 Cost-optimised average levelised cost of electricity for 100 % supply of the Australian National Electricity Market in 2030 using combinations of (a) nuclear power, wind and open cycle gas; and (b) nuclear power, solar photo-voltaic and open cycle gas, by proportion of nuclear supply, at carbon prices of $0, $10, $20, $50 and $100 tonne CO_2-e^{-1}. LCOE = levelised cost of electricity; MWh = megawatt-hour.
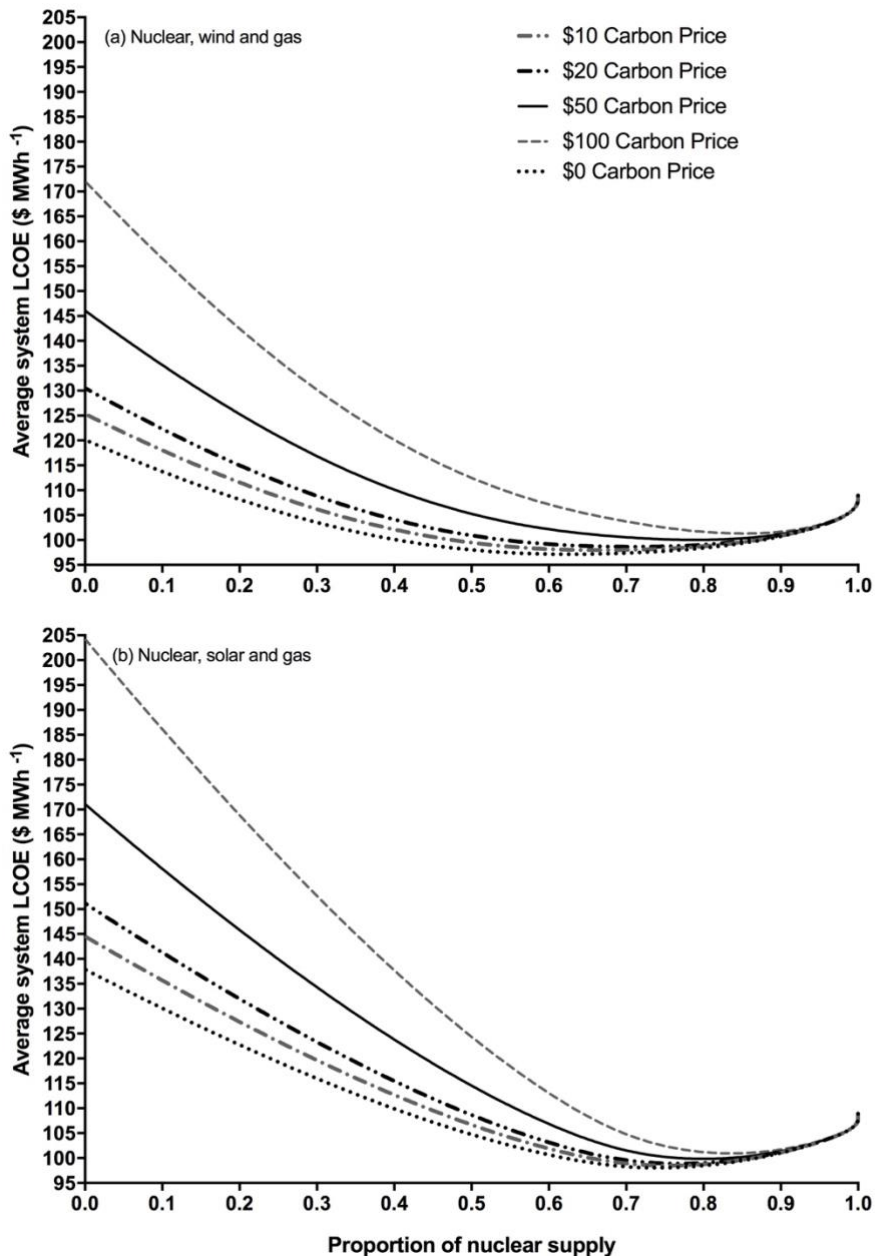
Model 4a: nuclear/wind/solar/gas (2020)

The supply combinations proposed by model 4a provides lower average prices ($94-99 MWh[-1]) with a similar range of greenhouse gas emissions (88-41 g kWh-1) as models 1 to 3 (Figure 15). Nuclear provides 59-78 % of the supply from an installed capacity of 15,500-20,700 MWe, operating at capacity factor of 91-89 %. The wind sector supplies 17-8 % of supply from an installed capacity of 12,500-7,000 MWe and a capacity factor greater than 28 %. The gas sector provides 14-7 % of supply from 18,600-13,800 MWe of installed capacity. Solar contributes 10-18 % of supply) from 8,300-8,600 MWe with capacity factor ranging from 30-24 %. The total proportion of supply met by the variable suppliers (wind and solar) is 26-16 %.

Model 4b: nuclear/wind/solar/gas (2030)

Model 4b provides a lower average price range that model 4a ($89-94 MWh[-1]) with a similar range of greenhouse-gas emissions (87-50 g kWh[-1]) as model 4a. Nuclear provides 60-74 % of supply from an installed capacity of 15,600-19,600 MWe, operating at capacity factor of 90 % or greater in all cases. The wind sector provides 16-9 % of supply from an installed capacity of 12,200-7,700 MWe and a capacity factor of 30 % or above in all cases. The gas sector provides 14-8 % of supply from 18,500-14,900 MWe of installed capacity. Solar provides 10-9 % of supply at capacity factors of 30-26 %.

Model 4c: nuclear/wind/solar/gas (2050)

Model 4c provides a lower average price range that models 4a and 4b ($86-92 MWh[-1]) with a similar range of greenhouse-gas emissions (93-50 g kWh[-1]) as models 4a and 4b. Nuclear provides 58-74 % of supply from an installed capacity of 15,100-19,600 MWe (in all cases operating at or above 90 % capacity factor). The wind sector provides 17-9 % of supply from an installed capacity of 12,900-7,700 MWe at a capacity factor greater than 30 % in all cases. The

gas sector provides 15-8 % of supply from 19,000-14,900 MWe of installed capacity. The contribution of solar is 10-9 % of supply.

Model 4d: nuclear/wind/solar/gas (2050, weighted against nuclear)

With our additionally imposed weighting on the cost of nuclear power (making its levelised cost of electricity ~ three times greater than that of solar photo-voltaics and twice as expensive as wind at the outset), model 4d offers results that are notably different than models 4a to 4c. Supply from model 4d is more expensive ($108-130 MWh^{-1}) than models 4a to 4c. Greenhouse-gas intensity is higher (289-108 g kWh^{-1}) than in models 4a to 4c. With a $0 tonne CO_2-e^{-1} carbon price, nuclear provides none of the supply. However, with the increase of the carbon price to $20 tonne CO_2-e^{-1}, the nuclear sector increases to 7,500 MWe and 29 % of supply.

At $0 carbon prices, the model finds a system provided entirely by wind (53 % of supply) and gas (47 % of supply). The model does not add additional solar photovoltaic capacity (beyond that assumed as subtracted demand from rooftop systems) until the carbon price reaches $20, at which point additional solar provides 3 % of supply. At a carbon price of $50, nuclear becomes the largest supplier (42 %), followed by wind (29 %), gas (23 %) and solar (7 %).

The main change from models 4a, 4b and 4c to model 4d is a shift to a wind/gas-dominated supply, with decreases in the size of the contribution from nuclear and solar at low carbon prices, and a higher system-wide carbon intensity. Contribution from both nuclear and solar increases as the carbon price rises, displacing both wind and gas. The total proportion of supply met by the variable suppliers (wind and solar) is 53-30 %.

Figure 15 Cost-optimised average LCOE for 100 % supply of the Australian National Electricity Market in 2030, based prices for on (a) 2020; (b) 2030; (c) 2050 (d) 2050, with weighted nuclear price, using combinations of nuclear, wind power, utility scale single-axis tracking solar photo-voltaic and open cycle gas power, by proportion of nuclear supply, at carbon prices of $0, $10, $20, $50 and $100 tonne CO_2-e-[1]. LCOE = levelised cost of electricity; MWh = megawatt-hour;
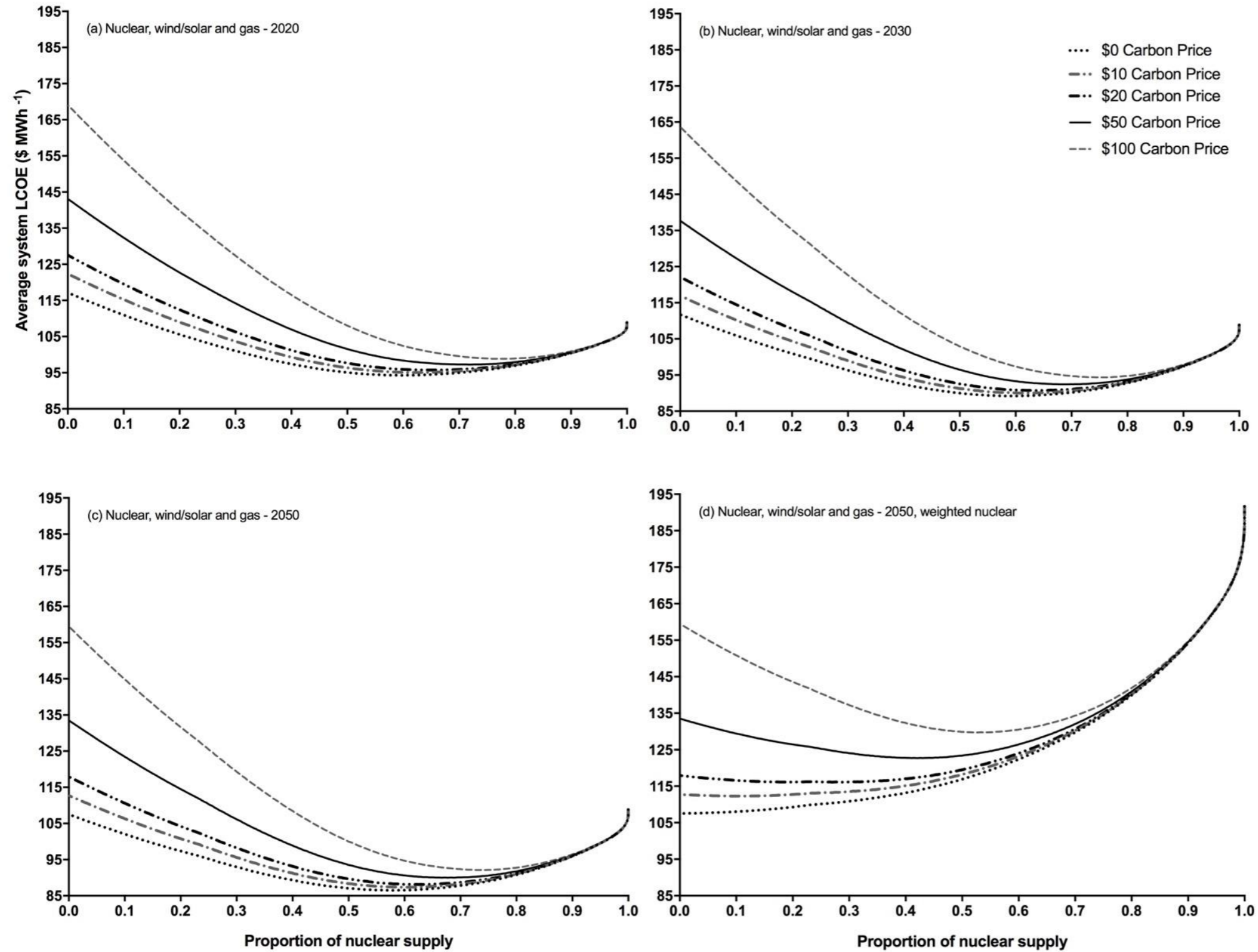
Model 5: wind +solar + gas

Model 5 finds that a sufficiently large (119,300 MWe), geographically dispersed wind sector,

operating at 21 % average capacity factor, underpins the lowest cost-optimal supply (97 % of the

supply), if backed up by an additional 25,600 MWe gas sector (utilised at 2 % of its potential

capacity). The model found no additional contribution from solar photo voltaic further reduces the

cost of supply, with this result likely influenced by the 22 TWh from rooftop photo-voltaics that are

already included in this scenario, subtracting demand from periods where photo-voltaic performs

more strongly. At 14 g kWh^{-1}, emissions for model 5 are the lowest of all models; however, at $147

MWh^{-1} this is also the most expensive supply option.

Figure 16 Cost-optimised average levelised cost of electricity for 100 % supply of the Australian

National Electricity Market in 2030 using combinations of wind power, solar photo-voltaic and open

cycle gas, by proportion of wind supply, at carbon prices of $0, $10, $20, $50 and $100 tonne CO_2-e^{-1}. LCOE = levelised cost of electricity; MWh = megawatt-hour.
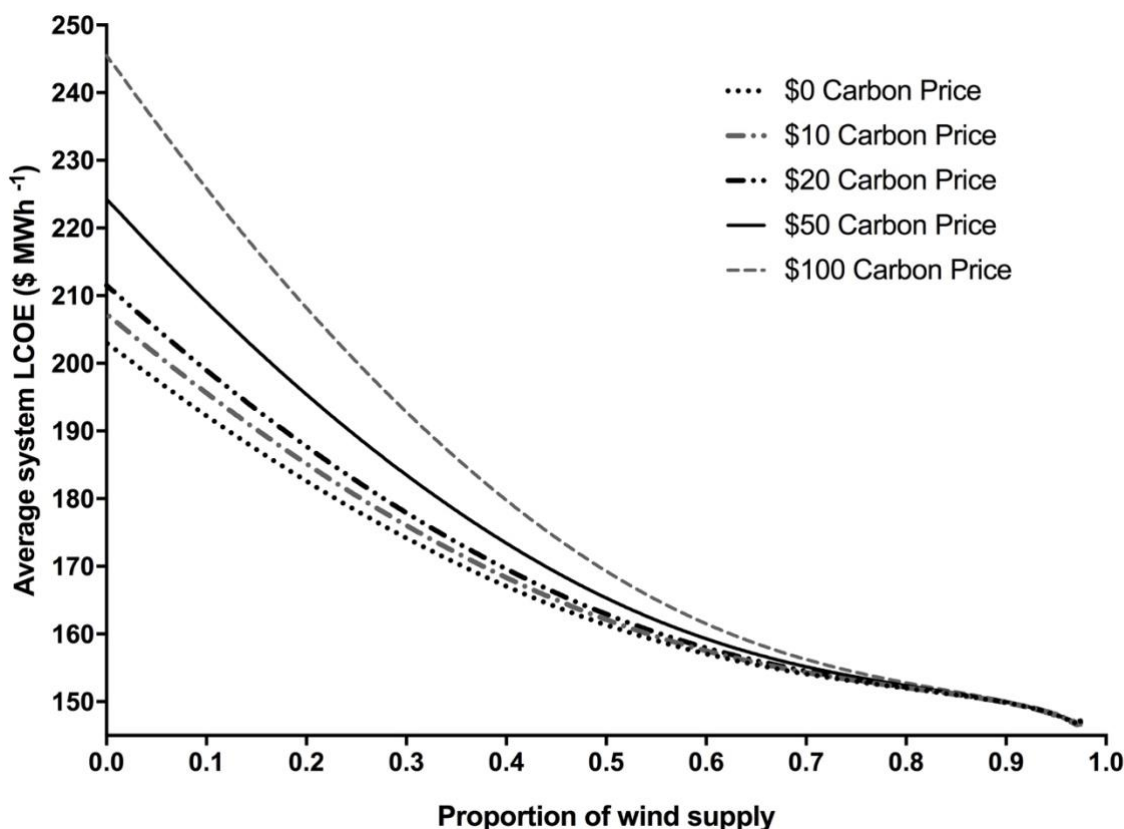
Discussion

Our results demonstrate we can meet the forecast 2030 electricity demand of the Australian National

Electricity Market less than 100 g kWh[-1] of greenhouse gases, based on various combinations of five

technologies: nuclear power, on-shore wind, utility-scale single-axis tracking solar photo-voltaics,

existing hydro-electric supply and open-cycle gas turbines. As such, our modelling provides

compelling new insights to answer an often-asked question: how much supply can be cost-effectively

provided by variable renewable energy sources without additional storage infrastructure? In what is

arguably a best-case spatial and geophysical environment for onshore wind and solar photo-voltaics

(the Australian National Electricity Market), with the beneficial assumption of a copperplate network,

our models demonstrate that the maximum cost-effective contribution from variable renewable

energy sources, without the addition of new storage capacity, is likely up to and just over 30 % of the

total quantity of electricity demanded by a modern grid, or approximately 40 % when the contribution

of projected rooftop photo-voltaic is also accounted for. Even changing prices of the variable

renewable energy providers to forecast values in 2030 and 2050 did not greatly increase their total

contribution compared to 2020 prices. However achieving the highest penetration of variable

renewables results in the highest average emissions MWh $^{-1}$ (over 140 kg) thanks to the greater

reliance on open cycle gas supply to maintain reliability with the larger variable renewable supply.

In model 4d, weighting the price of nuclear power to open up a starting gap of \$80-100 MWh^{-1}

between nuclear and wind/solar produced the highest range of total supply from variable renewable

energy (53-30 %) (excluding Model 5). However, this came at a cost of a more greenhouse-intensive

supply overall (289-108 kg MWh^{-1}), because the contribution from open-cycle gas was greatly

increased (47-17 % of total supply). Models 2, 3, and 4a-d all illustrate this relationship between

variable renewable penetration and the requirement for a responsive, back-up supply. In our models,

this role is filled entirely with open-cycle gas. Raising the carbon price reduces the penetration of the

variable renewables as the emissions from the supporting gas are impacted. The models find a lower

cost by raising the contribution of the nuclear sector. The re-entry of the nuclear sector with rising

carbon price in model 4d also pulled more solar capacity back into the cost-optimal supply mixes.

The baseload provided by the nuclear power diminished the size of the required gas-back-up to

maintain reliability in the worst renewable energy conditions, and this assisted solar power back into

the supply mix. A similar observation was made by Blakers *et al.* (2017)[365], who observed that wind

can deliver energy at any time, rather than only during the day, and is better able to service

successive days of high demand during winter. In the absence of a nuclear baseload, our model

found wind and gas to be a more cost-optimal combination than wind, gas and solar.

The combinations of nuclear/wind/solar/gas in models 4a show the lowest prices for 2020 (\$94-99

MWh^{-1}). The installed nuclear sector is performing an economically optimal baseload role, which

provides a floor in the amount of synchronous generation in the system, providing the inertia for rapid frequency control. The wind sector, similarly, is not over-built and hence curtails minimal supply and delivers electricity at $82-101 MWh^{-1}. The contribution from the necessary gas back-up is effectively driven down by carbon pricing which raises the contribution of nuclear and reduces the contribution of wind, solar and gas.

Model 4a therefore offers a compelling illustration of efficiently deploying different technologies according to their respective advantages and disadvantages. Conceptualising these technologies as competitors might be unconstructive, assuming priority is placed on achieving effective mitigation of climate change via a reduction in greenhouse-gas emissions from electricity generation, rather than on maximum penetration of either renewables or nuclear *per se*. These technologies should instead be considered more like complementary collaborators. Attending to either capital costs or published levelised cost of electricity estimates in isolation can obscure this systemic relationship. In particular, the higher capital cost of nuclear power per unit of installed capacity elides its value in the challenge of creating an overall least-cost, reliable supply.

The next challenge to the feasibility assessment of this suggested supply mix is to model the necessary transmission network across the geographic expanse of the National Electricity Market, thereby overcoming the assumption (in our models) of free and 'copperplate' transmission. Pricing this additional transmission requirement is outside the scope of our study, but must be considered to identify a realistic grid[71]. The Australian Energy Market Operator suggested additional transmission capacity would be expected to add $6-10 MWh^{-1}, although this was declared an underestimate because it excluded several costs, including land acquisition[115]. When such costs are taken into account, the true cost of this supply mix could be higher than the costs proposed *prima facie* by models 4a-d. Reducing transmission costs could be achievable, but only with a trade-off in reducing

the geographic smoothing of the supply traces for wind and solar. To achieve similar contributions from renewable generators would therefore require either increased generating capacity and/or the addition of broad-scale and high-magnitude storage capacity[71,279,280,337]. Additional costs cannot be escaped; they can only be displaced.

In contrast, model 1 presents a suggested supply mix that is compelling in its simplicity. Merging the two most mature, reliable suppliers delivers emissions intensity and costs that are nearly the same as those of (the considerably more complex and less-proven) model 4a-d, or likely much cheaper when transmission requirements are included in the costs. From a purely operational perspective, a nuclear sector of ~ 27,000 MWe as suggested by model 1 represents nothing more complex than like-for-like replacement of existing fossil assets (largely coal-fired generators), using existing transmission infrastructure, and even potentially taking advantage of existing sites. Matters of frequency control and stability are answered *a priori* by the supply being 100 % synchronous. This raises a challenging possibility.

Compared to using nuclear power and open-cycle gas, there might be no net-benefit, in either cost or emissions reduction, from accommodating high penetrations of variable renewable suppliers. There might instead be net financial, social and environmental costs[180,376-378], in the form of (*i*) increased transmission requirements, (*ii*) greater acquisition and use of land for energy production, with associated environmental impacts (such as potential impacts on endangered species[379-387]), (*iii*) greater consumption of materials[388], amplified by the potential asset life of only 20-25 years for wind turbines[389] and solar panels[390], and (*iv*) the prevailing lack of decommissioning and end-of-life planning for renewable-generation assets (although this is largely a problem of policy rather than intractable technical difficulty).

But can nuclear be provided to Australia at a capital cost of $5.6 million MWe[-1] or below? Current global experience offers conflicting evidence of what could be available to Australia (discussed further in Supplementary Information). The new build program of the United Arab Emirates is tracking to deliver 5,600 MWe of generating capacity, on time and on budget[391,392], at a price of approximately US$3,600 MWe[-1] (~ AU$4,600 MWe[-1]). Were Australia to emulate the model of the United Arab Emirates with a competitive tender, capital costs of ~ AU$5.6 million MWe[-1] as assumed in our models could be available immediately.

However, capital cost is only one of four inputs to which the levelised cost of nuclear electricity is sensitive, along with discount rate, amortisation period, and assumed capacity factor. The most recent government analysis of nuclear power in Australia[174] assumed a discount rate of 10 %, amortisation period of 30 years plus construction, and an assumed a capacity factor of 83 % for a nuclear plant. We find all these assumptions to be, on the balance of reviewed literature, unsupportable. As shown in [38], both amortisation and discount rate should be carefully differentiated among technologies. We find instead that an amortisation of 40 years for nuclear power and discount rate of ≤ 7 % is consistent with the majority of the available literature[55,374,393-396], and lower discount rates to be wholly appropriate when considering the challenge of mitigating climate change and the long design life of nuclear power plants (see further discussion in Supplementary Information). We note, for example, the application of a 5 % discount rate by Blakers *et al.* (2017)[355] in their modelled build-out of solar, wind, and pumped hydro storage infrastructure. The assumed capacity factor (83 %) in Bureau of Resource and Energy Economics (2012)[172] is consistent with a 2005 global average[397], but this same reference stipulates that the top quarter of reactors reached an energy availability factor of greater than 91 %. Our review of the performance of the nuclear fleet of the United States (nearly 100,000 MWe) for 10 years to 2015 suggests an energy availability factor of 91

%. This is a far more appropriate figure assuming new build of the most modern nuclear power plants in Australia, targeted at the replacement of the incumbent fossil-fuel sector.

Using the same assumed capital cost ($5.6 million MWe^{-1}) and changing other assumptions to those deployed by Bureau of Resource and Energy Economics (2012)[172] (30 year amortisation, 10 % discount rate, 83 % capacity factor) increases the levelised cost of nuclear electricity from $89 MWh^{-1} (used in models 1-4c) to $142 MWh^{-1} — close to the price in our weighted case for model 4d ($149 MWh^{-1}). In determining whether or not nuclear power has a role in the future electricity supply mix of the National Electricity Market, we must carefully scrutinise the assumptions used to determine levelised cost of electricity, particularly in light of the intergenerational challenge of climate change. Failure to do so obscures the true value of this energy source.

Our results have important implications for clean-electricity generation outside of Australia. Many electricity markets, particularly those at high northern latitudes, lack the excellent solar resource available to Australia, and they have greater population densities making the development of comparatively large wind sectors additionally challenging[377]. Even in Australian conditions with relatively abundant wind and solar capacity, and even at costs assumed virtually unchanged from today, nuclear power has a clear role in developing reliable, lowest-cost electricity supply. Elsewhere, where conditions are less favourable to variable renewable generation from wind and solar, the optimal role for nuclear fission will likely be much larger, particularly if these markets eschew the use of biomass as a reliable electricity supplier on the grounds of well-established sustainability concerns relating to the experience gained with first-generation biofuels[228,328,334,335,398,399].

Limitations and further research

We did not consider the role of large-scale electricity storage explicitly in our model. We instead assumed supply shortfalls were met by fast-response (open-cycle) gas. Part of that demand might be more cost-effectively (and cleanly) provided via stored electricity — including batteries and, for larger volumes, pumped hydro-electric storage[355] — capturing some of the excess supply from either variable renewables or under-utilised nuclear generators for use during peak demand. The quantity of electricity demanded that is provided by gas in, for example, models 4a-c ranges from 8-15 % of the total quantity demanded (approximately 16-30 TWh). To put that into perspective, the world's largest chemical-electric battery, to be built by Tesla in South Australia by 2018[400], will have a storage capacity of 123 MWh with a peak output of 100 MWe. To perform the role performed by gas in these models would require 130,000-243,000 complete discharges of a battery that size. The maximum power output would be around 19,000 MWe, or 190 units of a size equivalent to the batteries to be installed in South Australia. Given this reality of scale and cost, large-scale batteries will likely best serve the market by mitigating costs in peak periods while also providing ancillary services, with supply that might otherwise be curtailed, rather than providing a large quantity of the supply itself. Larger amounts of storage are arguably more cost effectively provided by an expanded network of pumped hydro-electric storage[355], that can be powered by nuclear and renewable electricity alike. Again, positioning technologies as collaborators, rather than competitors, appears to be the more helpful framework.

Our models examined demand for Australia in 2030 on an hourly basis, and apply matching hourly supply traces derived for variable renewable resources. As previously identified, renewable resources also vary substantially on sub-hourly timescales[70,71]. The use of hourly supply and demand modelling might obscure variability in renewable supply that could have material

implications in providing actual reliability. In our models, this could be represented by the maximum hourly shortfall (and therefore, the capacity factor and levelised cost of the gas back-up sector), being an underestimate.

As previously discussed, our model assumed unconstrained transmission of electricity. Power-flow modelling of hypothetical transmission networks, with these costs incorporated into determining cost-optimised supply mixes, would be beneficial. Connection constraints could also limit the scale of uptake of nuclear power plants in the Australian National Electricity Market without additional network investment (unless smaller nuclear reactors, in the order of less than 300 MWe, were to become commercially available). Further consideration of network connection and transmission requirements must be considered across technology options.

Our models applied no constraint relating to a minimum amount of synchronous supply to maintain system inertia and frequency control. This is a beneficial exclusion for finding higher penetrations of asynchronous wind and solar photo-voltaics. [38] found that a minimum of 4,000 MWe output must be maintained from synchronous generation at all times, from a minimum of approximately 8,000 MWe of synchronous capacity. This reinforces that system supply mixes operating with a baseload of nuclear power are far more likely to meet essential requirements for system feasibility.

We have not explicitly considered end-of-life costs for any of the technologies. While commonly ascribed as a central concern for the nuclear sector, all energy technologies incur decommissioning costs. For instance, both solar photo-voltaic panels[401] and wind turbines[402] must manage the challenge of chemical toxicity as they reach end of life. The storage of used nuclear fuel is estimated to be in the order of US$1 MWh^{-1} of electricity sold[403]. We have elsewhere argued the mature, robust and well-demonstrated storage of used nuclear material in dry casks ought be adopted without

hesitation, in anticipation of comprehensively recycling this material in the future via generation IV fast reactors[72]. Ideally, optimised cost modelling would take full account of environmentally responsible end-of-life costs of all technologies; however, the impact on identifying a cost optimal supply mix is likely to be small compared to capital costs and discount rates.

There could be an amount of wind and solar capacity that can be considered 'committed' in Australia based on current policy and technology costs. Interaction of nuclear power and open-cycle gas in such a 'policy committed' renewable scenario, in which renewables are given priority market access, also needs to be considered. Furthermore, beyond broad indications of the impact of carbon pricing on system-wide electricity costs, our results do not offer guidance for the type of market-based policies that could drive a transition to yield cost-optimal energy mixes. Implementing some combination of emission-intensity limits for new generators, along with a transition to a capacity market[404] over the current supply-driven market, could be effective in valuing the optimal mix of supply that is both low in greenhouse gas-emissions and reliable.

Conclusions

Eliminating our reliance on fossil carbon for reliable electricity is a great societal challenge. Meeting that challenge will necessarily span many decades, in which technological developments will continue to shape our energy decision making as we pursue outcomes that are financially, socially, and environmentally acceptable. It is reasonable to be wary of prescriptions, but if we are to act with the necessary efficacy then we must at least seek firm directions. Real-world operational evidence already demonstrates that nuclear fission can provide reliable, affordable electricity supply at relevant scales[41,70,363]. Our models demonstrate that even in Australia today — arguably a best-case environment for the deployment of variable renewable technologies — the cost-effective limit for

supply from variable renewable generation is likely 30 to 40 % of the total quantity demanded, and less if the costs of expanded transmission networks are fully accounted for. There is therefore, at the minimum, a crucial role for a medium-sized nuclear sector to bring stability, reliability, affordability, and overall feasibility to an electricity supply that is low in greenhouse-gas emissions. However our models also demonstrate that the desirable outcomes of an electricity supply that is reliable, affordable and as low as possible in greenhouse gas emissions may be better served by simply deploying nuclear power at large scale in partnership with open cycle gas. The final mix will be determined as technologies evolve in decades to come, but today's knowledge is sufficient to set a pathway with confidence.

Acknowledgments

CHAPTER 4 – Role for nuclear in lowering emissions from Australia's projected renewable-energy supply gap

Abstract

The rapid growth in the uptake of variable renewable-electricity generation globally, particularly in the form of wind and solar photo-voltaic power, is changing the renewable-energy supply gap in electricity grids. The supply gap, as applied in this paper, is the half-hourly load minus the half-hourly supply from renewable sources (otherwise known as 'net load'). In the Australian National Electricity Market, strong growth is forecast for wind, rooftop photo-voltaic, and utility-scale photo-voltaic power, but continued reliance on coal and gas is also forecast to maintain baseload. Nuclear technology, while not yet deployed in this market, could provide reliable electricity supply without greenhouse-gas emissions. However, there is little published literature examining how the supply gap is expected to change, and how this change might impact the ability of newly introduced, reliable nuclear power plants to contribute to reducing emissions from overall supply. I used recently published data to derive half-hourly supply gap profiles for the Australian National Electricity Market in financial years 2020 and 2035. I analysed the supply gap to determine changes in total electricity demand, maximum demand, minimum demand, and variability, and also to quantify the renewable energy oversupply for 2035. I also calculated the cost of meeting the residual demand from nuclear power with open-cycle gas back-up, and compared the emissions outcome with business-as-usual projections. The supply gap will increase in variability by approximately four times from 2020 to 2035. Nearly 1,000 half-hourly increments of oversupply will provide a total oversupply of approximately 1.3 TWh. To meet the supply gap under a business-as-usual supply mix will result in approximately 75 Mt CO_2-e year^{-1}, giving the overall supply an average emissions intensity of 340 kg CO_2-e MWh^{-1}. The supply gap could instead be met with a nuclear sector of approximately 8,800 MWe at a cost of \$107 MWh^{-1}, which

would reduce emissions to ~ 14 Mt CO_2-e year^{-1} with an average intensity of 63 kg CO_2-e MWh^{-1}.

It might be both necessary and beneficial to increase the electricity-storage capacity to the

National Electricity Market to capture excess supply from both renewable and nuclear generation.

This could in turn be dispatched directly, instead of relying on supply from open-cycle gas

turbines. This would further lower the overall emissions from the electricity supply, and might

provide the cleanest overall supply with the most efficient use of all installed generating capacity.

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Overall percentage (%)	70
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.
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By signing the Statement of Authorship, each author certifies that:

i. the candidate's stated contribution to the publication is accurate (as detailed above);

ii. permission is granted for the candidate in include the publication in the thesis; and

iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	Professor Corey J.A. Bradshaw		
Contribution to the Paper	Collaborated in determining content, structure and flow, reviewed all paper drafts.		
Signature		Date	13 September 2017

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Contribution to the Paper	Led preparation of code for cost optimisation modelling and data preparation		
Signature		Date	29 August 2017

Introduction

The amount of electricity generated by wind and solar is growing rapidly around the world. While initial investment and uptake has been largely driven by shifting policies in response to climate change, deployment has also accelerated as prices of both on-shore wind and solar photo-voltaic generation have declined[405]. The contribution of renewable electricity generation from non-hydro renewables grew over 16 % year[-1] for the ten years to 2016. This increased total annual electricity generated per year from these sources over four-fold to 1,854 TWh; of this, 960 TWh was generated by wind and 333 TWh was generated by solar, together representing 70 % of the total electricity generation from non-hydro renewables. Global investment in renewable generation in 2016 was larger than global investment in fossil-fuel generation for the fifth year in a row[26].

As discussed and reviewed in detail in Chapters 1 and 2, integrating variable renewable energy sources into electricity-supply systems is challenging[71,114,272-275]. One specific challenge as penetration of variable supply increases is meeting the evolving supply gap: the *total load* profile minus the supply from variable renewable sources (otherwise known as 'net load')[372,406,407]. If, in future, variable renewable energy generates a larger proportion of total supply, then it is also necessary to explore how to meet the supply gap to achieve an overall supply that is reliable, affordable and — consistent with the imperative driving the use of variable renewables in the first place — sufficiently low in greenhouse-gas emissions to have some chance of mitigating rapid climate disruption.

The supply gap will vary among electrical grids based on specific demand and renewable supply profiles in different jurisdictions[407]. In Chapter 3, I examined the Australian National Electricity Market, exploring cost-optimal supply mixes for demand in 2030. My models varied the cost of available supply based on forecasted technology costs to identify an optimal blend of nuclear and

variable renewable technology. However, the insight provided by those models was based on including nuclear technology in the decision-making process from today, based on the exclusion of fossil-powered supply (with the exception of open-cycle gas backup). This is certain not to be the case. Nuclear technology is constrained by prohibitions in Australian federal government legislation. Despite the supportive recommendations of a 2006 investigation[193], a 2007 parliamentary committee review[170], the recommendation of a 2016 Royal Commission[359], a current crisis in the price and security of Australian electricity[37], and a call for the inclusion of nuclear power from one of Australia's largest business lobby groups[408], more time will pass before these prohibitions are rescinded. Any commissioning of nuclear power will involve lead times relating to establishing licensing and regulatory infrastructure, proposals, tendering, and construction. Policy certainty regarding energy investment remains largely absent now, with Australia having previously debated a cap-and-trade system for greenhouse-gas emissions[409], introduced and rescinded a carbon tax[410], and now exploring the possibility of clean energy target[411]. Whatever eventual policy certainty is achieved, the supply mix of the National Electricity Market will change in the intervening years. Current forecasting suggests it will include a larger supply from variable renewable generators. Future decisions regarding the role of nuclear technology will therefore be based on supply gaps that are different to today. It is therefore essential to examine the potential future supply gap and consider the role for nuclear power generation from this perspective.

Using forecasted penetration of onshore wind, rooftop solar photo-voltaics, and large photo-voltaic installations, in this chapter I will answer the following questions: (*i*) What might be the supply gap for the National Electricity Market based on current near-term and mid-term forecasts (2020 and 2035)?; (*ii*) Is there a role for a nuclear power sector in 2035 based on the forecasted supply gap, and what is the levelised cost of that supply?; (*iii*) What does the profile of the future supply gap tell us about the potential need for, or role of, electricity storage in the National

Electricity Market?; and (*iv*) What are the potential greenhouse-gas emissions of the supply gap under business-as-usual forecasts?

Methods

I first developed half-hourly supply-gap profiles for the financial years 2020 and 2035 using data published by the Australian Energy Market operator at the *National Transmission Network Development Plan Database*[362]. The year 2035 is the latest year for which data are available. These data include: (*i*) half-hourly demand by National Electricity Market region, excluding rooftop solar photo-voltaic installation, (*ii*) forecasted renewable energy installation by National Electricity Market region (see Supplementary Material), and (*iii*) forecasted half-hourly supply traces for: rooftop photo-voltaic (by region), large-scale single-axis tracking photo-voltaic generation (by sub-region), and wind generation (by geographic regions, called 'wind bubbles').

I determined supply-gap profiles, excluding the contribution from hydroelectricity, according to the following formulae:

$$L = \sum_{i=1}^{R} D_i - {}^{PV}T_i \, {}^{PV}F_i$$

where L = total load excluding rooftop photo-voltaic, D_i = demand in region i, ${}^{PV}T_i$ = rooftop photo-voltaic trace in region i, ${}^{PV}F_i$ = forecasted rooftop photo-voltaic in region i, over a total of R regions;

$$S_W = \sum_{i=1}^{R} {}^{W}\overline{T_i} \, {}^{W}\overline{F_i}$$

where S_W = wind supply over the entire National Electricity Market, ${}^{W}\overline{T_i}$ = mean wind bubble supply trace over all bubbles in region i of the National Electricity Market, ${}^{W}\overline{F_i}$ = forecasted wind in region i, over a total of R regions;

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$$ {}^{l}S_{\mathrm{PV}} = \sum_{i=1}^{R} {}^{\mathrm{PV}}\overline{T_{i}}\, {}^{\mathrm{PV}}\overline{F_{i}} $$

where ${}^{l}S_{\mathrm{PV}}$ = large photo-voltaic supply over the National Electricity Market, ${}^{\mathrm{PV}}\overline{T_{i}}$ = mean large

photo-voltaic supply trace in region i of the National Electricity Market, ${}^{\mathrm{PV}}\overline{F_{i}}$ = forecasted large

photo-voltaic installed in region i, over a total of R regions; and

$$ G = L - {}^{r}S_{\mathrm{PV}} - S_{\mathrm{W}} - {}^{l}S_{\mathrm{PV}} $$

where G = supply gap (excluding hydroelectricity).

As in Chapter 3, I included hydroelectric supply based on the constraints applied in the *National*

Transmission Network Development Plan, where supply is assumed to return to starting values

each year[29,362]. A peak capacity of 7,524 MWe is available, with a maximum supply of 16 TWh

year[-1]. Consistent with earlier examinations of 100 % renewable electricity for the National

Electricity Market[115], I treated the hydroelectricity as dispatchable capacity to meet periods of

high demand, after accounting for supply from wind and solar.

I dispatched the available hydroelectric capacity according to the following process. Using the

half-hourly profile G (determined above) I calculated the mean value of load. I then sorted the

supply gap values from largest to smallest. Beginning with the highest supply gap, I dispatched

6,500 MWe if the difference between that value and the mean supply gap was larger than 6,500

MWe. If the difference was less than 6,500 MWe, I dispatched the difference. I continued

dispatching in order of supply-gap increments (largest to smallest) until the available supply

(initially 16 TWh) became zero, or until there were no more periods of supply gap above the

mean. This process yielded half-hourly supply-gap profiles for the Australian National Electricity

Market for the years 2020 and 2035 including hydroelectric supply. I do not assume that these

load profiles represent actual outcomes of future market dispatch.

For each supply gap profile, I calculated the coefficient of variation, being a measure of relative variability determined by calculating the ratio of the mean value and the standard deviation. A greater coefficient of variation indicates a more variable supply gap. This provides insight into the potential technical challenges of meeting the supply gap.

I then used a previously developed model (Chapter 3) to find the cost-optimal mix of nuclear power and open-cycle gas to meet the supply gap in 2035. Details of the model operation and inputs are found in Chapter 3, but I summarise them here: I began with a quantity of installed nuclear supply capable of meeting 100 % of the hourly demand of the supply gap, i.e., installed nuclear = maximum supply gap / energy availability factor (E_A). The model progressively reduces the available nuclear capacity to zero in increments of 100 MWe. Each increment of reduction leaves a new supply gap, evaluated half-hourly over the full year of demand. This supply gap is met by open-cycle gas, which is assumed to ramp perfectly to meet demand without curtailment ('curtailment' refers to generated electricity that cannot be used or stored, and thus is not dispatched to the market[364]). The model finds the lowest-cost combination across all increments of reduction of nuclear capacity. My model assumes that the nuclear plant capacity is able to ramp perfectly, thus reducing operational costs when not dispatching supply. This assumption is increasingly material as the variability of the supply gap increases. I modelled a carbon price of $0 only, to generate results that are most applicable to the policy-neutral data that have been used for the determination of the supply gap.

Finally, I calculated the total greenhouse-gas emissions, and average emissions MWh[-1] for the overall supply forecasted for 2035 from the Australian Energy Market Operator (*Total NEM Generated Energy by Technology (TWh) using Nash-Cournot bidding*[362]), which is based on the same projected increase in renewable-energy generating capacity as my derived supply gap. I compared this with the emissions from the following supply mixes (1) Nuclear and gas to meet

the 2035 supply gap, modelled in this paper, (2) Combined cycle gas to meet the 2035 supply gap.

Results

While the total quantity of electricity demanded will increase by 16 TWh between 2020 and 2035, the supply gap will fall from 136.0-88.4 TWh, as the amount of renewable-energy supply nearly doubles from 64.5-126.0 TWh (Table 7). The increased variability of the supply gap in 2035 is evident with a co-efficient of variation of 49, nearly four times larger than for the supply gap in 2020 (Table 7 and Figure 17). One indicator of that variability is that while the amount of electricity required to meet the supply gap nearly halves, the peak power requirement to meet the supply gap *increases* from approximately 24,400-27,200 MWe (2020-2035) (Figures 17, 18 and Table 17). So, a similar quantity of installed generating capacity from reliable suppliers will be needed to meet the supply gap, even as the overall contribution from renewable energy increases. This leaves less demand into which the reliable generators might sell electricity, necessarily increasing the average cost of electricity from those reliable suppliers.

For projected supply in 2035, we found be 982 thirty-minute periods of renewable energy oversupply from wind, rooftop photo-voltaic, and large-scale photo-voltaic supply alone (hydroelectricity was not dispatched in these periods) (Figure 1). If this variable renewable energy were dispatched in full (assuming no transmission constraints), then no reliable generators would be able to sell electricity in every hour of the year. The maximum instantaneous oversupply in 2035 is 11,676 MWe (Table 7, Figures 17 and 18). The sum of this oversupply is 1.27 TWh (Table 7 and Figure 17). Eighty percent of the oversupply (1.03 TWh) is accrued in periods of oversupply ≤ 6,233 MWe (Figure 19).

Table 9 Characteristics of derived supply gap for 2020 and 2035. TWh = terawatt-hour; MWe = megawatts-electric. PV = solar photo-voltaic; RE = renewable energy; SG = supply gap; Max = maximum; Min = minimum; CV = coefficient of variation. Negative numbers in 'Minimum demand' indicate oversupply.

Year	Total demand (TWh)	Hydro supply (TWh)	Roof PV supply (TWh)	Large PV supply (TWh)	Wind supply (TWh)	Total RE (TWh)	Total RE oversupply	Total SG (TWh year^{-1})	Max SG (MWe)	Min SG (MWe)	Mean SG (MWe)	CV SG
2020	197.1	12.5	11.3	2.6	34.6	64.5	0	136.0	24,389	8,139	15,520	13
2035	213.4	16	25.5	26.7	58.1	126.0	1.3	88.4	27,198	-11,676	9,943	49

Figure 17 Derived supply gaps in half-hourly periods from 1 July to 30 June for the Australian

National Electricity Market for 2020 (top), and 2035 (bottom).
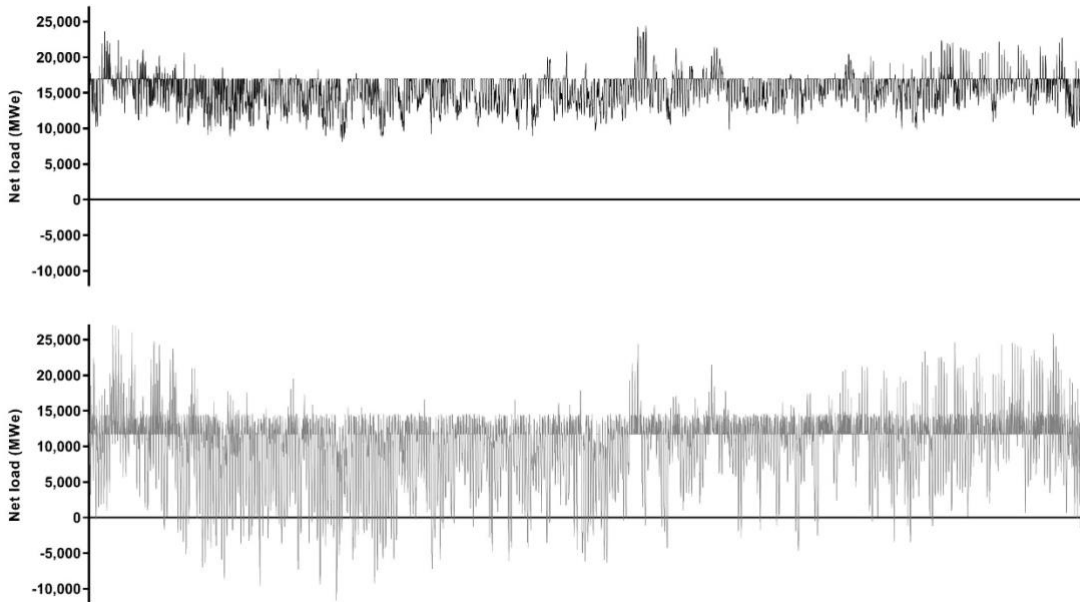
Figure 18 Week of supply-gap minimum (beginning 26 September) (top) and supply gap maximum

(beginning 6 July) (bottom) in 2035 for Australia's National Electricity Market.
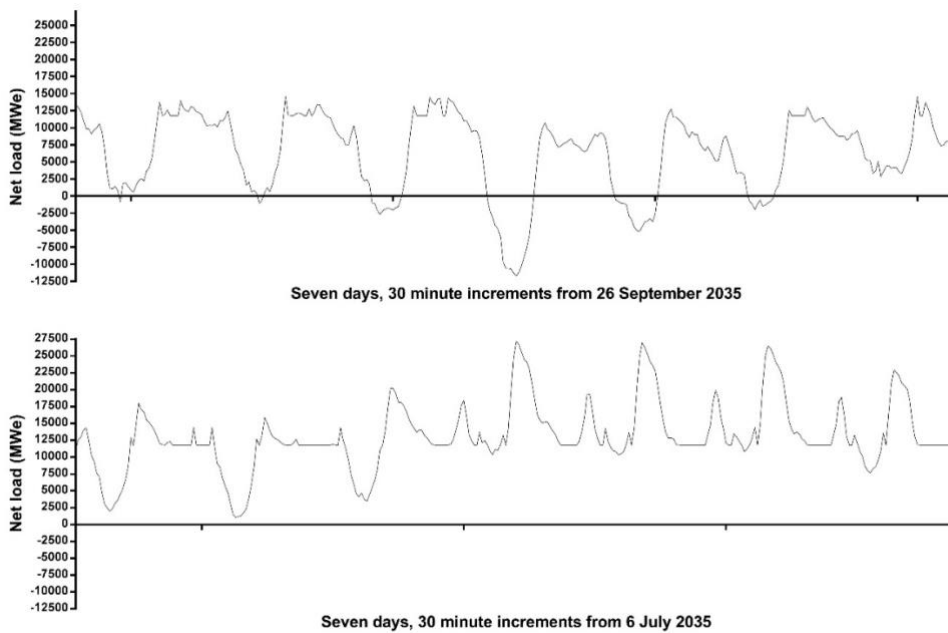
Figure 19 Accrued oversupply in 2035 by incremental increase of instantaneous oversupply. TWh = terawatt-hour; MWe = megawatts-electric
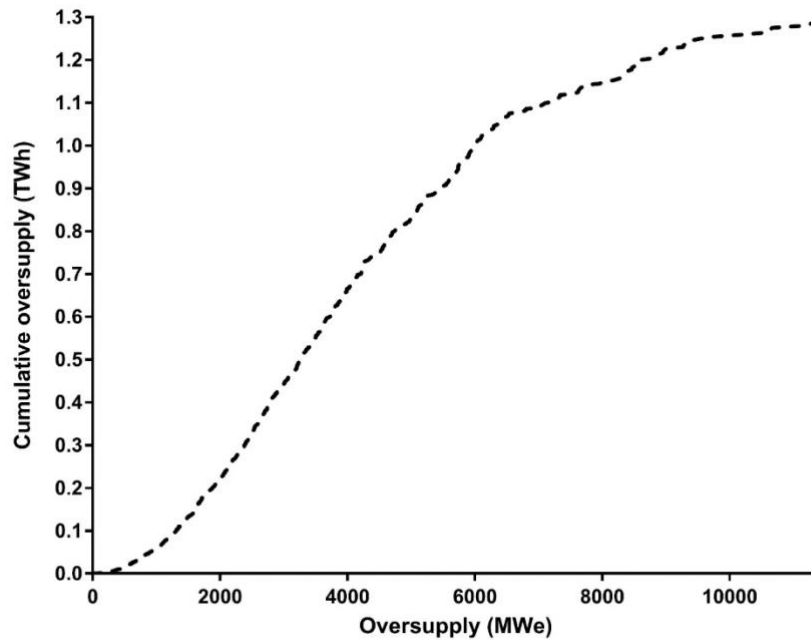
To meet the supply gap in 2035, the cost-optimal mix of nuclear power and open-cycle gas includes a nuclear sector of 8,800 MWe, which would meet 74 % of the supply gap (Figure 20) along with 18,400 MWe of installed gas providing the balance of supply. The average levelised cost of the supply is \$107 MWh^{-1}.

Figure 20 Cost-optimised supply to meet the supply gap for the Australian National Electricity Market in 2035 using combinations of nuclear power and open-cycle gas, by proportion of nuclear supply, at a carbon price of $0 CO_2-e^{-1}. LCOE = levelised cost of electricity; MWh = megawatt-hour.
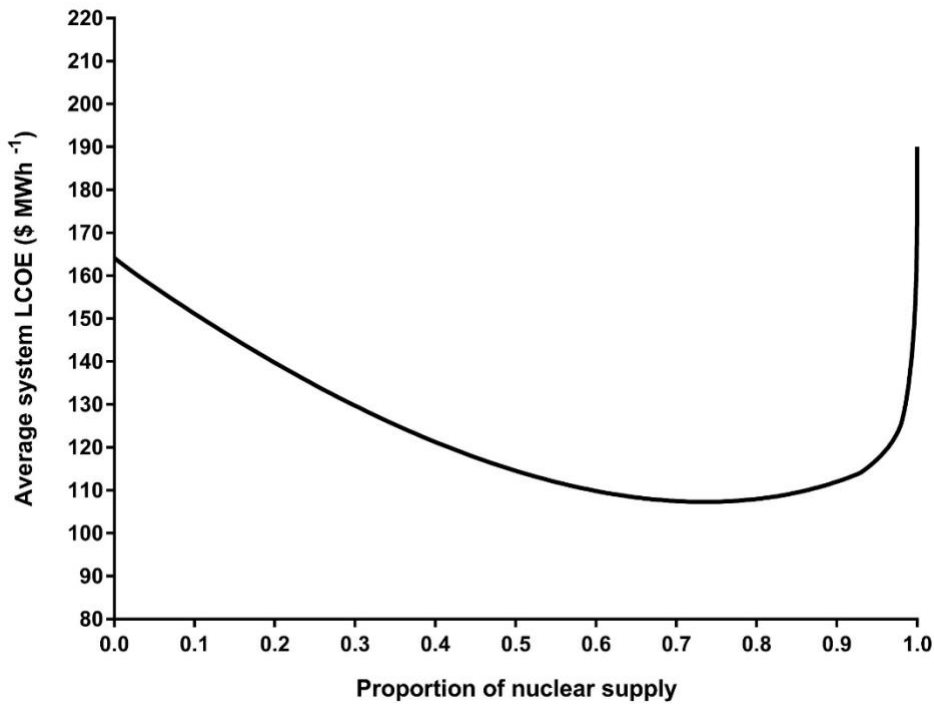
The projected supply mix from the Australian Energy Market Operator in 2035 includes approximately 9,200 MWe of coal generation and approximately 8,000 MWe of combined-cycle gas generation alongside the forecasted growth in variable renewable generation, to provide 95 TWh of supply (Table 2). Based on this supply, the Australian National Electricity Market in 2035 would emit greenhouse gases at a rate of approximately 75 Mt CO_2-e year^{-1}, at an average intensity of 348 kg CO_2-e MWh^{-1} and 2.7 t CO_2-e capita^{-1}(Table 2). If the supply gap were instead met with nuclear and gas, as modelled here, total annual emissions would be approximately 14 Mt CO_2-e year^{-1} at an average emissions intensity of 63 kg CO_2-e MWh^{-1} and 0.5 t CO_2-e capita^{-1} (Table 8).

Table 10 Comparison of total annual greenhouse-gas emissions, greenhouse-gas emissions intensity and per capita greenhouse-gas emissions of three supply mixes for the Australian National Electricity Market. AEMO = Australian Energy Market Operator; NTDP = National Transmission Development Plan; OGCT = open-cycle gas turbine; CCGT = combined-cycle gas turbine; PV = solar photo-voltaic MWh = megawatt-hour; t CO_2-e = tonnes of carbon dioxide equivalent.

Technology	Emissions (kg MWh^{-1})	AEMO NTDP Neutral Policy 2035		Nuclear and gas supply gap		CCGT meets gap	
		Generated (TWh)	GHG (Mt CO_2-e)	Generated (TWh)	GHG (Mt CO_2-e)	Generated (TWh)	GHG (Mt CO_2-e)
Nuclear	0	0	0	65	0	0	0
Black Coal	940	42	39.3	0	0	0	0
Brown Coal	1,140	10	11.7	0	0	0	0
OCGT	620	13	8.2	23	14.3	0	0
CCGT	370	43	15.9	0	0	88	32.3
Hydro	0	16	0	16	0	16	0
Wind	0	39	0	58	0	58	0
Large-scale PV	0	26	0	27	0	27	0
Rooftop PV	0	25	0	26	0	26	0
Oversupply	NA	0	0	-1	0	-1	0
Total	-	215	75.0	213	14.3	213	32.3
Intensity (kg MWh^{-1})	-	349		63		153	
t CO_2-e capita^{-1}		2.7		0.5		1.1	

Discussion

The forecasted amount of variable renewable generation to be installed in the Australian National Electricity market will profoundly change the supply gap in both size (reduced) and variability (increased) from 2020 to 2035. While this will reduce greenhouse-gas emissions, unless additional investments are made in clean generation to meet the supply gap, the Australian National Electricity Market in 2035 could have a similar average emissions intensity had fossil gas been deployed to meet 100 % of the demand in efficient, modern, dispatchable plants (at a rate of ~ 370 kg CO_2-e

MWh^{-1}, as shown in Appendix B of Finkel *et al.* (2017)[37]). I argue that this is unacceptable, given that creating a cleaner electricity supply than might be met with fossil fuels has been the motivation to accept the expense (in the form of subsidies) and the necessary complexity of adding variable renewable energy. To achieve the lowest system-wide average greenhouse-gas emissions while maintaining reliable supply, nuclear power plants should therefore be considered to meet the supply gap instead of coal and gas. My models suggest that the addition of nuclear power in Australia's electricity sector could reduce emissions to an average of 67 kg CO_2-e MWh^{-1} by 2035. This would make the National Electricity Market among the lowest carbon-emitting electricity grids in the world[70]. But, can nuclear plants be efficiently deployed to address a supply gap with such extreme variability, including 982 half-hourly instances of oversupply?

My model demonstrates that nuclear power and open-cycle gas could meet the supply gap at an average price of $107 MWh^{-1}; however, those costs assume a perfectly ramping nuclear supplier that can save on variable costs when not dispatching supply. The ability to follow load and vary output is already a feature of commercial nuclear technology, within certain constraints[412]. Developers of advanced nuclear reactors are prioritising much better load-following capability directly in response to the value in being able to integrate with variable renewable suppliers[413,414], however such nuclear technology is not yet commercially available. Supply from currently commercial nuclear power plants with limited load-following capability might meet the supply gap with excess generation curtailed. This will raise the average levelised cost of the sold electricity from the nuclear power plants.

A better approach might be to sell the excess generation from both nuclear and variable renewables into storage for future dispatch in peak periods. Storage capacity — for example, grid-connected pumped hydroelectric storage or batteries — can be efficiently used with *any* available supply that

has a low-marginal cost with low greenhouse-gas emissions. Both nuclear and variable renewable generation fits this description. In the 2035 supply gap, I predicted a cumulative total oversupply of 1.27 TWh. To capture 80 % of the oversupply (1.03 TWh) would require a peak storage offtake of 6,233 MWe (Figure 19). Assuming round-trip efficiency of 85 %[415], this amount of peak storage capacity would operate with a capacity factor of approximately 1.7 %, dispatching less than 1 TWh year^{-1}. While beneficial, dispatch from the storage of renewable energy oversupply alone will evidently provide only a minor contribution to overall supply. After contributing to the supply gap, the nuclear fleet of the modelled 8,800 MWe could produce an additional supply of 11.6 TWh, which is more than 10 times the oversupply from variable renewables. All excess renewable *and* nuclear supply could be dispatched in place of open-cycle gas, further lowering system-wide greenhouse-gas emissions. The most cost-effective combinations of renewable energy, nuclear power, and storage is therefore an important direction for further modelling.

Limitations and additional research

I derived the supply gaps based on calculations of available supply, but they do not represent a complex market in operation. Electricity storage is already a feature of the Australian National Electricity Market in the form of pumped hydroelectricity[416], and this will increase in the near future with the addition of the first grid-scale batteries[400,417]. Given that variable renewable technology and nuclear power both offer supply at low marginal cost and low marginal environmental impact, their generation in tandem is an important consideration for the efficient deployment of storage to find cost-optimal supply and storage combinations (Chapter 3). While the supply profiles of nuclear, wind, and solar are different, the economic use of all three might be enhanced with larger energy-storage capacity. The economic case for storage capacity is improved by the availability of all three types of supply to increase the utilisation of any installed storage capacity. Incorporating energy storage in

cost-optimised modelling of nuclear and renewable supply is therefore an important future research direction.

Conclusions

The increase in variable renewable-electricity generation, based on falling costs, appears inexorable. Forecasted uptake to 2035 of rooftop photo-voltaics, large-scale photo-voltaics, and wind generation in the Australian National Electricity Market supports this. However, without additional investment in clean energy to meet the supply gap, the Australian National Electricity Market might become considerably more complex, but with average greenhouse-gas emissions similar to a system exclusively dependent on efficiently combusted fossil gas. This would be an unacceptable outcome given the motivation for the use of renewable technology in the first place is a reduction in greenhouse-gas emissions compared to the use of fossil fuels. A nuclear sector partnered with open-cycle gas could meet this supply gap with far lower emissions. The efficient use of both nuclear and variable renewable generation in such a system might only be possible with, and would likely be enhanced by, additional energy-storage capacity. Therefore, the best and most efficient portfolio of solutions is likely to be found when all individual technologies are deployed to the extent of their advantages, and not beyond. The advantages of nuclear power in the Australian National Electricity Market remain underappreciated portfolio of solutions is the poorer for it.

Acknowledgments

I thank Professor Tom Wigley for additional close review.

CHAPTER 5 – Closing the cycle: How South Australia and Asia can benefit from re-inventing used nuclear fuel management

Abstract

A large and growing market exists for the management of used nuclear fuel. Some of the most urgent need for service lies in Asia, also the region of fastest growth in fossil fuel consumption. A logical potential provider of this service is acknowledged to be Australia. We describe and assess a novel model of service to the used-fuel-management market via an approved multinational storage coupled with an advanced fuel-reconditioning facility. We describe the required infrastructure and model of service delivery, including the commercialisation of advanced nuclear reactor technologies. We estimate that this project has the potential to deliver a net-present value of AU (2015) $30.1 billion. This economic finding compares favourably to recent assessment based on more conventional deep geological repository pathways. Providing a secure destination for used nuclear fuel and leadership in the commercialisation of next-generation nuclear power generation would: *(i)* mitigate a serious current constraint on, and *(ii)* catalyse the expansion of, nuclear technology for energy requirements across Asia and beyond. The consequent reduction in greenhouse emissions from the global energy sector would contribute to tackling anthropogenic climate change. Pathways based on leveraging advanced nuclear technologies are therefore worthy of consideration in the development of policy in this area.

Statement of Authorship – Chapter 5

Principal Author

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Name of Principal Author (Candidate)	Benjamin P. Heard
Contribution to the Paper	Led the research, drafting and finalisation of this paper, including all literature review, business case development, and cost-benefit analysis.
Overall percentage (%)	85
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.

Signature		Date	29 August 2017

Co-Author Contributions

By signing the Statement of Authorship, each author certifies that:

    i.   the candidate's stated contribution to the publication is accurate (as detailed above);

    ii.   permission is granted for the candidate in include the publication in the thesis; and

    iii.   the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	**Professor Barry Brook**		
Contribution to the Paper	Reviewed the early and final paper drafts, provided guidance and input on paper style, structure, content and preparation of tables and figures.		
Signature		Date	29 August 2017

Introduction: Addressing a need

Humanity faces a daunting challenge this century: to rapidly phase out the use of fossil fuels to mitigate climate change, whilst simultaneously delivering a secure, long-term energy supply for modern society. Nuclear fission has an enormous and proven potential to supply reliable baseload electricity and displace fossil-fuel power plants, and at a deployment rate in some nations commensurate with the demands for clean energy this century[41]. The fundamental advantages of nuclear power (a compact and near-zero-carbon energy source with energy dense fuel) remain critically important in many Asian markets, which are experiencing continued growth in population and electricity demand[418,419]. One of the most enduring obstacles to accelerated expansion of nuclear electricity generation has been the uncertainty surrounding the management of used nuclear fuel. There are approximately 270,000 tonnes of heavy metal (tHM) of used nuclear fuel in storage worldwide[420]. In addition, approximately 12,000 tHM of used nuclear fuel are produced each year[420]. Recent estimates suggest this will exceed one million tHM by 2090[421,422].

There is no multi-national spent-fuel repository available today[198]. The International Atomic Energy Agency states that a disposal service for used fuel would be an attractive proposition for smaller nuclear nations and new market entrants[423]. For instance, the mature energy market of Singapore has near-total reliance on imported natural gas for electricity[424] to serve a developed population of 5.4 million residents. A moderate-sized nuclear sector (approximately 10 gigawatts-electric (GWe) installed)[425] offers high-certainty decarbonisation with enhanced fuel security. Fast-growing demand in the developing-nation market of Indonesia means electricity use is expected to almost triple from 2011 to 2030, predominantly based on coal[423] with 25 GWe of new coal generation planned from 2016 to 2025[426]. An approved, regional solution to used fuel management might catalyse

acceleration of energy investment away from fossil fuels in this region and toward nuclear fission, with commensurate benefits in reduced greenhouse gas emissions and reduced air pollution.

Countries with already-established nuclear-power programmes also require services. Japan has accumulated US$35 billion for the construction and operation of a nuclear repository[427]. South Korea faces impending shortages of licensed storage space for used nuclear fuel[428,429] and has expressed an urgent need for more storage[430]. In 2015, Taiwan Power Co. sought public bids worth US$356 million for offshore used fuel reprocessing services, at a price of nearly US$1,500 kgHM[-1] [175], to be funded from its *Nuclear Back-End* fund, which currently totals US$7.6 billion[431].

Australia, in contrast to its near-neighbours in Asia, has long been considered a logical jurisdiction for the management of used nuclear fuel thanks to a convergence of factors[*]. Highly stable geology, finance, institutions and politics promotes confidence in the international community. Australia has the advantage of respected nuclear regulatory bodies in the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) and the Australian Safeguards and Non-Proliferation Office (ASNO) and a 50-year history of successful operation of a research reactor and associated facilities (run by ANSTO). Australian has been ranked first in the world for the last three years for nuclear security[432]. Australia's institutions retain the justified confidence of the international community.

The establishment of the South Australian Nuclear Fuel Cycle Royal Commission in 2015 resulted in a detailed examination of the potential for Australia's expanded involvement in the nuclear fuel cycle.

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[*] A major research program in the 1990s by Pangea Resources identified Australia as the optimal siting for a multinational geological waste repository for spent nuclear fuel. The proposal failed to find support among the Australian Government and public and was abandoned. For more information, see the World Nuclear Association webpage *International Nuclear Waste Disposal Concepts.*

Its terms of reference included exploring opportunities that may lie in the back-end of the fuel cycle, as well as the potential for generation of electricity from nuclear reactors.

The Royal Commission delivered findings in May 2016[359]. It ruled out any involvement in the development of advanced nuclear technologies in South Australia in the short term, including reactor technologies capable of recycling used nuclear fuel. Related investigations of the used fuel management and disposal market were thus limited in scope to geological disposal concepts. However the same analysis identified the potential future pathway of used fuel for "new generations of nuclear reactors" which could "both provide an income stream and avoid some significant costs", choosing to leave this as un-modelled upside [422]. These decisions left potentially viable pathways unexamined. Given (*i*) the cost of a geological disposal facility has been estimated at AU$33.4 billion[422] (*ii*) the lead time to emplacement in geological disposal is estimated at 28 years[422] and (*iii*) the demonstrable need for global-scale generation of clean electricity and heat, we argue it is important for any jurisdiction to explore, from the outset, pathways that consider the recycling of used fuel and the development of advanced nuclear reactors. If sufficiently large economic benefits can be demonstrated, an argument can be formed for inclusion of advanced nuclear technology deployment in policy options for managing the back end of the nuclear fuel cycle.

Given the component parts of a comprehensive recycling solution to used fuel management are either well-established or ready for commercialisation, we sought to investigate a pathway not considered by the Royal Commission: namely whether the implementation of such an *integrated* solution might be economically beneficial by defining a project and assessing the business case. In this paper we discuss the proposed project and the outcomes of our assessment of the business case.

Forming a viable solution

Although technically well-supported, the securing of a radiotoxic waste product in the form of used-nuclear fuel, in geological disposal, for potentially hundreds of centuries presents a worrying philosophical problem for any society to face. We therefore chose to assess the economic viability of an alternative technical pathway based on:

1. An above ground independent spent fuel storage installation (ISFSI) (discussed below) to be developed synergistically with

2. Modern, full-fuel recycling fast-neutron nuclear reactors and low-cost, high-certainty disposal techniques for eventual waste streams.

An ISFSI refers to a stand-alone facility for the containment of used nuclear fuel in dry casks for a period of decades[433]. Cumulative international experience in interim management of used nuclear fuel provides a vast technical and operational record of practices[199,434]. Recent ruling from the US Nuclear Regulatory Commission stated that used nuclear fuel may be stored safely in an ISFSI legally for around a century[199]. The advantages of this approach have been documented along with operational and maintenance requirements[175,435,436], the physical resilience of the containment[437] and the end-of-life considerations[438]. One identified advantage is retaining flexibility to deploy alternative solutions such as fuel recycling.

All constituent heavy-metal elements of used nuclear fuel, other than about 3-5 % of fission products (the isotopes that are created from uranium after it has been fissioned in a reactor), can be recycled as fuel for a fast-neutron reactor. This firstly requires electrolytic reduction for converting oxide fuel to metal and removing most of the fission-product gases, followed by electro-refining to further cleanse the fuel of fission products and finally, segregating the main metals (uranium, plutonium, minor

actinides and zirconium) for the fabrication of new fuel rods[439]. The viability of this process, known as pyroprocessing, was established many years ago at the level of high-capacity testing[206]. Research and investigation into pyroprocessing has continued to the present day at Idaho National Laboratories[440]. This ongoing research process has permitted refinement of the process towards commercialisation and detailed design and costing is available of a commercial-scale oxide-to-metal fuel conversion and re-fabrication facility[439], demonstrating the feasibility of a closed fuel recycling facility operating at a rate of 100 t year^{-1}. Such a facility is included as a component in our project.

The impact of such developments on the goals of nuclear non-proliferation must be examined carefully. Safeguarding nuclear actions is rendered more effective by technologies with intrinsic technical barriers to nefarious use. Materials directly usable for weapons cannot be produced by pyroprocessing. The plutonium product is inherently co-mingled with minor actinides, uranium and 'hot' trace fission products[441] due to the separation being electrolytic and not chemical. Pyroprocessing is thus far more proliferation resistant than existing aqueous-chemical plutonium-uranium extraction processes (known as PUREX, which has been used since the 1940s). Recycling processes take place via remote handling in hot cells This presents physical-radiological barriers that increase the ease of monitoring and provide the fuel with a 'self-protecting' barrier that results in difficulty of access and diversion of the fissile material[197]. Furthermore, the responsible centralisation of the used-fuel material in a single approved location with international oversight would assuredly deliver a net-security benefit at the global scale[442].

Pairing the recycling technology with an advanced fast-neutron reactor unlocks the full benefits of the used fuel material. One example of this technology is the Power Reactor Innovative Small Module (PRISM) from GE-Hitachi[202]. Each pair of PRISM modules offers 622 megawatts-electric (MWe) of

dispatchable, near-zero-carbon[†] generation by making use of two nuclear reactors of 311 MWe each. This size provides no barrier to connection in the Australian National Electricity Market, including in smaller regions like South Australia[443]. With flexibility in core configuration the PRISM can a conversion ratio (transmutation of fertile to fissile isotopes of actinide elements) of less than1 or greater than1, providing an effective, direct route to net-consumption and rapid elimination of long-lived material, or alternatively rendering existing used fuel a potentially vast source of further energy[203,441]. Following a fuel cycle the recycling facility cleans the metal fuel and re-casts new metal fuel pins with the addition of make-up material from the used-fuel stockpile [206]. The removed impurities, mostly fission products, are small in mass and short-lived, rendering management and disposal well-within institutional capabilities[444].

With the inherent safety properties that accompany the use of metal fuel and metal coolant[197,203,445,446], PRISM has the necessary design attributes of a successful nuclear energy system that could be feasibly deployed in the near term[444] and provides sufficient data for consideration and assessment in our project.

It is important to consider why other nations may not be actively pursuing this technology commercialisation pathway. Densely populated, fast-growing economies across Asia need the reliable clean energy output that a functioning nuclear sector offers, in order to support broader economic development. The pursuit of solutions to the back end of the fuel cycle is not, of itself, a priority particularly while current generation nuclear fuel remains low cost and reliable in supply. For

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[†] In this context, zero-carbon refers to the point of generation. While all generation sources have embedded carbon dioxide emissions from across the lifecycle, nuclear reactors are among the least carbon-intensive energy sources across the full lifecycle .The reactors under discussion here, that recycle fuel rather than mining it, will be even lower in lifecycle emissions. Lifecycle emission results from the National Renewable Energy Laboratory are found at http://www.nrel.gov/analysis/sustain_lca_results.html

other nations the level of interest in implementing a technology-based solution may be higher. However, idiosyncrasies of geology, climate and geopolitics render them relatively less suitable to housing such a group of facilities, with high barriers to implementation. Finally, a compelling commercial case may be weak on a nation-by-nation basis, whereas aggregating the proceeds of multiple national used fuel budgets at one multinational facility changes that commercial equation.

Determining the business case

Our project thus merges (*i*) An ISFSI (*ii*) a fuel recycling facility and (*iii*) metal fuelled, metal cooled fast-breeder reactors based on the PRISM design. For eventual disposal of fission products, our project assumes the use of deep borehole disposal[447]. The full details of the business case assumptions are provided in Supplementary Chapter 1.

In order to capture a range of potential outcomes, we estimated the business case for nine scenarios and selected three illustrative scenarios (low, mid and high) based on a range of assumptions for key variables. These scenarios are defined in Table 9. The capital and operating costs for all scenarios are shown in Table 10 and Table 11 respectively and described in further detail in Supplementary Chapter 1. These assumptions were applied to determine net present value of the integrated process, including disposal of fission products in deep-boreholes, over a 30-year project life at a 5 % discount rate. The impact of different discount rates ranging from 1-10 % is shown in Supplementary Chapter 2. The net-present value outcomes at 4 % discount rate are shown in Figure 22.

Table 11: Scenarios and key assumptions for the business-case assessment of used-fuel storage and recycling. ISFSI = Intermediate spent fuel storage installation. tHM = tonnes of heavy metal. MWh = megawatt-hours

Scenario	ISFSI size (tHM)	Fuel custody price to charge (2015 AU$ (tHM^{-1})	Electricity price (2015 AU$ MWh^{-1})
L40 (Low scenario)	40,000		
L60	60,000	685,000	20
L100	100,000		
M40	40,000		
M60 (Mid scenario)	60,000	1,370,000	50
M100	100,000		
H40	40,000		
H60	60,000	2,055,000	80
H100 (High scenario)	100,000		

Table 12 Summary of capital costs for the business-case assessment of used-fuel storage and recycling. ISFSI = Intermediate Spent Fuel Storage Installation; PRISM = Power Reactive Innovative Small Module

ISFSI size (tHM)				
	40,000	60,000	100,000	
Capital Item	Cost (2015 AU$U million)			Source
ISFSI	912	1,026	1,245	Electric Power Research Institute[448]
Fuel recycling and fabrication plant		617		Argonne National Laboratories / Merrick and Company[439]
PRISM 622 MWe		8,302		United States Department of Energy[449]

Table 13 Summary of operational costs for the business-case assessment of used-fuel storage and recycling. ISFSI = Intermediate spent fuel storage installation; tHM = tonnes of heavy metal. MWe = megawatts-electric; PRISM = Power Reactive Innovative Small Module (nuclear power plant)

ISFSI size (tHM)	40,000	60,000	100,000	-
Operational item	Cost (2015 AU$ million)			Source
ISFSI loading	620	698	853	Electric Power Research Institute [448]
ISFSI caretaker	6	7	8	Electric Power Research Institute[448]
Fuel recycling and fabrication plant		70		Argonne National Laboratories/ Merrick and Company [439]
PRISM 622 MWe		208		United States Department of Energy [450]
Deep borehole disposal		0.086		Adapted from Brady *et al.* [447]

Figure 21 Net present value of the nine business case scenarios defined in Table 9, 30-year project life, 4 % discount rate
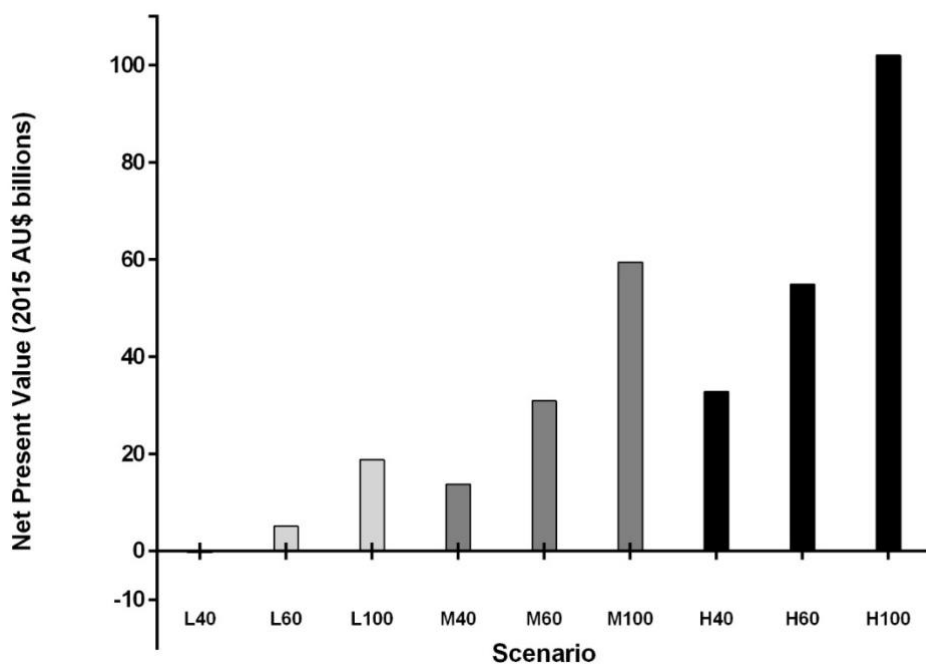
The business case reveals a multi-billion-dollar net present value (NPV) in all scenarios except the illustrative low scenario. The illustrative mid-range scenario delivers NPV of AU$30.9 billion at 4 % discount rate.

Comparing findings with the Royal Commission

In the analysis supporting the final report of the Royal Commission[422], a similar project was assessed, predicated on firstly establishing above-ground storage for used nuclear fuel. Key differences in the favoured scenario modelled by the Royal Commission include:

- Larger assumed volumes of material to be stored i.e., a bigger project

- Higher assumed base case 'price to charge' for acceptance of used fuel

- Longer assumed period for accepting used fuel material

- No integrated commercialisation of recycling and advanced reactor technology

- No revenues related to the sale of electricity from nuclear power plants

- Establishment of permanent geological disposal facility

- Revenues from the acceptance of intermediate level waste

A compare-and-contrast between the base case of our analysis and the base case of the Royal Commission is given below (Table 12). As shown, as well as recommending a much larger role in accepting used fuel, the Royal Commission directs revenue (at a capital expenditure of AU$33.4 billion) towards geological disposal, while our concept directs revenue toward recycling and clean electricity generation (at a capital expenditure of less than$10 billion). Both projects delivered NPV in the tens of billions. The larger NPV of the Royal Commission project is substantially explained by (*i*) the much larger assumed revenues from accepting 2.3 times more used fuel material, (*ii*) accepting intermediate level waste for disposal, and (*iii*) the higher assumed price paid (AU$1.75 million ton^{-1}) for the used fuel material (our assumed base case price was AU$1.37 million ton^{-1}). In Table 13 the

results of our analysis are updated to reflect the higher assumed price for used fuel acceptance identified by the Royal Commission. The NPV changes from AU\$30.9 billion to AU\$44.1 billion.

Table 14: Comparison of project assumptions between Nuclear Fuel Cycle Royal Commission (2016)[359] and Heard and Brook (2016)[72]. All dollar figures are 2015 Australian dollars. tHM = tonnes of heavy metal; MWh = megawatt-hour

Assumptions	Royal Commission	Heard and Brook
Amount of used fuel accepted (tHM)	138,000	60,000
Fuel custody price to charge ($ million ton^{-1})	1.75	1.37
Period of used fuel acceptance (years)	82	20
Capital cost of fuel recycling ($ billion)	N/A	0.617
Capital cost of fast reactors ($ billion)	N/A	8.3
Capital cost of geological disposal facility ($ billion)	33.4	N/A
Price of sold electricity ($ MWh^{-1})	N/A	50
Sold electricity year^{-1} at commissioning (MWh)	N/A	5 million
Intergenerational discount rate	4 %	4 %
Net present value ($ billion)	51.4	30.9

On the basis of this analysis we argue that commercial development of advanced nuclear reactors, treated as principally a recycling facility paired with an ISFSI, is economically viable immediately. Deploying advanced nuclear reactors for their recycling capabilities represents an innovative approach to both the development and deployment of low-carbon energy technologies and the resolution of long-standing challenges related to used nuclear fuel.

Table 15: Net present value (NPV) outcomes for Heard and Brook proposed business case based on price to charge and intergenerational discount rate applied by the South Australia Nuclear Fuel Cycle Royal Commission[422].

Price to charge ton accepted $^{-1}$ (2015 AU$ million)	NPV [name] (2015 AU$ billion @ 4 % intergenerational discount rate)
1.37	$30.9
1.75	$44.1

Limitations and uncertainties

The novel nature of this business case involves inevitable uncertainties. Our transportation costs were based on inclusive estimates for a national facility serving the United States using ground transport only. In addition to such ground transport costs, ocean-going transport will be required to South Australia. Recent work suggests ocean transport costs to South Australia of AU$7,500-AU$37,500 tHM^{-1} [422] with this range covering a range of potential customer nations. Present value outcomes of this study will not be materially altered by these inclusions which assessed 'price to charge' across a range of approximately AU$1.3 million tHM^{-1}.

The lack of services, globally, for the management of used nuclear fuel means the assumed 'price to charge' was based on desktop sources. This is an obvious limitation; such a market is not yet established and tested. However more recent willingness-to-pay analysis supported a higher base-case price than that used in our analysis[422], suggesting any uncertainty is likely to be positive for the present value outcomes of our proposed pathway (see Table 12). The sensitivity of our project to the assumed capital expenditure of the nuclear reactors was tested in a cost-overrun scenario (see Supplementary Material) which found positive NPV in all but the low scenario.

Conclusion

The South Australian Nuclear Fuel Cycle Royal Commission provided an important opportunity for an evidence-based re-appraisal of the opportunities available in serving the back end of the nuclear-fuel cycle. However, the analysis undertaken under that process chose a deliberately constrained pathway that neglected to examine opportunities based on advanced nuclear technologies and recycling of used nuclear fuel. Our proposal identifies the opportunity for an integrated financial project to commercialise new technologies that allow the complete recycling of used nuclear fuel, with the production of abundant, near-zero-carbon clean electricity (and industrial heat) as a result. If implemented this would make an important contribution in the fight against climate change, nuclear proliferation, and containment of pollution while offering (2015) AU\$30-44 billion in present value. Implementation of an integrated solution could also play a vital role in shifting the balance of energy decision making, particularly in the fast-growing Asian region, away from polluting fossil fuels and towards clean, near-zero-carbon nuclear generation by providing assurance of responsible and secure centralised management of used nuclear fuel.

CHAPTER 6- Discussion

In writing this thesis I set out to explore an apparent paradox. Based on our civilisation's ready access to large amounts of energy, we have raised great a great proportion of humanity from poverty to relative wealth, lengthened our lives, and slowed the rate of our population's growth. Yet, that very energy consumption raises the risk of future calamity of comparable scale through the disruption of the global climate system. How can humanity break out of this paradox? How can we not only simultaneously preserve, promote, and extend the benefits of human civilisation and avert a crisis of climate disruption, but also protect, preserve, enrich, and restore the greater natural world around us?

As I detailed in the introduction, evidence from the previous three decades shows that humanity is unwilling to forgo its access to energy, which is essential to addresses its development and environmental needs today, in order to mitigate the less-tangible future risks presented by climate change. While climate change has grown in prominence in public discourse since the first report of the IPCC in 1990, this period has also delivered rapid growth in overall energy consumption and greenhouse-gas emissions. We can now see the early signs of a partial transition away from fossil fuels in a single energy sector, in the form of increased renewable-electricity generation. This tentative decoupling contributed to a two-year stasis in annual global greenhouse emissions, while economic growth and growth in energy consumption continued. However this stasis has ended, with global greenhouse emissions rising once again[451]. In the face of the evidence, proceeding under an assumption of stable or decreasing global energy consumption would be an act of denial, arguably as consequential as denying the science of climate change itself. Equally, proceeding under the assumption that we can outpace that energy growth with growth in renewable energy supply alone appears flawed. Somehow, *all* our energy needs to be clean.

Facing this challenge, I identified that nuclear technologies provide a seemingly logical technological intervention with which we might break the paradox, being the only fuel-based energy system that does not rely on the combustion of carbon, with an established track-record in scalable supply of reliable electricity. Yet, this has not happened. In the previous three decades, nuclear technology has been conspicuously slow-growing, including an outright contraction in supply over the last ten years.

If renewable technology were now positioned to displace both fossil fuel and nuclear power generation rapidly, the apparent stalling of nuclear power over the last three decades would be immaterial. However, as I demonstrated in this thesis, this is not the case. In Chapter 1, we identified three risks to price and reliability as the model state of South Australia makes a rapid transition to variable renewable energy sources: (*i*) the inability to retire other generators; (*ii*) the reduction in frequency control through the displacement of synchronous generation; (*iii*) the need to increase investment in network interconnection to manage the variability of supply efficiently. That chapter (and the ensuing peer-reviewed article) proved prescient. I was wrong on the first point: there was no governmental or regulatory intervention to avert the mothballing of 240 MWe of combined-cycle gas generation in April 2015, and the permanent exit of 760 MWe of coal-fired generation in the middle of 2016[452]. However, these losses brought forward the other stressors with evident consequences. In winter of 2016, South Australia experienced extreme spikes in electricity prices due, in part, to greater exposure to the cost of gas[453]; in September 2016, a major storm damaged transmission lines, triggering a state-wide blackout as wind farms shut down due to fault settings, and inadequate synchronous generation was left to maintain frequency control in response to this loss of supply[287,454]; in the summer of 2017, South Australia experienced load shedding during extreme heat[455]. In response, the South Australian government announced policies including (*i*) the purchase of the world's largest battery[400], (*ii*) a new government-controlled gas-fired power station, (*iii*) incentivising the exploration and development of gas resources within South Australia, and (*iv*)

mandating energy retailers to purchase more electricity generated from within South Australia (a target that will predominantly benefit gas-fired electricity production)[456]. The Australian Energy Market Operator identified the need for network upgrades to manage the loss of system resilience, based on the decline in synchronous generation within the borders of the state and the forecast closure of synchronous generation in neighbouring regions[29]. The challenge of accommodating a larger proportion of supply from variable renewable sources is therefore now playing out in South Australia, and has been one trigger for a national review into the security of Australia's electricity supply[37].

Led by the Chief Scientist of Australia, Dr Alan Finkel, the Independent Review into the Future Security of the National Electricity Market that quickly became known as the ('Finkel Review'), flagged that the security and reliability of the National Electricity Market had become compromised by poorly integrated variable renewable energy, which coincided with the unplanned and disorderly departure of coal and gas-fired generators[37]. These were two of the risks that I forecast in Chapter 1. In response, the Finkel Review suggested new security obligations be put in place for new entrant generators, including for the maintenance of minimum system inertia (i.e., frequency control), another of the risks I flagged in Chapter 1, four years earlier. The review lacked any clear stance on greenhouse-gas emissions reductions in the National Electricity Market, speaking instead the need for further exploration and production of fossil gas, and speaking of zero emissions as a target to be achieved only sometime in the 'second half of the century'[37].

In Chapter 1, I also highlighted that the exclusion of nuclear technologies in both governmental and academic research from even partial consideration, was a seemingly systemic trend in Australia. The Finkel Review continued this trend, publishing a table of estimated operating emissions for new power stations that did not include any reference to nuclear generation[37]. The report acknowledged that nuclear generation provides a secure, affordable and zero-emissions electricity supply to many

nations, with the added benefit of synchronous generation to support system security. Despite these manifest advantages across the scope and terms of reference of this study, there was not a single recommendation pertaining to nuclear technology, and no reason given for this exclusion[37]. The trend continued in Blakers *et al.* (2017)[365]. These authors erroneously justified the exclusion on the grounds that it would require 'heroic assumptions' for nuclear to grow at a rate necessary to achieve emissions reduction in an acceptable timeframe; the exact opposite has been demonstrated[41]. The authors further justified the exclusion on the basis of the 'unlikelihood of its deployment in Australia' - a decision that reinforces this very outcome.

These exclusions seem all the more confounding given the recently increased in focus on Australia's electricity 'trilemma' of reliability, affordability and low emissions/sustainability. These principles have been central in the Finkel Review[37] and associated supporting research[38], the first report of the newly formed Energy Security Board[457], and their recommended policy to the Federal Government known as the National Energy Guarantee[458]. None of these processes have made any recommendation relating to Australia changing its position with regard to the use of nuclear generation. The Council of Australian Governments Energy Council goes so far as to label the National Energy Guarantee 'technology neutral'[459]. That claim is undermined by the legislative prohibition on nuclear generation technologies of any type or size.

The Health of the National Electricity Market report[457] highlighted that there has been 'insufficient recognition' of the need to maintain dispatchable power and frequency control as the National Electricity Market has rapidly pursued uptake of variable renewable electricity generation[457]. The board assigned a 'critical' rating (the highest) for (*i*) the need for efficient prices and affordability; (*ii*) the health of Emissions Reduction Policy; (*iii*) Reliability of supply; and (*iv*) System security health. While interventions are underway to address these deficiencies, that risks overlooking a crucial point. On global standards, from a greenhouse gas emissions perspective, the electricity of the Australian

National Electricity Market remains among the dirtiest the world. The challenges highlighted by the

Energy Security Board are not a matter of restoring stability after sector-wide reform for achieving

very low emissions. That job has barely started. The need for genuine technology neutrality to

facilitate genuine consideration of the use of nuclear technologies, could scarcely be clearer.

So, in the course of preparing this thesis, the urgency of the discussion in Australia about electricity

supply has increased as appreciation of the threats to reliability, security and affordability of

electricity have become impossible to ignore. But the discussion remains stunted by the broad

refusal to fully consider the role of nuclear technology which, ironically, is the only class of

technology capable of meeting all three points of the trilemma on its own. The work presented in this

thesis (Chapter 3 and 4) is, at the time of submission, the only research effort in Australia to

pointedly include nuclear technologies alongside renewable technologies with a goal of affordable,

reliable and very low-emissions electricity supply.

Fortunately, the connection of a 100 MWe/129 MWh battery in South Australia[400] has demonstrated

provision of frequency control to the grid and provided some of the additional stability

requirements[460,461]. Following the tripping of a unit of coal-fired generation in Queensland in

December, 2017, the battery was the first responder, boosting system frequency near-

instantaneously, before retreating as synchronous generating units followed through to complete the

restoration of frequency to normal levels[461]. This is a clear example of a novel technology working in

collaboration with existing systems; such collaborations between technologies should be sought and

exploited to make a transition to decarbonised electricity supplies as cost-effective as possible. For

as Blakers *et al.* (2017)[365] have argued, on matters of cost and scalability, batteries are unlikely to

provide the volume of electricity storage that may be required or beneficial. That job, if deemed

necessary, appears better suited to the expansion of pumped hydro-electric storage facilities[365].

Investigations of demand response have also continued and expanded since the beginning of my thesis, with pilot projects to make 143 MWe of demand response available during extreme peaks in the 2017/2018 summer[361]. Peak demand of the National Electricity Market is currently approximately 37,000 MWe[462], so these pilot, proof-of-concept initiatives represent approximately 0.4 % of peak demand. While this is short of the assumption of a fully flexible 5 % and 10 % of demand applied by AEMO in their 100 % renewables study[115], it is indicative of the dynamic nature of our electricity system. Knowledge, experience and understanding will continue to evolve, and the determination of 'optimal' responses to the challenge of creating a clean energy supply must evolve with it. We will need to develop sounds principles, and be wary of prescriptions. True technology neutrality with the inclusion of nuclear technologies for full consideration and assessment is one such principle.

In Chapter 2, we demonstrated that existing plans for 100 % renewable electricity do not meet a basic definition of feasibility, and, if implemented, would deliver serious, adverse environmental and social outcomes. Subsequent work from Clack *et al.* (2017)[242] made headlines across the United States when it exposed major mathematical and physical flaws in the most high-profile of the studies we reviewed[299]. The lived experience of South Australia, and oversights in the literature examining 100 % renewable-energy scenarios, indicate that a short-term, single-minded focus on variable renewable generation is ironically likely only to reinforce longer-term dependence on fossil fuels.

Efforts to establish the feasibility of 100 % renewable electricity generation have continued since the publication of this chapter. Notably in Australia, Blakers *et al.* (2017)[365] repudiated previous studies exploring this question[112,114,115,218,225,226] by limiting technologies to those deemed to be commercially established beyond doubt: just wind, solar photovoltaics, hydroelectricity and pumped hydro-electric storage. They purport to find a reliable system for around $93 MWh^{-1}. This is a similar price to what I determined with my nuclear/gas and nuclear/wind/solar/gas models. However, there are important differences. Blakers *et al.* (2017)[365] assumed static electricity demand of 205 TWh year^{-1},

acknowledging that just penetration of electric vehicles would alter electricity demand. They applied

a 5 % discount rate, rather than the 7 % used in my modelling and that of the Finkel Review[37]. As

discussed in Chapter 3, lowering the discount rate delivers lower levelised cost of electricity,

especially for capital-intensive projects. That might partly explain the levelised cost of generation for

solar photovoltaic and wind of $78 and $64 MWh-1, compared to $92 and $91 MWh[-1], respectively

that I applied for 2020 (identical figures as used in the 2017 Finkel Review[37]). Blakers *et al.* (2017)[365]

acknowledged the importance of maintaining frequency control, and excluded this issue from their

models, leaning on the presence of increased pumped hydro-electric storage to mitigate this

exclusion[365]. My work answers this concern *prima facie* with the use of synchronous nuclear

generation.

The variation in levelised cost of electricity inputs for modelling ostensibly the same technologies

reinforce a point I made in Chapter 3. We must scrutinise the inputs behind published levelised

costs, not accept those costs at face value, and be rigorous and consistent in those inputs if we are

to make informed decisions regarding energy investments. So, while Blakers *et al.* (2017)[365] provide

further information and insights, they do little to advance the case for the feasibility of 100 %

renewable electricity, scoring 1.5 out of 7 in the framework we established in Chapter 2.

In Chapter 3, we determined that including nuclear technology alongside wind and solar photo-

voltaic generation could create a reliable electricity supply for the Australian National Electricity

Market for less than $100 MWh[-1], with average emissions intensity of the generated electricity less

than 100 g kWh[-1]. A nuclear sector of approximately 15,000-25,000 MWe would provide supply,

reliability, and frequency control alongside much-expanded wind and solar sectors. This finding has

global implications because, in terms of available solar and wind resources and relatively low

numbers of customers, the Australian National Electricity Market is arguably a best-case situation for

the uptake of variable renewable energy. This is particularly true of our modelling where we assumed unconstrained transmission interconnectivity.

A challenge in models such as that described in Chapter 3 is accounting for cost inputs that are constantly changing. For example, the LCOE of utility-scale solar photovoltaic projects fell by approximately 67 % from 2010 to 2016 (globally weighted average)[27]. The globally weighted average levelised cost of electricity of on shore wind power fell 18 % from 2010 to 2016, with the globally rated average capacity factor rising from 20 % in 1983 to 29 % in 2016[27]. While the recent period has been remarkable for cost declines in these two technologies, nuclear technology is not static either. In recent years, the nuclear power sector of the United States has completed up-rating of existing plants that have delivered additional generation capacity equivalent to seven new nuclear power plants[463,464], giving this sector of approximately 96,000 MWe a capacity factor of approximately 91 % (see Chapter 3). Further uprates of the global nuclear sector could be achieved with the introduction of advanced metallic fuel rods, that could increase output of existing light-water reactors by 10 %, with a subsequent boost in their commercial competitiveness[465-467]. As highlighted by my work in Chapter 3, we can develop greater understanding in modelling when we consider the costs of technologies relative to each other, rather than in absolute terms. Such an approach is more amenable to a world in which absolute costs will continue to change.

In Chapter 4, we found that without the inclusion of nuclear technology, twenty years from now the Australian National Electricity Market is forecast to incorporate much larger wind and solar sectors in a supply with average emissions from about 340 g kWh^{-1}. That is little cleaner, on average, than were it running exclusively on efficiently combusted methane. The variable renewable supply will greatly alter the nature of electricity supply; however, it will offer insufficient excesses of supply for storage to overcome that variability and displace the balance of fossil fuels. In that context we argue not against the development of greater electricity storage, such as pumped hydroelectricity as

recommended by Blakers *et al.* (2017)[365]. Instead, we argue for an underlying clean-generation system that ensures any investments in electricity storage are fully utilised, and thus most cost-effective. In Chapter 5, we explored the profound implications of advanced nuclear technologies that can recycle existing used nuclear fuel, delivering approximately 20 times more energy and reducing the half-life of waste material to 30 years. The science and engineering of nuclear fission for energy production continues to develop, and holds extraordinary potential.

Yet, the general public's determination to reject nuclear technology appears difficult to alter, demonstrated in a crisis that has beset the nuclear power sector in the United States, Western Europe, and developed East Asia (South Korea, Taiwan, and Japan). The failure of US industry giant Westinghouse on the back of delays and cost overruns of what was intended to be their flagship Generation III reactor (AP 1000), demonstrate the negative ramifications of a 20-year hiatus in nuclear construction[468]. Existing nuclear plants in the United States — workhorses of reliability and dependability (91 % availability factor from 2005 to 2015[363]) — are economically and politically assailed. The sustained low price of gas has left nuclear power uncompetitive against polluting power stations while highly subsidised variable renewable generators gain a larger market share[468]. But a fightback is underway, led by an energised pro-nuclear environmental movement[61], even though it still faces an uphill battle against well-organised and well-funded opponents. This has met with early victories, with the inclusion of nuclear power in clean energy standards in New York and Illinois[469].

In Western Europe, Germany accelerated the closure of its nuclear fleet despite decades of reliable performance. After more than five years, this policy has embedded German dependence on coal and left greenhouse-gas emissions stagnant[470-472], with costs exceeding €20 billion per year in subsidies to renewable generators[472]. The French government of newly elected Emmanuel Macron in 2017 initially promised to reduce nuclear power to 50 % of the electricity supply, despite France having

some of the lowest per-capita greenhouse-gas emissions among developed nations[70]. However by December of 2017 Macron dropped this pledge, stating that the priority must be the reduction of greenhouse gas emissions[473]. Delays and cost overruns in the commissioning of the French company's Areva's flagship reactor, the European Pressurised Reactor, in both Finland[474] and France[475] likely placed pressure on the political tenability of the French nuclear sector. These reactors are the first nuclear new-builds in Western Europe for close to twenty years. Commissioning at both Olkiluoto in Finland and Flamanville in France appears to be drawing close[474,475], and the United Kingdom has commenced site preparation for a new build to keep nuclear as part of a low-carbon energy mix for that nation[476]. However, criticism of the costs and timeframes of these projects remains a regular discussion point[477,478].

A restart of the Japanese nuclear fleet following the failures at Fukushima Daiichi has been slow, with just five of forty-two operable reactors returned to service so far[479]. This has increased Japan's consumption of imported fossil fuels, and an increase in the associated greenhouse-gas emissions and other air pollutants[480,481], not to mention greater financial costs. In Taiwan, completed new nuclear reactors sit idle. The lack of generating capacity in Taiwan now threatens energy security[482], with a tripping of gas stations during conditions of supply stress causing outages to over six million households[483]. In South Korea, the newly elected government intends to phase out nuclear power over the next 45 years[484]. However, an independent citizen's jury voted in favour of the completion of reactors currently under construction, hinting at the potential for a more difficult path away from nuclear power for South Korea.

There is debate as to whether failures of nuclear new build are attributable to industry decline through simple lack of exercise; Kafkaesque regulations that might be traced to pervasive activism over the course of several decades; a decline in capabilities for central planning and project delivery in liberal democracies, or interactions between these influences[485-488]. What might no longer be

debatable is that the United States and Western Europe have ceded leadership in the large light-water reactor industry, and developed East-Asian nations might follow with the active urging of major environmental groups[489]. Based on my research for this thesis, I do not expect this crisis to trigger a transformational surge in renewable technology. I consider it a harbinger of continuing failure to deliver a rapid transition of energy systems away from fossil fuels. The next thirty years are on track to reflect the thirty years past, filled with talk that delivers little or no meaningful reduction in greenhouse-gas emissions in the face of ongoing growth and development of human civilisation.

However, this crisis in the nuclear power sector is not global in nature. The nuclear power sector continues to grow, albeit slowly, with increasing industry dominance by Russian, China, and emerging markets. China has commissioned approximately 20,000 MWe of nuclear in the last ten years, and is moving toward an export footing[490]. Russian state provider Rosatom has orders for over 30 reactors worth US$300 billion[491], and is opening markets for nuclear power in Turkey[492], Egypt, Nigeria and Sudan. India has announced plans for a doubling of its nuclear fleet with a new 7,000 MWe commitment[493]. Other nations including Kenya[494] and Malaysia[495] are moving toward nuclear power. South Korean provider KEPCO is close to completing a successful turn-key export development to the United Arab Emirates, with four generators (5,600 MWe total capacity) being delivered on time and on budget[391]. Nuclear power is therefore far from dead, but it has emigrated. The global industry centre of gravity is in Russia and China, and the markets they are developing in northern Africa, the Middle East and elsewhere.

This divergence in the status of lightwater reactor deployment is evident in the projected levelised costs of nuclear electricity in different global markets. For Korea, the projected cost is $ 34.05; for China it is $34.57; for the United States it is $64.81; for the United Kingdom it is $80.88 (all figures 2013 US$ using 5 % real discount rate)[395]. The cost of ostensibly the same output (nuclear generated electricity) varies by a factor of 2.4 between jurisdictions. This suggests nuclear power is

neither inherently cheap nor inherently expensive. Rather, the issue is how we go about doing it. Some nations are doing it better than others and achieving notable growth domestically and in emerging markets.

However, that growth might do little more than maintain approximate stasis of nuclear power in its percentage contribution to global energy supply. Something much different could be needed to trigger the necessary transition away from fossil combustion to nuclear fission alongside the growth in deployment of renewable technologies.

That 'something different' might be found under the umbrella term 'advanced nuclear'. Small modular reactors, molten-salt reactors, fast-breeder reactors, or high-temperature gas reactors; all these descriptors, and more, are applicable. Developments in advanced nuclear are global and interest in small modular reactors is high[178,496-498]. Generally regarded as nuclear reactors of less than 300 MWe output, the small modular reactor concept seeks to move nuclear from a construction paradigm to a manufacturing paradigm. In so doing, with reactors built in factory environments and then shipped to sites to be 'dropped in' to power plants, proponents of SMR suggest this will enable nuclear power to achieve the increase in quality control and decrease in cost that has been deployed for products ranging from passenger aircraft to solar photo-voltaic cells[496,498]. By dividing the total power output of the nuclear island among several smaller reactors (i.e. a 1,000 MWe site consisting of five, 200 MWe SMR modules), SMR might also ease the risk of nuclear developments, allowing returns to flow sooner and more sequentially in response to incremental investment, rather than large capital expenditure followed by many years of on-site construction[496,498]. While these principles appear sound, caution is also required. At the time of writing, there are no new-generation SMRs that are licensed and available for order. Recent years have seen both strong progress[499-502] and outright attrition among developers of SMRs[503]. Order books are yet to be filled, factories and workforces are yet to be established, and the production-line development of nuclear modules is not yet a reality.

The enthusiasm for smaller nuclear must be tempered with a realistic appreciation of the challenges of bringing new products to market in this sector.

As well as reducing the size of nuclear power reactors, advanced reactor developers are working to bring new designs and products to market (including General Electric-Hitachi with the PRISM reactor, discussed in Chapter 5)[504]. China commissioned its high-temperature, gas-cooled reactor this year[505]. Russia commissioned a new metal-cooled fast-breeder reactor in 2016[506]. Canada is planning a special site for development and prototyping of small modular reactors[507]. While the technology is diverse, the justification is fairly uniform: cheaper, better, safer and more easily delivered nuclear power. Difficulties relating to large, light-water reactors provides a compelling justification to the call for 'better nuclear'. Yet, the excellent historic performance of the bulk of these fleets[363] and the successful new build in the United Arab Emirates, Russia, China, and South Korea, also suggests that large, light-water reactors are not, in point of fact, 'the problem'. Environmental activist Michael Shellenberger (Environmental Progress, California, USA) argued that we cannot innovate our way out of constraints on nuclear technology that are imposed by our own political and social constructions[64]. Furthermore, the road to commercial deployment of new nuclear technology is long, expensive, and littered with attrition. At the time of writing, aggressively cheap electricity from new nuclear reactors remains a promise. So, is there an iron-clad case for advanced nuclear technology? If the answer is yes, then the key word is 'heat'.

Nuclear might be the only solution for process heat, industrial emissions, and synthetic fuels
My thesis makes additional contributions to understanding how to decarbonise electricity production. But we must consider the overall energy challenge when responding to the dilemma of climate change. In the United States, energy use in transportation is nearly as large a contributor of greenhouse gases (26 % in 2014) as electricity[508]. The industry sector was responsible for another

20 %[509]. German industry accounts for 27 % of total final energy consumption, with 74 % of this being direct thermal energy — i.e., heat[510].

Process heating supplies thermal energy to transform materials into a wide variety of industrial and consumer products, including ubiquitous materials (such as concrete and steel), chemicals (hydrogen, ammonia, etc.), and processed food[265]. The sector is heterogeneous, but with scant data providing accurate breakdowns of requirements by both quantity and temperature[265,511]. For example, food processing demands temperatures from 65-250 °C. Some common chemical processes such as the production of hydrogen or ammonia demand 500-1,000 °C. The smelting of metals and the processing of metal ores applying calcination and hardening could demand 800-1,500 °C[265].

However, Naegler *et al.* (2015)[511] identified that the heat sector has no legislative, binding targets relating to renewable energy in the European Union. Likewise, the US Department of Energy identifies numerous interventions to boost efficiency, but no interventions to displace the carbon-based fuels[265]. [512] reported the 'sobering' projections of the World Energy Outlook that assumes no 'significant' uptake of renewables for feedstock or direct use of other forms of renewable energy. Lauterbach *et al.* (2012)[510] estimated a technical potential for solar thermal of 3.4 % of the overall demand for process heat in Germany, and Taibi *et al.* (2012)[512] estimated 2 % of requirements could be met by solar thermal, 2 % by heat pumps, and 16 % by biomass in 2050, assuming industry can compete for scarce biomass stocks, and heat pumps achieve "… breakthroughs in the temperature levels supplied". [513] recommended considering solar-thermal applications in the lower end of the process heat temperature range (less than 250 °C), conclusions echoed by the US Environmental Protection Agency[514]. There are evident limitations to the scalability of renewable resources for lower temperature process heat, and no foreseeable, cost-effective options for providing higher temperatures[510-514].

Fortunately, a nuclear reactor provides continuous and reliable heat at industrial scale. While light-water reactors are large and offer relatively low outlet temperatures (approximately 350 °C), much development in the advanced nuclear sector is focussed on reactors that are smaller, with outlet temperatures ranging from 500-1,000 °C[203,505,515,516], suitable for a range of industrial applications. One important application of advanced nuclear reactors is the greenhouse gas-free creation of hydrogen[312,517-519]. Hydrogen is an ingredient of ammonia (a base component of fertilisers)[520], and is also the chemical reductant for iron production. With clean, reliable, low-cost heat, hydrogen can be produced from the ambient environment using high-temperature steam electrolysis[311,312,519,521,522]. This could substitute for methane in ammonia production and promote direct-injection iron production, resulting in higher-quality iron with much-reduced greenhouse-gas emissions compared to blast furnace production[523]. Hydrogen can be combined with carbon-dioxide to create synthetic crude oil[524] (C_nH_{2n+2}), methanol (CH_3OH), or dimethyl ether (C_2H_6O)[266]. These chemicals are energy-dense, stable, easily stored and transported and can be refined into the full range of hydrocarbon fuels. Such fuels could all but eliminate net greenhouse-gas emissions from transport and other processes that demand directly combustible fuel.

A holistic view of energy suggests that the role of nuclear fission in decarbonisation might have barely started, but the obstacles to nuclear technology in the power sector have proven durable. Despite additional evidence of the value and utility of nuclear technology such as that provided in my thesis, it is conceivable that the only path for nuclear to break out in future will be through sheer, inarguable market power, from a vastly economically superior new product. The industrial heat market could be the proving ground for advanced nuclear reactors. Cost-effective electricity might, in coming years, be no more than one of myriad applications. Further research is required to understand these possibilities, as well as barriers to future implementation. The climate, and our civilisation, may well depend upon it.

Conclusion

If we are to break the paradox of our carbon-fuelled civilisation, then the thirty years from 2020 will need to be different than the thirty years from 1990. It seems beyond question that nuclear technologies will need to grow to achieve this outcome. The question of whether they will, however, is open. We will likely require the 'better' nuclear offered by the advanced nuclear sector. But we will also require better decision-making based on a more informed appreciation of the nuclear technology that is operating and available today. The hour is late, and the time for equivocation has long passed.

Closing thoughts

Much in this world is growing increasingly scarce, including many beautiful, important things.

Things like healthy coral reefs, tigers, rainforests and, perhaps, courage.

Fortunately, our two most vital resources are inexhaustible: energy and human ingenuity.

With those, we can achieve great things, greater than perhaps we dare dream.

So, let's be daring with our dreams. Let us have courage. Our future is there, waiting to be made.

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Supplementary Material

Contents

Supplementary material for *CHAPTER 2 – Burden of Proof*: *A comprehensive review of the feasibility of 100 % renewable-electricity systems*

My review of 24 studies of 100 % renewable electricity systems finds that none individually, nor the literature in aggregate, provides compelling evidence for even the basic feasibility (as defined in the Chapter 2) of such proposed systems. As shown in Sup. Table 1, many of the assessed studies scored zero against our framework. This is all the more important given that my review gave no assessment whatsoever of important viability aspects such as financial cost, planning constraints, technology assumptions, governance and policy requirements and land use conflicts. The true costs of 100 % renewable electricity systems cannot be determined on the basis of systems that are not even technically feasible, yet at this time that is all the literature offers.

As shown in Sup. Table 1, few studies did system simulations on timeframes of < 1 hour. Only two studies specifically sought to address extreme but credible conditions of low availability of the renewable resources. Almost all studies assumed away the constraints of transmission requirements, with some (unrealistically) assuming copperplate networks, others applying simplistic cost multipliers to compensate, and none undertaking actual power-flow modelling. Only one author, Australian Energy Market Operator[1], seemed aware of the importance of maintaining ancillary services in the face of wide-scale modifications of existing, known and understood systems and practices. In Sup. Table 2, we exclude the transmission criteria, effectively granting all work the assumption of a copperplate network, and re-score all studies out of a total of six. This is to acknowledge that the use of transmission is well known and understood and may be argued to be more a matter of viability (chiefly cost, planning constraints and pace of roll-out).

Sup. Table 1 Scoring against feasibility criteria for 25 100 % renewable electricity scenarios. Criterion are defined in the Methods of Chapter 2. 'Coverage' refers to the spatial/geographic area of each scenario. 'Total' means the aggregated score for the scenario across all criteria with a maximum possible score of 7. *Scenario* refers to the scenario that we selected from the study under examination, where there were several named scenarios. *'Year(s)'* refers to the year(s) in which the scenario explores a 100 % renewable electricity. Where the *Scenario Year(s)* are historic, the authors have replicated previous years. DEM.Real = realistic demand; Rel.hr = Hourly simulation; Rel.hr/2 = half-hourly simulation; Rel.5min = five-minute simulation; Trans = transmission; Anc.ser = ancillary services

Study	Coverage	Scenario name	Year(s)	DEM.Real	Rel - hr	Rel – hr/2	Rel – 5min	Extreme event	Trans	Anc.ser	Total
Mason *et al.*[2,3]	New Zealand	GM3	2020	1	1	1	0	1	1	0	4
Australian Energy Market Operator (1)[1]	Australia (NEM*- only)	Scenario 1 2050	2050	1	1	0	0	0	1	0.5	3.5
Australian Energy Market Operator (2)[1]	Australia (NEM*–only)	Scenario 2 2050	2050	1	1	0	0	0	1	0.5	3.5
Jacobson *et al.*[4]	Contiguous USA	N/A	2050-2055	0	1	1	1	0	0	0	3
Wright & Hearps[5]	Australia (total)	Plan	2050	0	1	1	0	0	1	0	3
Fthenakis *et al.*[6]	USA	2050	2050	1	0	0	0	1	0	0	2
Connolly *et al.*[7]	Ireland	COMBO	2005-2007 & 2005-2010	1	1	0	0	0	0	0	2
Fernandes & Ferreira[8]	Portugal	Scenario 3	2007	1	1	0	0	0	0	0	2
Krajacic *et al.*[9]	Portugal	100 % RES	2050	1	1	0	0	0	0	0	2
Hart & Jacobson[10]	California ISO†	N/A	2010	1	1	0	0	0	0	0	2
Esteban *et al.*[11]	Japan	Low-cost	2010	1	1	0	0	0	0	0	2
Allen et al.[12]	Britain	ZCB	2050	0	2	0	0	0	0	0	2
Elliston, MacGill & Diesendorf[13]	Australia (NEM*-only)	Low cost, 5 % discount rate	2050	0	1	0	0	0	0	0.5	1.5
Budischak *et al.*[14]	PJM‡ Interconnection	Least-cost optimised 99.9 % renewable supply	1999-2002	0	1	0	0	0	0	0	1
Lund & Mathiesen[15]	Denmark	IDA 2050 Combination	2030	0	1	0	0	0	0	0	1
Cosic, Krajacic & Duic[16]	Macedonia	100 % RES 2050	2020	0	1	0	0	0	0	0	1
Elliston, Diesendorf & MacGill[17]	Australia (NEM-only)	NEM simulation	2050	0	1	0	0	0	0	0	1
Jacobsen *et al.*[18]	New York State	N/A	2006	1	0	0	0	0	0	0	1
Price Waterhouse Coopers[19]	Europe and North Africa	2050 low-carbon	2050	1	0	0	0	0	0	0	1
European Renewable Energy Council[20]	European Union 27	N/A	2100	1	0	0	0	0	0	0	1

* National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania, making up approximately 85% of total Australian electricity demand
† Independent Service Operator
‡ Pennsylvania New Jersey Maryland

Study	Coverage	Scenario name	Year(s)	DEM.Real	Rel - hr	Rel – hr/2	Rel – 5min	Extreme event	Trans	Anc.ser	Total
ClimateWorks[21]	Australia	N/A	2060	1	0	0	0	0	0	0	1
World Wildlife Fund[22]	Global	N/A	2100	0	0	0	0	0	0	0	0
Jacobsen & Delucchi[23,24]	Global	WWS	2050	0	0	0	0	0	0	0	0
Jacobson *et al.*[25]	California	WWS	2050	0	0	0	0	0	0	0	0
Greenpeace (Teske *et al.*)[26]	Global	100 % renewables grid	2050	0	0	0	0	0	0	0	0

Sup. Table 2 Criterion are defined in the Methods of Chapter 2. 'Coverage' refers to the spatial/geographic area of each scenario. 'Total' means the aggregated score for the scenario across all criteria with a maximum possible score of 7.

'Scenario' refers to the scenario that we selected from the study under examination, where there were several named scenarios. 'Year(s)' refers to the year(s) in which the scenario explores a 100 % renewable electricity. Where the Scenario Year(s) are historic, the authors have replicated previous years. DEM.Real = realistic demand; Rel.hr = Hourly simulation; Rel.hr/2 = half-hourly simulation; Rel.5min = five minute simulation; Trans = transmission; Anc.ser = ancillary services

Scoring for *Transmission requirements* has been excluded, indicated by *NA*.

Study	Coverage	Scenario name	Year(s)	DEM.Real	Rel - hr	Rel – hr/2	Rel – 5min	Extreme event	Trans	Anc.ser	Total
Mason *et al.*[2,3]	New Zealand	GM3	2020	1	1	1	0	1	NA	0	3
Australian Energy Market Operator (1)[1]	Australia (NEM§- only)	Scenario 1 2050	2050	1	1	0	0	0	NA	0.5	2.5
Australian Energy Market Operator (2)[1]	Australia (NEM*–only)	Scenario 2 2050	2050	1	1	0	0	0	NA	0.5	2.5
Jacobson *et al.*[4]	Contiguous USA	N/A	2050-2055	0	1	1	1	0	NA	0	3
Wright & Hearps[5]	Australia (total)	Plan	2050	0	1	1	0	0	NA	0	2
Fthenakis *et al.*[6]	USA	2050	2050	1	0	0	0	1	NA	0	2
Connolly *et al.*[7]	Ireland	COMBO	2005-2007 & 2005-2010	1	1	0	0	0	NA	0	2
Fernandes & Ferreira[8]	Portugal	Scenario 3	2007	1	1	0	0	0	NA	0	2
Krajacic *et al.*[9]	Portugal	100 % RES	2050	1	1	0	0	0	NA	0	2
Hart & Jacobson[10]	California ISO**	N/A	2010	1	1	0	0	0	NA	0	2
Esteban *et al.*[11]	Japan	Low-cost	2010	1	1	0	0	0	NA	0	2
Allen et al.[12]	Britain	ZCB	2050	0	2	0	0	0	NA	0	2
Elliston, MacGill & Diesendorf[13]	Australia (NEM*-only)	Low cost, 5 % discount rate	2050	0	1	0	0	0	NA	0.5	1.5

§ National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania, making up approximately 85 % of total Australian electricity demand
** Independent Service Operator

| Study	Coverage	Scenario name	Year(s)	DEM.Real	Rel - hr	Rel – hr/2	Rel – 5min	Extreme event	Trans	Anc.ser	Total
Budischak *et al.*[14]	PJM[††] Interconnection	Least-cost optimised 99.9 % renewable supply	1999-2002	0	1	0	0	0	NA	0	1
Lund & Mathiesen[15]	Denmark	IDA 2050 Combination	2030	0	1	0	0	0	NA	0	1
Cosic, Krajacic & Duic[16]	Macedonia	100 % RES 2050	2020	0	1	0	0	0	NA	0	1
Elliston, Diesendorf & MacGill[17]	Australia (NEM-only)	NEM simulation	2050	0	1	0	0	0	NA	0	1
Jacobsen *et al.*[18]	New York State	N/A	2006	1	0	0	0	0	NA	0	1
Price Waterhouse Coopers[19]	Europe and North Africa	2050 low-carbon	2050	1	0	0	0	0	NA	0	1
European Renewable Energy Council[20]	European Union 27	N/A	2100	1	0	0	0	0	NA	0	1
ClimateWorks[21]	Australia	N/A	2060	1	0	0	0	0	NA	0	1
World Wildlife Fund[22]	Global	N/A	2100	0	0	0	0	0	NA	0	0
Jacobsen & Delucchi[23,24]	Global	WWS	2050	0	0	0	0	0	NA	0	0
Jacobson *et al.*[25]	California	WWS	2050	0	0	0	0	0	NA	0	0
Greenpeace (Teske *et al.*)[26]	Global	100 % renewables grid	2050	0	0	0	0	0	NA	0	0

†† Pennsylvania New Jersey Maryland

One of our main findings has been that many studies examining 100 % renewable electricity and energy do not adhere to mainstream projections of demand for both energy and electricity. Put differently, many of the studies we examined created, as a starting point, a highly modified energy/electricity demand scenario that is either unlikely to materialise or, if it did, would likely have deleterious consequences for the advancement of human welfare in the developing world. As shown in Sup. Figure 1, even the strongest mitigation scenario under consideration by the IPCC projects growth in primary energy demand to the end of the century. This calls into question the usefulness and validity of any subsequent outputs including simulations of hypothetical supply solutions meeting these contrived demand scenarios. It is apparent that demand scenarios need to be regionally specific and, for the proposed solutions to be considered robust, a reasonable range of projected demand outcomes must to be considered.

Many of the studies we considered in our review pertain to Australia. Demand for electricity in Australia is projected to continue to grow mainly on the back of a strongly increasing population[27]. While recent years have defied this trend with an anomalous reduction in total electricity demand, increased demand remains the mainstream forecasting expectation (Sup. Figure 2). We see that the assumed demand for Elliston *et al.*[17], based on actual 2011 consumption values, is unlikely to be the demand across a timeframe where implementation of broad-scale energy transition can occur. So while this choice was defensible in that the simulation mimics both actual quantity of electricity demanded and the actual pattern of that demand, the quantity is likely to fall far short of needs over relevant timeframes. In the case of Wright & Hearps[5], we see that primary energy was assumed to reduce by 58 % in a little over 10 years, with a corresponding sharp increase in electrification, giving an electricity demand at the highest end of the range of mainstream projections; this outcome will certainly not occur (Sup. Figure 2). In contrast, the two scenarios applied by the Australian Energy Market Operator[1] are placed far enough into the future to be

relevant with regard to energy transitions, and encompass a range that is consistent with more

recent trends and projections. The outputs are thus worthy of closer consideration.

Sup Figure 1 Primary energy (exajoules [EJ] year-1) and emissions of carbon dioxide (gigatonnes

[Gt] year-1) under Intergovernmental Panel on Climate Change (IPCC) scenario RCP2.6.[28].

Sources: emissions values from RCP Database 2015[29]; energy values from van Vuuren *et al*.[28].
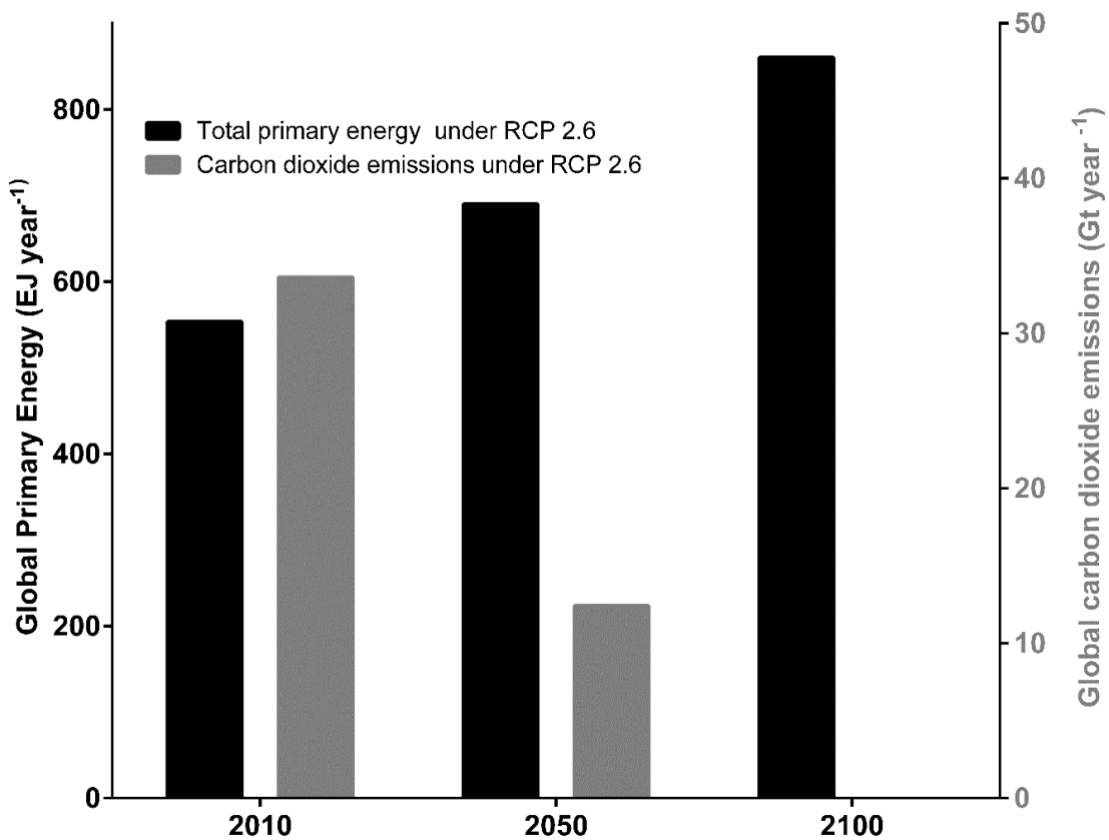
Sup Figure 2 Comparison of scenarios for Australian electricity consumption (terawatt-hours, TWh) from Bureau of Resources and Energy Economics (BREE), ACIL Allen, Australian Energy Market Operator/Independent Market Operator (AEMO/IMO), Australian Government Treasury Strong Growth, Low Pollution (SGLP), all sourced from[30], National Electricity Forecasting Report (NEFR)[31], Department of Industry and Science (DOIS)[32], Wright and Hearps[5] and Elliston *et al.*[17] (EDM), Australian Energy Market Operator 100 % Renewables[1] (AEMO). Figures from National Electricity Forecasting Report were converted from National Electricity Market figures to Australia-wide figures by multiplying annual data by 1.14
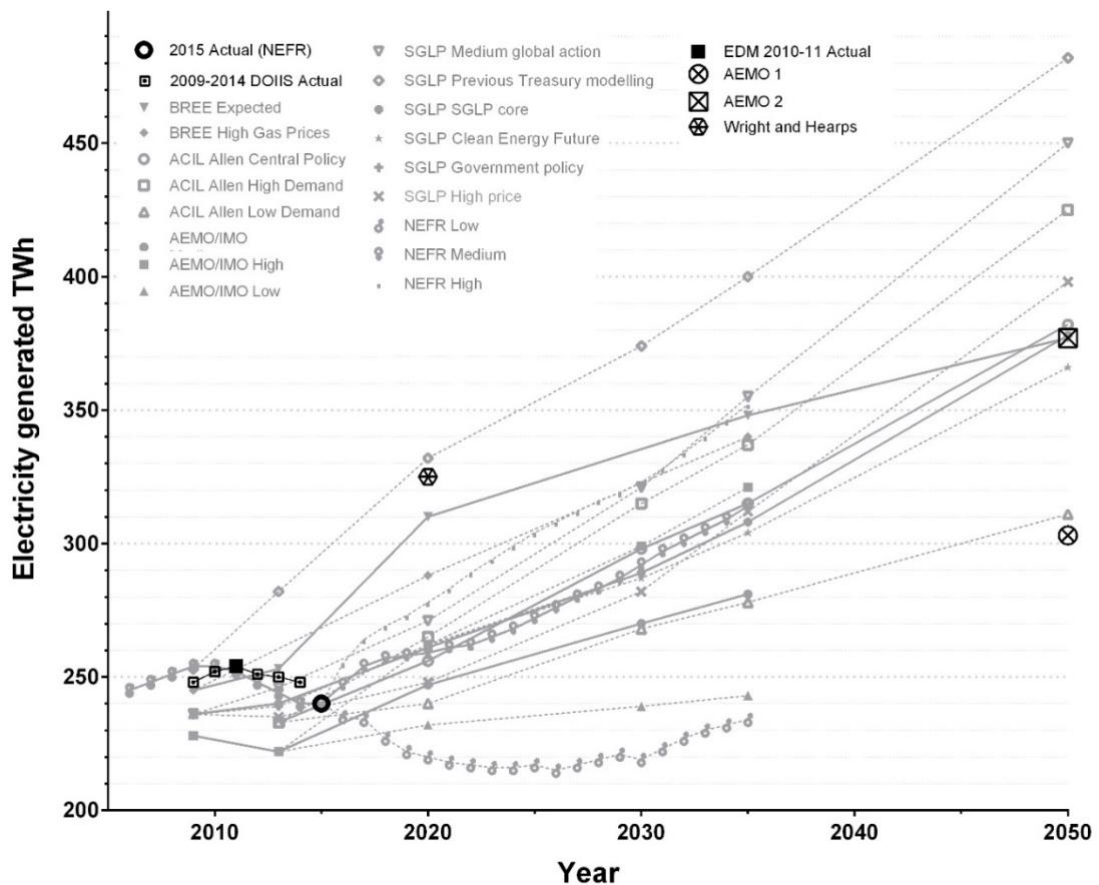

California presents a similar case, where projections from three sources point toward the likelihood that electricity consumption will continue to increase (Sup Figure 3). The scenario applied by Hart and Jacobson[10] falls at the lower end of this range. However, Jacobson *et al.*[25]

assumed the complete electrification of all energy use in California and applied a scenario where electricity consumption is 1,375 TWh year^{-1}, 567 % of the baseline year (2010) and 261 % of the 2050 electricity demand under the *Efficiency, Clean Electricity Electrification* scenario of Wei *et al.*[33]. This result is a stark outlier and suggests the assumptions of energy transition under Jacobson *et al.*[25] are unrealistic. All subsequent findings from that work must be discarded.

Other locations around the world, including Japan and much of Northern Europe, have base scenarios of steady or even falling energy demand. In the case of Denmark, base projections of primary energy to 2050 are just +14 % on 2004 values[15]. The scenario applied by Lund *et al.*[15] to test the potential of 100 % renewable electricity applies a scenario of -59 % primary energy compared to base expectations for 2050[15]. This suggests a large change in the nature of energy consumption across the entire Danish economy, far beyond current expectations. Again, all subsequent outputs can be largely disregarded as unrealistic.

Sup Figure 3 Comparison of projected Californian electricity demand (terawatt-hours, TWh) between scenarios from E3[34], Kavalec and Sullivan[35] (CEC) , Wei *et al.*[33] (Wei), Jacobson *et al.*[25] and Hart and Jacobson[10],
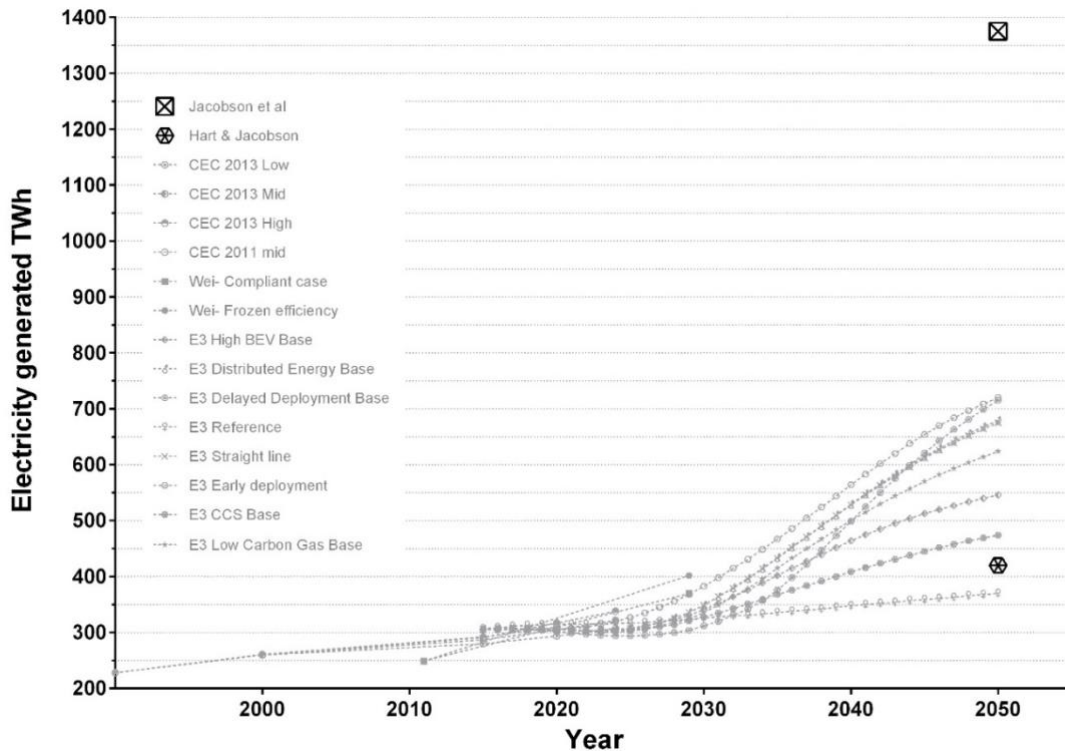
What might be the requirements for storage under a 100 % renewable electricity system? The literature addressing storage requirements under high-penetration renewable-electricity scenarios provides some insight into the scale of the potential requirements. One study purporting to identify the storage needs for a 100 %-renewable system for Europe did so without estimating actual capacity requirements or costs; it also assumed unconstrained transmission[36]. Another Europe-focussed study cautioned that the "technical feasibility" of the required storage is questionable, highlighting the land constraints for pumped-hydro storage and the nascent stage of development of batteries at the terawatt hour (TWh) scale, along with large-scale production of hydrogen or methane. A study of the Electric Reliability Council of Texas (ERCOT) network (which provides 90 % of the load of Texas for about 24 million customers)[37] suggests that a scenario of just 80 % variable renewable generation requires a full day of storage capacity to ensure reliable

supply. At 34 GW of delivered power, that requirement for Texas is 160 % of the current installed electricity storage in the entire United States[38]. Additional storage capacity had diminishing return in terms of the percentage of supply that can be provided by variable renewable energy[38]. An attempt to identify global energy storage needs under 100 % renewable energy suggests over 11,000 TWh of electricity would need to be provided by storage, which is 35 % of global electricity demand (based on 2010 demand)[39]. That figure alone is ten times the theoretical maximum generation from all grid-connected storage in the world today, of which > 99 % is pumped hydro [40], and the study did not identify the actual installed capacity requirements. The storage requirements for Japan under a 100 % renewable-energy system is estimated to be 41 TWh[11]. For context, an electric car fleet of 35 million vehicles would provide < 5 % of that capacity, and would be clearly ill-suited to cover the long-term supply fluctuations needed to ensure reliability[11]. In Sup Table 3, I summarise the storage assumptions that are incorporated into all the study assessed under our framework.

Sup. Table 3 Summary of assumed energy storage for 25 100 % renewables studies.

Study	Coverage	Storage reliant (Y/N)	Details
Mason *et al.* [2,3]	New Zealand	Y	Relies on stored hydro energy and use of pumped lake storage to historic values with unconstrained ramping or flow
Australian Energy Market Operator (1)[1]	Australia (NEM–only)	Y	CST with molten salt, biogas stored in the existing gas systems, biomass and additional pumped hydro
Australian Energy Market Operator (2)[1]	Australia (NEM–only)	Y	CST with molten salt, biogas stored in the existing gas systems, biomass and additional pumped hydr006F
Jacobson et al.[4]	Contiguous USA	Y	Assumes use of solar thermal with molten salt storage (16 hr for baseload plants, 6 hr for peak plants) at approximately 1500 GW installed by 2050 (up from 9 GW currently). Assumes use of compressed air energy storage in geological formations with working capacity of plants in 2050 a factor of 10 greater than the current working underground gas storage capacity in the US.
Wright & Hearps[5]	Australia (total)	Y	Assumes 60 % of annual electricity provided by 42.5 GW installed of concentrating solar thermal plant with 17 hours of energy storage
Fthenakis *et al.* [6]	USA	Y	Assumes use of solar thermal with molten salt storage (16 hr for baseload plants, 6 hr for peak plants) at approximately 1500 GW installed by 2050 (up from 9 GW currently). Assumes use of compressed air energy storage in geological formations with working capacity of plants in 2050 a factor of 10 greater than the current working underground gas storage capacity in the US.
Allen *et al.*[12]	Britain	Y	180 TWh of surplus electricity is used to produce hydrogen (126 TWh), which could be stored in salt caverns. It is used to produce syn gas (27 TWh per year) that is then used to provide back-up electricity (14 TWh) via 45 GW of gas power stations
Connolly *et al.*[7]	Ireland	N	
Fernandes & Ferreira[8]	Portugal	Y	Hydro dam storage increases from 2117 to 6971 MW
Krajacic *et al.*[9]	Portugal	Y	6848 GWh storage assumed across hydro reservoirs, hydrogen storage and batteries
Esteban *et al.*[11]	Japan	Y	
Budischak *et al.*[14]	PJM Interconnection	Y	Unspecified; however, indicates strong dependence on concentrating solar power with 3-hr storage, and assumes additional load balancing will be available from the following: CSP with storage longer than 3 h, additional pumped hydroelectric storage, distributed or large-scale battery storage, compressed-air storage, flywheels, seasonal heat storage in soil, out-of-state WWS resources, the addition of flexible loads such as electric vehicles , vehicle-to-grid methods
Elliston, MacGill & Diesendorf[41]	Australia (NEM–only)	Y	Assumes 15.6 GW installed of solar thermal generation with 15 hours of storage.
Lund & Mathiesen[15]	Denmark	N	No indication of direct storage reliance in meeting electricity demand. Excess electricity is assumed converted to hydrogen for substitution of fossil fuels in other areas of energy demand
Cosic, Krajacic & Duic[16]	Macedonia	Y	Increase pumped hydro storage from 350 to 1500-1800 MW
Elliston, Diesendorf & MacGill[17]	Australia (NEM–only)	Y	Assumes approximately 13 % of electricity generated by concentrating solar thermal with storage
Jacobsen *et al.*[42]	New York State	Y	Details are not disclosed. The study states that it requires: storing energy in thermal storage media, batteries or other storage media at the site of generation or use; and storing energy in electric-vehicle batteries for later extraction. Further, indicates the application of using concentrated solar power storage to provide solar power at night; and storing excess energy at the site of generation with pumped hydroelectric power, compressed air (e.g., in underground caverns or turbine nacelles), flywheels, battery storage packs, or batteries in electric vehicles.
Price Waterhouse Coopers[19]	Europe and North Africa	Y	No quantification of storage requirements. Repeated reference to the role of concentrating solar thermal with storage, pumped hydro storage and other, undefined "storage".
European Renewable Energy Council[20]	European Union 27	Y	Indicates approximately 25+ times expansion in solar thermal with storage, references decentralised storage devices with solar PV

ClimateWorks[21]	Australia	Y	Solar thermal with 6 hr storage is deployed for ~ 20 % of generated electricity; however, no detail is provided regarding installed capacity. The underlying ESM model also allows battery storage in the grid
World Wildlife Fund[22]	Global	Y	Depends on expansion of pumped hydro, centralised hydrogen generation and storage, and heat storage
Jacobsen & Delucchi[23,24]	Global	Y	Assumes storage with batteries, hydrogen gas, pumped hydro-electric power, compressed air, flywheels, thermal storage medium, electric vehicles with smart charging.
Jacobson *et al.*[25]	California	Y	Assumes utility concentrating solar power with storage
Greenpeace (Teske *et al.*)[26]	Global	Y	22 % of electricity generated from solar thermal with storage systems. Hydrogen storage in use. General remark on dependence on "expansion of smart grids, demand side management and storage capacity".

Case study for policy makers: high-penetration renewables in South Africa

In August 2016, the Council for Scientific and Industrial Research (CSIR) Energy Centre of South Africa released a report outlining high-penetration renewable scenarios for South Africa[43]. The report proposed a system to provide 86 % of the total electricity demand from renewable sources. This percentage (being < 95 %) rendered the report outside the screening criteria outlined in the Chapter 2. However, many of the issues remain relevant and an appraisal of this report demonstrates the utility of our proposed framework for policy-makers.

Publicity accompanying the release included the following statements regarding feasibility:

> 'Instead of renewable energy playing only a modest and supportive role in the future supply mix, research conducted by the Council for Scientific and Industrial Research (CSIR) Energy Centre shows that, having the bulk of the country's generation arising from wind and solar is not only technically feasible, but also the lowest-cost option … The outcome shows that it is technically feasible for such a 30 GW mix to supply the 8 GW baseload in as reliable a manner as conventional baseload generators, while the economic analysis suggests that such a mix will deliver electricity at a blended cost of 100c/kWh[44]'.

South Africa is a developing nation of over 50 million people with a high reliance on coal for existing electricity generation[43]. The decisions made by policy makers in nations like South Africa will have a material impact on the trajectory of global greenhouse gas emissions in this century. The framework we proposed in the Chapter 2 provides a quick and reliable means of testing the assertion of feasibility, thus equipping policy-makers to scrutinise such claims. In Sup. Table 4 we have scored this report against our framework. We discuss each score with reference to the study.

Criterion I: Demand

The CSIR study assumes for its high-penetration scenario an annual demand of 261 TWh year[-1].

This figure is 15 % greater than the current volume of electricity distributed in South Africa (227

TWh)[45]. That figure is similar to annual electricity demand in Australia today, a nation with less

than half the population of South Africa (24 million people). The population of South Africa

(currently approximately 54 million people) is expected to reach 67.3 million people by 2035[46]. The

Integrated Resource Plan from the South African Department of Energy suggests annual

electricity demand in South Africa in 2030 will be 436 TWh, 70 % higher than current demand[43].

Load-shedding is currently a regular occurrence in South Africa due to lack of supply[47]. Currently,

consumption is constrained by availability of affordable supply and thus the true electricity demand

is not known[47]. The Institute of Security Studies advises in the context of South Africa that energy

planners need to err on the side of optimism in growth forecasts[47]. The CSIR study has taken the

opposite approach.

A policy maker could have little doubt that the electricity demand proposed by the high-penetration

renewable scenario from CSIR is not realistic and not in keeping with the imperative of alleviating

wide-spread poverty in South Africa. Based on these findings, the CSIR study scores zero for this

criterion. This unrealistic assumption has an obvious and material impact on the cost inferred by

CSIR for a reliable system. We discuss this below under Criterion 2.

Criterion II: Reliability

The CSIR simulated over three years of demand, using meteorological data from across South

Africa to assess renewable-resource availability to 15-minute intervals. This is finer resolution than

many of the studies we examined in the Chapter 2. With the additional dispatchable back-up, this

study asserts that the proposed supply reliably meets the demand. The report explicitly identifies

the lowest supply period of wind and solar in that three-year simulation[43]. However, there is no evidence that the simulation identified a credible extreme event over, for example, a 100-year timeframe. Hence, we have the study a score of 2.5 for simulating to 15-minute intervals.

Note however that the assumed demand scenario interacts with the supply reliability in a material way. Page 43 of the report identifies the highest residual load, at the time of lowest wind and solar supply, of 34 GW[43]. However, this is for a scenario where electricity demand is nearly unchanged from today. In a more realistic scenario where electricity demand has increased 70 % from today, the supply gap would be far greater. For while more wind and solar could be added to serve the larger demand in average conditions, the correlated supply indicated in Bischof-Niemz and Mushwana [43] means this additional capacity would be of little additional benefit during the periods of extremely low supply. The maximum instantaneous supply gap could well be double the suggested 34 GW. This would add cost in the form of a greater low-utilisation back up. As identified in the report (page 8), changes to the assumed full-load hours for conventional generators changes the fixed-cost components per kWh[43]. This additional, low-utilisation, conventional back-up could materially impact the average price of electricity across the modelled period.

Criterion III: Transmission

The CSIR study has made the assumption of a copperplate network. There was no power-flow modelling. The report indicates that the geographic distribution of supply assumed from wind and solar covers all of South Africa. Similarly, the study maps all of South Africa for solar potential, and refers only to "exclusion zones". Based on work done for Europe, it might be that reaping most of the benefits of this distribution would require a transmission network perhaps five to six times greater than that required under a centralised supply model[48]. The required network for this system to function has not been identified and hence the costs proposed for the system are incomplete. The study scores zero under this criterion.

Criterion IV: Ancillary services

The study offers no solutions in relation to ancillary services. The report declares additional analyses are required to determine stable operations of power-electronics based power systems[43]. This acknowledges that the proposed system will, at times, need to operate with a virtual absence of synchronous generation. As discussed in Chapter 2, the novel solutions to this challenge are nascent, with some investigation under way, no demonstration or comprehensive modelling at relevant scale and few demonstrations globally[49]. Proposed solutions such as the widespread use of large-capacity batteries to provide frequency control will add cost to the proposed system. An actual portfolio of solutions has not been described. Hence, the costs proposed for the system are incomplete and the claim of feasibility is dubious. The study scores zero for this criterion.

Sup. Table 4 Scoring against feasibility criteria for a single, high-penetration renewable energy scenario. 'Coverage' refers to the spatial/geographic area of each scenario. 'Total' means the aggregated score for the scenario across all criteria with a maximum possible score of 7. Criteria are defined in Chapter 2. For concision, the 'Reliability' column aggregates all four potential scores for reliability into a single score.

Study	Coverage	I (Demand)	II (Reliability)	III (Transmission)	IV (Ancillary)	Total
CSIR [43]	South Africa	0	2.5	0	0	2.5

Summary

The CSIR study has improved our understanding of what might be provided by wind and solar photovoltaics in South Africa in the future. There can be no argument that the falling levelised cost of electricity from these sources boosts the prospects for their economic deployment. Overall we

conclude both the use of the terms "technically feasible" and the attempted costing of the proposed system are inappropriate and premature, being undermined by (*i*) an unrealistic electricity-demand scenario, (*ii*) no simulation to finer time scales, (*iii*) no consideration of extreme events beyond three years of data, (*iv*) no identified transmission requirements, and (*iv*) no solutions to provide vital ancillary services. Our framework thus provides policy-makers with a simply and readily applied screening of the feasibility of proposed electricity solutions, including other recently published studies[50,51]

Supplementary Material for *CHAPTER 3: Cost optimised, low-carbon electricity-supply combinations for Australia*

Exclusion of certain renewable technologies

Based on the price identified for electricity generated from light-water nuclear reactors in this process, we found no grounds for modelling the following renewable technologies: solar thermal with storage, geothermal, wave, ocean or biomass. As in recent Australian Government publications[1,52,53], these technologies provide either more expensive electricity that is not 100 % guaranteed (and thus would not be selected by our model)(i.e., solar thermal, wave, ocean, hot-dry rock geothermal); similar-price electricity with limited scalability close to Australian demand centres (i.e., hot-aquifer geothermal), or slightly less-expensive electricity with well-documented environmental impacts and concerns in other sustainability domains, or limited availability at the lower prices (i.e., biomass resulting in expanded conversion of land to cropping for biofuel production, particulate and other air pollution uncertainty regarding reductions in life-cycle greenhouse emissions).

Further discussion on curtailment in electricity systems

Our model explores the cost implications of freely permitting curtailment of excess generation from variable suppliers (wind and solar photo-voltaics), rather than enforcing reduced output from firm suppliers (nuclear). Curtailment refers to generating electricity that cannot be used or stored, and thus is not dispatched to the market[54]. Alternately, generation can be curtailed from reliable sources of supply either in response to changes in load or, more recently, to prioritise dispatch of electricity from variable renewable generation. Curtailment can occur for many generators for many reasons, and it is now an observed phenomenon in many markets in response to higher penetrations of variable renewable-energy generation[38,55-58]. In the absence of remedies such as

storage of excess electricity, curtailment is expected to increase as penetrations of variable renewable sources rise in other markets[54,56,59,60]. In north-eastern China, an installed wind sector that is 30 GW greater than that of the USA delivers almost 20 % less electricity, primarily due to curtailment of wind electricity[61]. Two principal drivers of this curtailment have been identified: transmission constraints and coal-fired combined heat and power generation. Zhang *et al.* [62] state that, compared to wind-farm development, transmission development and expansion is long, complex, fraught with uncertainty and hence of lesser investment appeal. This is compounded by the large distance between the bulk of energy demand in China and the location of the renewable-energy sources (and developments)[62]. In winter, coal-fired plants also operate at nearly full capacity to deliver heat and, by design, generate electricity. As the heat requirement must be met regardless, wind farms are idled in response to electricity oversupply[61].

The economically optimal path for integrating higher penetrations of variable renewable electricity generation remains unclear and is likely to vary between jurisdictions[58]. Waite and Modi [63] explored the impacts of managing wind curtailment in New York State, finding that under scenarios of 20 GW installed wind, the entire baseload fleet would need to be curtailed 2.6 % of the year on average, and this rises to 13.1 % under 30 GW of installed wind. Johnson *et al.* [54] found that curtailment of variable renewable energy increases to 15–30 % when its share increases to 100 %. Higher variable renewable generation comes with material costs from the curtailment of electricity; however, curtailment (as opposed to storage) in some settings might be the most cost-effective approach. Bove *et al.* [58] found that wind power curtailment is likely the most cost-effective option at penetrations up to approximately 20 to 50 % of total electricity demand (above this, electricity storage is favoured); however, this assumed unconstrained electricity transmission. Similarly, Budischak *et al.*[14] found that the lowest costs for high penetrations of renewables are achieved with diverse renewable generation, high curtailment and low storage. This is the approach we explore in Chapter 3.

Further discussion on dispatch order

Our model dispatched available supply in the order of (*i*) nuclear fission, (*ii*) wind, (*iii*) solar photo-voltaic, and (*iv*) gas. This dispatch order places the focus on overall system value, rather than the lowest marginal cost of individual generators. Variable electricity generators, such as wind and solar photo-voltaics, can have low marginal cost of production and hence appear to provide cheaper electricity. This is in part caused by capacity factors in published values of levelised cost of electricity that refer only to the physical limitations of the plant operation, without taking account of the market and operating regime it faces[64]. After examining higher variable renewable electricity penetration in California, Shaker *et al.* [57] found that such higher penetrations do not necessarily realise the full environmental benefits of these sources, as well as creating inefficient operation regarding emissions and economics. The tendency of variable renewable energy generation to be temporally correlated, even over large geographic areas, raises system costs at higher penetrations due to the need to maintain close-to-equivalent reliable capacity in the market[65,66] and by lowering the actual average capacity factor of the sector with every additional increment of installation.

By prioritising curtailment of wind and solar photo-voltaics over curtailment of nuclear, our model explicitly values all the different capacity values (or capacity credits) of these technologies. Johnson *et al.*[54] defined capacity value as a technology's contribution to the firm capacity requirement, being the available capacity during peak load times. Whereas nuclear technologies can be assumed to contribute close to their full nameplate capacity to firm capacity, the capacity values of wind and solar photo-voltaics tend to decline with increasing market share[67-69].

Variable renewable generators have typically been granted priority market dispatch, and maintaining this priority dispatch is openly declared as vital to the development of the renewable-energy industry[70]. The European Wind Energy Association is blunt in its industry-driven motives, stating:

> 'The purpose of Priority Dispatch is to further the objective of the integration of renewable energy into the electricity system to promote sustainability and security of supply for Europe'[71].

An environmental case can be made where dispatch of renewable electricity displaces high greenhouse-gas emissions (such as from coal or gas). However, the firm supplier with high capacity value (nuclear fission) in our model has lifetime carbon emissions similar to wind and below solar photo-voltaics[72]. Therefore, no climate-mitigation imperative exists to prioritise dispatch of variable renewables in a way that displaces supply from the more reliable supplier. The firm supplier also provides essential frequency control via synchronous generation, so there is a reliability imperative to maintain dispatch of the nuclear generation. Finally, reliance on the most reliable, least geographically dispersed generator (nuclear) constrains the need to develop new, inefficiently used transmission networks to bring power from distant renewable-energy catchments to load centres. Nonetheless each of our models explicitly consider scenarios of zero nuclear generation.

Summary of use of real discount rates in the energy literature

We calculated the levelised cost of electricity from each source based on the actual capacity factor calculated in the model. The other inputs for calculation of the levelised cost of electricity are shown in Table 2. An important consideration is determining the appropriate discount rate to apply to the cost-benefit analysis determination of levelised cost of electricity. This is a critical

parameter of analysis whenever costs and benefits differ in their distribution over time, and especially where they occur over long time periods[73]. In the case of policy-based investments that might be tied to responding to a long term issue like climate change, there are arguments for lowering discount rates to infer greater value on benefits received in future, and arguments for raising the rate based on discouraging delay in action[73]. As Harrison [73] explains, when the discount rate is higher, future costs and benefits count for less, favouring projects with benefits that accrue early. An illustrative example was the Stern report regarding climate change action in the UK, which assumed a real discount rate of 1.4 %[74]. The conclusions of this report were promptly and firmly challenged as being dependent on this outlying (low) discount rate and not representative of, or resiliant to substitution with, assumptiosn that were consistent with interest rates, the market and savings rates at that time[75]. Nonetheless, lower discount rates are common in environmental applications where returns accrue in the distant future. For example the United States Environmental Protection Agency recommends a discount rate of 2-3 %, and no discounting for intergenerational projects[76]. Steinbach and Staniaszek[77] recommend discount rates for energy system analysis of 1-7 %, representing risk-free discount rates, declining over long time horizons, for which long-term governments bonds are an appropriate proxy. For commercial and industrial investors, these authors recommend a range of 6-15 %. The energy plan for Saudi Arabia assumes a base case real discount rate of 5 %, and tests against 3 % and 10 %[78], while an assessment of renewable energy scenarios for Saudi Arabia by the Tyndall Centre applies a discount rate of 8 %, though this also relates only to renewable energy projects with assumed lifetime of 25 years[79]. The OECD/IEA tests against three discount rates (3, 7 and 10 %) in the 2015 edition of *Projected Costs of Electricity* where previous editions have examined only 5 and 10 %. Historically low global interest rates are one reason cited for lowering the discount rates[80].

In a 2017 report commissioned by the Australian Government, Jacobs Group presents findings on the basis of a 7 % discount rate. It further and suggests a differentiated weighted average cost of capital for investment in different types of generation, based on perceived market risk, ranging between 6.6 % for renewables and open cycle gas turbines and 9.9 % for coal projects. Nuclear projects were excluded from consideration (without comment or justification)[53]. A recent modelling study of the Australian National Electricity Market that focussed on wind, solar photovoltaic, and pumped hydroelectric storage applied a real discount rate of 5 % in determining levelised cost of electricity.

My examination of the use of discount rates in energy literature suggests some important guidelines: *(i)* there is no single 'correct' discount rate readily identifiable across literature; therefore *(ii)* it is essential to test across a range of discount rates; *(iii)* consideration of environmental issues and intergenerational equity, exemplified by the challenge of responding to climate change, support the application of lower discount rates, perhaps as low as 3 % real and certainly 5 % real; *(iv)* higher discount rates are more indicative of commercial rates of return and shorter investment time horizons. We applied a real discount rate (i.e. not including inflation, as opposed to nominal discount rate) discount rate of 7 % as our base case, and sensitivity tested at 10 % for the nuclear provider alone (Model 4d). In our models, all supply options benefit from lower discount rates in terms of lowering the levelised cost of electricity, however the nuclear investments, with greater capital expenditure, longer construction time and longer amortisation period, benefit relatively more than do the other supply options.

Comparison of a nuclear sector with the current Australian electricity supply

Currently, 50 % of greenhouse-gas emissions from Australia's electricity supply comes from 15,000 MWe of installed capacity, operating at an average capacity factor of 64 % and providing

37 % of the total electricity sold. All of these 34 individual generators are registered providers of ancillary services, including frequency control at all temporal increments requested by the market operator. An 11,000 MWe nuclear sector operating at 91 % capacity factor would replace this 84 TWh of annual supply, cutting greenhouse-gas emissions from electricity generation by 50 % (from 2016) while maintaining ancillary services. This would leave 154 TWh of electricity to be sold in the market by other clean-generation sources based on 2050 demand; potentially a larger nuclear sector, and potentially by a greatly expanded contribution from onshore wind and solar. However, based the outcomes of our five models, there is a strong case for planning a nuclear power sector of 15,000 – 20,000MWe for Australia, representing a no-regrets policy for achieving a clean-electricity supply that is also reliable and as affordable as possible.

Sup Figure 4 – Electricity generation by single generating location and cumulative generation, and cumulative greenhouse gas emissions from electricity generation in Australia (2013). Source: data from [81]
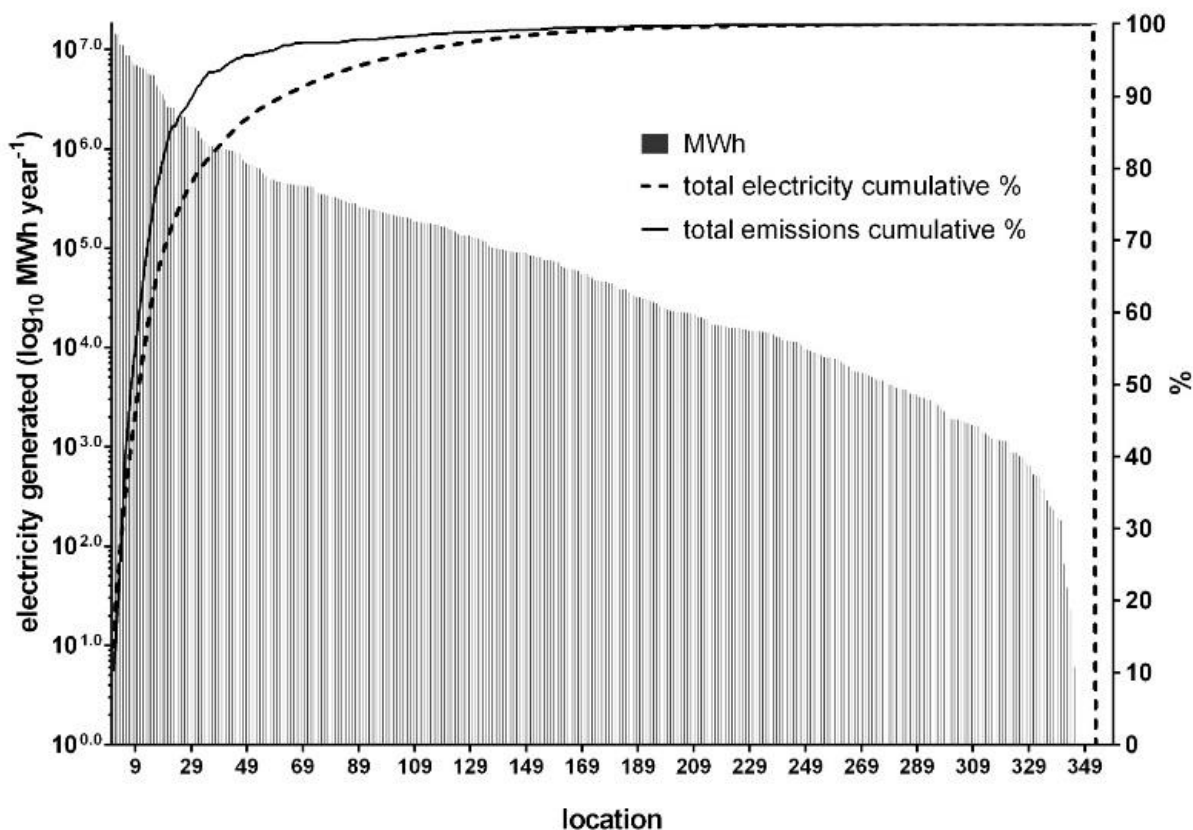
Further discussion of global evidence for capital costs of nuclear

But can nuclear be provided to Australia at a cost of $5,600 MWe^{-1} or below? Answering this question is a challenge, in part because the arbitrary legislative prohibition maintained by the Australian Government serves to prevent fulsome investigations with serious commercial providers. Globally, nuclear build is in a state of turmoil, with both successes and failures offering conflicting evidence of what could be available to Australia. On the one hand, new nuclear builds in the United States and Western Europe have encountered great challenges. Westinghouse faces bankruptcy in the United States in relation to the construction of AP1000 plants Vogtle 3 and 4, with any pathway to completion of the plants uncertain[82]. Construction of European Pressurised Reactors in Finland and France are likely to be completed within the next two years; however,

only after delays and cost overruns place them beyond the $5.3 million MW^{-1} used as nth-of-a-kind cost in our models[83]. At the same time, China has commissioned nearly 20,000 MWe of nuclear power since 2010, with much of this construction at capital costs in the range our modelling suggests would see uptake in planning a decarbonised Australian grid[84]. New builds are also set to proceed in Egypt[85] under an exclusive agreement with Russia. The published cost is US$6,250 MWe^{-1}; however, 85 % of the cost will be loaned to Egypt at just 3 % interest rate[86], comparable to a real discount rate of as little as 2.5 %. The new build program of the United Arab Emirates is tracking to deliver 5,600 MWe of generating capacity, on time and on budget[87,88], at a price of approximately US$3,600 MWe^{-1} (~ AU$4,600 MWe^{-1}). Were Australia to copy the model of the United Arab Emirates with a genuine process of international competition, prices of ~ AU$5,600 MWe^{-1} could be available immediately. Such an open, competitive tender process was deployed for the delivery of Australia's OPAL research reactor[89], which is now a leading global provider of nuclear medicine[90], doped silicon[91], and other nuclear research services. The Australian energy sector could benefit from the same competitive scrutiny applied to a nuclear energy project. It is important to note that even as the cost gap for the marginal cost of electricity production widened between nuclear and wind/solar (Model 4 (b-c)), the cost optimal supply mix still included a nuclear sector of 15,000-20,000 MWe. The case for a nuclear sector in this range is robust across a range of variables.

Supplementary material for *CHAPTER 5 – Closing the cycle*

Detailed business case

This section presents the assumptions underpinning the indicative business case for the development of an intermediate spent fuel storage installation (ISFSI), plus a fuel recycling and fabrication facility, plus PRISM reactors, plus eventual waste disposal. We used a net-present value assessment, with a project life of 30 years consistent with South Australian government treasury guidelines. All costs referenced below have been inflated to 2015 dollars, and all $US values have been converted to $AU based on the exchange rate at July 2015 (AU$1.37 per US$1), and are thus to be read as 2015 $AU.

Scenario development

To cover a range of potential outcomes, the business case presented nine possible scenarios based on a range of assumptions for key variables. Three illustrative scenarios are chosen from these nine scenarios: low, mid and high. Key assumptions and inputs for our scenarios are discussed below.

Size of the storage facility

An ISFSI of 60,000 tHM storage capacity was selected for the mid scenario. This selection is based on the fuel inventory modelling discussed below. A 40,000 tHM capacity is a conservative low estimate for developing the range of illustrative scenarios and an input to the low scenario. A 100,000 tHM ISFSI was selected as a plausible upper estimate to bound the illustrative scenarios. This size is selected for the high scenario.

Revenue assumptions

Price to charge

The mid scenario applies a price to charge of $1,370,000 (US$1,000,000) tHM^{-1}. This figure is commonly quoted for the disposal of spent nuclear fuel [92]. This is below the US$1,500,000 tHM^{-1} currently offered for reprocessing services from Taiwan, and below quoted ranges of US$1,200,000- US$2,000,000 tHM^{-1} [93]. Conversely, consultation suggested a price of US$400,000 tHM^{-1} was approximately accurate based on current rates of saving in the US nuclear power industry. A low-price of $685,000 tHM^{-1} (US$500,000) and a high price of $2,055,000 tHM^{-1} ($US1,500,000) is applied as upper and lower bounds in the development of the illustrative scenarios, and applied in the high and low scenarios respectively.

Electricity price

The mid scenario applies a wholesale electricity price of $50 MWh^{-1}, which is below the average wholesale price of $74 MWh^{-1} for 2012/13 in South Australia [94]. NEM-wide, a wholesale electricity price of $50 MWh^{-1} is representative of recent pricing [94]. The low scenario and high scenario apply wholesale electricity prices of $20 and $80 MWh^{-1} respectively. All scenarios assume operation of the 622 MWe PRISM reactor units at a capacity factor of 90 %. This provides just under 5 million MWh year^{-1} and assumes unconstrained export when necessary from South Australia via the existing National Electricity Market interconnectors to Victoria and New South Wales.

Residual asset values

The PRISM reactors have an assumed rated life of 60 years. The analysis assumes linear depreciation of asset value and quantified residual asset value as a benefit to the project arising in project year 30. The fuel recycling facility has an assumed rated life of 40 years. The analysis assumes linear depreciation of asset value and quantified residual asset value as a benefit to the project arising in project year 30.

Cost assumptions

Capital costs

Capital costs for the ISFSI are based on inclusive, detailed figures cited in a 2009 report [95] and set at $912 million for a 40,000 tHM facility. The source report also provided disaggregated scaling of capital costs for a 60,000 tHM facility, being $1,026 million. Applying these same cost-scaling assumptions we cost a 100,000 tHM facility at $1,256 million.

Capital cost for the development of a 100 t year^{-1} fuel recycling and fabrication plant is set at $617 million, a high-end figure from a specific design report which incorporates a 20 % contingency loading [96]. Our modelling has assumed global first-of-a-kind (FOAK) capital costs for the PRISM reactors of $8,302 million for two reactor units of 311 MWe each (622 MWe total) with shared balance of plant [97]. This is a cost watt-installed^{-1} of approximately $13,000.

Operational costs

Operational costs for the loading period of the ISFSI are based on inclusive, detailed figures and are set at $620 million year^{-1} and $698 million year^{-1} for the 40,000 and 60,000 tHM facilities respectively [95]. This includes provision of dual-purpose canisters for transport and storage of all material. Cost-scaling assumptions have been applied to cost the operations and loading of a 100,000 tHM facility at $853 million year^{-1} [95]. A total loading period of 20 years has been assumed irrespective of facility size to determine total operational costs for the loading period.

Annual operational costs for the post-loading, caretaker period for a 40,000 tHM and 60,000 tHM ISFSI are set at $6.1 million and $6.8 million year^{-1} respectively [95]. Cost-scaling assumptions have been applied to scale-up these costs for the 100,000 tHM facility to $8.4 million year $^{-1}$.

Operational costs for the 100 t year^{-1} fuel recycling and fabrication plant are set at $70 million year^{-1} [96]. Annual operational costs for the PRISM twin pack are $208 million year^{-1} [97].

A disposal cost of $138 kg^{-1} is assumed for conditioned fission products. This is lower than published estimates of $216 kg^{-1} [98], accounting for the shorter half-life of the material, permitting shallower drilling in a wider range of conditions to achieve the required confidence of isolation of the material for the required time, which is 2-3 orders of magnitude less than the material considered in Brady *et al.* [98]. Fission products are produced at a rate of approximately 1 kg MWyear^{-1} (based on figures from Carmack *et al.* [99]) resulting in annual cost of approximately $86,000 year^{-1}. This is a strictly pro-rated figure based on the mass of fission products produced every year. In operation, it may well be that these small quantities of fission products are safely stored for several years and disposed of together in a single project of drilling, emplacement and capping. Such operational decisions cannot be foreseen at this time.

Project timelines

This analysis assumes the commencement of a committed project in project-year 0 and assumes firm bipartisan political support at both state and federal government level. For the ISFSI 3-year planning is assumed followed by 3-year construction, with revenues commencing in project year 6 (consistent with indicative timeframe in [95]). A linear, staggered increase in loading is assumed over the first four years, steady loading rates for twelve years followed by linear decrease in loading rates for the final four years to the 20th year of loading. A concurrent planning, designing and site preparation program is assumed for the fuel recycling facility over project years 0-2, with construction and commissioning in project-years 3-6 and operations commencing in project year 7 (consistent with schedule shown in [96]). Operational costs are assumed to be uniform for the remainder of the project period. For the PRISM reactors, planning and approvals are assumed underway from project years 0-4, with construction and commissioning from years 5-9 and

operations commencing in project-year 10. This has been selected to represent an ambitious mid-point estimate between literature suggesting timeframes of as little as six years[100] and up to approximately fifteen years[101].

Economic Findings

The *Guidelines for the evaluation of public sector initiatives*[102] applies a 30-year project life for major construction proposals and a real discount rate of 5 %, representing medium market risk. In the interests of ready comparison with the findings of the Royal Commission economic analysis, we have applied a 4 % discount rate. Under these conditions and based on the timelines determined, net present value (NPV) of the illustrative scenarios is shown in Sup. Table 5.

Sup. Table 5 Net present value (NPV) for low, mid and high scenarios, 4 % discount rate

	NPV 4 %
Low (L40)	-0.2
Mid (M60)	30.1
High (H100)	102.0

Net present value outcomes for discount rates ranging from 1 - 10 %

The discount rate has a material impact on net-present value assessment outcomes. Discount rates reflect assumptions regarding the type of competing commercial returns that may be available to investors as well as the relative value placed on future versus present outcomes for a range of non-financial values.

For the base case assessment presented in Chapter 5 we applied a 4 % discount rate consistent with that applied in the economic analysis undertaken for the Nuclear Fuel Cycle Royal

Commission. This section presents the same business case outcomes for all scenarios across

discount rates ranging from 1 – 10 %.

Sup. Table 6 Present value (PV) costs and net-present value (NPV) of Low scenarios at a range of discount rates for three sizes of Intermediate Spent Fuel Storage Installations (ISFSI). tHM = tonnes of heavy metal

ISFSI Size (tHM)	40,000	
Discount rate	**PV Costs ($ Millions)**	**NPV ($ Millions)**
1.0 %	-28,406,657,275	2,495,475,379
2.0 %	-24,501,236,437	1,362,570,774
4.0 %	-18,877,886,146	-220,402,768
5.0 %	-16,805,981,022	-762,073,347
7.5 %	-12,959,829,204	-1,635,603,616
10.0 %	-10,327,251,901	-2,064,552,651
ISFSI Size (tHM)	**60,000**	
Discount rate	**PV Costs ($ Millions)**	**NPV ($ Millions)**
1.0 %	-31,657,832,988	11,238,070,042
2.0 %	-27,504,926,318	8,789,534,784
4.0 %	-21,476,662,425	5,156,903,906
5.0 %	-19,237,321,853	3,817,865,766
7.5 %	-15,046,985,439	1,429,593,632
10.0 %	-12,148,107,409	-26,768,959
ISFSI Size (tHM)	**100,000**	
Discount rate	**PV Costs ($ Millions)**	**NPV ($ Millions)**
1.0 %	-34,681,423,897	32,022,668,545
2.0 %	-30,184,114,602	26,807,521,455
4.0 %	-23,616,508,935	18,831,408,160
5.0 %	-21,164,436,508	15,786,868,434
7.5 %	-16,559,666,084	10,119,309,308
10.0 %	-13,365,048,780	6,390,379,659

Sup. Table 7 Present value (PV) costs and net-present value (NPV) of Medium scenarios at a range of discount rates for three sizes of Intermediate Spent Fuel Storage Installations (ISFSI) tHM = tonnes of heavy metal

ISFSI Size (tHM)	40,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-16,977,719,074	13,802,910,130
2.0 %	-16,977,719,074	13,802,910,130
4.0 %	-16,977,719,074	13,802,910,130
5.0 %	-16,977,719,074	13,802,910,130
7.5 %	-13,005,404,080	9,186,076,464
10.0 %	-10,311,229,548	6,098,095,179

ISFSI Size (tHM)	60,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-30,042,907,630	49,252,403,174
2.0 %	-25,960,655,375	42,088,389,684
4.0 %	-20,057,802,813	30,956,383,064
5.0 %	-17,874,567,379	26,637,322,278
7.5 %	-13,809,198,662	18,454,022,139
10.0 %	-11,017,748,409	12,920,514,402

ISFSI Size (tHM)	100,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-34,299,974,535	92,773,711,920
2.0 %	-29,833,295,668	79,773,144,996
4.0 %	-23,319,025,140	59,476,425,653
5.0 %	-20,890,163,310	51,558,406,875
7.5 %	-16,335,032,275	36,455,333,949
10.0 %	-13,180,199,260	26,127,896,258

Sup. Table 8 Present value (PV) costs and net-present value (NPV) of High scenarios at a range of discount rates for three sizes of Intermediate Spent Fuel Storage Installations (ISFSI) tHM = tonnes of heavy metal

ISFSI Size (tHM)	40,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-29,967,810,234	53,406,773,588
2.0 %	-25,995,655,297	45,277,638,411
4.0 %	-20,252,702,996	32,862,350,859
5.0 %	-18,126,883,801	28,112,809,136
7.5 %	-14,159,943,406	19,212,344,365
10.0 %	-11,422,977,954	13,265,677,846

ISFSI Size (tHM)	60,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-31,694,676,797	87,298,902,619
2.0 %	-27,683,916,529	74,571,959,106
4.0 %	-21,889,577,464	54,917,444,226
5.0 %	-19,745,614,390	47,317,843,544
7.5 %	-15,742,707,567	32,924,871,401
10.0 %	-12,973,154,742	23,163,136,864

ISFSI Size (tHM)	100,000	
Discount rate	PV Costs ($ Millions)	NPV ($ Millions)
1.0 %	-32,299,457,423	156,451,551,417
2.0 %	-27,916,328,763	135,216,655,785
4.0 %	-21,551,747,801	102,008,120,129
5.0 %	-19,190,377,335	89,022,269,223
7.5 %	-14,786,592,461	64,167,094,854
10.0 %	-11,762,828,528	47,060,277,835

Fuel inventory modelling

This section details the methodology applied to model expected inventories of used nuclear fuel in a sample of existing nuclear nations in Asia. These outcomes informed the assumed range of sizes of the Intermediate Spent Fuel Storage Installation for the business case analysis.

Method

Four nations were selected for inventory modelling: China, Japan, South Korea and Taiwan. Due to the different conditions of the selected countries different approaches and scenarios are applied.

China

Currently China operates about 23.1 GWe of nuclear power capacity [84], and plans to add about 217 GW by 2050. We modelled the following scenarios:

Plan: The plan scenario of this analysis follows the nuclear plan. The nuclear capacity for the plan scenario will reach 58 GWe by 2020, 150 GWe in 2030 and 250 GWe in 2050.

Low: The low scenario assumes that there is no additional nuclear power excluding currently operating, constructing and planned capacity. The total capacity for the low scenario will reach 91 GWe by 2050.

High: The high scenario follows the assumption by Hu and Cheng [103]. About 70 GWe of nuclear power plants will be installed by 2020, 200 GWe by 2040 and 500 GWe by 2050. This is the pre-Fukushima nuclear plan in China. The capacity of breeder reactors are excluded from the calculation.

Due to the large gap between the currently operating capacity and the future expected capacity, the calculation method is applied[104].

$$M = \frac{P_e \cdot CF \cdot 365}{\eta_{th} \cdot B_d}$$

Where: M is mass of fuel loaded per year (MTHM/year; B_d is discharge burnup which is between 8 GWd/MTHM (PHWR) and 65 depended on the type of reactors; P_e is installed electric capacity (GWe); CF is capacity factor (85%); η_{th} is thermal efficiency (33%).

Japan

Currently Japan has about 44.6 GWe of nuclear power capacity in shut down in response to the Fukushima-Daiichi nuclear accident[105]. We modelled the following scenarios:

Plan: This assumes that nuclear power in Japan will generate ~ 22 - 24 % of the total electricity consumption[106]. It is assumed that currently closed nuclear power plants (including Fukushima power plants) will remain so, the other nuclear power plants will be restarted to operate from 2016, and will continue operations to 2050.

Low: The low scenario is assumed that all nuclear power plants will be decommissioned when they reach the expected life span, and all new power plants under construction or planned will be cancelled.

High: The high scenario is based on the plan scenario; however, assumes that aged power plant (the expected life span < 2040) will be replaced to advanced reactors with larger capacity.

A calculation approach similar to that applied to China is applied to Japan due absence of actual inventory data. The capacity factor of nuclear power in Japan is noticeably low (<70%) compared with other countries like South Korea and China. Discharge burnup is 40 GWd/tU, and thermal efficiency is 33 %. The conversion factor of 0.95 is multiplied to convert the amount of uranium input to spent fuel (heavy metal) output.

South Korea

Currently nuclear power with the capacity of 20.7 GWe is being operated in South Korea [107]. We modelled the following scenarios:

Plan: The plan scenario follows the current electricity generation plan until 2035[108]. Between 2015 and 2023, South Korea is planning to build 1.4 GWe of nuclear capacity every year. The total capacity of nuclear power will be 32.9 GWe by 2023, and the capacity will be maintained thereafter. Aged reactors will be renewed.

High: The high scenario is assumed that nuclear power plants will be constructed with the reduced trend (1.4 GWe bi-annually) between 2024 and 2050). Additionally aged nuclear reactors will be replaced with generation III reactors with higher capacity (1.4 GWe). The total nuclear capacity will be 54.3 GWe by 2050.

Phase-out: The phase-out scenario is assumed that all nuclear power plants will be phased out in South Korea when reaching the planned operational life span of each nuclear power plant, and all the nuclear power plant plans will be cancelled.

We obtained the annual nuclear fuel data by power plants between 2000 and 2014 from Korea Hydro and Nuclear Power (KHNP)[109]. The conversion factor of 0.95 is multiplied to convert the

amount of uranium input to spent fuel (heavy metal) output. For the generation III reactors (APR1400) that do not have historical data, the average value of generation II reactors (OPR1000) which use the same type of nuclear fuel (PLUS 7) is applied. The capacity difference is compensated by multiplying by 1.4.

Taiwan

Currently nuclear power with the capacity of 7.6 GWe is being operated in Taiwan [110]. We modelled the following scenarios:

Plan: The plan scenario follows the new energy policy of Taiwan (8.3 GWe by 2050). Since the energy policy of Taiwan has the "Move towards a nuclear-free homeland" position, it is difficult to expect increasing nuclear power capacity in Taiwan. Therefore the high nuclear scenario assumes only that aged nuclear power plants will be replaced with advanced nuclear power reactors with higher capacity after the expected life span year (11.2 GWe by 2050).

Low: The low nuclear power scenario is assumed that Taiwan will cancel all nuclear power programs currently planned and decommission currently operating power plants when they reach the expected life span. For the low scenario, maximum capacity is 4.3 GWe in 2025 and it will maintain by 2050.

An empirical approach that uses the historical data of Taiwan is applied to calculate the amount of spent fuel[110]. Here the quantity of spent fuel is assumed to follow the historical trend of each power plant.

Modelled Spent Fuel Inventories

The outputs for each modelled nation are shown in the tables below. The inventories of all modelled nations are combined in Sup. Table 13.

Sup. Table 9 Modelled used fuel inventories for South Korea under three nuclear sector scenarios

	2015	2020	2025	2030	2035	2040	2045	2050
High	13,808	19,000	24,500	29,727	35,380	41,291	47,628	54,224
Plan	13,808	18,854	23,797	28,570	33,344	38,117	42,890	47,663
Low	13,808	18,071	21,478	23,343	24,398	25,189	25,695	26,009

Sup. Table 10 Modelled used fuel inventories for China under three nuclear sector scenarios

	2015	2020	2025	2030	2035	2040	2045	2050
High	4,254	8,720	17,934	32,199	51,565	75,457	104,168	137,774
Plan	4,254	8,720	16,765	27,878	43,016	60,049	78,599	98,739
Low	4,254	8,720	16,205	24,426	32,646	40,867	49,087	57,308

Sup. Table 11 Modelled used fuel inventories for Taiwan under three nuclear sector scenarios

	2015	2020	2025	2030	2035	2040	2045	2050
High	3,595	4,314	5,344	6,511	7,678	8,845	10,012	11,180
Plan	3,595	4,226	4,905	5,584	6,263	6,943	7,622	8,301
Low	3,595	4,080	4,322	4,322	4,322	4,322	4,322	4,322

Sup. Table 12 Modelled used fuel inventories for Taiwan under three nuclear sector scenarios

	2015	2020	2025	2030	2035	2040	2045	2050
High	19,000	22,676	26,520	30,365	34,209	38,158	42,194	46,229
Plan	19,000	22,676	26,,520	30,365	34,209	38,053	41,898	45,742
Low	19,000	22,280	25117	27,063	28,283	28,738	29,041	29,110
No	19,000	19,000	19,000	19,000	19,000	19,000	19,000	19,000

Sup. Table 13 Modelled used fuel inventories for South Korea, China, Taiwan and Japan under three nuclear sector scenarios

	2015	2020	2025	2030	2035	2040	2045	2050
High	40,657	54,710	74,298	98,802	128,832	16,3751	204,002	249,407
Plan	40,657	54,476	71,987	92,397	116,832	143,162	171,009	200,445
Low	40,657	53,151	67,122	79,154	89,649	99,116	108,145	116,749
Low + No Japan	40,657	49,871	61,005	71,091	80,366	89,378	98,104	106,639

In 2025, under no scenario was total inventories of these four nations found to be less than 60,000 tHM. Given an assumption that all nuclear nations would have commercial access to a multinational ISFSI, on the basis of these modelled outputs we assumed for the purposes of our indicative business case, the following capacities:

Low: 40,000 tHM

Medium: 60,000 tHM

High: 100,000 tHM

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