The role and value of CCS in different national contexts

FINAL REPORT

by Yoga Wienda Pratama[a,b] and Niall Mac Dowell[a,b]

[a]Centre for Environmental Policy,
[b]Centre for Process Systems Engineering
Imperial College London,
Exhibition Road, London, SW7 1NA, UK

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Executive Summary

Delivering the ambition of the 2015 Paris climate agreement requires a global transition to net zero CO_2 emissions on average by between 2050 and 2070[1], and to net negative thereafter. Achieving the ambitions of the Paris Agreement will require a rapid and unprecedented transformation of global energy systems, with the power sector at the forefront of this transformation.

Since 2015, there has been significant focus around the world on setting national targets to deliver this aim. Norway, Sweden, the United Kingdom, and France have put in place legally binding targets for net zero emissions by 2050 – Norway and Sweden are aiming for 2030 and 2045, respectively. Several other countries are in the process of proposing legislation, developing policy documents, or at least discussing "net zero" as an ambition. This political ambition notwithstanding, estimates are that total anthropogenic CO_2 emissions in 2018 were 37.1 Gt_{CO_2}. This significantly exceeds the 35.63 Gt_{CO_2} emitted in 2015, or the 11.47 Gt_{CO_2} in 1965. 2018 was a record year.

In 2018, oil, natural gas, and coal provided approximately 32%, 23%, and 26% of the world's primary energy respectively. In other words, approximately 81% of the world's energy came from fossil fuels [1]. This can be compared with the approximately 86% provided by fossil energy in 1971. However, this decline in relative share must be contrasted with the fact that, in 2017, the world used just over two and a half times as much energy as it did in 1971[2].

Therefore, the evident inertia of the global energy system, combined with a growing global population, requires that we find a pragmatic solution. This solution must necessarily be socially equitable, technically feasible, and financially viable, if it is ever to become more than an academic thought experiment.

[1] In scenarios with low or now overshoot

[2] A more accurate estimated is 2.58.

It is this pragmatism that brings us to carbon capture and storage (CCS). CO_2 capture and storage is a technically mature option for the sustainable use of fossil energy resources, and is equally applicable to coal, gas, and biomass. CCS is capable of delivering near zero emissions heat and power generation from fossil fuels, and is also key to the carbon dioxide removal (CDR) services required to meet the ambitions of the Paris agreement.

However, deployment of CCS has traditionally been challenged by perceptions of cost. As long as environmental concerns are treated as an externality, CCS-equipped power stations are inevitably more costly than the unabated alternative. Moreover, given the rapidly declining cost of renewable energy sources, such as wind and solar power, it is often proposed that their combination with energy storage technologies would allow them to cost-effectively completely displace fossil energy.

Concerns of cost notwithstanding, it is nevertheless true that CCS technology is technically mature and commercially available today. All elements of the CCS value chain – capture, transport, and storage – have been demonstrated around the world for decades. The core technologies for the capture step were developed in the early part of the 20$^{\mathrm{th}}$ century, and are in regular commercial use today. There are currently more than 7,000 km of CO_2 pipelines in the United States alone. Moreover, whilst CO_2 injection for enhanced oil recovery has been commercial practice in the United States since 1972, CO_2 injection into saline aquifer formations in the North Sea has been ongoing at the megaton scale since 1996 in the Sleipner field. Importantly, geologically sequestered CO_2 is considered to be secure.

The purpose of this study, therefore, is to quantify and qualify the role and value of CCS technologies in the electricity system in several key regions around the world. The Electricity Systems Optimisation (ESO) framework was used to deliver this study. ESO is a hybrid capacity expansion and unit commitment model which allows the investigation of electricity system transitions. ESO acts to minimise the cost of this transition, subject to the constraints of meeting power demand and emission targets. This study examined the potential evolution of the electricity grid in the United Kingdom, Poland, New South Wales in Australia, and the Java-Madura-Bali (JAMALI) system in Indonesia, the Electric Reliability Council of Texas (ERCOT) grid, and the PacifiCorp East (PACE) grid in the United States of America.

In each case study, a reference scenario, with no emissions target, was developed – "Business As Usual" (BAU). Then, three scenarios were developed which required the transition to a zero emissions paradigm in 2050. The first, "All Technologies", allowed the deployment of all technologies – biomass and fossil fuels with and without CCS, nuclear, geothermal (where relevant), on- and off-shore wind, solar, pumped hydro and battery storage – was permitted. The second scenario – "No CCS" – prohibited the sequestration of CO_2, but allowed everything else. The final scenario, "Renewables and Storage" only permitted the deployment of renewable power generation and energy storage technologies. Existing thermal assets were permitted to serve their remaining lifetimes, but further deployment was prohibited.

The core, overarching conclusion of this work is that, as illustrated in figure 1 and table 1, regardless of national context, CCS is integral to delivering a resilient and cost-effective, zero emissions electricity system. Regardless of context, the exclusion of CCS technology from the portfolio of available options has the effect of increasing the cost of delivering a net zero system by between a factor of two and seven.

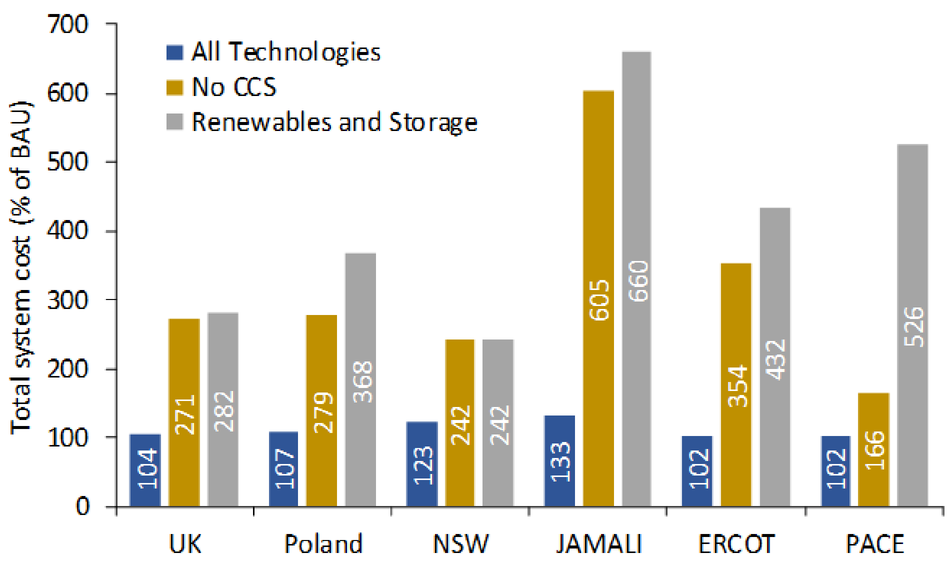

Figure 1: Total system costs of decarbonised systems as percentage of the BAU costs.

Additional insight generated by this work includes the impact of seasonality of power demand on the value of CCS. Regions with a highly seasonal power demand, such as the UK or the ERCOT grid, will likely derive maximum value from including CCS owing to its ability to operate in a flexible, load following manner. It might be anticipated that the electrification of other sectors, such as heating or transport, would enhance this value proposition.

Table 1: Summary of results.

	BAU	**All Tech.**	**No CCS**	**Renewables & Storage**
	$ Bn	$ Bn	$ Bn	$ Bn
UK	555.0	573.0	878.0	1,374.0
Poland	289.0	308.0	805.0	1,061.0
New South Wales	83.0	102.0	201.0	201.0
JAMALI	588.0	780.0	3,554.0	3,876.0
ERCOT	330.5	338.2	1,171.2	1,426.1
PACE	45.8	46.6	57.6	241.0

However, there were two other key observations that are important to highlight. First was the rate at which power generation technology must be deployed in order to meet the net zero target[3]. In the BAU and All Technologies scenarios, technology deployment rates were considered to be in line with historical precedent for each region. This is important as the deployment of power generation assets of *any* kind requires the coordinated interaction of a complex, global supply chain, which is unlikely to be able to significantly increase its output in the short term. Moreover, any demand for power generation deployment beyond the existing capacity of this supply chain is likely to exert a material upwards pressure on costs throughout that chain. These system dynamics are not accounted for in typical energy systems studies, where costs typically considered to reduce with deployment. In the case of the "No CCS" and "Renewables and Storage" scenarios, the rate at which power generation capacity needed to be deployed was unprecedented.

A second key observation is that, despite significantly relaxing the build-rate constraint, both the "No CCS" and "Renewables and Storage" scenarios were frequently unable to satisfy the demand for power. Putting that another way, removing the option of deploying CCS appears to either jeopardise the resilience

[3]In modelling parlance, this is the "build-rate constraint"

of the electricity system, or require a significant reduction in energy demand, and also a substantial change in the way in which energy is used.

In the literature, it is common to assume that CO_2 capture technology can only abate 90% of the emissions associated with a given power station. This means that there are inevitably residual CO_2 emissions which, in the context of a net zero emissions scenario, must be offset. However, it has been recently demonstrated that near zero emissions from CCS power plants is possible at a limited marginal cost relative to the cost of a conventional process with 90% capture [2]. In this study, it was observed that increasing the CO_2 capture rate beyond 90% had the effect of increasing CCS capacity deployed and also increasing the capacity factor of the underlying thermal power plants. Thus, future modelling exercises should recognise that greater than 90% capture is feasible, and may, in fact, reduce total system cost.

A final important observation from this study was that, in no system, was CCS observed to significantly reduce the deployment of renewable capacity. Further, in all cases, owing to their near-zero marginal cost, renewable power was found to dispatch ahead of CCS power. This remained true even in the case of the USA, where the 45Q and 48A tax credits for CCS were included. The effect of these tax credits was to privilege CCS-equipped coal, gas and biomass over their unabated counterparts, but not over the renewable alternatives. In other words, it is not a case of "CCS ***or*** renewables", but rather one of "CCS ***and*** renewables".

While this report and the supporting research has identified a clear value for the role of CCS, both in ensuring that electricity demand can be met and offering the lowest total investment to do so while decarbonising, it is important to note that only the power sector was considered in this work. While a full economy decarbonisation is outside the scope of this work, it is likely that electrification would need to occur under such a scenario, and therefore the decarbonisation of the power sector is integral to this transition. Given that this study did not assume any increase in electricity demand, it is fair to conclude that the value of CCS discussed throughout this document is a conservative estimate.

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Nomenclature

Abbreviations

Symbol	Explanation
AS	Ancillary Services
ASU	Air Separation Unit
BAU	Business as usual (electricity demand scenario)
BEIS	Department of Business Energy and Industrial Strategy
CAPEX	Capital expenses
CC	Capacity Credit
CCS	Carbon Capture and Storage
CDR	Carbon Dioxide Removal
CF	Capacity Factor
CCGT	Combined Cycle Gas Turbine
CI	Carbon Intensity
ED	Economic dispatch
ExP	Extreme peak (electricity demand scenario)
ERCOT	Electric Reliability Council of Texas
FF	Fossil Fuels
FOAK	First-of-a-kind
IGCC	Integrated Gasification Combined Cycle
iRES	intermittent renewable energy source
JAMALI	Java-Madura-Bali
LCOE	Levelised Cost of Electricity
LP	Linear Program

MILP	Mixed-Integer Linear Program
MSG	Minimum Stable Generation
NGCC	Natural Gas Combined Cycle
NLP	Non-Linear Program
NOAK	Nth-of-a-kind
PACE	Pacificorp East
OCGT	Open Cycle Gas Turbine
OPEX	Operating expenses
Relative SV	Relative System Value ($/kW)
SRMC	Short-Run Marginal Cost
STOR	Short-term Operating Reserve
SV	System Value
TSC	Total System Cost
UC	Unit commitment
VoLL	Value of Lost Load
WTA	Willingness-to-accept
WTP	Willingness-to-pay

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Chapter 1

Introduction

Motivated by evolving prices and the need to combat climate change, the global energy landscape is changing, with investment in renewable energy capacity rising from $60 billion in the year 2000 to $304 billion in 2018 [3]. Globally, approximately 81% of primary energy is produced from fossil fuels with approximately 2% from intermittent renewable sources such as wind and solar [1][1]. It is likely that fossil fuels will remain vital to the global energy supply for the foreseeable future [4, 5].

It is also recognised that the continued exploitation and utilisation of fossil fuels in the conventional way is not a sustainable option [6], and in this context CO_2 capture and storage (CCS) has a uniquely important role to play in the transition to a low carbon economy [7]. There is a growing body of evidence that CCS is key to the least cost decarbonisation of both the power and industry sectors [7, 8], in addition to being able to generate carbon negative electricity via bioenergy with CCS (BECCS) [9–13].

CCS is a well understood technology, relying on the integration of a range of technical elements which are themselves technically mature [14–16]. Of particular importance is the ability of power plants with CCS to operate synergistically with intermittent power generation, providing a flexible buffer between intermittent renewable generation capacity and less flexible nuclear baseload capacity [17, 18].

It is relatively well accepted that CCS at a global scale is uniquely valuable to limiting global warming to 2°C [7], and is essential in scenarios that limit

[1] Note, however, that, in 2018, solar and wind power supplied 2 and 5% of the world's electricity respectively. Ibid.

temperature increase to 1.5 °C [6]. However, the way in which CCS will integrate with specific power systems around the world remains unclear.

Therefore, the purpose of this report is to provide quantitative and qualitative insight into the role and value of CCS power plants in different energy systems around the world. This study will demonstrate how these systems will evolve as the energy landscape changes from the current period to 2050. This evolution will be studied in the context of the energy trilemma – carbon reduction, cost minimisation, whilst maintaining security of supply.

1.1 Project objectives

The objectives of this study are as follows:

1. To develop detailed national- or regional-scale models of electricity grid systems for key areas around the world;
2. Using this model, derive insight and understanding of the value of CCS technology applied to coal-, gas-, and biomass-fired power plants in each of these countries, and likely operating patterns, *e.g.*, baseload, or load-following operation;
3. Quantify the value of CCS to the electricity system in the context of meeting emission mitigation targets consistent with the Paris Agreement, whilst simultaneously ensuring affordability and security of supply.

In order to quantify and qualify the role and value of CCS in a whole-electricity systems context, we use the Electricity Systems Optimisation framework [19,20]. It maps a national-sized electricity system, tailored to represent a specific grid, simultaneously determining the amount and type of power generating capacities as well as the detailed plant-level operation. The objective function is to minimise total system costs of the electricity system, which includes the construction and operation of the power plants, subject to system-wide balance, reliability, operability, and emission constraints. This multi-scale model determines the optimal system design and dynamic behaviour of power plants such that the overall system benefits the most. To this end, the following national systems have been used as individual case studies:

- United Kingdom
- Poland

- New South Wales, Australia
- Java-Madura-Bali (JAMALI), Indonesia
- Electric Reliability Council of Texas (ERCOT), USA
- PacifiCorp East (PACE), USA.

In performing this study, a scenario-based approach was adopted, with four distinctive scenarios evaluated, namely:

- Business As Usual (BAU): prevailing policies are maintained, there is no carbon target, all technologies can be deployed in line with historical build rates.
- All Technologies: there is a target of net zero CO_2 emissions by 2050, all technologies can be deployed in line with historical build rates.
- No CCS: there is a target of net zero CO_2 emissions by 2050, all technologies except for CCS can be deployed in line with historical build rates.
- Renewables and Storage: there is a target of net zero CO_2 emissions by 2050, only renewable energy and energy storage technologies can be deployed.

For the BAU and All Technologies scenarios, the total system cost was minimised, subject to the primary constraint of meeting electricity demand and, where relevant, the end-point constraint of net zero CO_2 emissions. For the No CCS and Renewables and Storage scenarios, the security of supply constraint was relaxed *via* the incorporation of a slak variable which assigned a value of lost load (VoLL) of $10,000/MWh. This relaxation was necessary in the context of these scenarios in order to ensure the feasibility of the problem. In the context of meeting a net zero emissions target, the value of CCS was defined as the cost of meeting the emissions target in a given scenario, namely the "No CCS" and "Renewables and Storage" scenarios, less the cost of meeting the targets in the case with CCS.

The balance of this report is set out as follows; the remainder of this Chapter describes the approach and methodology used in this study, and details the input data and assumptions. Then Chapter 2 presents the results for each individual case study, with Chapter 3 presenting the results of a sensitivity analysis to the assumption of 90% capture from CCS power plants. Finally, Chapter 4 presents the conclusions of this study.

1.2 Approach and methodology

This project uses the Electricity Systems Optimisation (ESO) framework [19, 20] as the basis for this analysis. The ESO framework couples detailed engineering and electricity market models to provide a bottom-up analysis of the impact of deploying CCS power plants in different energy systems in terms of system cost and operability. The heart of the technology valuation algorithm is a mixed-integer linear optimisation model, which was formulated and modelled in GAMS 23.7.3 [21] and solved with the optimiser CPLEX 12.3. Pre-processing steps, such as data clustering and profiling are executed in the R environment [22]. A high-level description of the model is presented in section 1.2.1, and a schematic of how the different software and modelling platforms integrate is provided in section 1.2.2.

1.2.1 Overview of the ESO framework

The formulation of ESO is presented in detail in Appendix A, with key assumptions, constraints, and input data presented here.

Objective function

The objective function used throughout this study is the aggregated total system cost (tsc) over the period. This quantity is defined in equation 3c.1, and is a combination of capital, fixed, and variable operating costs.

Input data and treatment of regional variation in cost

In any study of this type, one of the key elements of input data are the costs, efficiencies, and performance data assigned to the range of power generation technologies included in the portfolio.

In specifying technology costs and economic assumptions, one of the most important factors is that the costing basis is consistent, and equitable. This will ensure that the different technologies compete against each other on an equitable basis.

Therefore, individual technology costs, efficiencies, and performance data are taken from the report from the Department for Business, Energy and Industrial Strategy (BEIS) in the UK [23]. This is on the basis that the costing methodology used therein is entirely transparent and delivered by an independent, dispassionate third party. For the cost of retro-fitting CCS technology to coal, gas, and biomass power plants, these costs were taken from the IEAGHG [24].

These data are presented in table C.1 below for convenience.

Table 1.1: Economic parameters for individual generation technologies used in this study. (Ret) denotes technologies that have been retrofitted with CCS.

Tech	**CAPEX**	**Fixed O&M**	**Variable OPEX**	**Start-up cost**	**OPEX No Load**
	\$/kW	\$/kW	\$/MWh	\$/unit.start	\$/h
Nuclear	5,896	115	4.1	5,405,405	4,743
Coal	1,945	54	2.7	268,281	4,535
Biomass	4,109	81	3.4	268,281	4,262
CCGT	709	20	2.7	107,519	3,008
OCGT	466	20	6.8	5,095	120
Coal-PostCCS	4,865	128	3.8	338,034	5,715
CCGT-PostCCS	2,484	54	3.8	112,895	3,158
BECCS	5,811	122	13.5	338,034	5,715
Wind-Onshore	2,003	41	6.8	0	0
Wind-Offshore	3,941	61	4.1	0	0
Photovoltaic	1,080	14	0.0	0	0
Hydro	4,081	61	0.0	0	0
Pumped Hydro	1,469	34	8.1	0	0
Lead Acid Battery	2,432	27	4.1	0	0
Coal-PostCCS(Ret)	3,480	128	3.8	338,034	5,715
CCGT-PostCCS(Ret)	1,953	54	3.8	112,895	3,158

Furthermore, given that costs are known to vary with location, the BEIS costs were scaled based on the technology cost relative to European cost assumptions in the 2018 World Energy Outlook [5]. For the Australian case study, costs are scaled based on the Australian Energy Market Operator (AEMO) report.

These data are presented in summary form in table 1.2 for convenience.

Table 1.2: Cost scaling parameters for different countries/regions.

Tech	**Poland**	**ERCOT**	**PACE**	**NSW**	**JAMALI**
	% of UK CAPEX				
Nuclear	100	76	76	126	39
Coal	100	105	105	133	48
Biomass	100	104	105	73	78
CCGT	100	100	100	143	63
OCGT	100	100	100	110	75
Coal-PostCCS	100	102	102	98	67
CCGT-PostCCS	100	100	100	121	73
BECCS	100	104	104	101	70
Wind-Onshore	100	89	89	80	63
Wind-Offshore	100	89	89	98	63
Photovoltaic	100	120	120	116	86
Hydro	100	102	102	35	68
Pumped Hydro	100	102	102	100	68
Lead Acid Battery	100	100	100	108	70
Coal-PostCCS(Ret)	100	102	102	98	67
CCGT-PostCCS(Ret)	100	100	100	121	73

As this study also seeks to describe the way in which different technologies are dispatched, ensure security of supply and contribute to grid resilience, information on minimum and maximum stable generation, capacity credit [18], system inertia, and efficiency are also required to characterise a given system. A representative unit size and physical lifetime are also required. These data are summarised in table 1.3 below.

One final piece of data that is required to describe a given electricity grid is the age profile of the existing power generation fleet. This dictates the replacement rate of generation capacity, and is input on a case-by-case basis.

Finally, consistent with the general literature, a 90% capture rate is assumed for all CCS-equipped technology in this study, noting that a sensitivity analysis of this assumption is presented in Chapter 3.

Table 1.3: Technical parameters of technology, where P_{min} and P_{max} are the minimum and maximum power output, respectively.

Tech	P_{min}	P_{max}	Cap. Credit	Inertia	Efficiency	Capacity	Life-time
	% cap.	% cap.	% cap.	s	%	MW	yrs
Nuclear	75	80	80	7	37	600	50
Coal	30	88	88	6	42	500	40
Biomass	30	88	88	6	42	500	40
CCGT	50	87	87	6	57	750	40
OCGT	10	94	94	6	40	100	40
Coal-PostCCS	30	80	80	6	34	500	40
CCGT-PostCCS	30	80	80	6	50	750	40
BECCS	30	85	85	6	32	500	40
Wind-Onshore	0	100	40	2	100	20	30
Wind-Offshore	0	100	53	2	100	50	30
Photovoltaic	0	100	12	0	100	10	30
Hydro	10	100	50	3	81	300	60
Pumped Hydro	10	100	50	3	0	300	60
Lead Acid Battery	0	100	50	0	89	100	10
Coal-PostCCS(Ret)	30	80	80	6	34	500	40
CCGT-PostCCS(Ret)	30	80	80	6	50	750	40

1.2.2 Model structure and interfaces

This work relies on three software tools: Excel as data carrier, R for data pre-processing, and GAMS for the actual modelling and solving of the optimisation program. Figure 1.1 visualises how the choice of scenario influences the solution procedure and where information is transferred. In the upper right hand side of the schematic we list the parameters which have to be defined for each scenario. Additional parameters, according to the list of parameters in table A.1, can be perturbed in any model run. We choose the hourly electricity demand profile according to the scenario year. The hourly data set for one year of the UK's electricity demand, onshore wind, offshore wind, and solar power availability (4 dimensions) is transferred to the R clustering script. Here, the (8760, 4) sized data set, *i.e.*, year of 8760 hours by 4 dimensions, is clustered, profiled, and consequently reduced in size to a $((k+1){\cdot}24$, 4) data set. As a result of the clustering, which is described in detail in Appendix B, we obtain information about the weight of the individual clusters as a part of the entire data set. This time-dependent and time-independent data is then fed into the GAMS optimisation framework. We rigorously solve the mixed-integer linear program (MILP) and determine the optimal electricity system design, operation, *etc.*, subject to the constraints outlined in Appendix A. The data output from GAMS is then transferred back to the Excel interface for post-processing and archiving.

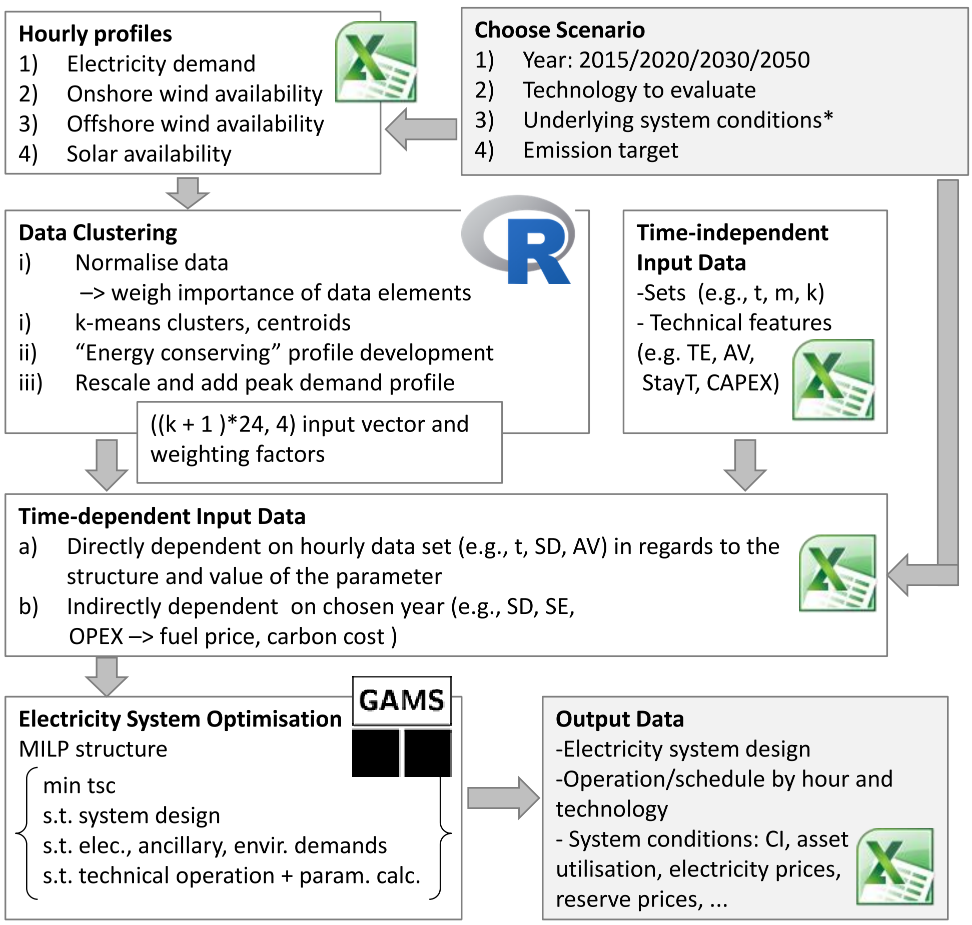

Figure 1.1: Model integration and solution process for the ESO framework. The final data output is followed by post-processing steps to retrieve the relevant information for analysis and visualisation.

Chapter 2

Country specific case studies

This chapter presents the results from the electricity systems optimisation for each country, *i.e.*, UK, Poland, New South Wales (NSW) in Australia, and Java-Madura-Bali (JAMALI) in Indonesia, PacifiCorp East (PACE) and the Electric Reliability Council of Texas (ERCOT) systems in the US. For each country, the results for different scenario evaluations are presented.

In all cases, country specific data for the availability of solar [25] and wind [26] potential were taken from the Renewables.Ninja[1] database while the hourly electricity demand were taken from the publically available literature [27–30]. Technology costs are from BEIS cost of power generation technologies [23] for UK and Poland and we scale those costs for other countries and regions proportional to the data in the World Energy Outlook 2018 by the International Energy Agency (IEA) [31]. Demand growth for each of the UK, ERCOT, PACE, and NSW is assumed to be constant at 1%/yr for the period to 2050, with growth in Poland held at 1.7%/yr [32]. Demand growth in Indonesia starts at 6.7%/yr in 2015 and is gradually reduced to 3.7% in 2050 [33]. Changes to the demand curve are not considered in this study. Importantly, biomass is not considered to be a carbon neutral fuel in this study, and is assumed to have a carbon intensity of 110 $\mathrm{kg}_{\mathrm{CO_2}}/\mathrm{MWh}_{\mathrm{th}}$ [34] – this means that it is unavailable in scenarios that prohibit CCS.

[1] https://www.renewables.ninja/

2.1 United Kingdom

In 2008, under the Climate Change Act, the UK committed to reduce greenhouse gas emissions by 80% by 2050 from a 1990 baseline. In 2013, owing to challenges with delivering reliable power from an electricity system with a growing share of renewable energy, the UK reformed its electricity market for the third time since privatisation in 1990. The 2013 Electricity Market Reform (EMR) introduced four instruments; competitive auctions for both firm capacity and renewable energy, a carbon price floor (CPF), an emissions performance standard (EPS), and a contracts for difference (CfD) scheme. Competitive auctions for both firm capacity and renewable energy received unexpectedly low bids, the carbon price floor served to displace coal, and the EPS[2] prohibited the construction of new coal without CCS. As a result, by 2018, total UK greenhouse gas emissions had been reduced by approximately 44%[3] from the 1990 baseline, and in 2019, the UK increased its ambition to entirely eliminate its CO_2 emissions by 2050. At present, all technologies[4] are anticipated to play a role in this transition, with the UK government currently actively pursuing new nuclear power and CO_2 capture and storage (CCS) on gas, and potentially biomass.

As with all regions in this study, the first scenario to be examined is the Business As Usual (BAU) option. This assumes that current policy instruments[5] remain as they are, with the exception that the current ban on onshore wind is discontinued. These results are presented in figure 2.1.

As can be observed, the current CPF of US$ 24.3/t_{CO_2} is insufficient to incentivise the deployment of CCS in the period to 2050. The share of renewable power, primarily onshore and offshore wind, continues to increase, and, in combination with interconnection and new nuclear power serves to reduce the share of unabated CCGT. The capacity share of intermittent renewable energy sources (iRES) increases to approximately 43%, which it achieves by 2035. However, owing to a costly increase in the rate of curtailment beyond this level of deployment, and the fact that unabated CCGT is a more cost-effective option for the provision of firm capacity than battery storage, deployment of iRES does not

[2]The Large Combustion Plant Directive (LCPD, 2001/80/EC) also contributed to this effect.

[3]The figure for CO_2 emissions was 39%.

[4]With the exception of onshore wind for the foreseeable future owing to a political ban.

[5]CPF, EPS, CfD, and capacity market.

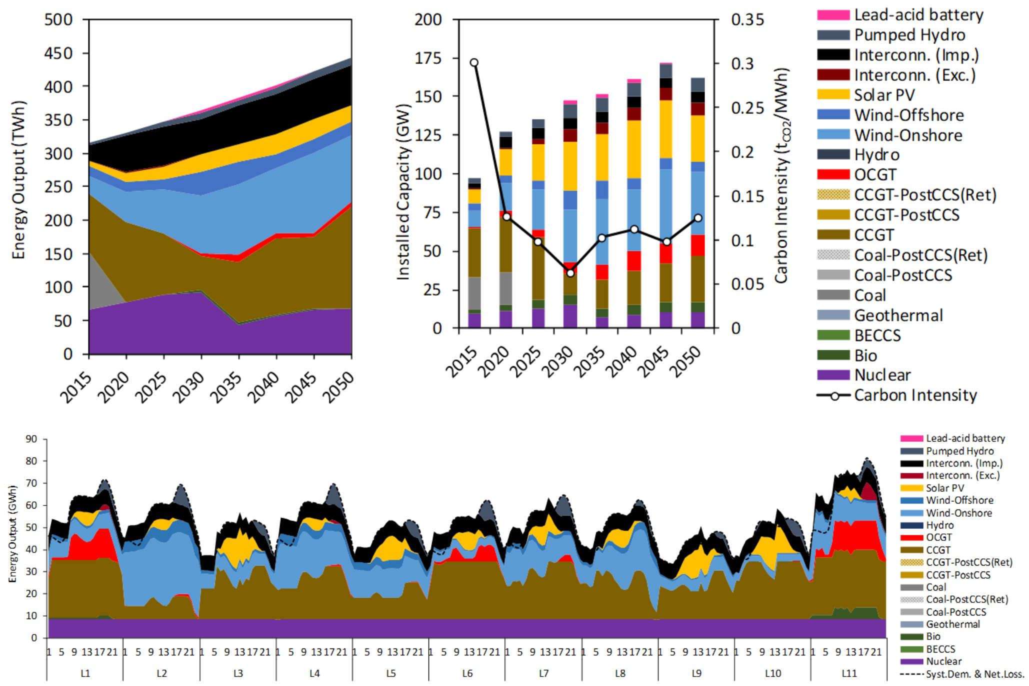

Figure 2.1: Power output (TWh), installed capacity (GW), and dispatch pattern by technology for the UK power system under BAU scenario.

expand beyond what is observed in 2035. This scenario achieves a final carbon intensity of 126 kg_{CO_2}/MWh in 2050.

This expansion of renewable capacity increases the share of wind in the UK electricity system from 13% in 2015 to a maximum of 36% in 2035 and 27% in 2050. Whilst this does deliver upon the UK's goals for the deployment of renewable power, as can be observed in figure 2.1, this also results in significant changes to the way in which the thermal plants, *i.e.*, CCGT, OCGT, and nuclear power, are required to operate. Specifically, CCGTs are required to operate in a highly flexible, load-following manner, and OCGTs exclusively provide a peaking service. The nuclear baseload is also reduced. Interestingly, whilst the amount of solar PV capacity deployed also increases, its role in meeting the UK's demand is limited to approximately 7% owing to the relatively high cost of battery storage. Beyond this level, curtailment is relatively high.

As can be observed from figure 2.2, the introduction of a constraint to meet a net zero emissions target in 2050 does not qualitatively change the structure of the electricity system in the All Technologies scenario.

The share of wind and solar in 2050 are 30% and 8%, respectively – almost

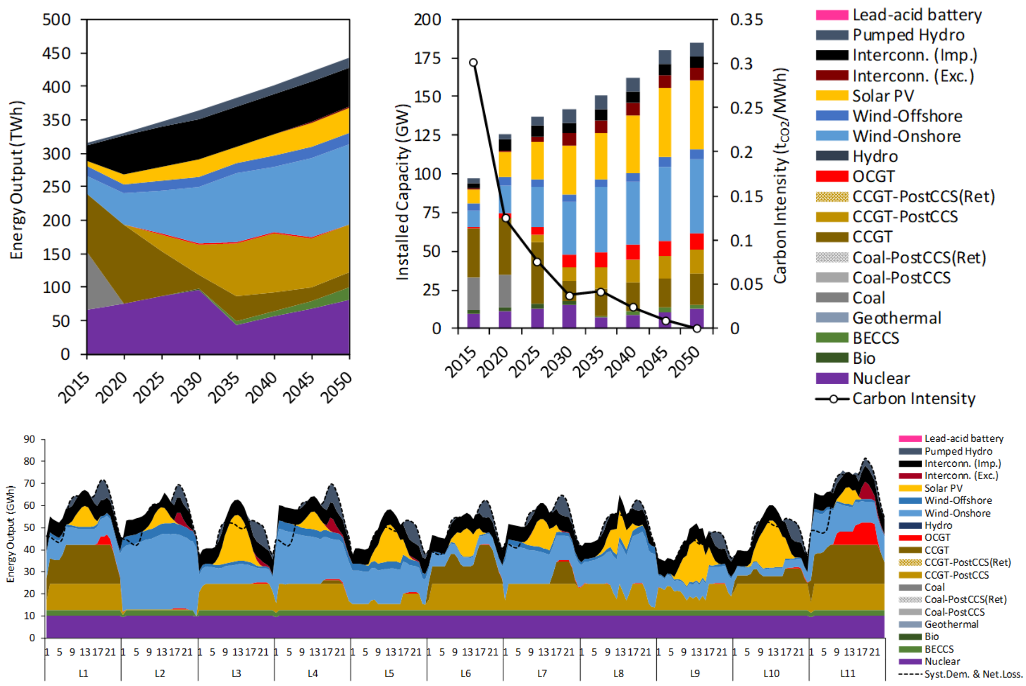

Figure 2.2: Power output (TWh), installed capacity (GW), and dispatch pattern by technology for the UK power system under the All Technologies scenario.

identical to the BAU scenario. The primary change is that unabated CCGT capacity is almost entirely replaced with gas CCS, with the addition of some negative emissions technologies, in the form of bioenergy with CCS (BECCS) to offset any emissions from the remaining unabated thermal plants and the residual emissions from the CCS plants. It is interesting to note that in this scenario, the role played by gas CCS in the All Technologies scenario is almost identical to that played by unabated CCGT in the BAU scenario.

However, removing the option to deploy CCS, as in the No CCS scenario, has very significant effects on both the quantitative and qualitative structure of the electricity system. As can be observed from figure 2.3, this scenario requires the very rapid expansion of the UK's iRES capacity to replace the thermal plants as they retire. As has been discussed elsewhere [18], owing to the absence of dispatchable capacity in the system, very significant amounts of over-capacity need to be deployed in order to minimise lost load. This has the net effect of increasing installed capacity in 2050 to approximately 483 GW, relative to approximately 185 GW in 2050 for both the BAU and All Technologies scenarios.

An interesting observation in this scenario is that, despite it being permitted, very

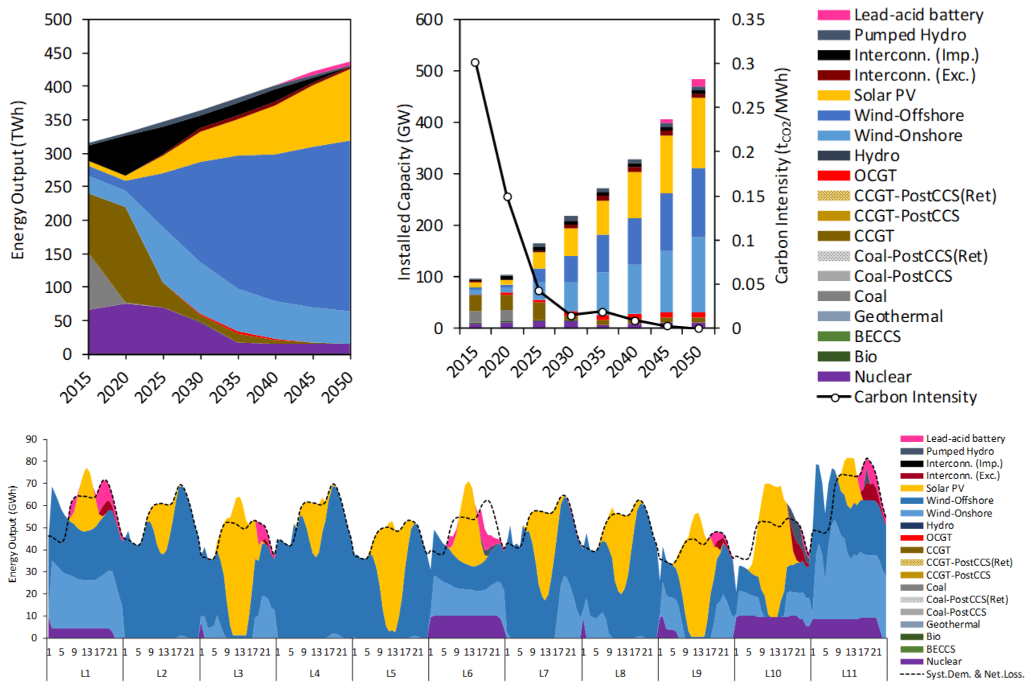

Figure 2.3: Power output (TWh), installed capacity (GW), and dispatch pattern by technology for the UK power system under No CCS scenario.

little nuclear capacity is deployed after the existing fleet is retired. The underlying driver for this phenomenon is that the over-capacity of, and subsequent over-generation of power from, the iRES means that the dispatchable technology operates at a very low capacity factor. This essentially prohibits the deployment of baseload generating assets in the system.

Prohibiting the deployment of nuclear power and CCS in the Renewables and Storage scenario further exacerbates the challenges observed in the No CCS scenario. These results are presented in figure 2.4.

Although up to 5 GW of demand response is potentially available in the UK [35], and despite the very significant over capacity, the absence of dispatchable generation in the system makes it increasingly difficult guarantee security of supply. Electricity storage technologies can reduce the frequency and magnitude of the lost load, though their economic level of deployment is also limited by low operating hours and their dependency on other technologies to provide excess electricity to be stored. The results of the Renewables and Storage scenario, illustrated in figure 2.4 are very similar to those of the No CCS scenario, with many of the same drivers.

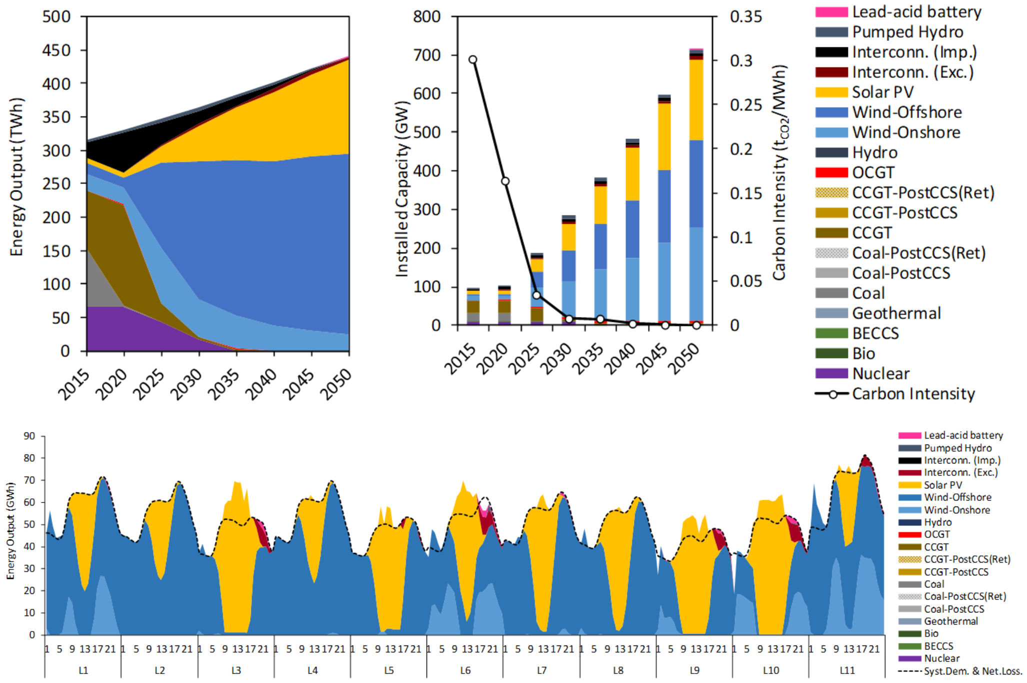

Figure 2.4: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for UK power system under Renewables and Storage scenario.

In this scenario, no new nuclear capacity is deployed which results in an increase in installed capacity to approximately 716 GW, relative to approximately 185 GW in the BAU and All Technologies scenario. Again, security of supply is significantly challenged in this scenario, despite the availability of energy storage technology.

2.1.1 United Kingdom case study: Concluding remarks

In order to conclude the UK case study, it is instructive to consider the total system costs associated with the final system design. These are illustrated in figure 2.5 below.

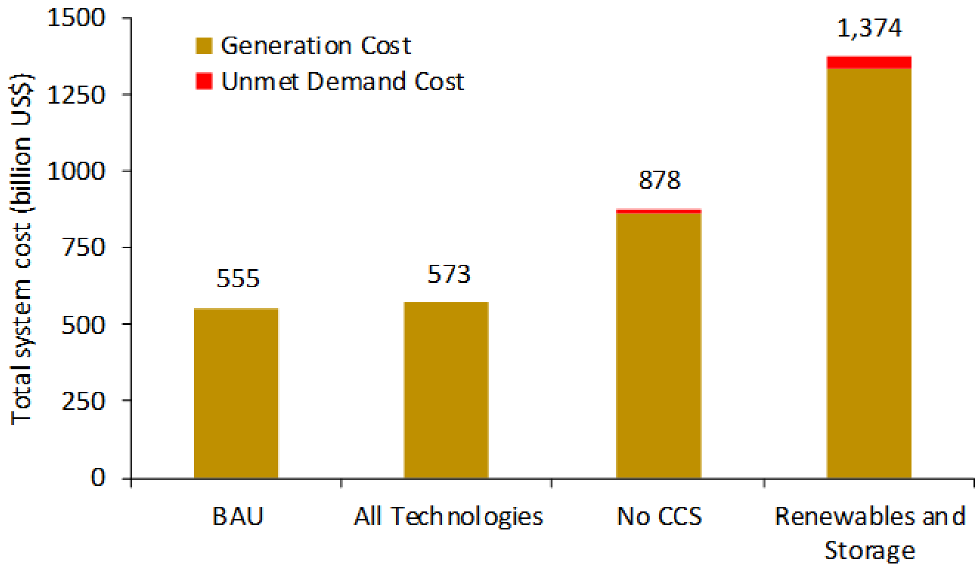

Figure 2.5: Total system costs of UK system under different scenarios.

As can be observed, the Business As Usual scenario has the least cost, noting that whilst this scenario does deliver a significant reduction in carbon intensity, the final value of 126 kg_{CO_2}/MWh in 2050 is still significantly greater than the net zero target at which the other scenarios are aiming. In line with this, the cumulative CO_2 emissions associated with BAU scenario in the period to 2050 is approximately 3.53 Gt. In comparison, the All Technologies delivers a net zero emissions system for a 3% premium, *i.e.*, \$573 Bn as opposed to \$555 Bn, and reduces the cumulative CO_2 emissions to 1.71 Gt. In contrast, the Renewables and Storage scenario costs approximately 247% of the BAU scenario, and cannot guarantee security of electricity supply.

2.2 Poland

Distinct from the UK, Poland has relatively high cost natural gas and inexpensive coal resources. Therefore, coal has traditionally been an important component of the Polish economy. This is reflected by the dominance of coal in Poland's incumbent electricity grid. Similarly to the UK, Poland is also engaging with the "energy trilemma", with current energy policy prioritising energy security, economic competitiveness, and a reduction of the environmental burden associated with the energy sector. An important additional element of these goals is the focus on the optimum use of indigenous energy resources. Importantly, the anticipated trajectory of the Polish electricity system is a reduction in the consumption of coal, and increase in the share of wind and solar power. Polish energy policy incorporates targets to reduce CO_2 emissions, with a goal of a 50% reduction by 2040 from a 1990 baseline currently under consideration. This reduction is anticipated to be primarily *via* the development of nuclear power in the early 2030's [36], though the replacement of low-efficiency thermal power plants.

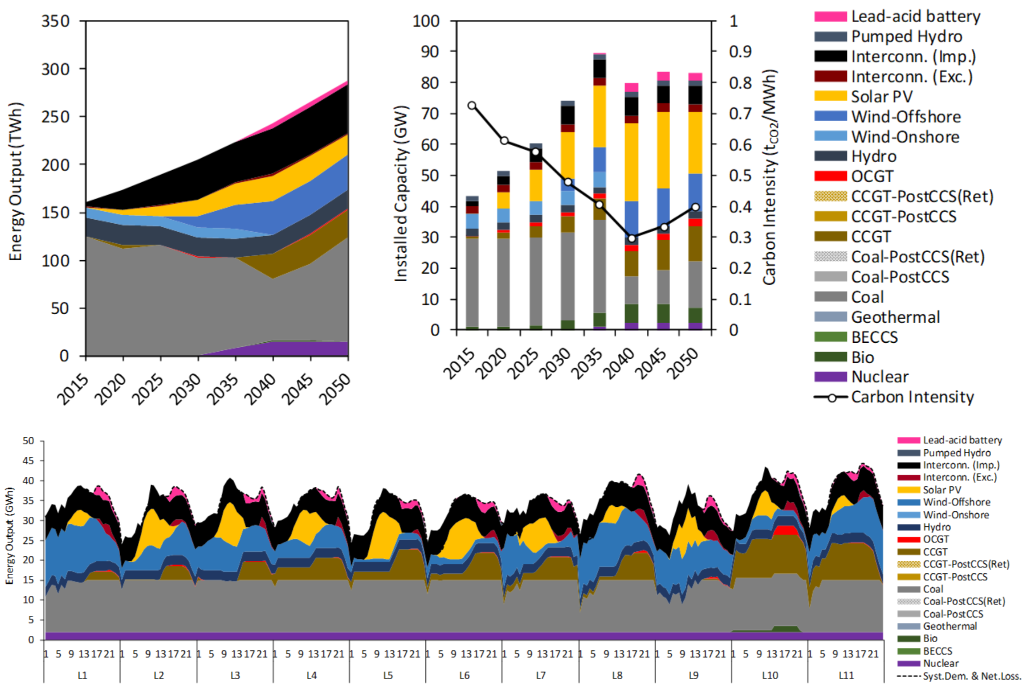

Figure 2.6: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for the power system in Poland under the BAU scenario.

These ambitions are largely reflected in this study's results of the Polish BAU scenario. Figure 2.6 shows a reduction in the share of coal, an expansion of iRES capacity and generation, and an introduction of nuclear power.

This appears to achieve the goals of existing Polish energy policy – security of supply is maintained, the share of coal declines, and CO_2 emissions are appreciably reduced. The impact of the expansion of iRES and CCGT, and the introduction of nuclear power which essentially operates in baseload fashion that the coal plants appear to operate in a more flexible fashion, with CCGT essentially providing load following power in 2050.

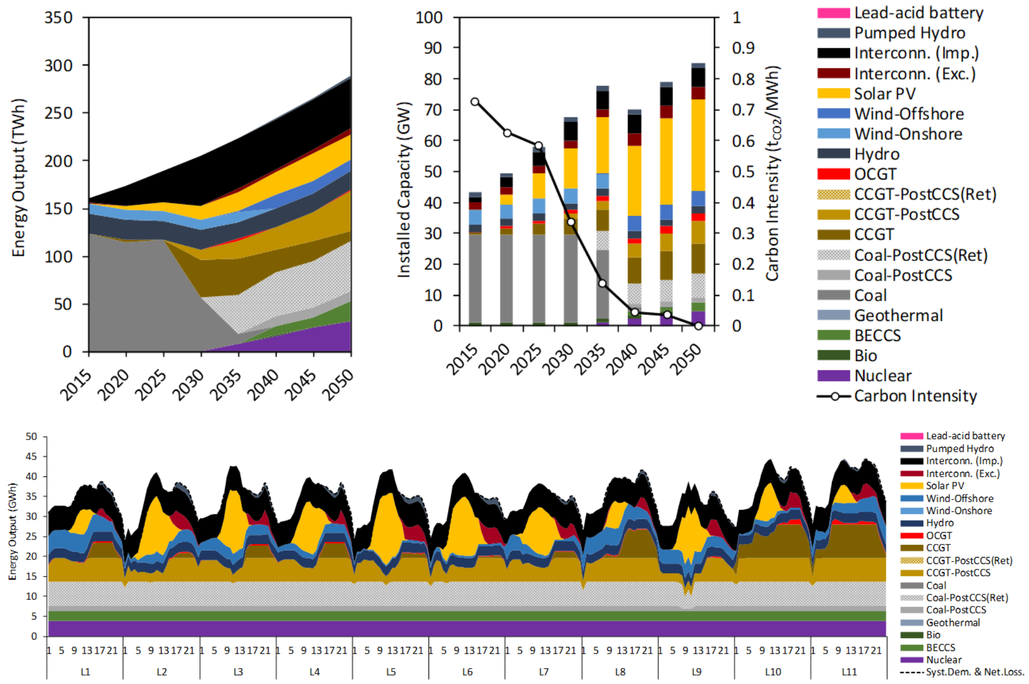

Figure 2.7: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for the power system in Poland under the All Technologies scenario.

As illustrated in figure 2.7, the introduction of a net zero emissions constraint in the All Technologies scenario does not significantly change the structure or size of Poland's electricity system. Total installed capacity in 2050 remains constant at 85 GW – very close to the 83 GW installed in the BAU scenario. Once nuclear power becomes available, it is deployed, and the share of both iRES and interconnection are expanded.

The primary change between the BAU and All Technologies is the introduction of CCS technology on coal, gas, and biomass. Coal-CCS is primarily retrofit,

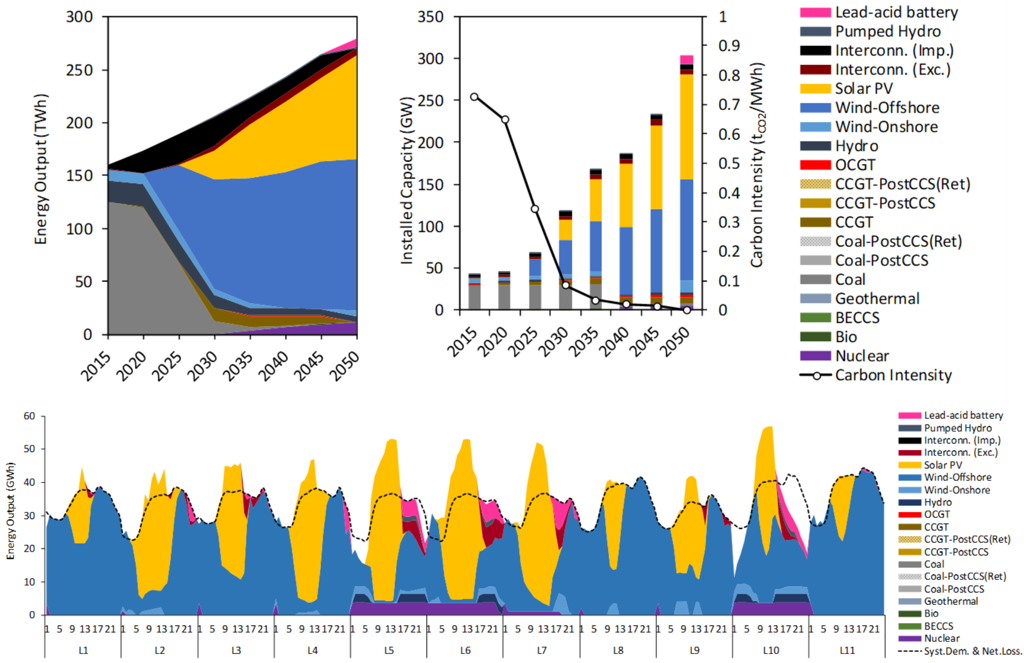

Figure 2.8: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for the power system in Poland under the No CCS scenario.

whereas the gas-CCS is almost exclusively new-build. There is some remaining unabated CCGT and OCGT capacity in 2050, and therefore BECCS, as in the UK case study, is deployed both to generate renewable power and offset the residual emissions from the coal- and gas-fired power plants.

In terms of dispatch patterns, nuclear power, coal-CCS, and BECCS operate in baseload fashion while CCGT-CCS capacity operates in a conventional mid-merit fashion, with coal-CCS generating more power than gas-CCS or biomass. The remaining unabated CCGT and OCGT assets are constrained to operate in peaking capacity, with their emissions offset by BECCS. There is some additional nuance here. Owing primarily to the relatively low cost of coal in Poland, Coal-CCS has a lower marginal price than gas-CCS, and therefore coal-CCS dispatches ahead of gas-CCS. However, despite the relatively high marginal cost of BECCS, these assets primarily operate in baseload fashion. This has been observed before [37], and is driven by the additional value of BECCS in providing a negative emissions service, leading to the prioritisation of this technology.

As was observed in the UK case study, removing the option of deploying CCS technology for Poland – the No CCS scenario illustrated in figure 2.8 – has profound impacts on the Polish transition to a net zero emissions paradigm.

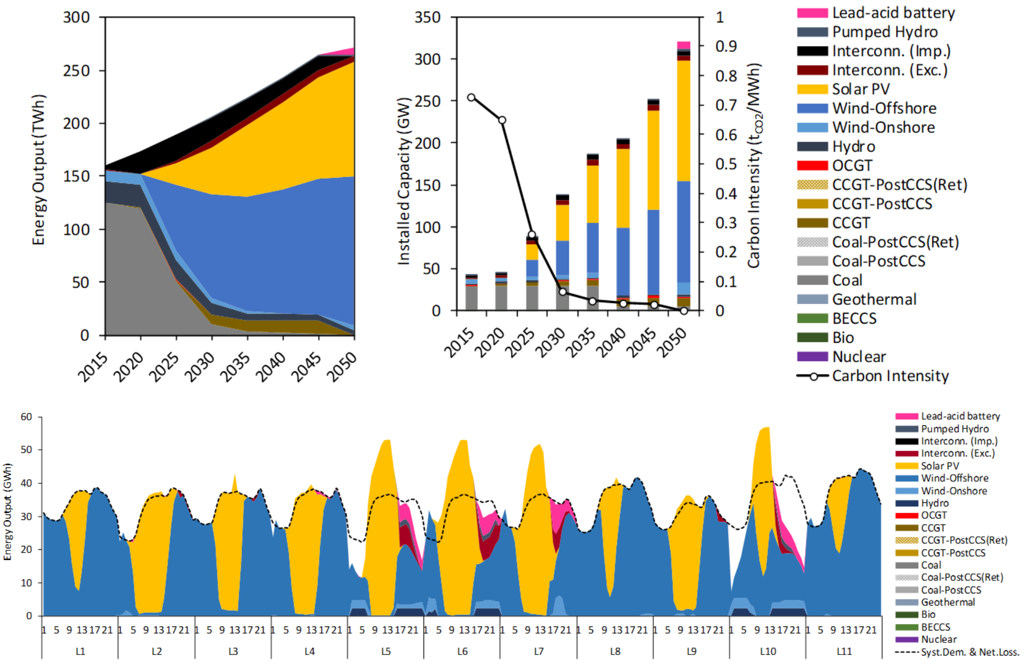

Figure 2.9: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for the power system in Poland under the Renewables and Storage scenario.

The combination of prohibiting CCS and the lack of incumbent nuclear power requires the rapid expansion of iRES capacity – by 2050 this is almost quadruple the capacity required under the BAU and All Technologies scenarios. As was observed in the UK case, this results in a system dominated by near-zero marginal cost assets, thus relegating nuclear power to essentially a back-up option, thus leading to the deployment of less nuclear capacity than would otherwise be possible.

Thus, in the No CCS scenario, despite the deployment of approximately 303 GW of capacity relative to a peak demand of approximately 42 GW we also see some compromises to security of supply.

Further eliminating the potential for deploying nuclear power, as in the Renewables and Storage scenario, presented in figure 2.8 exacerbates the challenges of meeting demand.

Owing to the combination of emissions constraints and a prohibition on the deployment of CCS and nuclear power, the Renewables and Storage scenario sees the abandonment of the coal industry by the mid-2030's and the stranding of a significant amount of CCGT assets from 2040. For both the No CCS and the Renewables and Storage scenarios, there is insufficient demand side response (DSR) capacity in Poland to make a material contribution to this case study. Hence, the role of the mechanism is negligible.

2.2.1 Poland case study: Concluding remarks

Figure 2.10 summarises the total system costs for energy system in Poland under different scenarios. The BAU and All Technologies scenarios have significantly lower system costs compared to the No CCS and Renewable and Storage scenarios. The cost of the Renewables and Storage scenario is the most expensive scenario, with costs being over three times greater than the All Technologies scenario (which has a net zero target).

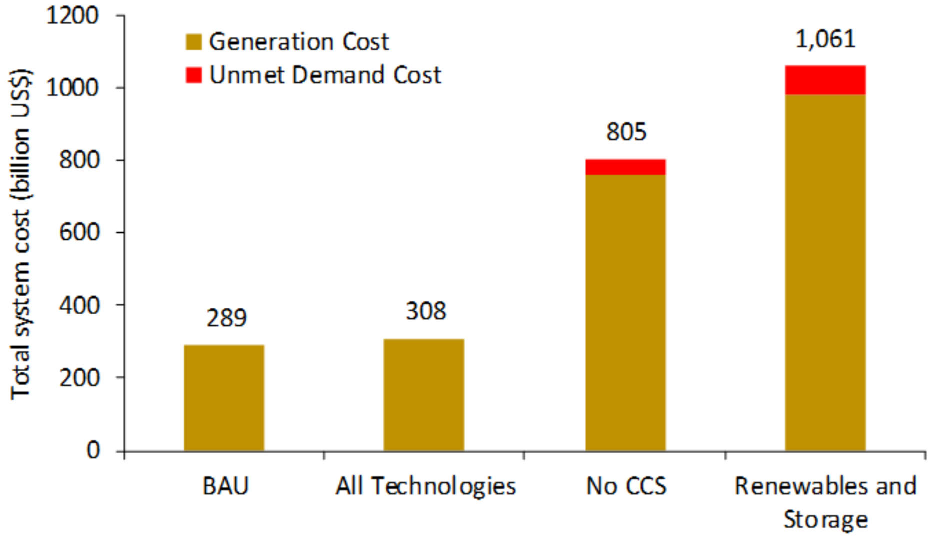

Figure 2.10: Total system costs of Poland system under different scenarios.

Relative to the BAU or All Technologies scenarios, over four times the deployment of installed generation capacity is required for the No CCS and Renewables and Storage scenarios. Consequently, these scenarios required capacity to be deployed at five times the historical deployment rate for Poland. Despite this accelerated rate of capacity deployment, there was still a material amount of unmet demand, resulting in the loss of power.

2.3 New South Wales

Similarly to Poland, coal dominates the existing electricity system in New South Wales (NSW). This is illustrative of the general significance of the coal industry in Australia. Pursuant to the Paris Agreement, Australia aims for a 26 - 28% reduction in CO_2 emissions by 2030 from a 2005 baseline. In July 2012, Australia introduced a carbon tax scheme to drive the decarbonisation of its energy system, which was subsequently repealed in 2014.

Despite being one of the worlds largest producers of uranium, Australia has no existing nuclear power plants, with nuclear energy being a source of contentious public debate since the 1950s. Similarly, there is currently no offshore wind generation capacity in Australia, though at least one offshore wind farm is currently in the planning stage in Victoria. Hence, in this study we assume that both offshore wind and nuclear are commercially available from 2030 onward, with the build rate assumed to be proportional to the UK's scaled on system size.

The results for the BAU scenario are presented in figure 2.11, and indicate that unabated coal-fired power generation continues to dominate in the system until 2050, though its share slightly declines as a result of the expansion iRES.

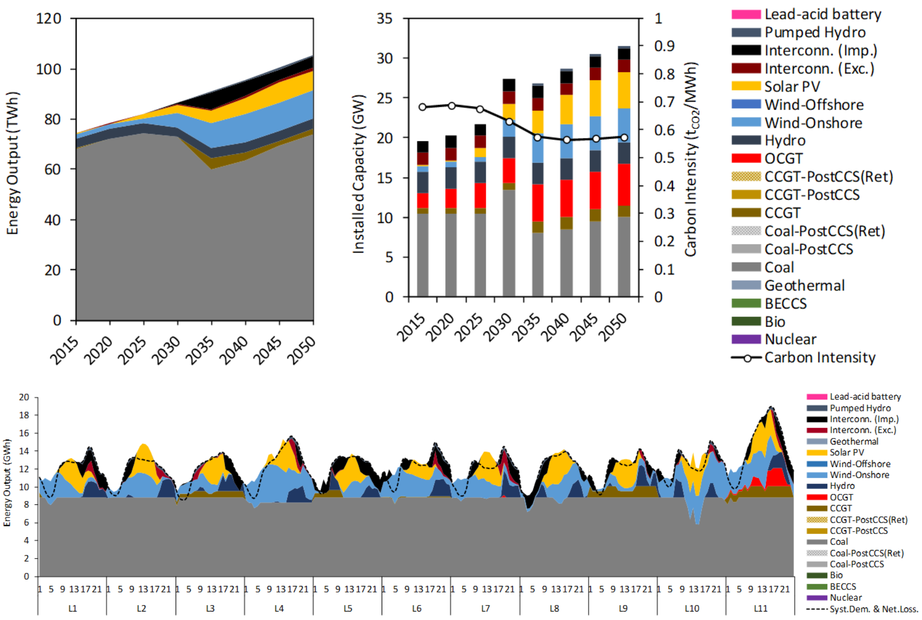

Figure 2.11: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for NSW power system under BAU scenario.

Interestingly, despite becoming available from 2030, offshore wind is not deployed and onshore wind continues to dominate. Moreover, nuclear power is never deployed in this scenario. Further, coal is observed to generally retain an essentially baseload operation role, and whilst increasing flexibility is required to accommodate the larger share of wind and solar power by 2050, coal is never entirely displaced from the grid. Consequently, carbon intensity of electricity in NSW declines from around 0.68 t_{CO_2}/MWh to around 0.57 t_{CO_2}/MWh, which is exclusively driven by the competitiveness of iRES.

The results of All Technologies scenario are presented in figure 2.12. The transition to net zero does results in a very substantial increase in the role of natural gas in the system.

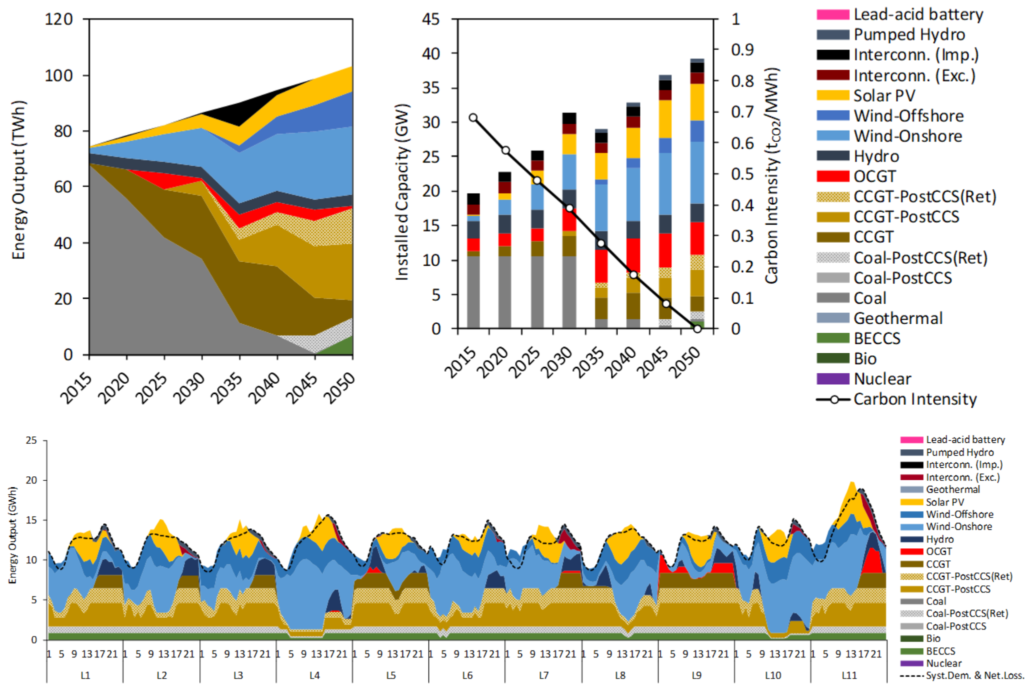

Figure 2.12: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for NSW power system under All Technologies scenario.

As can be observed, CCGT is expanded in the 2030s and displaces the new unabated coal that would otherwise have been added to the mix in that period. Gas-CCS is introduced from 2030, and CCS is finally retrofitted to the bulk of the remaining CCGT fleet in 2045–2050. The expansion of the coal fleet is not completely eliminated, however, and CCS is retrofitted to coal from 2045. As in previous case studies, BECCS is deployed towards the end of the period to offset residual emissions from both coal- and gas-fired power plants. Interestingly, despite being made available, nuclear power is not deployed in this scenario either. Offshore wind is, however, deployed from 2035. There is a substantial difference in system dispatch patterns relative to the BAU scenario. The increased deployment of iRES in the All Technologies scenario increases the requirement for the thermal plants to operate in a flexible load following manner.

As illustrated in figure 2.13, nuclear power is still not deployed in the No CCS scenario, and offshore wind capacity is deployed and rapidly expanded from 2035.

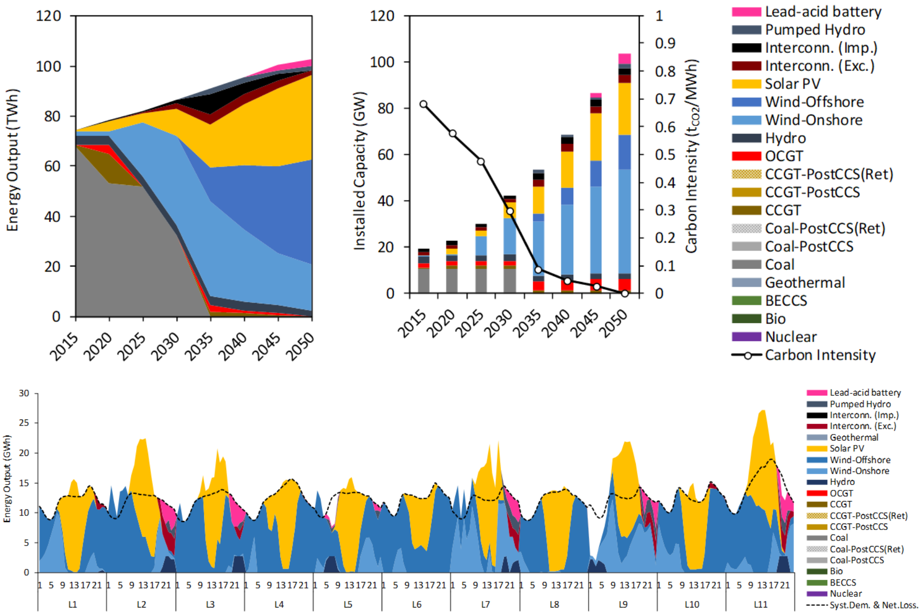

Figure 2.13: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for NSW power system under the No CCS scenario.

As can be seen in the dispatch patterns, if nuclear capacity is deployed, it will be severely underutilised and the capacity it provides for the system costs more than the value of lost load we assumed in this study. As might be expected, therefore, the system is dominated by iRES with the majority of power coming from offshore wind, owing to its higher capacity factor and better correlation with demand patterns.

As nuclear capacity is not selected under the No CCS scenario, the results for the Renewables and Storage scenario are similar to that of the No CCS scenario, and, as illustrated in figure 2.14, security of supply is again compromised, despite the availability of a very significant amount of capacity relative to peak demand.

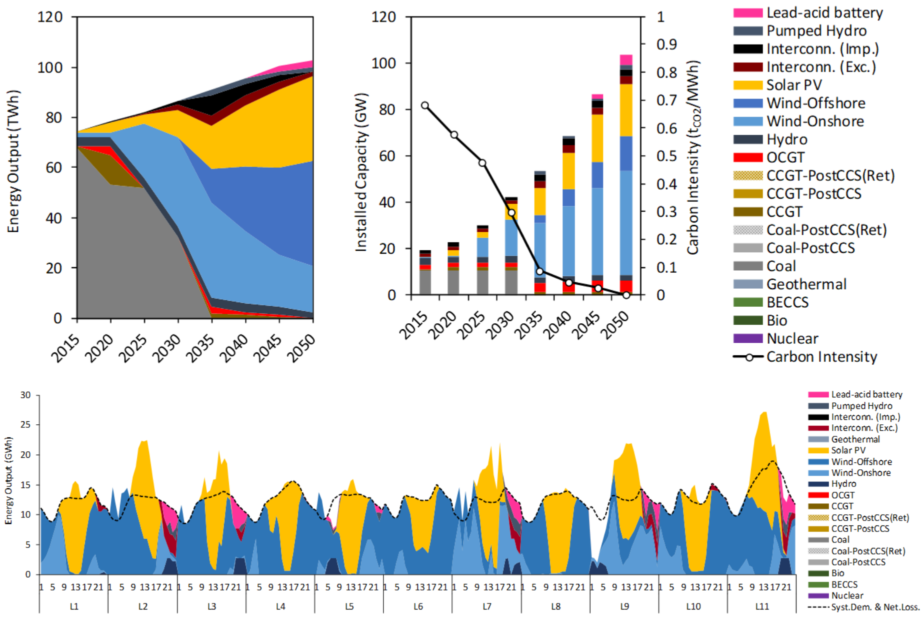

Figure 2.14: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for NSW power system under the Renewables and Storage scenario.

As iRES availability fluctuates, despite installed capacity being seven times bigger than peak load, the mismatch between supply and demand can be as high as 45% of peak load demand. The installation of large storage capacity with very low operating hours will be more costly than the value of lost load assumed in this study, *i.e.*, \$15,400/MWh.

2.3.1 New South Wales case study: Concluding remarks

In the BAU scenario, coal dominates the energy system until 2050, with some deployment of renewable power (mostly onshore wind). The projected nuclear price in Australia is relatively expensive, and consequently, nuclear is never deployed in the BAU scenario.

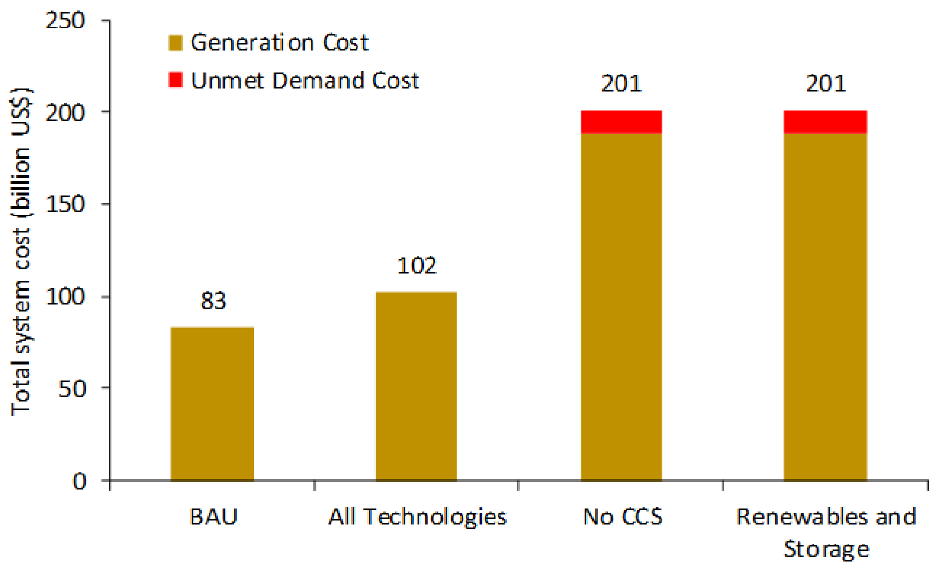

Figure 2.15: Total system costs of New South Wales system under different scenarios.

The All Technologies scenario achieves decarbonisation of the energy system by initially switching from coal power generation to natural gas generation, which provides significant reduction in CO_2 emissions. Nuclear power is not deployed in this scenario. Any coal plants that retire are replaced by unabated gas and gas-CCS plants. Some existing coal plants that have not retired are retrofitted with CCS. By 2050, all unabated coal and gas power plants are replaced with coal- and gas-CCS (both new build and retrofitted). The deployment of some BECCS capacity is also necessary to offset the residual emissions from coal- and gas- CCS.

In the No CCS scenario, the energy system is dominated by intermittent renewable power. There is finally some limited deployment of nuclear, however, it is underutilised. With the high penetration of iRES and no CCS, nuclear is used as an expensive option for system flexibility. The installed capacity of offshore wind is less than onshore wind in both the No CCS and Renewables and Storage scenarios. However, offshore wind provides a higher contribution to the electricity generation mix. Compared to onshore wind, offshore wind in New South Wales operates at higher capacity factors and its availability has a better match with demand.

The total system costs is lowest with the BAU and All Technologies scenarios (figure 2.15). However, total system costs double in the No CCS and Renewables and Storage scenarios, which predominantly deploy intermittent renewable energy. It is important to note that this study does not account for the potential for issues associated with public acceptance, which could delay or reduce the rate of technology deployment.

2.4 Java-Madura-Bali (JAMALI) System (Indonesia)

Indonesia is an island nation, and therefore its electricity system is composed of many systems disconnected from each other. The largest of these systems in Indonesia is the Java-Madura-Bali (JAMALI) system and provides approximately 60% of the electricity demand. Although the electrification ratio is already 100%, the consumption per capita is relatively low at 800 kWh/capita.yr, compared to the consumption in developed countries – normally greater than 7000 kWh/-capita.yr.

Indonesia's electricity demand is anticipated to grow rapidly, with a forecast rate of 6.7%/yr. This is elastic to the rate of economic growth of 5.1%/yr. Indonesia's energy system is currently dominated by fossil fuels, and, similarly to Australia, Indonesia has no experience with nuclear power. Therefore, this study assumes nuclear power is unavailable until 2035. However, once nuclear is available, we assume that the build rate is equivalent to that of the UK, owing to the rapidly growing demand.

The price of electricity in Indonesia is heavily regulated, as is the price of fossil fuels (natural gas and coal) *via* the domestic market obligation (DMO) policy imposed by the government. This leads to the coal price being capped at a maximum price of $70/t for electricity generation. Moreover, whilst Indonesia is currently a net exporter of natural gas, it is likely to become a net importer in the near future, increasing its exposure to the international gas markets. Relative to historical gas prices in Indonesia, international prices are very expensive, influenced by regional natural gas markets, with the price heavily linked to the world oil price and in competition with export markets to East Asia (Japan, China, and South Korea), which results in a high price of LNG. Therefore, unlike in other case studies where fuel price forecasts are readily available, for Indonesia, the price of natural gas is calculated using the following equation:

$$Price_{NaturalGas} = 11.2\% ICP + 0.4[\$/MMbtu] \tag{2.1}$$

where *ICP* is the price of crude oil in Indonesia, which is, in turn, based upon the West Texas Intermediate (WTI) price forecast. Finally, contrary to what might be expected, the availability of wind and solar power in Indonesia is relatively poor, effectively increasing their costs in this scenario.

Thus, in the BAU scenario, shown in figure 2.16, the electricity mix in Indonesia does not significantly change and continues to be dominated by coal providing baseload power, a CCGT mid-merit and a small amount of OCGT peaking capacity.

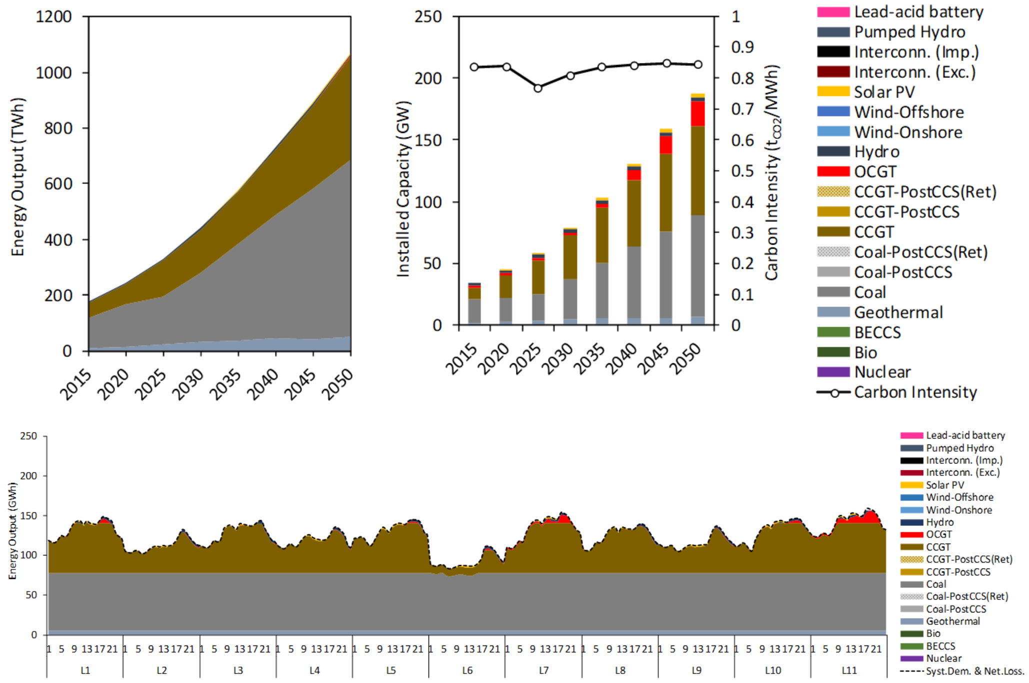

Figure 2.16: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for JAMALI power system under the BAU scenario.

Therefore, without the implementation of binding climate targets, the carbon intensity remains effectively constant, and total CO_2 emissions increase at a rate commensurate with increased power demand. Although alternative energy sources such as nuclear, geothermal and iRES could, in theory, be relatively competitive, the rate at which they can be deployed in this context significantly reduces their competitiveness with coal- and gas-fired power generation. Another factor that hinders the development of iRES in JAMALI is a relatively low wind speed. This results in potential Indonesian wind farms, having a lower capacity factor than might be otherwise expected, which, in turn, increases the cost per MWh_e. The combination of those factors and the strong rate of growth in

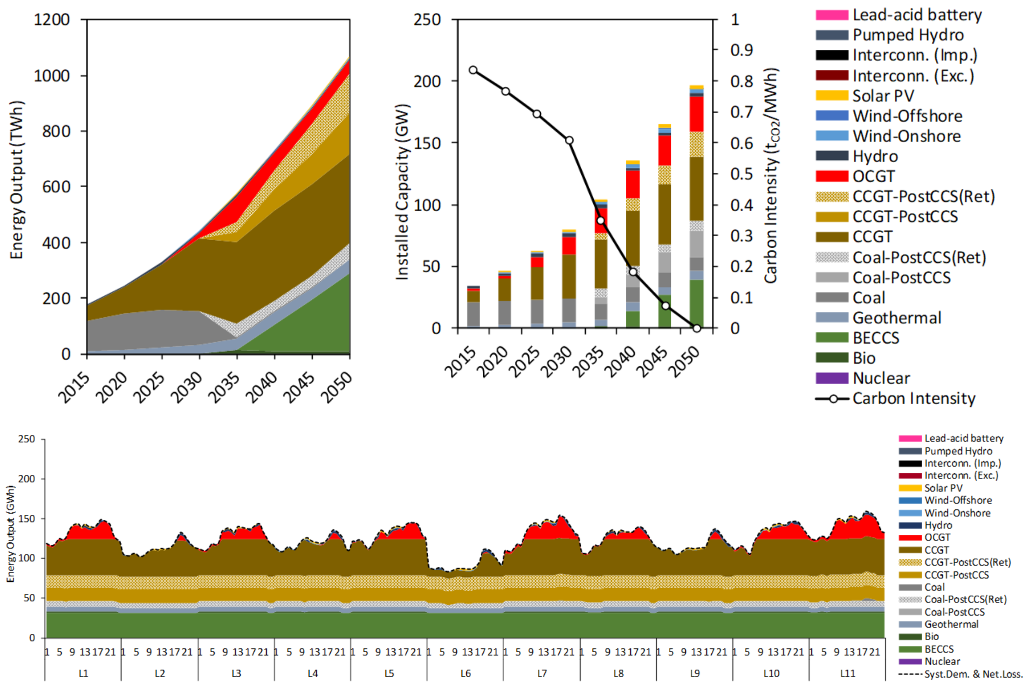

Figure 2.17: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for JAMALI power system under the All Technologies scenario.

electricity demand favours the deployment of technology with firm capacity with a high build rate, *i.e.*, coal and CCGT in this scenario.

The combination of a net zero target in 2050 and the rapid growth in electricity demand presents a unique challenge to Indonesia's system. Owing to growth in electricity demand, the continued use of legacy power plants is important to maintain security of supply and enable growth in demand. Attempting to deploy both replacement and additional capacity at a rate commensurate with projected demand growth is significantly beyond what is judged feasible in this context. The results of the All Technologies scenario for Indonesia are illustrated in figure 2.17.

Given the projected rate of increase in energy demand, Indonesia is unlikely to immediately reduce national CO_2 emissions under any realistic scenario. Hence, in the 2015 Paris Agreement, Indonesia pledged to reduce its CO_2 emissions by 29% of the BAU scenario by 2030. Therefore, in the scenarios with a net zero emissions target in 2050, we allow absolute Indonesian emissions, *i.e.*, Mt_{CO_2}/yr,

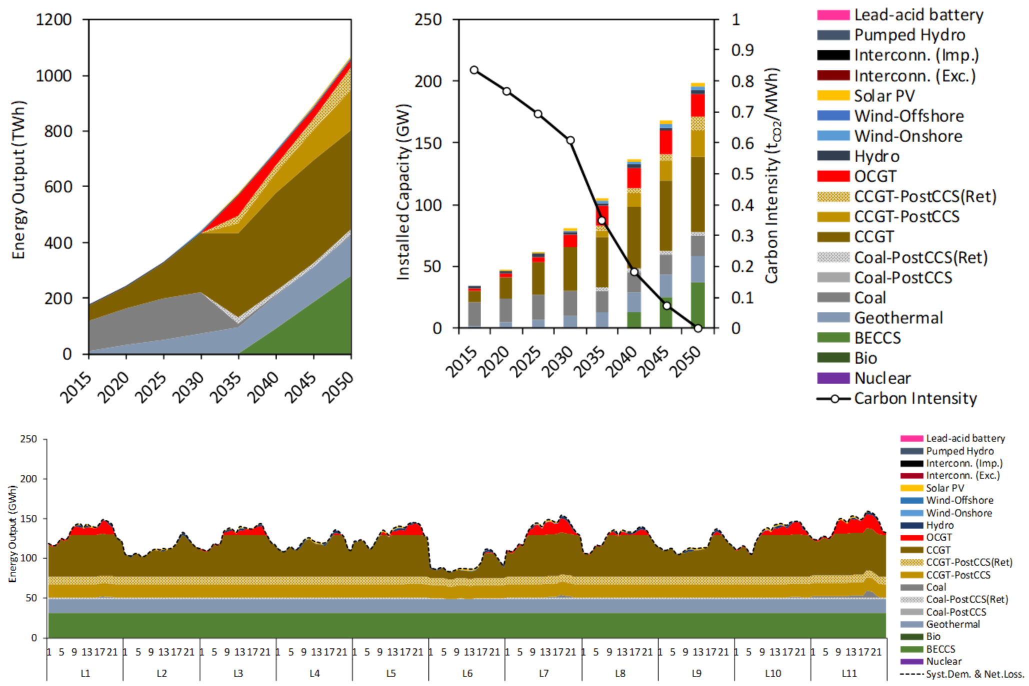

Figure 2.18: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for JAMALI power system under the Geothermal scenario.

to increase until 2030, and thereafter reduce in order to deliver net zero by 2050.[6]

Thus, owing to the continued dominance of fossil energy in Indonesia, in order to eliminate CO_2 emissions by 2050, all CCS technologies, *i.e.*, coal-CCS, CCGT-CCS, and BECCS, will play an important role. CCS is retrofitted to existing coal and gas power plants from 2030. Thereafter, additional gas capacity is deployed with CCS. Owing to low build rate of iRES, and limited build rate of coal- and CCGT-CCS, unabated CCGT remains an important technology to meet the increasing demand of electricity in JAMALI system. Consequently, BECCS emerges as a key technology to ensure security of supply and achieve net zero emissions by 2050.

Although Indonesia has significant potential for the deployment of geothermal power, owing to geographical challenges and costs associated with developing geothermal sites, the rate at which this energy source has historically been developed is very low. However, given the potential of geothermal power in Indonesia, a scenario with accelerated deployment of geothermal power has been explored

[6] Importantly, this is not the same as allowing the *carbon intensity*, *i.e.*, t_{CO_2}/MWh to increase.

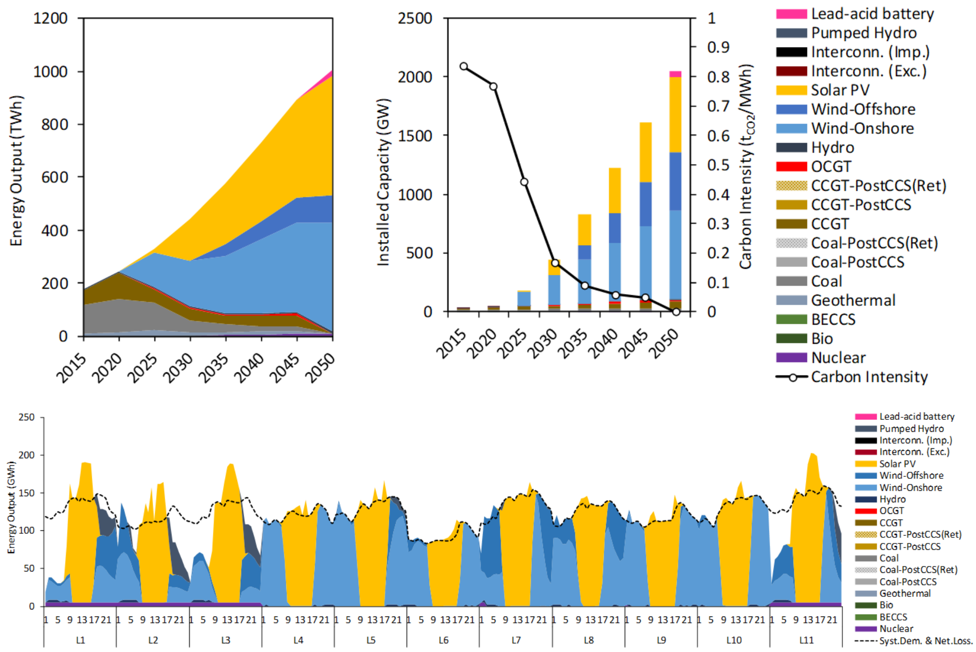

Figure 2.19: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for JAMALI power system under the No CCS scenario.

- the Geothermal Scenario - with results presented in figure 2.18.

The key observation is that if the build rate of geothermal plants is accelerated, geothermal can provide significant value to the system by reducing the total system cost by \$62 billion (around 6% of the total system cost). Geothermal is a near-zero marginal cost source of firm power, which also provides ancillary services to the electricity system. As a result, an expansion of geothermal displaces a portion of almost every other generator from the grid. Importantly, the fact that geothermal also displaces CCS means that the quantity of negative emissions required to offset residual CO_2 emissions is also reduced. Importantly, geothermal is itself not an absolutely zero-emissions technology, emitting between 4 and 740 kg_{CO_2}/MWh of power generated, with an average carbon intensity of 122 kg_{CO_2}/MWh [38]. Therefore, it also incurs a carbon debt to be offset *via* CCS or, as in this study, BECCS. As before, owing to the dual service of CO_2 removal and power generation, BECCS is observed to provide a baseload service, and CCS, particularly gas-CCS, operates in a load following fashion.

As might be anticipated, removing CCS from the portfolio of technologies has a profound impact on the structure of the system. This is illustrated in figure 2.19 wherein the results of the No CCS scenario for the Indonesian case study

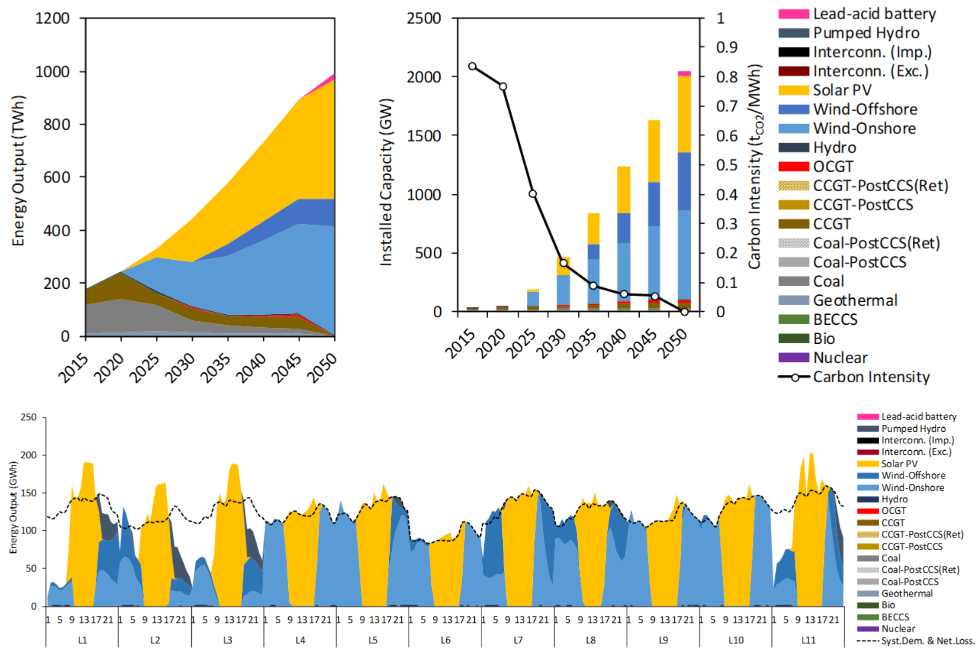

Figure 2.20: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for JAMALI power system under the Renewables and Storage scenario.

are presented.

Prohibiting CCS in Indonesia, for the first time, precipitates the deployment of nuclear power. However, as with the other case studies, the combination of a relatively high capital cost and relatively low deployment rate mean that this is a relatively costly option for providing flexibility to the grid. Moreover, as has been discussed before, the high rate of deployment of iRES significantly curtails the limited amount of nuclear power that is deployed. As can be further observed from figure 2.19, the combination of low wind speed and relatively high capital cost disadvantage offshore wind relative to onshore wind. A further observation is that this scenario required an iRES build rate two hundred and fifty times greater than the historical build rate. This accelerated rate of deployment needs to begin from the first planning period, *i.e.*, from 2020. Similar results are also obtained for the Renewables and Storage scenario, as illustrated in figure 2.20.

For both the No CCS and Renewables and Storage scenarios, the system size is over 2,000 GW in 2050, or an order of magnitude greater than what is required in the BAU, All Technologies, or Geothermal scenarios. This is relative to the initial level of installed capacity of 35 GW.

2.4.1 Java-Madura-Bali (JAMALI) case study: Concluding remarks

In the BAU scenario, coal and gas power dominates the JAMALI system continuously until 2050, with a small proportion of geothermal and negligible share of iRES. A reduction in annual system emissions is unlikely. This is due to the mismatch between the historically low build rates of low carbon energy technologies and the rapid growth of electricity demand, which exacerbates further upon imposing immediate constraints on CO_2 emissions.

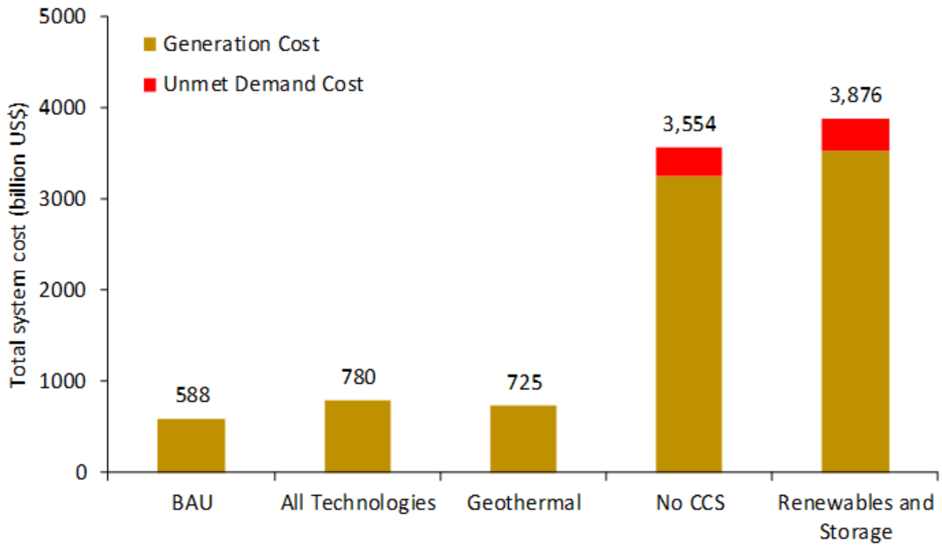

Figure 2.21: Total system costs of JAMALI system under different scenarios.

In the BAU scenario, coal and gas power dominates the JAMALI system continuously until 2050, with a small proportion of geothermal and negligible share of iRES. A reduction in annual system emissions is unlikely. This is due to the mismatch between the historically low build rates of low carbon energy technologies and the rapid growth of electricity demand, which exacerbates further upon imposing immediate constraints on CO_2 emissions.

To accommodate the rapid growth in demand in the scenarios with a net zero emissions target (*i.e.*, All Technologies, Geothermal, No CCS and Renewables and Storage), a CO_2 emissions "inertia" is permitted until the year 2030. Beyond 2030, the CO_2 emissions need to be reduced significantly to reach net zero by 2050. To ensure the system capacity growth meets the rapidly increasing electricity demand, the use of legacy power plants becomes essential. Therefore, a high fraction of existing unabated fossil fuel power plants remain in use (observed in the BAU, All Technologies and Geothermal scenarios). Negative emissions technologies such as BECCS have an important role in offsetting the CO_2 emissions from thermal power plants.

In the Geothermal scenario, electricity from retrofitted CCS plants will be significantly displaced by geothermal, with unabated CCGT remaining in operation and unabated coal not utilised. Geothermal provides firm power and ancillary services at near-zero marginal cost with lower CO_2 emissions than CCS plants. As geothermal displace CCS plant, the negative emissions required to offset residual emissions decreases, thereby reducing the need for BECCS.

Intermittent renewables dominate the energy system in both the No CCS and Renewables and Storage scenarios. To meet the rapidly growing demand in electricity, the iRES build rates must accelerate to 250 times the historical build rate of renewables. The high penetration of iRES in the system requires less baseload generation and more flexibility. Without CCS, the system underutilises the installed nuclear capacity to provide flexibility. Whilst it is possible to operate nuclear power in a non-baseload manner, it must be noted that this is a highly specialised skill set, and the complexity of this approach should not be underestimated. Operating a system dominated by iRES will also require a specialised skill set, and a workforce will have to be trained.

Figure 2.21 shows that the BAU, All Technologies, and Geothermal scenarios have relatively consistent costs, which indicates that Indonesia can achieve both targets for economic growth and net zero CO_2 emissions. However, this becomes significantly more challenging in the context of the No CCS and Renewables and Storage scenarios, where system costs and build rates need to be significantly higher. It is interesting to observe that JAMALI system has one of the highest relative increases in total system costs without CCS. Further, the instances of lost load are some of the most severe yet observed.

2.5 United States of America

The US is the second largest electricity consumer in the world after China. In 2018, the total electricity consumed by the US was 4480 TWh/yr, of which, 28% was generated from coal, 34% from gas, 19% from nuclear, and the remaining 18% was generated from renewable sources. Unlike our other case studies, energy policy in the US is determined at the federal, state, and local levels. Currently, there is no federal carbon carbon tax scheme in the US, and in order to reduce the carbon intensity of electricity, some states, *i.e.*, California and ten state members of the Regional Greenhouse Gas Initiative (RGGI), have already implemented a CO_2 cap and trade scheme [39]. However, there are federal level initiatives to encourage the reduction of CO_2 emissions at a wider scale, namely the 45Q and 48A tax credits.

The 48A investment tax credit has its origins in the 2005 Energy Policy Act where $500 million for advanced coal-based generation technologies (ACBGT), at a 15% tax credit rate[7]. By 2006, nearly $1 billion in investment tax credits had been awarded to nine clean coal projects in nine states out of 49 companies from 29 states that originally applied for a total of $5 billion requested in tax credits.

Thereafter section 48A the 2008 Energy Improvement and Extension Act authorised an additional $1.25 billion in investment tax credits for IGCC and ACBGT projects under Section 48A and an additional $250 million for qualified gasification projects under section 48B. At this point the 48A tax credit rate increased to 30% for qualifying advanced coal projects generating electricity that also capture and sequester at least 65% of their CO_2 emissions. It is important to note that credits allocated under sections 48A and 48B with five- and seven- year in-service deadlines, which means once tax credits are allocated, project developers have five or seven years to place the project in service. In the past, project cancellations have resulted in forfeiture of hundreds of millions owing to this deadline.

As of 2019, 48A is fixed at a tax credit rate of up to 30%, and the minimum CO_2 capture percentage was raised to 70%, with projects having five years from the date at which the tax credit is issued to place the project in service. Finally, the current scheme allows for up to $2,550 million for both IGCC other ACBGT.

[7] Note that this excludes gasification projects, as they were explicitly dealt with under section 48B which allocated $800 million at a 20% tax credit rate

As can be observed, the 48A tax credit has a history of being extended and increased and therefore, the 48A tax credit assumed for this study has been expanded compared to the current program.

The 45Q tax credit was introduced by the Emergency Economic Stabilization Act of 2008 to provide a tax credit for each metric ton of CO_2 geologically stored, or used in enhanced oil recovery (EOR). Originally the value of the credit was set at \$10/t_{CO_2} for EOR, and \$20/t_{CO_2} for geologic storage. The 45Q credit was then ammended in 2009 to introduce a 10-year ramp up to \$35/t_{CO_2} stored through EOR, to \$35/t_{CO_2} converted to, *e.g.*, fuels, chemicals, *etc*, and finally up to \$50/t_{CO_2} per ton for CO_2 stored in geologic formations and not used in EOR. At the time of writing, post-2026 the credit will be adjusted to increase with inflation. Importantly, the amended version for not include a cap on credits, though in order to claim credits, projects must begin construction before January 1st, 2024, and thereafter can be claimed for up to 12 years after facility startup.

This section presents modelling results that illustrate the value and role of CCS in the US power system. Owing to the size of the US electricity system and its diverse characteristics, we select the Electric Reliability Council of Texas (ERCOT) and PacifiCorp East (PACE) systems as case studies. The 4 main scenarios (BAU, All Technologies, No CCS, and Renewables and Storage) are presented alongside three additional US-specific scenarios, which evaluate the impact of potential changes to the 45Q and 48A tax credit schemes on the decarbonisation pathways for the ERCOT and PACE systems. In order to ensure consistency with the other case studies, the scenarios evaluated in sections 2.5.1 and 2.5.2 do not include EOR as an option, and assume that captured CO_2 is exclusively geologically sequestered. The impact of including CO_2-EOR is subsequently evaluated in section 2.5.3. Finally, our reference case assumes that 45Q is only available for 12 years, but that plant can be constructed at any time before 2050.

2.5.1 Electric Reliability Council of Texas (ERCOT)

Currently, electricity demand in ERCOT is mainly met by natural gas, coal, onshore wind and nuclear, as shown in figure 2.22. Interestingly, under this scenario, the share of coal in ERCOT remains relatively constant, and the onshore wind capacity is anticipated to expand. Although CO_2 emission reduction targets are not imposed on the system in the BAU scenario, the availability of tax credits encourages the development of coal-CCS plant over unabated fossil fuel and nuclear plants. Consequently, as existing capacity retires, they are replaced with new coal-CCS plants. Some of the existing coal plants are also retrofitted with CCS. Although the capital expenditure of coal-CCS (taking into account the 48A tax credit) remains higher than CCGT-CCS, coal-CCS is further privileged over gas by the 45Q scheme, which provided tax credit based on the quantity of CO_2 captured. Interestingly, the existing nuclear fleet appears to retire after 2035, and – again owing to the combination of 45Q and 48A, is replaced by coal-CCS.

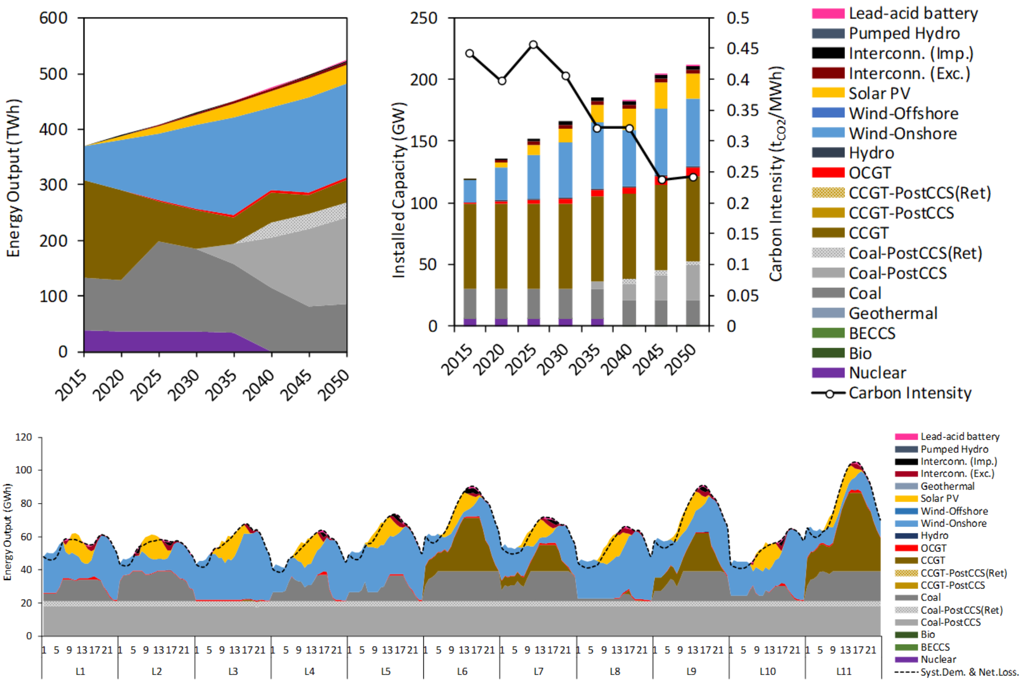

Figure 2.22: Power output (TWh) and installed capacity (GW) by technology for ERCOT power system under the BAU scenario.

In 2050, coal-CCS will provide baseload generation for ERCOT, whereas existing unabated coal operates in load following mode. Although the share of existing

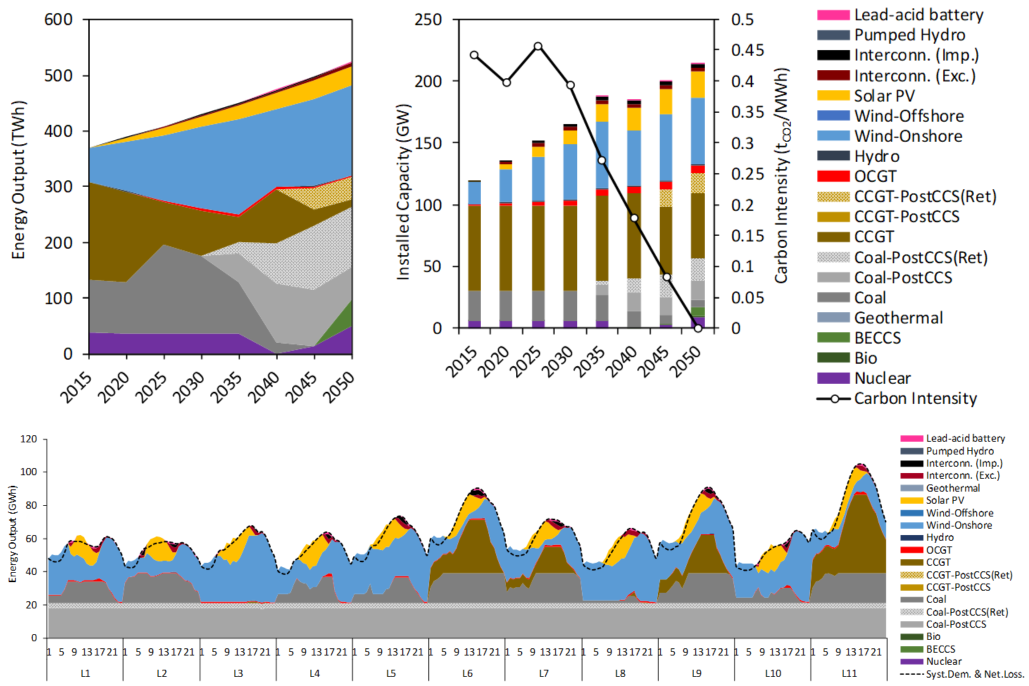

Figure 2.23: Power output (TWh) and installed capacity (GW) by technology for ERCOT power system under the All Technologies scenario.

natural gas plants in the system significantly decreases, these plants will play a critical role by providing peaking power generation and back-up capacity when the availability of wind and solar PV is low. Therefore, the combination of cost reductions in renewable power – particularly wind – and the availability of the 45Q and 48A credits reduce the carbon intensity of the ERCOT grid to approximately 0.25 t_{CO_2}/MWh by 2050.

It is therefore interesting to note that, as can be observed in figure 2.23 for the first time, introducing a net zero emissions target for 2050 does not appear to very significantly change the structure of the electricity system. As in the BAU scenario, coal remains an important source of electricity in the ERCOT system. However, in comparison with the BAU scenario, electricity is primarily generated from coal-CCS power plants, with both retrofit and new-build playing an important role. For natural gas plants, only a small fraction of the existing plants are retrofitted with CCS. However, this fraction of retrofitted gas-CCS generates predominantly more electricity than the unabated power plants. Finally, once again, BECCS is observed to supply the negative emissions to offset the residual emissions, and nuclear power persists throughout the period.

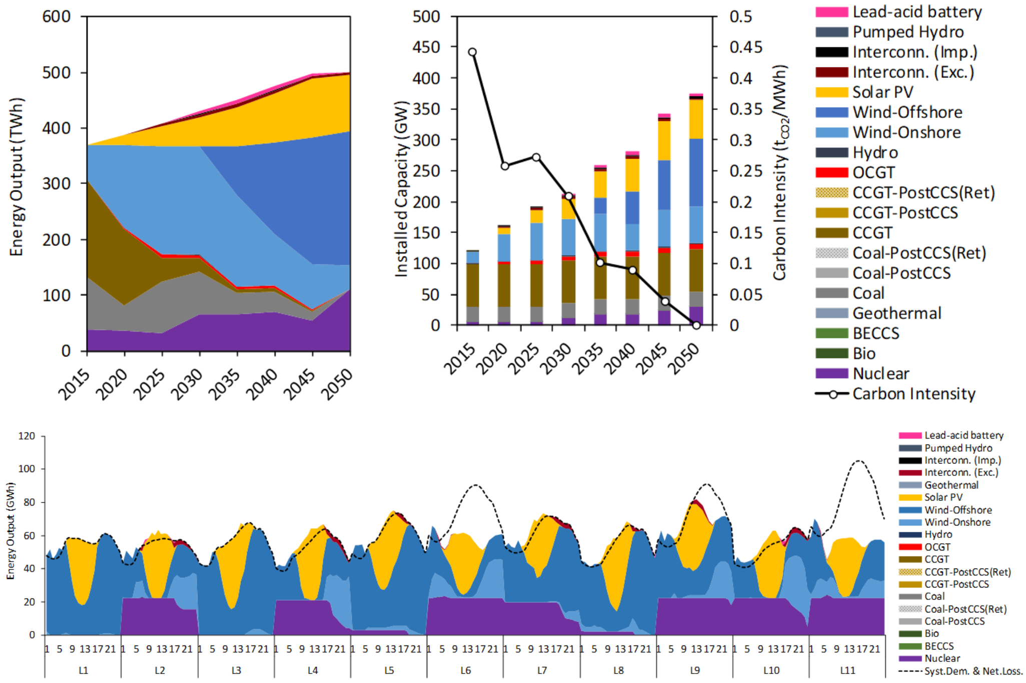

Figure 2.24: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for ERCOT power system under the No CCS scenario.

Owing to the benefits of the 45Q scheme and low fuel cost, coal-CCS operates as baseload generation, and is therefore dispatched ahead of nuclear power but behind renewables. In contrast, gas-CCS has higher fuel cost and lower tax credits on a per MWh basis of electricity generated. Therefore, the gas-CCS plants provide a load following service and are dispatched ahead of existing unabated gas, which, in turn, act as peaking generation when availability of renewable power is low.

The results of the No CCS scenario for the ERCOT case study are presented in figure 2.24. As with the other case studies, the No CCS scenario for ERCOT is characterised by a rapid expansion of renewable power, with iRES generating the majority of power. Whilst offshore wind was not selected in the BAU and All Technologies scenarios due to its substantially higher capital cost compared to onshore wind and solar power, offshore wind emerges as an important technology to achieve net zero emissions in the No CCS scenario. In comparison with other iRES, offshore wind promises more reliability, Which reduces the need for technologies that provide flexibility and security of supply. Nevertheless, substantial amounts of power demand go unmet in this scenario.

In the No CCS scenario, the ERCOT nuclear capacity is is maintained and expanded, and is observed to operate with a high frequency of start-up/shut-down cycles. Nevertheless, when the availability of iRES is low and the demand is high, there are several instnaces of unserved demand owing to the cost of nuclear backup being more expensive than the value of lost load, which is assumed to be $15,400/MWh.

As was observed in the previous case studies, for a system with a high share of iRES, the frequency of system oversupply increases. Subsequently, the operating hours of baseload generation decreases, *i.e.*, the scope for a reasonable case for investment for firming capacity decreases. This implies that if countries or regions are to pursue this strategy, there may be significant value in policy support for firming capacity, as in the Capacity Market in the UK.

The Renewables and Storage scenario presented in figure 2.25 has similar results to the No CCS scenario, with offshore wind again providing the largest share of electricity in the ERCOT system.

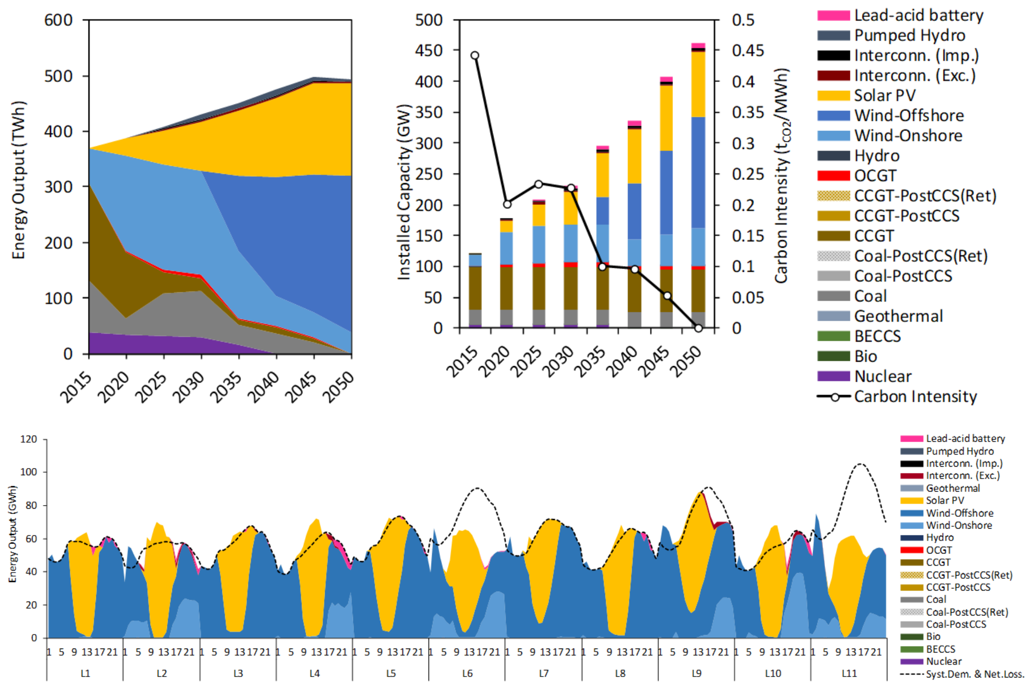

Figure 2.25: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for ERCOT power system under the Renewables and Storage scenario.

Contrary to the BAU and All Technologies scenarios, solar PV generates more electricity than onshore wind in the No CCS scenario and is the largest share under the Renewables and Storage scenario. This is because the availability of solar PV most closely matches the residual load of the ERCOT system after the generation by offshore wind has been accounted for. In the Renewables and Storage scenario, a limited capacity of battery storage is installed (figure 2.25), providing some back-up for the system to an extent. However, a significant quantity of unserved demand is expected. Without dispatchable generation technologies, the ERCOT system must increase its installed capacity to around 450 GW, or approximately four times the size of the current system.

2.5.2 PacifiCorp East (PACE)

PacifiCorp East (also known as Rocky Mountain Power) serves the Wyoming, Utah and Idaho electricity markets. Although it serves three states, power generators connected to this operator are located in Wyoming and Utah. The state of Wyoming has an abundance of coal, and consequently most of the existing generators are coal-fired power plants. However, many of those plants have been in operation for several decades and are scheduled to retire within the next 20 years. In contrast, electricity generation in the state of Utah predominantly comes from coal, however, a significant proportion is generated from natural gas-fired power plants [40].

In the regions served by the PACE system, the electricity demand is primarily industrial. In other words, there is very little seasonality associated with this demand, which, in turn, encourages the development of baseload power generation. This is reflected in the forecast of the BAU scenario for the PACE system, presented in figure 2.26. Here, coal-fired power generation dominates the electricity mix in the PACE energy system throughout all of the time periods, with gas and renewable power playing a relatively minor role.

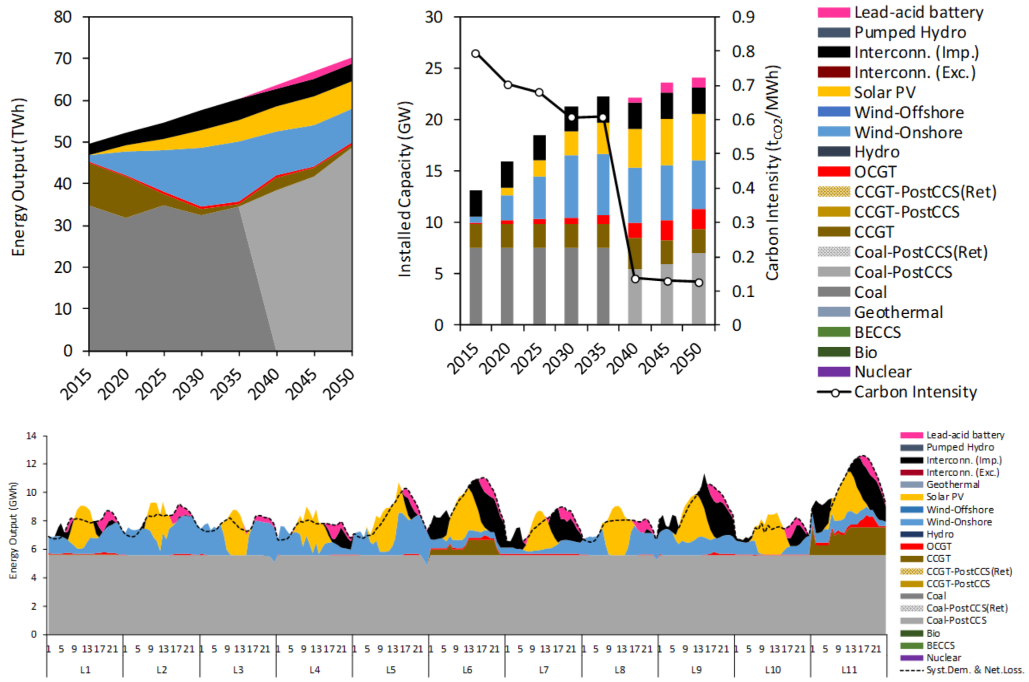

Figure 2.26: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the BAU scenario.

Owing to a projected increase in the price of natural gas, the role of "load following" generation shifts from being provided by unabated CCGT power plants to a combination of onshore wind, solar PV and battery storage. Although net zero targets are not imposed on the system, carbon intensity in PACE between 2015 and 2035 is expected to decline following the shift from natural gas power to renewables and storage. Assuming the 45Q and 48A tax credits remain effective, carbon intensity of the system drops from 0.6 t_{CO_2}/MWh in 2035 to around 0.12–0.15 g_{CO_2}/kWh in 2040 to 2050 as retired coal power plants are being replaced by coal with CCS.

Even if CO_2 emissions from the system are constrained to meet a net zero target by 2050, as is the case in the All Technologies scenario presented in figure 2.27, the configuration of the electricity system does not qualitatively change.

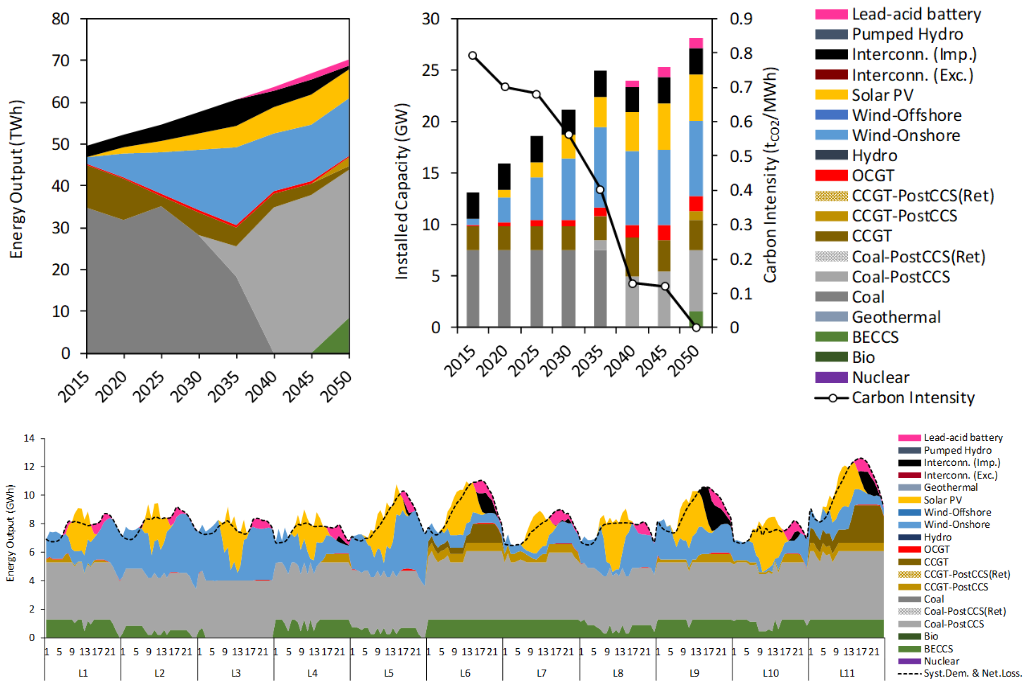

Figure 2.27: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the All Technologies scenario.

The primary differences would appear to be that CCS is applied to coal slightly earlier, and some BECCS capacity is deployed in the final periods to offset the residual emissions from the coal- and gas-fired power plants. The amount of power generated by gas (both OCGT and CCGT) remains low, and there is a substantial expansion of wind, solar, and battery storage capacity.

Under the No CCS scenario, the prohibition on CO_2 sequestration negates the utility of the 45Q and 48A tax credits, and consequently nuclear power is rapidly expanded from 2030 and thereafter nuclear power generates the majority of electricity in the PACE system as illustrated in figure 2.28.

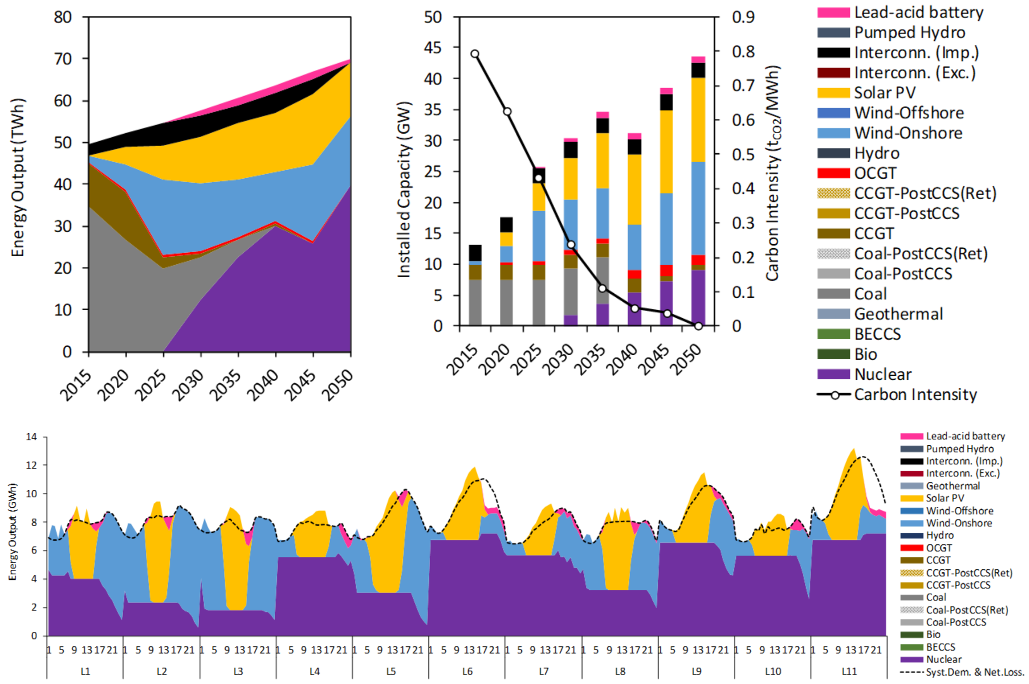

Figure 2.28: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the No CCS scenario.

The PACE system results are distinct from the other case studies, where the absence of CCS in a system tends to result in low contribution from nuclear. However, the relative lack of seasonality exhibited by the PACE system favours the deployment of baseload generation such as coal-CCS and nuclear. Nevertheless, by 2050, the operational pattern of nuclear is far from baseload. Without CCS to provide system flexibility, other technologies are used to balance the system in response to increasing deployment of iRES. Additional nuclear is deployed and operated at lower capacity factors to provide flexibility. A final interesting point is that, owing to the deployment of nuclear power, this instance of the No CCS scenario only results in approximately a doubling of deployed capacity relative to the BAU scenario.

As illustrated in figure 2.29, eliminating both CCS and nuclear power in the Renewables and Storage scenario necessarily greatly increases the dependence on renewable power.

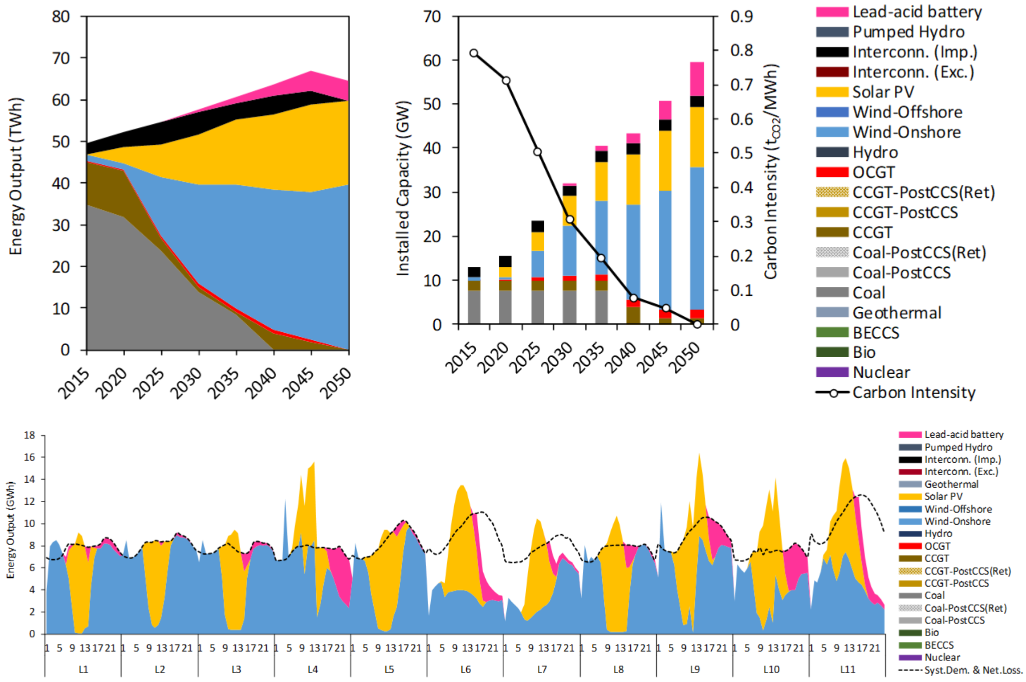

Figure 2.29: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the Renewables and Storage scenario.

The PACE system is land-locked, and lacks access to offshore wind energy, which is more reliable than onshore wind and solar PV. With only iRES and storage available, the PACE system will experience frequent loss of load in 2050 owing to the large mismatch between hourly iRES availability and system demand. Given the prevalence of industrial demand in the PACE grid, the value of lost load is particularly high. Although energy storage technologies play an important role in this scenario, the level of deployment that can be achieved is nevertheless relatively small, and is insufficient to ensure security of supply. As can be observed from figure 2.29, the capacity of energy storage needed to secure the electricity supply can be as high as 7.6 GW, which is equivalent to 60% of the peak load demand, thus, owing to system costs arising from round trip efficiency, charge and discharge duration, and sheer quantity of generation capacity required, reliance on battery energy storage would be uneconomical.

2.5.3 The impact of 48A & 45Q tax credits and EOR payments

As discussed in the introduction to this section, the US system of tax credits is part of a dynamic and continuously evolving landscape, with the level, duration, and cap on the different instruments subject to continuous revision. Each revision has the potential to significantly effect the economics of electricity system transition, and, in the case of 45Q and 48A, improve the economics of CCS and promote its deployment. However, it is important to note that the efficacy of these mechanisms will vary with jurisdiction and coexisting mechanisms. For example, in addition to the availability of the 45Q and 48A tax credits, in September of 2018, California – then the fifth largest economy in the world – passed Senate Bill 100 (SB 100) which stated that "eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045". Several other US states, such as New Mexico, Washington, Nevada, and Maryland, have adopted similarly ambition clean energy targets[8]. Currently, 37 US states have renewable energy directives, with Texas, in 1999, setting a renewable energy standard to deploy 5 GW of renewable capacity by 2015 and 10 GW by 2025[9]. Therefore, it is of interest to evaluate the impact of changes to the 45Q and 48A mechanisms on the evolution of the PACE and ERCOT grids. To this end, three additional US-specific scenarios have been developed and described as follows:

1. **48A + 45Q + EOR**: Extends the All Technologies scenario to include using CO_2 for EOR and accounts for the additional revenue.
2. **48A-ext + 45Q + EOR**: As above but with the extension of the 48A scheme to be applicable for all coal-CCS plants built any year within the period.
3. **EOR Only**: Assumes that 45Q and 48A are discontinued and that only EOR is available to support CCS.

As illustrated in figure 2.30, under the 48A + 45Q + EOR scenario, the share of coal-CCS increases significantly relative to what was observed in figures 2.23

[8] It is important to note some nuance in language, however. Some states aim for "renewable" energy, others "clean and renewable", and still others simply "clean". The analysis presented in this report would suggest that a broad portfolio approach to this transition is vital to ensure a cost-optimal transition.

[9] Texas surpassed this target in 2009

(ERCOT) and 2.27 (PACE), and almost entirely displaces gas from both the ERCT and PACE grids.

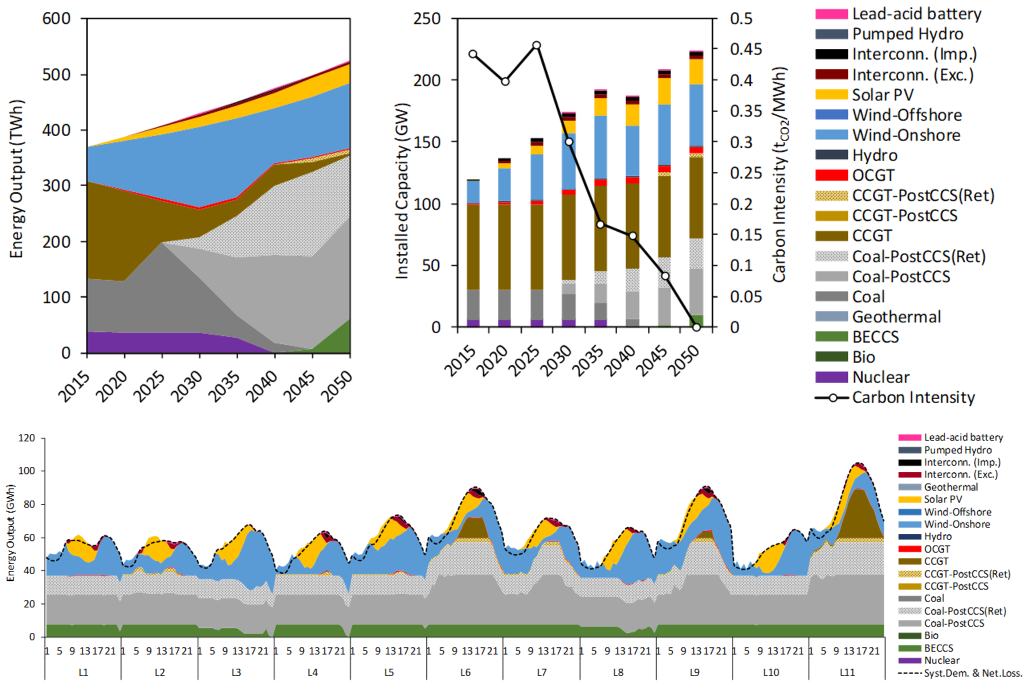

Figure 2.30: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for ERCOT power system under the 48A + 45Q + EOR scenario.

In both systems, the share of new-build coal-CCS is significantly expanded, and, in ERCOT, nuclear power is entirely displaced. Renewable power continues to play an important role, and by 2050, there is only a small amount of legacy unabated gas remaining in either system.

A conclusion here is that current policy environment of 45Q, 48A, and opportunities for CO_2-EOR in combination with relatively low coal prices significantly privilages coal over gas. One reason for this is that for the same MWh of electricity generated, coal-CCS captures more CO_2 than gas-CCS and, therefore, receives more 45Q tax credit and revenues from the sale of CO_2 for EOR. The dispatch pattern in figures 2.30 and 2.31 indicate that, in this context, coal-CCS provides both baseload and some load following services. These results indicate that with an additional revenue stream from EOR, it is more economical to install a slight overcapacity of coal-CCS to provide some head-room rather than exclusively installing CCGT-CCS for system flexibility.

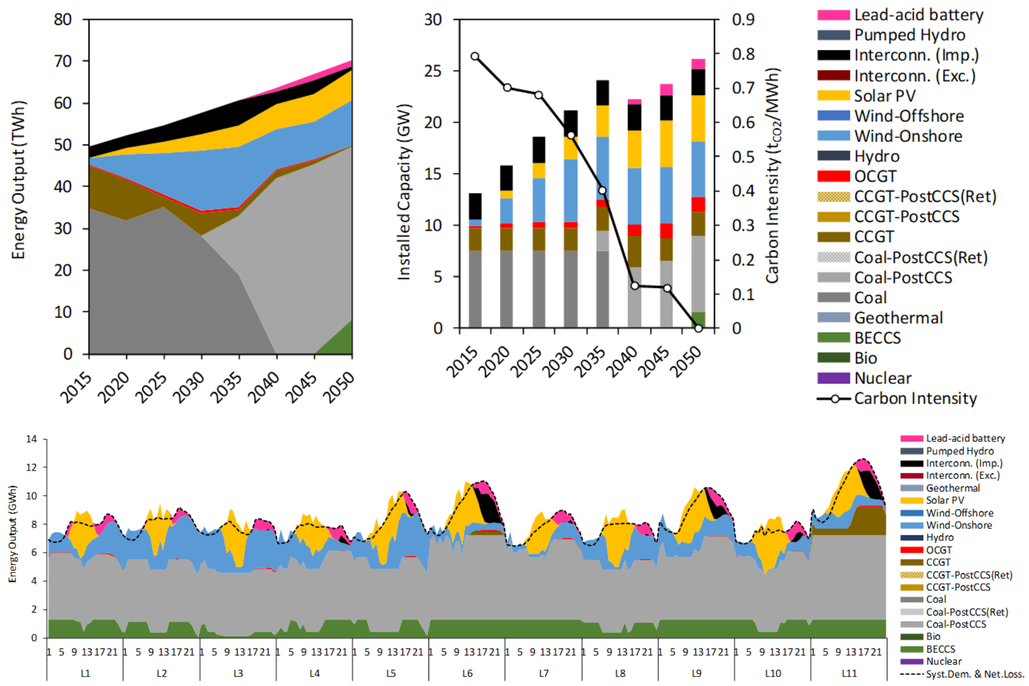

Figure 2.31: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the 48A + 45Q + EOR scenario.

As shown in figures 2.23 (ERCOT) and 2.27 (PACE) under the 48A + 45Q scenario, the availability of the 48A and 45Q tax credits encourage the deployment of coal-CCS (for baseload generation) and gas-CCS (load following generation). Moreover, under the 48A + 45Q + EOR scenario, the share of gas-CCS in the ERCOT and PACE systems becomes much smaller. This is because for the same MWh of electricity generated, coal-CCS captures more CO_2 than gas-CCS and, therefore, receives more 45Q tax credit and revenues from the sale of CO_2 for EOR. The dispatch pattern in figures 2.30 and 2.31 shows that coal-CCS provides baseload and some load following generation. These results indicate that with an additional revenue stream from EOR, it is more economical to install a slight overcapacity of coal-CCS to provide some head-room rather than exclusively installing CCGT-CCS for system flexibility. Under the 48A-ext + 45Q + EOR scenario, illustrated in figures 2.32 and 2.33, we observe similar results for both the ERCOT and PACE systems. This indicates that as long as the 45Q tax credit and EOR payment are made available in the system, the the 48A scheme has a second order impact on the competitiveness of coal-CCS.

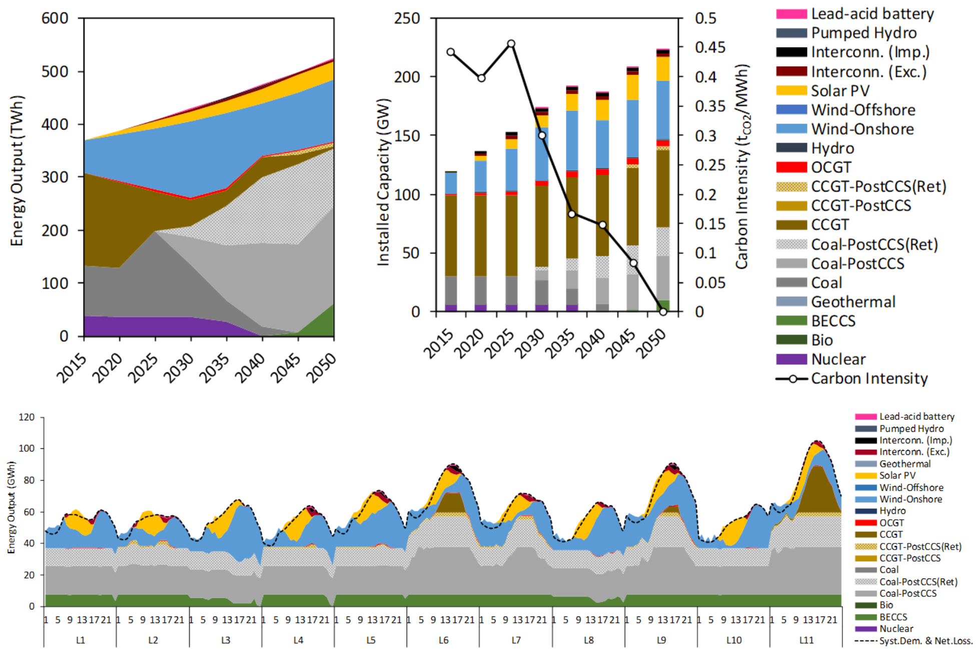

Figure 2.32: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for ERCOT power system under the 48A-ext + 45Q + EOR scenario.

In the EOR Only scenario, without the 48A and 45Q tax credits, coal-CCS becomes much less competitive against other dispatchable low carbon technologies, *e.g.*, CCGT-CCS and nuclear, despite the CO_2 markets for EOR being made available. As illustrated in figure 2.34, the nuclear fleet in ERCOT is expanded in the 2030s and is essentially providing a baseload service in the 2050s. Both abated and unabated gas capacity provide a primarily load following generation service. In the PACE system, illustrated in figure 2.35, under this scenario, CCGT-CCS displaces coal-CCS with a meaninful amount of gas-CCS deployed from 2040. Importantly, for all of these alternative scenarios, overall system capacity remains approximately constant for each scenario – the very significant capacity expansions observed in the No CCS and Renewables and Storage scenarios are consistently avoided.

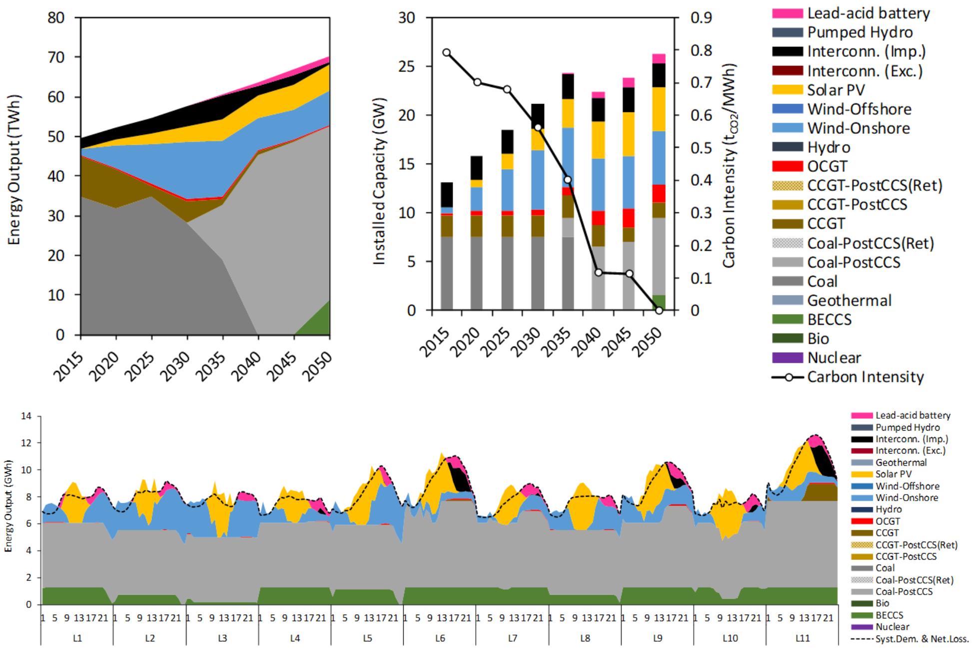

Figure 2.33: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the 48A-ext + 45Q + EOR scenario.

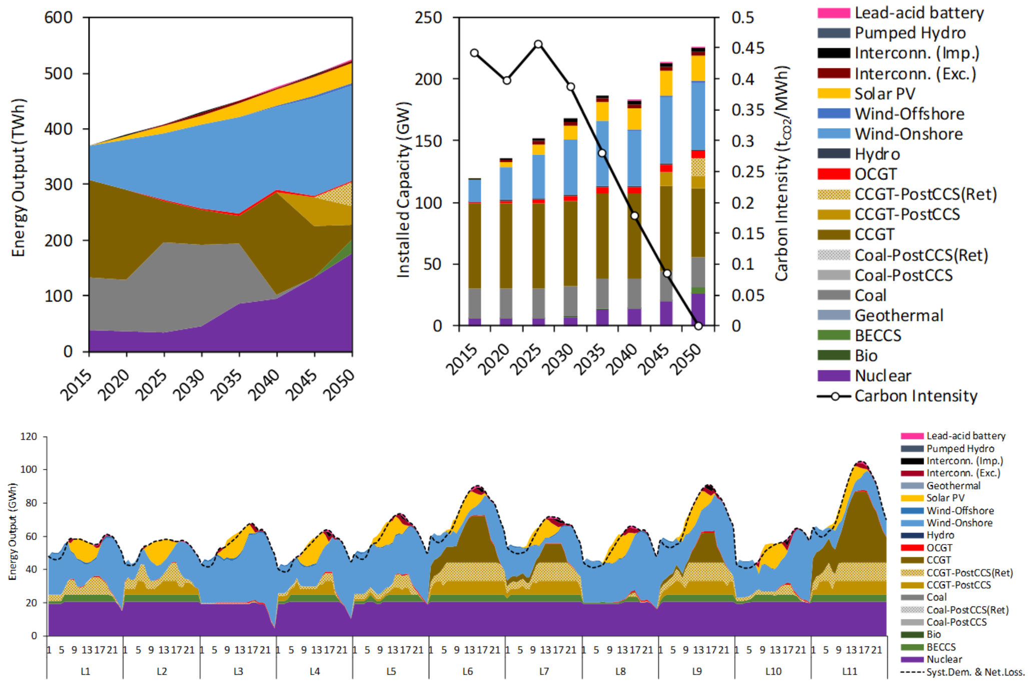

Figure 2.34: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for ERCOT power system under the EOR scenario.

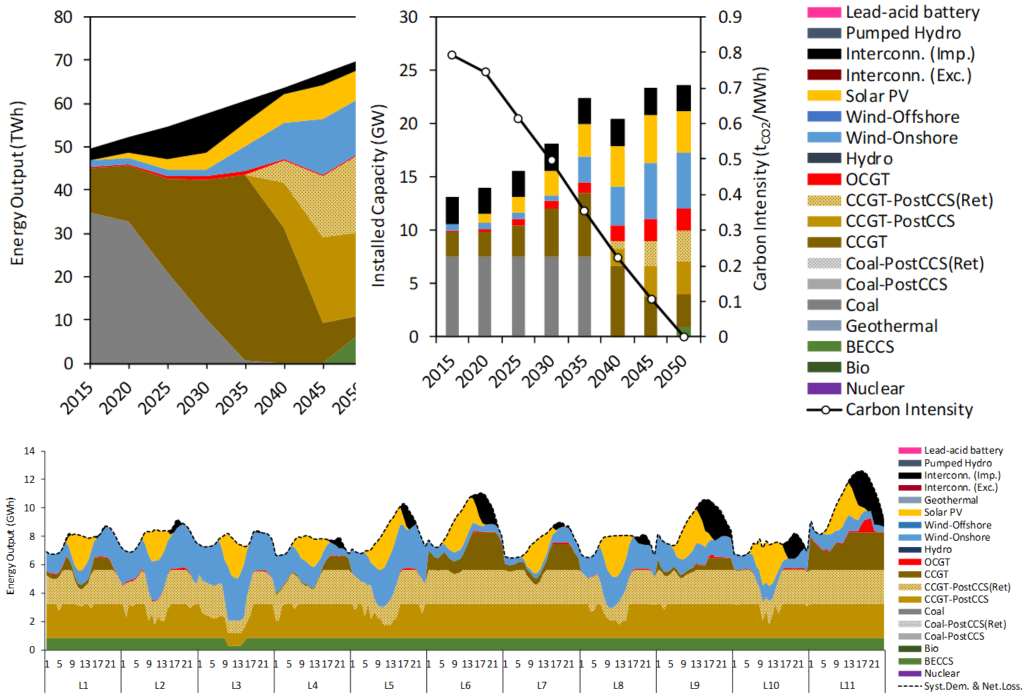

Figure 2.35: Power output (TWh), installed capacity (GW), and power dispatch pattern by technology for PACE power system under the EOR scenario.

2.5.4 USA case study: Concluding remarks

Owing to the diversity in technology composition of the energy systems and regional economies in the USA, two case studies were evaluated here. The US-specific case studies also offers one additional dimension to explore – the influence of the 45Q and 48A tax credits in addition to the potential for CO_2 EOR on technology deployment.

There are trade-offs between costs for the different fossil-fuel CCS technologies. The capital expenditure of coal-CCS is higher than gas-CCS, whereas the fuel costs of coal is lower compared to natural gas. As the coal-CCS system needs to handle larger volumes of CO_2, the cost of CO_2 transport and storage (T&S) is higher compared to gas-CCS. Therefore, without tax credits and EOR payments, the variable cost for coal-CCS is more expensive than gas-CCS.

Figure 2.36 (top) illustrates that by making 48A and 45Q tax credits available, the capital cost of coal-CCS can be lowered. Although it is still more expensive than gas-CCS, the variable costs of coal-CCS will be negative (*i.e.*, approximately -$5/MWh for PACE and -$12/MWh for ERCOT). Moreover, the additional availability of 45Q and EOR can make coal-CCS more economically favourable than gas-CCS. Generally, the levelised cost of electricity (LCOE) of nuclear is higher than coal-CCS and gas-CCS, shown in figure 2.36 (bottom). However, nuclear is still selected in some scenarios due to the fact that it is carbon neutral, where the deployment of nuclear can reduce the need for negative emissions from BECCS.

Electric Reliability Council of Texas (ERCOT)

Energy demand in the BAU scenario of the ERCOT system is mainly met by natural gas, coal, onshore wind and nuclear. The share of coal remains relatively constant, with unabated coal progressively being replaced by coal-CCS. Onshore wind capacity continually expands. To achieve zero carbon emission by 2050 in the All Technologies scenario, the deployment of retrofitted gas-CCS plants become necessary to reduce requirements of negative emissions from BECCS (relatively more expensive). With both 45Q and 48A tax credits available, coal-CCS dominates the system as it is more economically favourable compared to gas-CCS and unabated fossil fuel power.

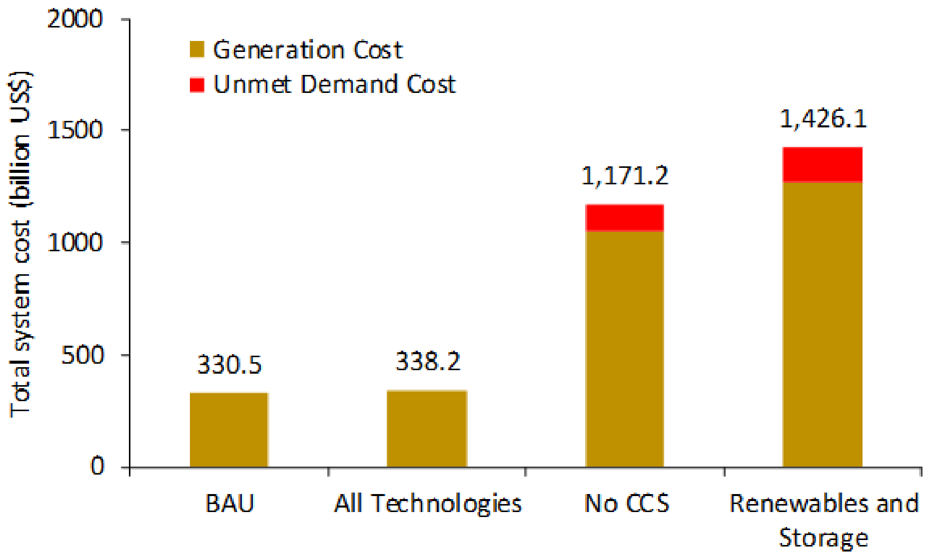

Figure 2.37: Total system costs of ERCOT system under different scenarios.

For the No CCS and Renewables and Storage scenarios, the net zero emissions target is achieved with a significantly high deployment of intermittent renewables, *i.e.*, solar PV and wind (mainly offshore wind by 2050). However, some system demand remains unmet as the installation costs of more renewables and nuclear to meet peak demand is more costly than the penalty of lost load. For the No CCS scenario, nuclear has a prominent role in meeting the system demand and net zero emissions target. In contrast, a limited capacity of battery storage provides some flexibility for the Renewables and Storage scenario. Without low cost dispatchable generation, the installed capacity in the system increases up to 450 GW – around four times the capacity of the BAU and All Technologies scenarios. Consequently, the system cost of the Renewables and Storage scenario is approximately 420% greater than that of the All Technologies scenario.

Impact of 48A and 45Q tax credits in the ERCOT system

Changes to the 45Q and 48A tax credit schemes can potentially impact the evolution of the energy system, thus this needs to be evaluated. Additionally, CCS can create an additional revenue stream through the sale of captured CO_2 for EOR. In the 48A + 45Q + EOR scenario, coal-CCS is more economically favourable compared to gas-CCS. In comparison with gas-CCS, a coal-CCS plant captures more CO_2 per MWh of electricity generated and, therefore, would receive more

45Q tax credit and revenue from EOR. There was no difference between the energy systems for the 48A + 45Q + EOR and 48A-ext + 45Q + EOR scenarios, indicating that as long as the 45Q tax credit and EOR payment are available, the 48A scheme has a second order impact.

The availability of the 45Q and 48A schemes in the future is uncertain. Power system expansion planning needs to consider the possibility that 45Q and 48A could be unavailable, with EOR being the only revenue stream. Therefore, an EOR Only scenario was considered. If the only economic benefit is available from EOR, coal-CCS is not selected due to its higher capital cost and CO_2 transport and storage costs. Instead, nuclear, unabated gas and gas-CCS are the main technologies selected in place of coal-CCS.

PacifiCorp East (PACE)

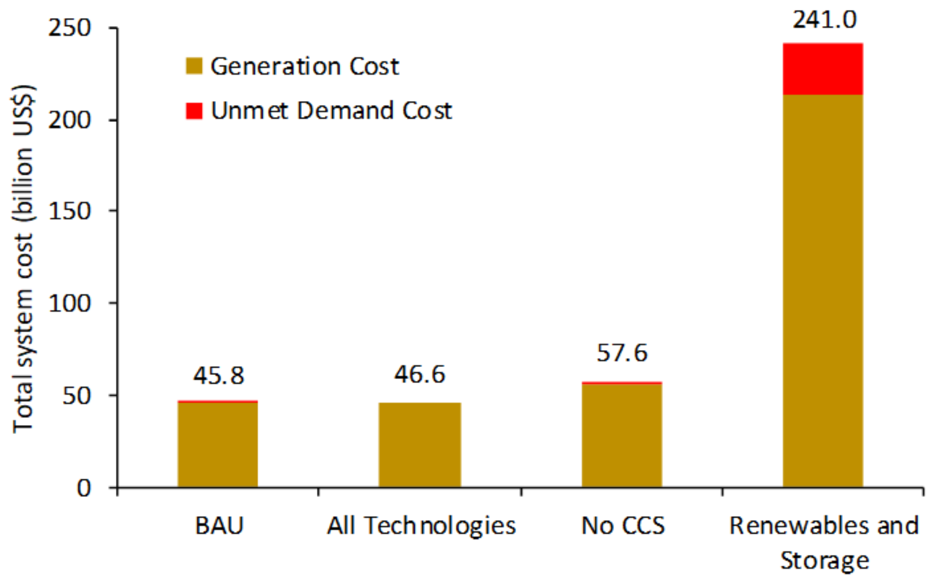

Figure 2.38: Total system costs of PACE system under different scenarios.

Most of electricity generation in the PACE system is from coal and the demand is primarily industrial, which mainly requires baseload generation. Under the BAU scenario (with the 48A and 45Q tax credits available), the PACE system is predominantly coal power. These coal plants are due to retire within the next 20 years. From 2040, the retired coal plants are replaces with new coal-CCS, which is more economical than the any other thermal power plant options.

Similar to the All Technologies scenario in the ERCOT system, the PACE system also requires gas-CCS to provide some flexibility, which reduces the use of unabated gas, decreasing the requirement for negative emissions from BECCS.

Under the No CCS scenario in the PACE system, the role of nuclear is even more important than in the ERCOT system. Located in land-locked states, the PACE system relies on nuclear for firm power due to the lack of offshore wind, which is relatively more reliable than onshore wind and solar PV. In contrast, the Renewables and Storage scenario has no nuclear and energy storage technologies play an important role. However, the level of battery deployment that can be achieved is insufficient to ensure security of supply, consequently, the value of lost load is particularly high. Therefore, unavailability of nuclear is potentially severely detrimental for Wyoming, which would experience significant lost load in 2050 due to the large mismatch between hourly availability of renewables and system demand.

Impact of 48A and 45Q tax credits in the PACE system

In the PACE system, the availability of EOR as a revenue stream encourages the installation of more coal-CCS and reduces utilisation of existing gas plants. Compared to gas-CCS plants, coal-CCS receives more revenue from selling CO_2 for EOR and, therefore, has lower variable cost. Assuming both 45Q and EOR payment are available, the availability of 48A further promotes coal-CCS deployment more than other energy technologies due to its slightly higher capital intensity and lower operating cost.

Applying an extended version of the 48A scheme had negligible impact to the energy system mix, suggesting that the 45Q tax credit and EOR payment have greater influence. In the absence of the 48A and 45Q tax credits (EOR Only scenario), gas-CCS is selected as it has lower capital cost than coal-CCS. Although natural gas fuel cost may higher than coal, the cost of CO_2 transport and storage is lower for gas-CCS (handling less CO_2) compared to coal-CCS.

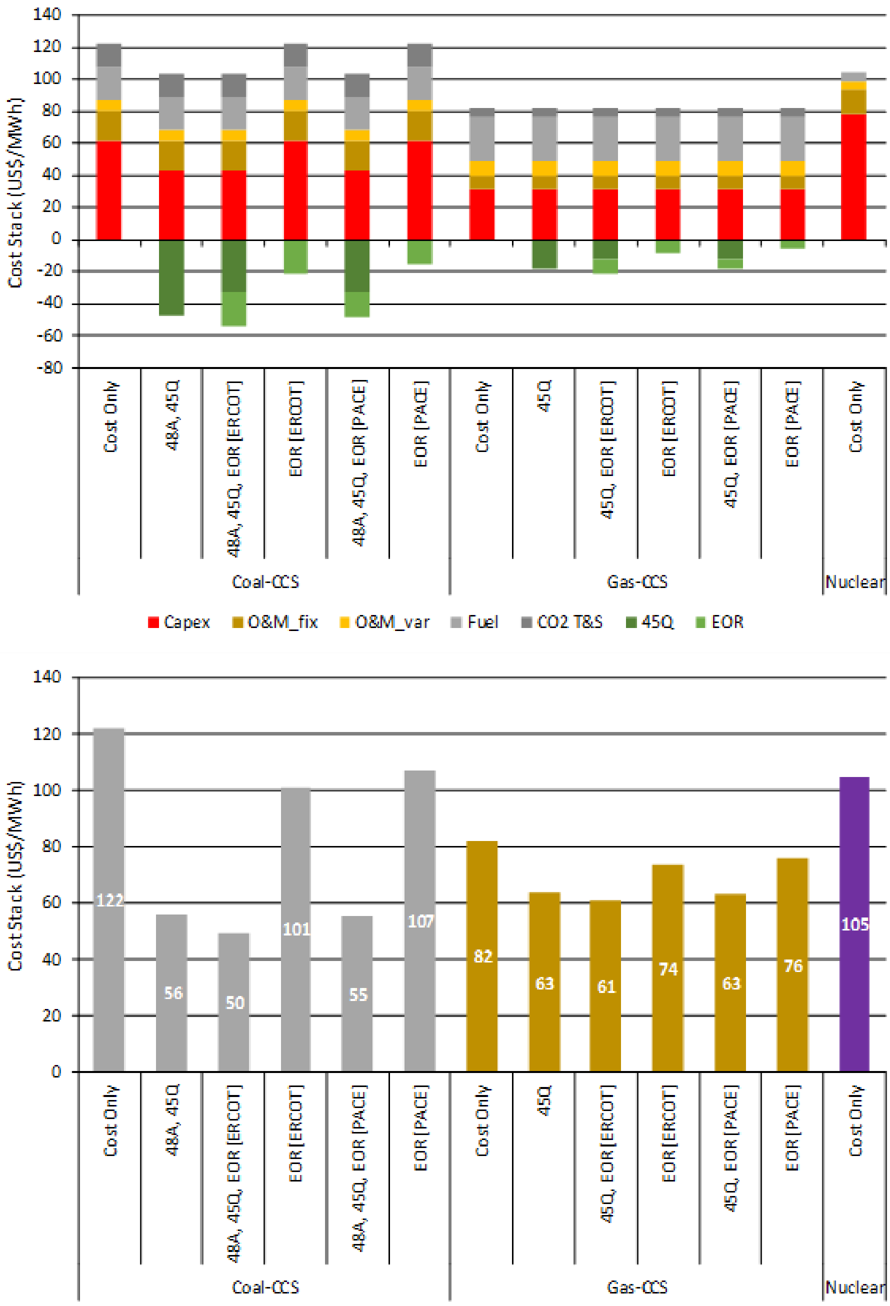

Figure 2.36: The (top) cost breakdown and (bottom) total LCOE comparison of CCS and nuclear under different tax credit scenarios in the ERCOT and PACE systems.

Chapter 3

CCS with greater than 90% capture rates

A ubiquitous assumption throughout literature is the 90% capture rate limit on CO_2 capture processes. There is growing evidence to indicate that capture rates above 90% can be techno-economically feasible. For instance, the Petra Nova CCS project (near Houston, US) captures as much as 95% of the CO_2 from the flue gas slipstream that is processed. Moreover, recent studies demonstrate that CO_2 capture rates as high as 99% can be achieved at a low marginal cost in coal- and gas-fired power plants equipped with CCS [2]. Therefore, CCS plant using greater than 90% capture rate have potentially significant value in the context of a net zero emissions target for an energy system. In this study, a system level analysis is performed using the ESO framework to model the UK's energy system.

Figure 3.1 evidently shows that using capture rates greater than 90% tends to increase the capacity factor of the CCS plants, but *not* at the expense of incorporating renewable energy into the grid.

Some further insight can be derived from studying the interaction between CCS and BECCS, as presented in figure 3.2. The results show that employing CO_2 capture rates greater than 90% in CCS plants can reduce the need for negative emissions from BECCS (observed as decreased BECCS power output).

This interaction is driven by the net zero emissions target imposed on the system. The residual emissions (*i.e.*, uncaptured CO_2) associated with the CCS plants need to be offset to meet this target, thus necessitating the deployment of neg-

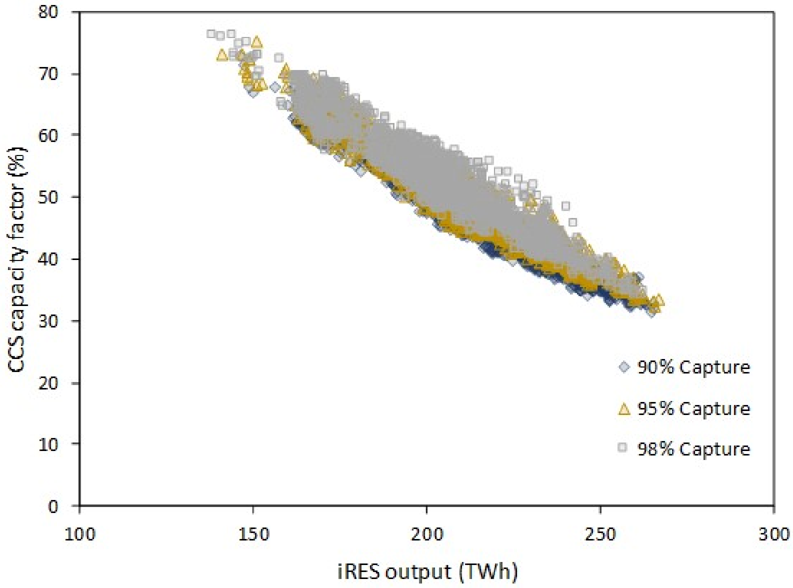

Figure 3.1: Impact of higher CO_2 capture rates (90%, 95% and 98%) on the capacity factor of CCS plants across varied levels of iRES power generation.

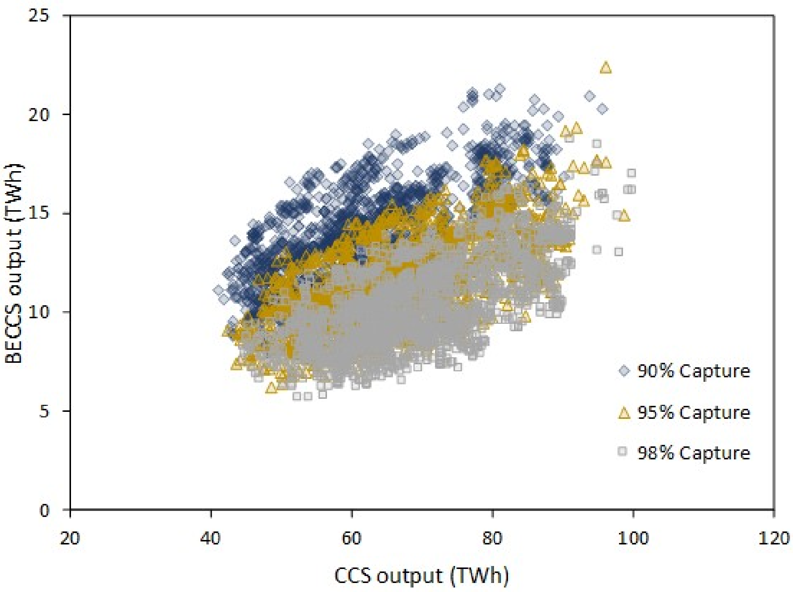

Figure 3.2: Impact of using different CO_2 capture rates (90%, 95% and 98%) in fossil fuel CCS on the system requirement for negative emissions *via* BECCS.

ative emissions technologies such as BECCS. As the CO_2 capture rate of the CCS plants increases, the need for emission offsets decreases. Hence, these CCS plants operating at higher capture rates can displace BECCS capacity, which is advantageous given that biomass is a limited resource.

If it is indeed possible to deliver near-zero emissions from coal- or gas-fired power plants with CCS for a marginal cost increase compared to 90% capture, there are potentially significant system benefits. These results demonstrate that greater than 90% capture in CCS plants have increased system value, especially in energy systems transitioning towards a net zero emissions target. For this reason, efforts to further develop near-zero emissions CCS options should be pursued with alacrity.

Chapter 4

Conclusions

The purpose of this project was to quantify and qualify the role and value of CO_2 capture and storage (CCS) technology applied to coal- and gas-fired power stations in different electricity markets around the world in the context of a transition to a net zero CO_2 emission power system by 2050. To this end, the following systems were studied using the ESO framework:

- United Kingdom,
- Poland,
- New South Wales, Australia,
- Java-Madura-Bali (JAMALI), Indonesia,
- Electric Reliability Council of Texas (ERCOT), USA,
- PacifiCorp East (PACE), USA.

In performing this study, a scenario-based approach was adopted, with four distinct scenarios evaluated for each grid, namely:

- Business As Usual (BAU): prevailing policies are maintained, there is no carbon target, all technologies can be deployed in line with historical build rates.
- All Technologies: there is a target of net zero CO_2 emissions by 2050, all technologies can be deployed in line with historical build rates.
- No CCS: there is a target of net zero CO_2 emissions by 2050, all technologies except for CCS can be deployed in line with historical build rates.
- Renewables and Storage: there is a target of net zero CO_2 emissions by 2050, only renewable energy and energy storage technologies can be deployed.

In the BAU and All Technologies scenarios, the rate at which power generation capacity was deployed in any country was constrained to be within what has been observed in that country in recent decades. The rationale behind this decision is to ensure that the transition pathways are as realistic as possible, reflecting contemporary social and regulatory constraints around technology acceptance and regulation. Moreover, best efforts were made to reflect the deployment of hitherto undeployed technology in a given system, *e.g.*, in the New South Wales example, nuclear power was considered to be unavailable until 2030. However, in order to minimise unmet demand, the build rates in the No CCS and Renewables and Storage scenarios had to be considerably increased. As there are limits to what supply chains can deliver, very significantly increased build rates might be expected to have an impact on costs, implying that the costs presented for these scenarios in this study may well be quite conservative.

For each scenario the total system cost was minimised, subject to the primary constraint of ensuring security of supply and, where relevant, the end-point constraint of zero CO_2 emissions. In the context of meeting a net zero emissions target, the value of CCS was defined as the cost of meeting the emissions target in a given scenarios, namely the "No CCS" and "Renewables and storage" scenarios, less the cost of meeting the target in the case with CCS.

As can be observed from figure 4.1, CCS was observed to have a strong positive value in all scenarios. A key conclusion is that including the option of deploying CCS on coal-, gas-, and biomass-fired power stations is unequivocally key to a least cost transition to a net zero electricity grid, which is, in turn the linchpin of the broader decarbonisation agenda.

Incorporating CCS in the electricity system allowed for a transition to net zero for a very low marginal cost relative to the BAU scenario, without compromising security of supply. Conversely, excluding CCS as an option was found to increase the total system cost by a factor of two to seven, depending on the case study and scenario. Importantly, CCS was observed to be relevant to coal-, gas-, and biomass-fired power generation, with both new-build and retrofit options playing important roles. It can be further observed that the value of CCS is greatest for the UK. This is primarily due to the highly seasonal nature of its power demand. In UK scenarios where CCS was not available, the potential for unserved demand significantly increased. In the PACE case study, however, owing to the high proportion of power demand coming from the industrial sector, power demand

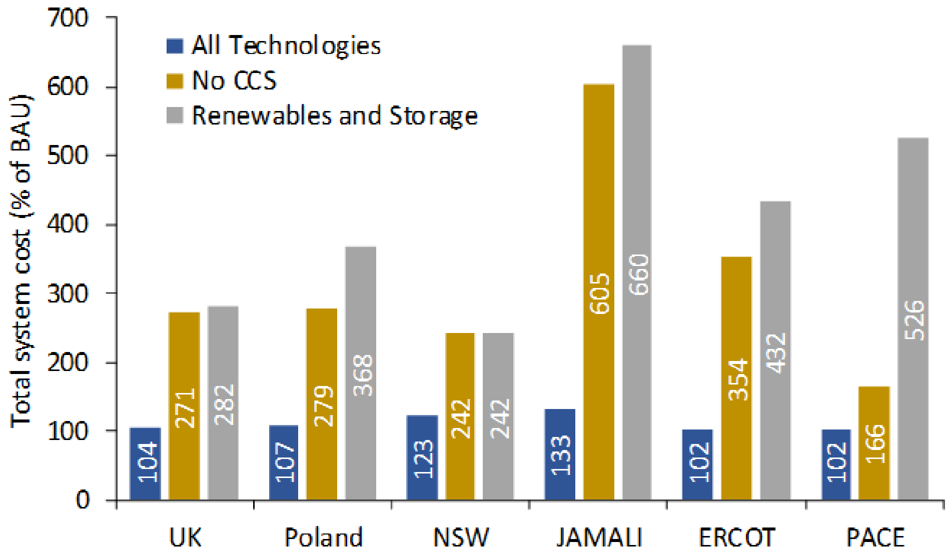

Figure 4.1: Total system costs of decarbonised systems as percentage of the BAU costs.

is much less seasonal, and therefore nuclear power has the potential to play an important role in meeting power demand and maintaining security of supply.

Further, the value (or avoided cost) associated with deploying even a modest amount of CCS capacity was consistently observed to be large. In all cases, the availability of CCS ensured the quantity of power generation capacity required to meet demand remained approximately consistent with the BAU scenario. In other words, CCS is key to avoiding significant pressure on relevant supply chains. This is important as the impact of this kind of pressure is expected to increase technology costs. Given that these system dynamics are not included in this modelling framework, the results presented here might be considered to be conservative.

In line with the broader literature, CCS technology was assumed to capture 90% of the CO_2 produced as a result of fossil fuel combustion. However, this has the effect of a CCS plant still emitting a non-negligible quantity of residual CO_2[1], in the context of a net zero target, this residual CO_2 will have to be dealt with. To this end, bioenergy with CCS (BECCS) was included in this study as a negative emissions technology (NET) and was observed to be persistently deployed to address this question of residual emissions. Importantly, owing to the potential for carbon leakage along the value chain, bioenergy was not considered to be

[1]Or indeed, the BECCS plants offsetting less CO_2 than they might otherwise be able to.

carbon neutral. This acted to limit its deployment in the context of the "No CCS" and "Renewables and storage" scenarios. Recognising the technical feasibility of higher rates of capture, scenarios of 95% and 98% capture were evaluated. As might be expected, this has the effect of reducing the residual emissions associated with the CCS plants, and thus reducing, but not eliminating, the need for BECCS to offset those emissions. Consequently, the capacity factor of the CCS power plants was observed to increase, with an associated reduction in total system cost. Given that near zero CO_2-emission fossil fuel-fired power stations have been recently shown achievable at a marginal additional cost relative to 90% capture [2], this is something which should be carefully considered by future studies.

The competitiveness of different technologies in an energy system depends on various factors. In addition to technology cost, another important factor that influences competitiveness of a technology is the demand profile of the system, where the availability of a technology will dictate the ability of a technology to meet demand within the energy system. Dispatchable technologies such as CCGT and CCGT-CCS are highly valuable in energy systems with significant variability in energy demand, *e.g.*, UK and ERCOT, which require technologies capable of providing flexibility to balance the system. In some systems, the energy demand is closely associated with the industrial sector, *e.g.*, PACE and Poland. Therefore, these systems have relatively constant demand profiles and favour the deployment of technologies such as nuclear and coal-CCS, which are well-suited for baseload generation. For regions with high demand growth rate (*e.g.*, JAMALI in Indonesia), dispatchable thermal power plants have a critical role in providing security of supply as demand rapidly increases over time.

Energy systems with high penetration of iRES tend to require less baseload generation and more flexibility, *i.e.*, load following generation. Where CCS is prohibited, systems with high iRES opt to utilise nuclear with lower capacity factors to provide flexibility, however, this is non-ideal and potentially quite expensive as nuclear is conventionally considered to be a baseload technology. Without flexible technologies, iRES generation will be curtailed at a higher rate, which may be more costly than sacrificing optimal operation of nuclear. Demand side response (DSR) can act to provide system flexibility and resilience, thus reducing the magnitude and frequency of instances of unmet demand, but in none of the scenarios investigated in this study was DSR found to be available in sufficient quantities to consistently ensure security of supply.

Renewable energy technologies, such as wind and solar power, have near-zero marginal costs. This means that, on an economic dispatch basis, renewable power generation will almost always displace the generation of thermal power plants whose marginal costs are necessarily greater. However, as has been discussed elsewhere [18], whilst renewable generation will directly displace thermal generation, intermittent capacity does not equivalently displace thermal capacity. This is an inherent characteristic of iRES, acts to limit its value – particularly at higher levels of deployment. The impact of intermittency can, to some extent, be reduced by energy storage. However, the extent to which this can be relied upon is attenuated by the cost, and round trip efficiency of storage, in addition to the requirement for adequate capacity to generate sufficient power.

It is a common practice to dispatch technologies with lower marginal costs ahead of technologies with higher marginal costs. Dispatch also depends on competing roles in terms of capacity and energy services provided to the grid. Technologies that provide negative CO_2 emissions, *i.e.*, BECCS, tend to be dispatched ahead of most other technologies despite having higher marginal cost. Negative emission technologies have a crucial role in mopping up residual emissions from other carbon emitting technologies. Therefore, baseload operation of BECCS to completely offset residual emissions can lower the capital cost requirement, and is much more economically favourable compared to operation at low capacity factors.

A final point is that CCS was not, in any case, observed to work against the deployment of renewable capacity. Rather, owing to the ability of CCS plants to operate in a flexible, load-following fashion, the result was one of "CCS and renewables", not "CCS or renewables".

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Appendix A

Model Assumptions, Constraints, and Formulation

1. Security constraint: We account for system reserve and inertia requirements to ensure reliable operation. Reserve requirements are included as a fraction of peak demand in addition to a proportion of the intermittent capacity online at every time period, t, to dynamically secure the largest firm and intermittent unit against failure.
2. Environmental unit commitment (UC): The formulation includes the CO_2 emission rates of the power generating technologies as well as a overall systems emission target.
3. Detailed operation UC: We introduce a coherent mode-wise operation of all technologies. Power output, emissions, costs, *etc.* varies between these modes.
4. Simultaneous design of the electricity system and unit-wise scheduling: We formulate the model such that the optimal number of installed units per power generating technology is determined as well as their respective operational time plan. The available number of power generating units is an integer decision variable to the optimiser.
5. Coherent technology representation: All types of power generating technologies, thermal and intermittent renewable technologies, are represented in a consistent fashion. The modularity of the formulation enables extension of the number and type of available technologies.

Type	Symbol	Unit	Description
Sets	i,j	-	technologies, $i \in I = \{1,...,I_{end}\}$, with alias j
	t	h	time periods, $t \in T = \{1,...,T_{end}\}$
	m,m'	-	modes of operation, $m \in M = \{off, su, inc\}$, with alias m'
	k	h	set of all possible stay times, $k \in K = \{1,...,max\{StayT(i,m,m')\}\}$
	ic	-	subset of I, $ic \subseteq I$, conventional technologies
	ir	-	subset of I, $ir \subseteq I$, renewable technologies, or such without modal operation
	$Trans(m,m')$	-	possible transitions from mode m to m', 1 if transition allowed, 0 else
	$ForbidT(m,m')$	-	forbidden transitions for mode m to m', 1 if transition forbidden, 0 else
Parameter	$Num(i)$	-	number of available units of technology i
	$Des(i)$	MW/unit	nominal capacity per unit of technology i
	$TE(i,m,*)$	diff.	mode-dependent features of technology i, where * is
where * is	"$Pmin$"	%-MW	minimum power output
	"RP"	%-MW	reserve potential
	"IP"	%-MW	inertia potential
	"Ems"	t_{CO_2}/MWh	emission rate
	$AV(i,m,t)$	%-MW	availability factor of technology i in mode m at time step t
	$StayT(i,m,m')$	h	minimum stay time of technology i in mode m' after transition from mode m to m'
	$CAPEX(i)$	\$/unit	annualised investment costs of technology i

	$OPEX(i,m)$	diff.	operational costs of technology i in mode m, in \$/MWh for $m = \{inc\}$, in \$/unit for $m = \{su\}$
	$OPEXNL(i)$	\$/MWh	fixed operational costs of technology i when operating in any mode
	$SD(t)$	MWh	system electricity demand at time period t
	$WF(t)$	-	weighing factor for clustered data at time period t
	PL	MW	peak load over time horizon T
	RM	%-MW	reserve margin
	WR	%-MW	reserve buffer for wind power generation
	$SI(t)$	MW.s	system inertia demand at time step t
	SE	t_{CO_2}	system emission target
Variables	$d(i$	-	number of units of technology i designed/installed
Integer	$n(i,m,t)$	-	number of units of technology i in mode m at time period t
	$z(i,m,m',t)$	-	number of units of technology i switching from mode m to m' at time t
Binary	$x(i,t)$	-	1, if at least one unit of technology i is not in mode "off" at time t
Positive	$p(i,m,t)$	MWh	power output of technology i in mode m as time period t
	$r(i,m,t)$	MW	reserve capacity provided by technology i in mode m at time period t
	$e(i,m,t)$	t_{CO_2}/MWh	emission caused by technology i at time period t
	tsc	\$	total system cost, subsequently corrected from penalty term $M\,x(i,m)$, where M is a large number

The objective function (3c.1) represents the annual total system cost tsc granularly subdivided by cost factors and operational modes. We differentiate between "no load" costs (\$/h), which occur for any power plant when being online, the incremental costs for providing power output or spinning reserve (\$/MWh), and start-up costs (\$/unit).

Due to the different units of operational costs, the $OPEX(i,m)$ term is split and multiplied by the respective decision variable. The hourly operational increments are multiplied by the vector $WF(t)$ which contains the weighting factors as derived from the data clustering in Appendix B. Hence, the obtained total system cost tsc are scaled back to represent annual construction cost and one year of operation.

$$
\begin{aligned}
min\ \ tsc = & \sum_{i \in I} CAPEX(i)\, d(i)\, Des(i) && \text{(A.1)}\\
& + \sum_{\substack{i \in I, m=\{su\},\\ m'=\{off\}, t \in T}} (OPEX(i,m) n(i,m,t)/StayT(i,m',m))\, WF(t) \\
& + \sum_{\substack{i \in I, m=\{inc\},\\ t \in T}} OPEX(i,m)\, p(i,\mathit{inc},t)\, WF(t) \\
& + \sum_{\substack{i \in I, m \in \{su,inc\},\\ t \in T}} OPEXNL(i)\, n(i,m,t)\, WF(t) && \text{(3c.1)}
\end{aligned}
$$

The design constraint (3c.2) limits the number of units of technology i to be installed (designed: $d(i)$) by the upper bound $Num(i)$. Equation (3c.3) ensures that each units of technology i is in a mode m (*off*, *su*: start-up, *inc*: incremental (running)) at each time period t.

$$
0 \le d(i) \le Num(i) \qquad \forall i \qquad \text{(3c.2)}
$$

$$
\sum_{m \in M} n(i,m,t) = d(i) \qquad \forall i,t \qquad \text{(3c.3)}
$$

System-wide constraints (3c.4)-(3c.6) include power balances which ensure sufficient electricity supply, reserve, and inertia requirements in the system at every time period t. Reserve is provided as measured by a predefined reserve margin RM, a percentage of peak load demand $PL = max_t SD(t)$ plus a percentage of intermittent power output, denoted as "wind reserve" WR.

System inertia requirements are met if enough units with "inertia potential" $TE(i,m,\mathit{IP})$ are on-line. All units which are online can provide inertia to the extent of their "inertia potential" ($IP(i)$). Intermittent power generators have very little or no inertia potential. Constraint (3c.7) sets the environmental target for the electricity system by limiting the sum of emissions of all units i in every mode m at all time periods t by an emissions target SE.

The dual variable for the power balance (3c.4) represent marginal electricity price; dual variable for the reserve balance (3c.5) the marginal price for reserve.

$$\sum_{i \in I, m \in M} p(i,m,t) = SD(t) \qquad \forall t \qquad (3c.4)$$

$$\sum_{i \in I, m \in M} r(i,m,t) \geq PL\,RM + \sum_{ir,m} p(ir,m,t)\,WR \qquad \forall t \qquad (3c.5)$$

$$\sum_{i \in I, m \in M} n(i,m,t)\,Des(i)\,TE(i,m,\textit{IP}) \geq SI(t) \qquad \forall t \qquad (3c.6)$$

$$\sum_{i \in I, m \in M, t \in T} e(i,m,t)\,WF(t) \leq SE \qquad (3c.7)$$

Unit specific constraints define the detailed operation as to comply with the technical abilities of each type of technology. Constraint (3.8) sets the overall output level (power and revere) for the generating technologies i by their installed capacity level and availability matrix $AV(i,m,t)$. Inequalities (3c.9) and (3c.10) define the upper and lower bounds of power output. With the mode dependent availability matrix $AV(i,m,mt)$ we define the hourly available level of onshore wind, offshore wind, and solar power output. For the conventional power plants, we can demonstrate part-load behaviour by defining a different maximum power output in the start-up mode.

$$\sum_{m \in M} p(i,m,t) + r(i,m,t) \leq \sum_{m \in M} n(i,m,t)\,Des(i)\,AV(i,m,t) \quad \forall i,t \quad (3c.8)$$

$$p(i,m,t) \geq n(i,m,t)\,Des(i)\,TE(i,m,\textit{Pmin})\,AV(i,m,t) \quad \forall ic,m,t \qquad (3c.9)$$

$$p(i,m,t) + r(i,m,t) \leq n(i,m,t)\,Des(i)\,AV(i,m,t) \quad \forall i,m,t \qquad (3c.10)$$

The provision of spinning reserve service is further constrained according to the mode-dependent "reserve potential" $TE(i,m,\textit{RP})$ matrix which prohibits reserve offer in the *off* and *su* mode and assigns the possible amount of capacity provided for the *inc* modes. An exception are power plants that are able to start-up very quickly and are therefore eligible to offer reserve while being off. The only type of power plant that falls into this category and is considered in this model are

OCGT power plants.

For intermittent renewable power generators, we exclude the possibility of exclusive reserve provision in the $TE(i,m,RP)$ matrix according to the current state of technology development. Nevertheless, it should be noted that the here presented model is easily adjustable, if through technological advancement the provision of capacity reserve service for intermittent power technologies becomes feasible.

$$r(i,m,t) \leq (n(i,m,t)\, Des(i)\, AV(i,m,t) - p(i,m,t))\, TE(i,m,RP) \quad \forall i,m,t \tag{3c.11}$$

The operation of the intermittent power generators $ir \subset I$ is modelled with fewer operational modes. If wind speeds are sufficient and power output is possible, there is not start-up behaviour in wind power plants compared to thermal power plants. Hence, constraint (3c.12) disables intermittent power generators from being in the *su* mode.

$$n(ir,m,t) = 0 \qquad \forall i,m = \{su\},t \tag{3c.12}$$

A set of integer constraints determines the optimal operational behaviour for the different units of the conventional technology type ($ic \subset I$). Equations (3c.13) and (3c.14) defines the switching between the operational modes as well as the region of allowed mode transitions by the set $Trans(m,m')$ and its inverse $ForbidTrans(m,m')$.

Inequality (3c.15) ensures that units stay in the operational mode m' for a minimum amount of time according to the set $StayT(i,m,m')$ after transitioning from mode m to m'. The number of units $n(i,m',t)$ in mode m' has to be greater or equal than the number of units that switched into mode m', $z(i,m,m',t)$, for the minimum stay time.

$$n(ic,m,t) - n(ic,m,t-1) = \sum_{m'} z(ic,m',m,t) - \sum_{m'} z(ic,m,m',t) \quad \forall ic,t,m \tag{3c.13}$$

$$z(ic,m,m',t) = 0 \qquad \forall ic,m \in ForbidT(m,m'),t \tag{3c.14}$$

$$n(ic,m',t) \geq \sum_{k=t-StayT(ic,m,m')+1}^{t} z(ic,m,m',k) \quad \forall ic,t,m \in Trans(m,m') \tag{3c.15}$$

Constraint (3c.16) determines the carbon emissions caused by each power generating technology i by operation on in mode m in each time period t.

$$e(i,m,t) = TE(i,m,\mathit{Ems})\,(p(i,m,t) + r(i,m,t)) \qquad \forall i,t,m \tag{3c.16}$$

The objective function (3c.1) and constraints (3c.2)-(3c.16) define the final model formulation which provides the basis for the analyses and results presented in the main body of this study. The optimisation problem is formulated as MILP, modelled in GAMS 23.7.3 and solved with CPLEX 12.3. We define a set of additional parameters to analyse and investigate the system behaviour and characteristics. In particular, the electricity costs and costs for reserve provision are the dual variables (the shadow price) of the electricity balance (3c.4) and reserve constraint (3c.5). The function $marginal()$ here refers to the mathematically marginal value of the respective constraint.

Type	Symbol	Unit	Description
Parameter	tse	t_{CO_2}	total system emission
	$MEP(t)$	\$/MWh	marginal electricity price
	$MRP(t)$	\$/MW	marginal reserve price
	$RL(t)$	MW	reserve level at time t
	CI	t_{CO_2}/MWh	system carbon intensity
	$CD(i)$	GW	chosen design of technologies
	$Util(i)$	%-capacity	utilisation of technologies

$$tse = \sum_{i,m,t} e(i,m,t)\, WF(t) \tag{A.1}$$

$$MEP(t) = marginal(ElecDem(t)) \tag{A.2}$$

$$MRP(t) = marginal(ResDem(t)) \tag{A.3}$$

$$RL(t) = PL\, RM + \sum_{ir,m,t} p(ir,m,t)\, WR \tag{A.4}$$

$$CI = tse / \sum_{i,m,t} (p(i,m,t) + r(i,m,t))\, WF(t) \tag{A.5}$$

$$CD(i) = d(i)\, Des(i)/10^3 \tag{A.6}$$

if $d(i) \geq 0$:

$$Util(i) = \sum_{m,t} p(i,m,t)\, WF(t)/8760/\,(d(i)\, Des(i)) \tag{A.7}$$

Appendix B

Clustering of Input Data

In order to reduce computational effort and to increase solution speed when solving our MILP energy systems model we have adapted a data clustering technique to reduce the hourly granular data of electricity demand, wind power, and solar power availability, to a manageable size, i.e. where solution time of the MILP is less than one hour. We apply the k-means data clustering method which is based on assigning raw data into k clusters such that the Euclidean distance between the data points in the clusters and the cluster mean or centroid is minimal [41]. Each cluster is assigned a specific weighting factor based on the number of data that is represented by the cluster. A cluster containing a large number of data points will have a high weight, whereas a cluster containing very few data points will have a low weight. The weighting factor is subsequently used to rescale the final calculations as to preserve the original data structure. The model formulation in section A includes the weighting factor, $WF(t)$, obtained in this manner.

In a next step, hourly profiles have to be assigned to each individual data cluster. Typically, the chosen profile for a cluster k is represented by its average value, its mean, or a randomly chosen profile belonging to the respective cluster. Each technique has its individual advantages and drawbacks; often this is a trade-off between representing the full range of values in the cluster while maintaining a realistic data structure without smoothing or perturbing effects. We have developed a profiling method which preserves the average value (i.e., energy in the case of electricity demand) of the clustered data as well as the realistic profile pattern. The "energy preserving" profiling method chooses a specific profile from the data subset in each cluster k such that the energy demand (power availability, respectively) across this profile is closest to the energy demand (power availability, respectively) of the mean of this cluster.

Figure B.1 gives an example for the clustered data for electricity demand, on-shore wind, off-shore wind, and solar power availability across the UK.

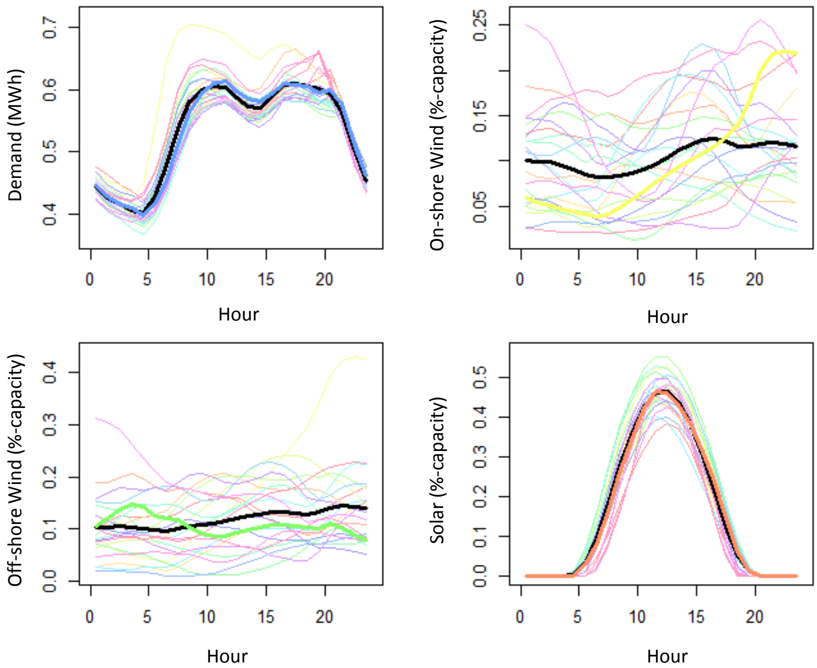

Figure B.1: Example of 4-dimensional data space, in electricity demand, on-shore wind, off-shore wind, and solar availability, assigned to the same cluster; The thin colourful lines represent all profiles that were clustered into cluster 11. The thick black line represents the mean of the cluster, and the thick colourful lines are the specific profile chosen to comply with the "energy preserving" profiling method.

Applying the aforementioned "energy preserving" profiling method to the individual days we obtain k clusters similar to the presented profiles and reduce the data space from 8760 hours per year to 480 (=20 · 24) time steps if $k = 20$. Figure B.2 visualises the k clusters with the respective profile for the four cohesive data sets. In order to ensure that the data sequence (daily profile) containing the peak demand is included in the reduced data set, we add the peak day with a weighting factor of 1 to the k obtained clusters, resulting in $((k+1) \cdot 24 =)$ 504 time steps. We find that a number of $k = 21$ clusters achieves a good trade-off between accuracy and computational tractability. The error between clustered and the full data set amounts on average to 0.6 % for system-level values, and to 4 % for technology-specific values.

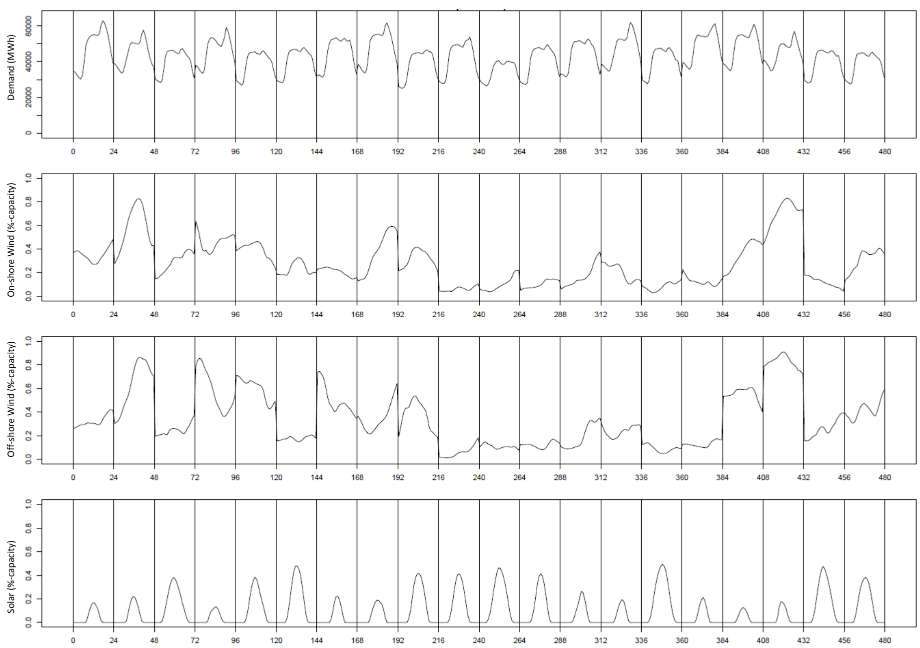

Figure B.2: Specific profiles according to the "energy preserving" profiling method for k clusters; The on-shore and off-shore wind profiles show most clearly the importance of preserving a realistic hourly pattern by applying the "energy preserving" profiling as opposed to using the cluster mean. The resulting smoothness of a mean-value profile would significantly misstate a wind power plants behaviour and strongly underestimate operational challenges laying herein.

In the challenge to create data which is as realistic as possible using the minimum data space, the difficulty of smoothness occurs not only within the individual cluster (daily profiles) but also between the clusters as they are connected in series without considering the potential "jump" between the last and first values of the consecutive clusters. The clustered data set which shows the largest value difference between two consecutive hours is the electricity demand profile at time periods 192 and 336 as shown in figure B.2. The demand here drops more than 10 GW in one hour which does not necessarily occur a realistic electricity demand curve. In 2014 the largest difference in electric demand in hourly averaged data (derived from half hourly data provided by National Grid [42]) reached 4.8 GW. However, a smoothing of these unusually large data jumps, as proposed for example by Green and Staffell [41], exceeds the scope of this work. In fact, maintaining the sharp drops in the demand data set allows us to study the power plants behaviour in such an occurrence. Since this report deals especially with the flexibility of individual power plants, as well as with the ability of entire power systems to react and adjust the operational schedule according to demand signals (as well as technical, economic, and environmental constraints), we consider the obtained data clusters and profiles as sufficient.

It is interesting to note that with the obtained profiling method we can allocate an order of importance to our raw data. Here for example, we apply the clustering to a 4-dimensional data set (demand, on-shore wind, off-shore wind, solar) simultaneously as to retain the hourly match between the data elements. Depending on the correlation of the numerical range of the data elements we can increase the importance of representation in the clusters. Including the demand vector with very high values ($\geq 10{,}000$) and while the remaining elements range in $[0, 1]$ would overstate the importance of the demand as the Euclidean distance for these vector elements has much larger weight. We chose to normalise all data to be in the same range of $[0, 1]$ as to equally weigh their importance. However, for some applications a different emphasis might be of interest.

Appendix C

Input Data

Table C.1: Economic parameters for individual generation technologies used in this study. (Ret) denotes technologies that have been retrofitted with CCS.

Tech	**CAPEX**	**Fixed O&M**	**Variable OPEX**	**Start-up cost**	**OPEX No Load**
	$/kW	$/kW	$/MWh	$/unit.start	$/h
Nuclear	5,896	115	4.1	5,405,405	4,743
Coal	1,945	54	2.7	268,281	4,535
Biomass	4,109	81	3.4	268,281	4,262
CCGT	709	20	2.7	107,519	3,008
OCGT	466	20	6.8	5,095	120
Coal-PostCCS	4,865	128	3.8	338,034	5,715
CCGT-PostCCS	2,484	54	3.8	112,895	3,158
BECCS	5,811	122	13.5	338,034	5,715
Wind-Onshore	2,003	41	6.8	0	0
Wind-Offshore	3,941	61	4.1	0	0
Photovoltaic	1,080	14	0.0	0	0
Hydro	4,081	61	0.0	0	0
Pumped Hydro	1,469	34	8.1	0	0
Lead Acid Battery	2,432	27	4.1	0	0
Coal-PostCCS(Ret)	3,480	128	3.8	338,034	5,715
CCGT-PostCCS(Ret)	1,953	54	3.8	112,895	3,158

Table C.2: Cost scaling parameters for different countries/regions.

Tech	Poland	ERCOT	PACE	NSW	JAMALI
		% of UK CAPEX			
Nuclear	100	76	76	126	39
Coal	100	105	105	133	48
Biomass	100	104	105	73	78
CCGT	100	100	100	143	63
OCGT	100	100	100	110	75
Coal-PostCCS	100	102	102	98	67
CCGT-PostCCS	100	100	100	121	73
BECCS	100	104	104	101	70
Wind-Onshore	100	89	89	80	63
Wind-Offshore	100	89	89	98	63
Photovoltaic	100	120	120	116	86
Hydro	100	102	102	35	68
Pumped Hydro	100	102	102	100	68
Lead Acid Battery	100	100	100	108	70
Coal-PostCCS(Ret)	100	102	102	98	67
CCGT-PostCCS(Ret)	100	100	100	121	73

Table C.3: Technical parameters of technology, where P_{min} and P_{max} are the minimum and maximum power output, respectively.

Tech	P_{min}	P_{max}	Cap. Credit	Inertia	Efficiency	Capacity	Lifetime
	% cap.	% cap.	% cap.	s	%	MW	yrs
Nuclear	75	80	80	7	37	600	50
Coal	30	88	88	6	42	500	40
Biomass	30	88	88	6	42	500	40
CCGT	50	87	87	6	57	750	40
OCGT	10	94	94	6	40	100	40
Coal-PostCCS	30	80	80	6	34	500	40
CCGT-PostCCS	30	80	80	6	50	750	40
BECCS	30	85	85	6	32	500	40
Wind-Onshore	0	100	40	2	100	20	30
Wind-Offshore	0	100	53	2	100	50	30

Photovoltaic	0	100	12	0	100	10	30
Hydro	10	100	50	3	81	300	60
Pumped Hydro	10	100	50	3	0	300	60
Lead Acid Battery	0	100	50	0	89	100	10
Coal-PostCCS(Ret)	30	80	80	6	34	500	40
CCGT-PostCCS(Ret)	30	80	80	6	50	750	40