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Valuing Flexibility in CCS Power Plants

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VALUING FLEXIBILITY IN CCS POWER PLANTS (FlexEVAL)

Key Messages

- Thermal power plants powered by coal and gas underpin the electricity systems of many of the world's economies. In fact, over 60% of global electricity is generated from plants powered by coal and gas.
- Unlike intermittent renewable energy technologies, coal and gas-fired power plants offer firm capacity to the electricity grid, i.e. they are guaranteed to be available to generate electricity at a given time.
- CCS enables deep cuts to be made in CO_2 emissions from coal and gas-fired power plants. When equipped with CCS, coal and gas-fired power plants become low-carbon technologies and, along with renewable energy technologies and nuclear plants, will make a valuable contribution to the establishment of a low-carbon electricity system.
- Flexible thermal plants, by virtue, e.g. of their ramp rates, maximum turndown and start-up times, are able to complement the operational characteristics of intermittent renewable technologies. Thus, flexible CCS power plants offer the triple benefit to the electricity system of firm, low-carbon technology with the ability to complement intermittent renewable energy technologies.
- The objectives of the FlexEVAL study were to investigate the need for operational flexibility and the additional value flexible CCS power plants can bring to the UK electricity system that result from the benefits described above.
- In an electricity system, dispatchable sources of generation contribute to system adequacy (cf. total installed generating capacity), system reliability (cf. reserve capacity) and system operability (cf. inertia or spinning reserve). While the cost of CCS has been the focus of many studies, its value as a firm, dispatchable source of generation – the focus of the current study – has not been explored nearly as often.
- The FlexEVAL study demonstrated that firm, dispatchable, flexible CCS power plants can bring additional value to the electricity system of the future. They are low-carbon and complement the addition of non-dispatchable, intermittent renewable capacity, characteristics that provide system-wide benefits critical to reducing the cost of the electricity system.
- The cost-optimal low-carbon electricity system of the future is projected to contain substantial intermittent renewable capacity. Difficulties are often encountered when integrating progressively higher shares of intermittent power generation into an electricity system.
- Flexible CCS technologies were shown to provide additional value to the electricity system by enabling it to accommodate higher levels of intermittent renewable capacity. In so doing, the total system cost (TSC) was reduced through increased electricity dispatch from intermittent renewables with low operating costs.
- Its ability to provide low-carbon electricity consistently identifies CCS as an essential component for a global, low-carbon energy system to be achieved at least cost. The ability of flexible CCS to provide dispatchable, low-carbon electricity is a further benefit. And its role in reducing TSCs by allowing an electricity grid to tolerate higher levels of low-cost generation from intermittent renewables makes it even more attractive.
- Furthermore, the study showed that:
    - In reducing TSCs, flexible CCS technologies reduce demand from interconnectors compared to non-flexible CCS options and are thus able to lower dependency on electricity imports;
    - The economic level of deployment is only marginally affected by the flexibility of the power plants.

- The study recognised that policy mechanisms would likely be required to encourage the uptake of flexible CCS in the future electricity grid.

Background to the study

Most informed studies indicate that the share of fossil fuels to generate electricity must reduce markedly in the future if the worst effects of global warming are to be avoided. Nonetheless, the use of coal and gas is likely to remain significant to mid-century at least, even under a low-carbon energy scenario. Some regions, such as Europe and the United States, may reduce their emissions from fossil fuels (and also their generation from fossil fuels) more quickly than others, e.g. China, India and Southeast Asia. In Europe, several countries expect to phase-out coal for power generation by 2030. To achieve an emissions trajectory consistent with limiting the global average atmospheric temperature increase to 2°C or less by 2100, however, major deployment of CCS will be essential in many countries (to address emissions from industry as well as power generation).

The trade-off between costs and reliable low-carbon power generation is not yet well understood. Moving from a fossil dominated power system to one with an increasing share of renewable energy technologies will be challenging, as some countries are already discovering. And of particular importance will be the ability for CCS (on coal or gas plant) to complement and work in synergy with renewable energy technologies, providing energy security, grid reliability and system strength as well as offering a flexible buffer for the intermittent renewable capacity. Note, however, that a CCS system using currently deployed technology that is engineered to be flexible and possessed of a larger operating envelope is also highly likely to be more capital intensive.

It is therefore important to look beyond cost and the traditional LCOE metric to quantify the value afforded to the electricity system by the availability of the flexible low-carbon electricity that CCS can deliver.

The UK's electricity sector, with its target to reduce (and ultimately to phase out) generation from coal, its significant gas and nuclear base, and its ambitious plans to increase the penetration of intermittent renewable generation through the 2030s, make it an ideal case on which to base this study.

The study was undertaken at Imperial College London by a team led by Dr. Niall Mac Dowell.

Scope of Work

The study was designed to investigate the value of flexible CCS-equipped power plants to the UK's electricity system. The metric used, the System Value (or SV), quantifies the benefit, i.e. the reduction in total system cost, of adding a unit of a particular technology to the electricity grid.

To operate effectively, an electricity grid must not only have adequate generating capacity to meet demand but also have reliable reserve generation capacity (e.g. as back-up for outages) and sufficient system inertia (for frequency control). While supply-side (e.g. energy storage) or demand-side (e.g. energy efficiency) mechanisms may offer alternatives to grid expansion, adding new capacity remains a central requirement for any grid, e.g. as power plants are retired and/or demand increases. Since not all technologies provide the same services to the grid, the value of adding a unit of a particular technology will be a function, at any given time, not just of the incremental increase in power demand that it must satisfy but also of the characteristics of the technologies already connected.

The main objectives of the study then were to:

1. Identify the role of flexible CCS in the UK electricity system;
2. Develop a metric to evaluate the system-wide benefit of energy technologies;
3. Quantify the value of flexible CCS to the UK electricity system.

The role of CCS power plants was examined as it might evolve in a changing UK energy landscape over the period from 2015 to 2050. Both non-flexible and flexible CCS power plants were included in the study, the latter deploying various means to enhance operational flexibility.

An optimisation-based electricity systems model, tailored to represent the UK, was developed to simultaneously determine the cost-optimal electricity systems structure (type and amount of generating capacity) and the optimal dispatch schedule (power output and services provided) subject to technical and environmental constraints. The value of flexible CCS to the UK electricity system was quantified under a range of scenarios, with reference scenarios for 2020, 2030 and 2050 characterised by fuel price projections from DECC and generating capacity projections from UKERC.

The model was validated for 2014 by observing that, given the mix of the UK's generation capacity for that year, the power plant behaviour was well reflected and the technology-specific operational patterns modelled correctly. Following that, the reference scenarios were analysed. In each of the reference scenarios the emission target was achieved. Electricity generation from intermittent renewable energy sources increased from 14% (in 2014) to 33% (in 2050).

The difference in performance of the electricity system depending on whether non-flexible or flexible CCS technologies were deployed was evaluated. The capacity of CCS technology deployed that gave the most favourable economics and the generation capacity displaced were determined.

Findings of the Study

The value of flexible CCS power plants to the future UK electricity system was quantified. Possible future developments in the sector were reviewed, where increasing demand for electricity and a tightening of carbon dioxide emission targets would require significant changes in the structure and operation of the electricity system. Key technical and market-relevant characteristics of CCS power plants were identified and flexibility concepts to enhance the ability of CCS power plants to adjust power output quickly were discussed.

As mentioned earlier, the metric used for valuing electricity generating technologies was the System Value (SV). The SV quantifies the value provided by a given technology from a total-system perspective. The SV is defined as the reduction in total system cost (TSC) that results from the integration of one capacity unit of that technology (i.e. in £/kW), and changes as a function of the level of penetration of that technology into the power system and the system conditions itself.

To evaluate the SV, an electricity systems optimisation model was developed, based on mixed-integer linear programming. The model simultaneously determines the cost-optimal electricity systems structure (type and amount of power generating technologies) and the optimal dispatch schedule (mode of operation service provided for each technology at each moment in time) subject to detailed technical constraints, as well as to security and environmental constraints (Figure 1).

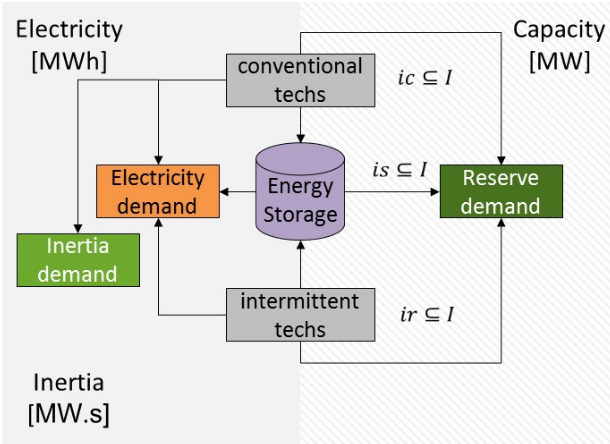

Figure 1: Schematic of services provided by conventional and intermittent power generation technologies, and energy storage technologies.

As far as possible, data to populate the model was accessed from UK government (DECC) and UKERC sources, with additional input from IEA data and IEAGHG publications. Through a range of scenarios and sensitivity analyses, it was identified that flexible CCS power plants do indeed provide an additional value to the electricity system. The detailed electricity systems model enabled this result to be explored in depth and its robustness evaluated.

Four types of CCS technologies and their flexible counterparts were evaluated in the study, namely: post-combustion capture on both pulverised coal and CCGT; Oxy-combustion on coal; and IGCC with pre-combustion capture. The flexible CCS power plants exhibited a greater operating range, i.e. they were able to turn down power output further and load-follow more quickly than their non-flexible counterparts. These features, however, came at greater cost and higher residual emissions. [It should be noted that technologies yet to be proven at scale (such as the Allam cycle) may have the potential to be flexible and lower cost but were not modelled.]

Each of the CCS technologies, whether non-flexible or flexible, reduced the TSC when being deployed in the future electricity system by replacing capacity with low capacity factor and higher CO_2 emissions (Figure 2). Their ability to provide low-carbon electricity and firm capacity, at moderate capital and operational cost became increasingly relevant in scenarios characterised by high penetration of non-synchronous intermittent renewable energy capacity.

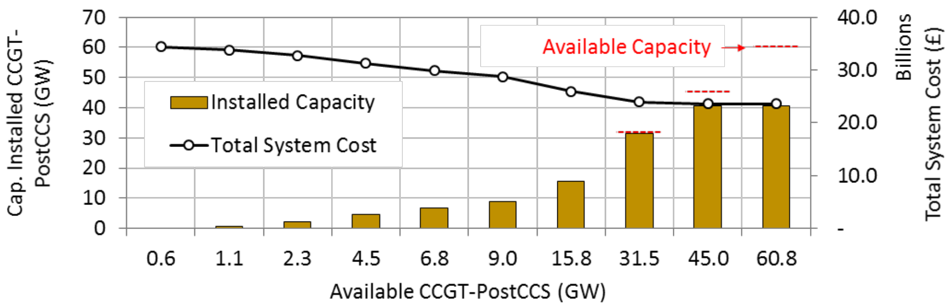

Figure 2: Example of the optimal installed capacity level and annual total system cost for post-combustion capture on CCGT power plants in a 2030 UK power system as a function of their available capacity deployment level in the optimisation model.

Flexible CCS technologies provided an additional value of being able to accommodate higher levels of intermittent renewable capacity and electricity generation in the system; since operational expenditure of intermittent renewables are near-zero, systems with higher levels of such power generators generally exhibit lower TSCs. System balancing mechanisms take advantage of the increased operating range and reduced start-up and shut-down times of flexible CCS technologies. Additionally, less interconnection capacity is required with the deployment of flexible versus non-flexible CCS technologies. This reduces the dependency on electricity imports and, consequently, lowers the TSC.

The theoretical level of economically optimal deployment, i.e. the capacity installation level beyond which CCS no longer adds value to the system, is quantified for the different CCS options. In Figure 2, for example, there is no further decrease in TSC for capacities of CCGT with post-combustion capture above 40.5 GW, i.e. adding further CCGT capacity no longer adds value to the system. The economic deployment level and the SV are both observed to be functions of the composition of the pre-existing system design. The installation of CCS power plants enables a displacement of unabated CCGT power plants, as well as of off-shore wind, solar and interconnection capacity. The relative SV (£/kW) is determined as a function of installed capacity and ranges from an initial £500-800/kW at low deployment rates to £200-250/kW at maximum economic deployment rates (Figure 3). The flexible CCS options outperform the non-flexible options at deployment levels of up to 10 GW as larger amounts of intermittent renewable power are integrated into the power mix. At levels above 10 GW of CCS capacity deployment, the lower capital cost of non-flexible CCS options are more beneficial from a system perspective, such that their value is marginally higher compared to the flexible CCS variants.

Under 2050 system conditions, the values of pulverised coal post-combustion CCS and CCGT post-combustion CCS power plants are analysed for two different electricity demand scenarios. The economic level of CCS deployment under the scenario with extreme peaks in the demand profile is marginally greater than in the business-as-usual case and provides insight into the different optimal operation strategies of flexible and non-flexible CCS technologies. Their relative SV ranges from £350-700/kW to £150-300/kW depending on the technology deployment level.

For flexible and non-flexible technology options, CCGT with post-combustion CCS provides the greatest economic and system value. This results from the lower capital cost, lower carbon emissions, higher efficiency and greater flexibility compared with other CCS technologies. Additionally, the 2030 greenfield scenarios, where the available amount of capacity per technology is not constrained, indicate that large amounts of CCGT post-combustion CCS in combination with wind power would be part of the economically and environmentally optimal solution.

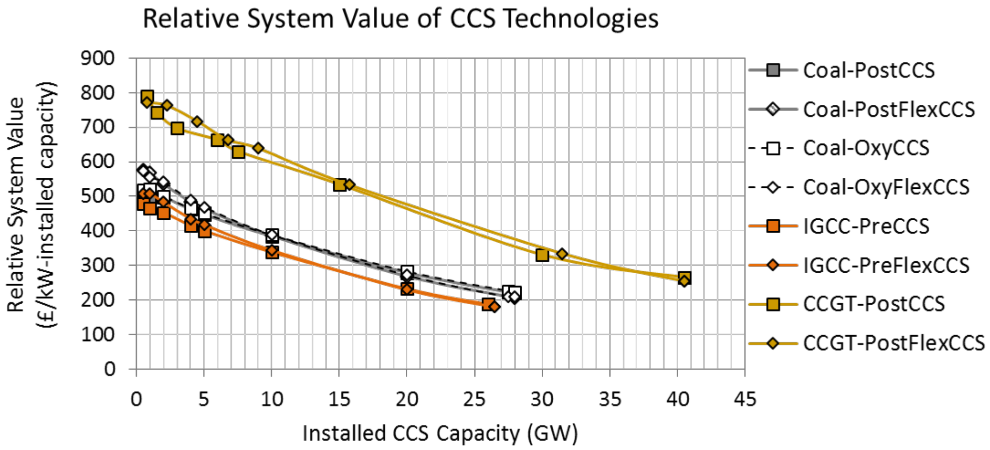

Figure 3: Relative System Value, as reduction in total system cost levelised by the respective level of CCS-equipped power capacity installed in a 2030 UK power system.

No learning rates were considered for the capital or operational cost of the technologies. However, neglecting CCS technology cost reductions (due to learning) leads to rather conservative results in overall TSC savings that would result from their deployment in the electricity system. Furthermore, energy storage technologies are not incorporated in the whole-systems analysis. An increased deployment of such technologies could potentially impact on the SV for CCS and would need to be evaluated in detail (outside of this study).

In summary, the interaction of CCS technologies with intermittent renewable capacity is found to be critical to reducing the TSC. Integrating CCS and renewable technologies allows a low-carbon and low-cost future electricity system to be achieved. An increased flexibility in CCS power plants has a positive effect on the integration possibilities. However, by enabling higher rates of intermittent renewable electricity generation, flexible CCS power plants generally exhibit lower utilisation rates, which could well disincentivise investors and the business sector. From a whole-systems perspective, however, the benefits of flexible CCS technologies on the costs and the carbon intensity of power generation are indisputable. Nonetheless, given these benefits, it is more than likely that appropriate political support mechanisms would need to be introduced to realise them.

Expert Review Comments

The draft report was generally well received by the reviewers, who felt it made a valuable contribution to the CCS literature. The authors addressed all comments received from the reviewers, with some examples discussed briefly below.

- The draft report was comprehensive in its treatment of the subject matter. However, it was generally felt to have been written in an academic style that made access somewhat more difficult for readers that did not have a strong modelling background. Steps were taken to rectify this in the final report, e.g. by revising the conclusions to more clearly bring out the key results and findings.
- With a mixed-integer linear programming approach taken, the results were highly dependent upon the input. Sensitivity analysis was undertaken to examine the impact of two important parameters, power plant efficiency and fuel prices.
- In the draft report, treatment of the annual total system cost was unclear to readers, with no differentiation made between the costs of existing and new build capacity. The authors clarified this by pointing out that the model represents a “snapshot” of the simultaneous design and operation of an electricity system in a particular future year. Hence, it was necessary to incorporate the annualised capital cost of the total installed generation capacity (affecting design) as well as the operational cost (affecting design and dispatch schedule) into the objective function. This enabled the authors to compare all technology types on a level playing field. Where appropriate, sections were adjusted by clearly defining the “CAPEX” parameter as annualised investment cost. Additionally, the annual nature of the objective function value was also clarified in the text.
- While the development and introduction of political support mechanisms would be important for the benefits of flexible CCS to be realised, these were not addressed in the analysis. If required, it would be the subject of a separate piece of work, drawing on results from the current study.
- While reviewers felt it would have been interesting if the analysis would have taken in a broader geographical reach, the study focused on a single country, the United Kingdom. To develop the methodology and model, it was important to manage the scope of the study and to select a country for which there was good access to data. The UK fulfilled those requirements.

Conclusions

The FlexEVAL study analysed the value of flexible CCS power plants to a future UK electricity system. The main findings were:

- As they reduce the total system cost (TSC), all CCS technologies, whether non-flexible or flexible and independent of type, provide a value to a 2030 and 2050 UK electricity system when deployed in the power generation mix.
- A cost-optimal future electricity system contains large amounts of intermittent renewable capacity. To integrate progressively higher proportions of intermittent power generation, thermal power plants must increase their cycling operation.
- Scenarios, without restrictions on the amount of capacity that can be installed, indicate that CCGT post-combustion CCS in combination with on-shore wind power would be part of the economically and environmentally-optimal solution under 2030 and 2050 conditions.
- Flexible CCS technologies provide an additional value in being able to accommodate higher levels of intermittent renewable capacity, reducing TSCs further through increased electricity dispatch from intermittent renewables with low operational cost.
- Non-flexible and flexible CCS power plants show different optimal operational strategies. Under 2030 conditions, flexible CCS power plants show more frequent start-up/shut-down behaviour than non-flexible CCS power plants to enable increased intermittent renewable power generation. Under 2050 conditions, with larger amounts of renewable and CCS capacity, non-flexible CCS power plants are forced into cycling operation that, due to their tighter operating envelope (higher minimum stable generation, longer start-up times, etc.), result in higher costs.
- Non-flexible CCS power plants show a higher utilisation than flexible CCS power plants with regards to absolute power output, but a lower utilisation in terms of time in operation.
- Flexible CCS technologies reduce the demand from interconnectors compared to non-flexible CCS options and are thus able to lower dependency on electricity imports.
- In 2030, the level of economically optimal deployment for the different CCS options was 28 GW for coal post-combustion, 28 GW for coal oxy-combustion, 26 GW for IGCC pre-combustion and 40.5 GW for CCGT post-combustion CCS.
- In 2050, the level of economically optimal deployment under the business-as-usual/extreme peak electricity demand scenario was 21/23 GW for coal post-combustion CCS, 31.5/33 GW for CCGT post-combustion CCS.
- The economic level of deployment is only marginally affected by the flexibility of the power plants.
- The relative System Value for the different CCS options indicates the reduction in TSC per installed capacity unit generated and is a function of the system conditions and amount of capacity deployment. It ranges from £500-800/kW at low deployment rates to £150-300/kW at maximum deployment rates. The value of FOAK plants in a carbon-constrained system is high as CCS-equipped power plants provide low-carbon dispatchable power while having the ability to provide conventional power grid services (firm reserve capacity, system balancing and frequency control). Moving to the NOAK plant such system services are in less demand and the ability to reduce total system cost further reduces.

In the analysis, energy storage technologies were not offered as a choice in the range of technologies captured by the electricity systems model. Further, cost learning (i.e. reduction of capital or operational costs as a function of deployment) was not taken into account. Modelling of electric interconnectors was simplified as one-way import options without taking the import electricity market price into account.

It is recognised that these shortcoming would influence the numerical results in this report. The authors of the report believe, however, that the methodology developed and the general trends found in the analysis would be unaffected.

Evidence gathered during the FlexEVAL study has demonstrated clearly the additional value flexible CCS power plants can provide to the electricity system of the future. The ability of flexible CCS power plants to complement increased capacity and power generation from intermittent renewable energy technologies is systematically beneficial and critical for system cost reduction.

Recommendations

CCS has long been acknowledged as an essential technology in a low-carbon energy system. However, when considering the deployment of CCS in the energy system, certainly when considering its application to reduce CO_2 emissions from power generation, cost has been a major focus of attention and a major constraint on its acceptance and ultimate deployment.

Less often explored has been the ‘value’ that CCS offers. Fortunately, this oversight is now more widely recognised and much more attention is being afforded to exploring the value CCS can bring, not only at the system level (as in the current study) but also more broadly to, say, energy security and the broader economy.

By placing greater emphasis on the value of CCS, the technology is more likely to be accepted by policy makers, project developers, investors and the general public alike. And the wider the acceptance, the greater likelihood that CCS would be selected as a key technology in the battle to mitigate climate change. The current study by Imperial College London makes an excellent contribution to this objective. It demonstrates the value that CCS, and particularly firm, dispatchable, flexible CCS, would bring by lowering the total cost of the electricity system of the future, a system where intermittent renewables are projected to play a dominant role.

To realise the value that flexible CCS would bring to the electricity system, policy support mechanisms are likely to be required to encourage its uptake. More studies like this, both across power and industry, are required to draw out the benefits of CCS and bring them to the broader CCS community, to policy makers, project developers and investors.

Suggestions for further work

A number of assumptions was made in the modelling undertaken for the study. For example, no learning rates were considered for the capital or operational cost of the technologies and energy storage technologies were not incorporated in the whole-systems analysis. The omission of learning rates would lead to rather conservative results in overall savings in the total system cost that would result from the deployment of CCS in the electricity system. The omission of energy storage, however, could well impact on the System Value for CCS and really needs to be evaluated in detail. Such an evaluation is recommended for further investigation.

While the development of policy mechanisms to realise the advantages of flexible, dispatchable CCS is required, this is rather a task for, e.g. the IEA Secretariat than for IEAGHG. The work undertaken by IEAGHG is policy relevant rather than policy prescriptive.

Valuing Flexibility in CCS Power Plants

FINAL REPORT ON THE FlexEVAL PROJECT

by Clara F. Heuberger[a,b], Iain Staffell[a], Nilay Shah[b,c], Niall Mac Dowell[a,b]

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FOR THE

International Energy Agency Greenhouse Gas R&D Programme,
John Davison, Keith Burnard

London, November 2016

Executive Summary

The FlexEVAL project quantifies the value of flexible CCS power plants to the future electricity system of the United Kingdom (UK). We review possible future developments in the energy sector, where increasing demand and a tightening of carbon dioxide emission targets will require significant changes in the energy systems structure and operation. We identify and review the key technical and market-relevant characteristics of CCS power plants and discuss flexibility concepts enhancing their ability to adjust power output quickly.

The threefold objectives of this report are defined as:

1. Identification of the role of flexible CCS in the UK electricity system;
2. Development of a systemic valuation technique for energy technologies;
3. Quantification of the value of flexible CCS in the UK electricity system.

We develop a new metric for valuing energy technologies within a power system, namely the System Value (SV). This metric quantifies the value provided by a given technology from a whole-systems perspective. The SV is defined as the reduction in total system cost (TSC) that results from the integration of the studied technology. The relative SV quantifies the reduction per installed capacity unit (£/kW).

In order to determine the SV, we have developed an electricity systems optimisation model, based on mixed-integer linear programming. The model simultaneously determines the cost-optimal electricity systems structure (type and amount of power generating technologies) and the optimal dispatch schedule (power output and service provided for each technology at each hour in one year of operation) subject to detailed technical constraints, as well as to ancillary requirements and environmental constraints. The detailed electricity systems model enables us to determine expected operating profiles of non-flexible and flexible CCS power plants. Through a range of scenarios and sensitivity analyses we explore the results in depth and evaluate their robustness.

We evaluate in the electricity system of the United Kingdom (UK) four types of CCS technologies and their flexible counterparts:

1. coal post-combustion and flexible coal post-combustion (bypass);
2. coal oxy-combustion and flexible coal oxy-combustion (storage);
3. IGCC pre-combustion and flexible IGCC pre-combustion (storage);
4. CCGT post-combustion and flexible CCGT post-combustion (bypass).

The flexible CCS technologies show a greater operating range, i.e. they are able to turn down power output further, and change between operational modes more quickly than the non-flexible CCS power plants. These features, however, come at higher cost and residual emissions. All CCS technologies reduce TSC when being deployed in the future energy system. Their ability to provide low-carbon electricity and firm capacity, at moderate capital and operational cost compared to unabated fossil fuelled power plants becomes increasingly relevant in carbon-constrained scenarios.

Flexible CCS technologies are able to accommodate higher levels of intermittent renewable capacity and electricity generation in the system; since operational expenses of intermittent renewables are near-zero, systems with a greater share of electricity from intermittent renewables show generally lower TSC. We observe how system balancing mechanisms take advantage of the increased operating range and reduced start-up and shut-down times of flexible CCS technologies. Additionally, less interconnection capacity is needed with the deployment of flexible versus non-flexible CCS technologies. This reduces the dependency on electricity imports and the TSC.

We find that the economic deployment level and SV is a function of the composition of the incumbent system design. The installation of CCS power plants gradually displaces unabated CCGT power plants, as well as off-shore wind, solar, and international interconnection capacity. Its ability to provide dispatchable low-carbon electricity is highly valuable to avoid carbon emissions while maintaining system operability, and reduces necessary balancing capacity. The relative SV is determined as a function of installed capacity and ranges from initial £500-800/kW at low deployment rates to £200-250/kW at maximum economic deployment rates. In other words, the total annual system cost of building and operating a power system is £200-800 less costly per installed Kilowatt of CCS-equipped power capacity depending on the prevalent capacity mix.

For flexible and non-flexible technology options CCGT post-combustion CCS provides the greatest economic and systemic value. This is caused by the low capital cost, low carbon emissions, high efficiency and flexibility, compared to the other CCS technologies.

Under 2050 UK electricity system conditions, we analyse the value of coal post-combustion CCS and CCGT post-combustion CCS power plants for two different electricity demand scenarios. The economic level of CCS deployment under the scenario with extreme peaks in the demand profile is marginally greater than in the business-as-usual case and provides insight into the different optimal operation strategies of the flexible and non-flexible CCS technologies. Their relative SV ranges from £350-700/kW to £150-300/kW depending on the technology deployment level.

We note, that the capital cost data of the CCS technologies refers to 2012 and 2014 report from the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) [1–3]. The omission of CCS technology cost reduction leads to rather conservative results in overall TSC savings caused upon their deployment in the electricity system. Furthermore, we do not incorporate energy storage technologies in the whole-systems analysis. An increased deployment of such technologies could potentially change the value for CCS and needs to be evaluated in detail.

In summary, we find that the interaction of CCS technologies with intermittent renewable capacity is decisive to TSC reduction. An increased flexibility in CCS power plants has a positive effect on the integration possibilities. The presence of flexible CCS capacity enables a larger share of intermittent power generation by providing low-carbon balancing capability. However, under higher rates of intermittent renewable electricity generation, flexible CCS power plants show generally lower utilisation rates, which could disincentivise investment. Defining market mechanisms that enable positive business cases under lower utilisation rates are essential for systems with high levels of intermittent renewable capacity. From a whole-systems perspective, however, the benefits of flexible CCS technologies on the costs and the carbon intensity of the power system are indisputable and political measures could carry them forward.

Table of Contents

Nomenclature

Abbreviations

Symbol	Explanation
AS	Ancillary Services
ASU	Air Separation Unit
BAU	Business as usual (electricity demand scenario)
CAPEX	Capital expenses
CC	Capacity Credit
CCS	Carbon Capture and Storage
CF	Capacity Factor
CCGT	Combined Cycle Gas Turbine
CI	Carbon Intensity
ED	Economic dispatch
ExP	Extreme peak (electricity demand scenario)
FF	Fossil Fuels
FOAK	First-of-a-kind
IGCC	Integrated Gasification Combined Cycle
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	N^{th}-of-a-kind
OCGT	Open Cycle Gas Turbine

OPEX	Operation expenses
Relative SV	Relative System Value (£/kW)
SRMC	Short-Run Marginal Cost
STOR	Short-term Operating Reserve
SV	System Value (£Reduction)
TSC	Total System Cost
UC	Unit commitment
VoLL	Value of Lost Load
WTA	Willingness-to-accept
WTP	Willingness-to-pay

List of Figures

List of Tables

Chapter 1

Project Objectives and Structure

Carbon capture and storage (CCS) is a promising technology for large-scale deployment and decarbonisation of the power generation sector and beyond [7, 8]. Of particular importance is the ability of CCS-based power plants[1] to complement and work in synergy with intermittent power generation, providing a flexible buffer between intermittent renewable electricity generation capacity and less flexible nuclear base-load capacity. However, it is highly likely that a CCS system which possesses a larger operating envelope and can be controlled more flexibly than existing CCS technologies will be more capital intensive. The trade-off between costs and reliable low-carbon power generation is not yet well understood. It is therefore imperative to qualitatively and quantitatively determine to the best of our abilities the value provided to the energy system by the availability of flexible low carbon electricity.

1.1 Main Objectives

The energy landscape is changing from a fossil fuel dominated system to one, which is increasingly integrating renewable energies and smart technologies, aiming to increase efficiency and to reduce environmental impact of energy consumption. In terms of electricity generation and grid management the penetration of

[1] Throughout the report, the abbreviation CCS mainly refers to CCS-equipped power plants as opposed to only the CO_2 capture and storage process parts.

renewable, and often intermittent power sources, is blurring the boarders between the typical operational schemes of the 20th century energy systems, classifying power plants as base-load, mid-merit, or peak-load power plants. This phenomenon, together with the need to reduce the carbon intensity of the power sector, can open new prospects to low-carbon power plants which are able to operate beyond these traditional schemes.

In this report, we provide insight into how the role of CCS power plants in the UK will evolve as the energy landscape changes in the decades from 2015 to 2050. We will analyse the types of power generating assets which could be displaced by CCS power plants and how this affects the threefold energy challenge of reducing carbon, minimising costs, and maintaining security of supply. In particular, we differentiate between non-flexible and flexible CCS power plants, where the first refers to common power plant designs with post-combustion, oxy-combustion, or pre-combustion CO_2 capture technologies, and the latter, to such systems including operational flexibility enhancing technology (e.g., solvent storage, oxygen storage, capture bypass or time-varying solvent regeneration [5, 9–11]). This report does not aim at studying power plant designs with increased operational flexibility in detail, but investigates whether the performance of flexible CCS-equipped power plants on a systems level increases its value to the electricity system.

In order to understand the role of CCS in a whole-systems context, we build an optimisation-based energy systems model. It maps a national-sized electricity system, tailored to represent the UK, simultaneously determining the amount and type of generating capacities as well as the detailed plant-level operation. The objective function is to minimise total electricity system costs, including 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.

Consequently, we define an evaluation scheme to qualify and quantify the individual value power generating technologies provide to the electricity system. We define and quantify the value of CCS power plants to the UK electricity system under a range of scenarios representative of projections for the period between 2030 and 2050. We investigate the overall carbon intensity of the electricity system, the total system costs, as well as the cost of electricity to the consumer whilst ensuring security of supply. A range of sensitivity analyses on the fuel price, power plant efficiency, and capacity availability are carried out to understand the parameters' influence on the model findings.

This report addresses the following key questions:

1. How is the UK's electricity system likely to change in the period between 2015 and 2050? Will the need for balancing services and flexible power generation increase? How will political and environmental targets incentivise and facilitate transition in the power generation sector?
2. What kind of operating profile can we expect for non-flexible CCS and flexible CCS? What kind of operating profiles would be cost-optimal? What are the capabilities, limitations, and key parameters for CCS power plants?
3. What role will non-flexible CCS and flexible CCS play in the future UK electricity system? Is there a distinction between the services that non-flexible CCS and flexible CCS could provide? What advantages and challenges could arise when integrating CCS-based power generation into the electricity system?
4. How do we qualitatively and quantitatively identify the value of technologies to the electricity system? And what is the value differential between non-flexible and flexible CCS in the future electricity system?

1.2 Approach and Methodology

The FLEX-EVAL project couples detailed engineering and electricity market models to provide a bottom-up analysis of the cost and value of making flexible CCS power plants available to the UK energy system. The heart of the technology valuation algorithm is a mixed-integer linear optimisation model which is formulated and modelled in GAMS 23.7.3 [12] and solved with the optimizer CPLEX 12.3. Pre-processing steps, such as data clustering and profiling is executed in the R environment [13]. A schematic of how the different software and modelling platforms integrate is provided in section 6.

Chapter 2

The Electricity System Transition

Investment in renewable energy capacity has been in the vanguard of the energy system change rising from $60 to $200 billion from 2000 to 2013, while investments in fossil fuel continue to dominate by increasing from $500 to $1100 billion in the same time span [14]. However globally, over 86 % of energy is produced from fossil fuels with only 2.2 % from intermittent renewable sources such as wind and solar [15]. It is likely that fossil fuels will remain vital to the global energy supply for the foreseeable future [16].

It is also recognised that the continued exploitation and utilisation of fossil fuels in the conventional way is not a sustainable option [17], with a significant fraction of the world's fossil reserves now being branded "unburnable" [18]. However, we contest that it is not that the fossil fuels are themselves "unburnable", rather it is that the CO_2 that arises from their combustion is "unemittable" and in this context CCS technology finds a particular niche in the transition to a low carbon economy. There is, in fact, a growing consensus that CCS is key to the least cost decarbonisation of both the power and industry sectors [17, 19], with both the Energy Technologies Institute (ETI) and Intergovernmental Panel on Climate Change (IPCC) recognising the value of CCS also in being able to generate carbon negative electricity via bioenergy CCS (BECCS) [20, 21].

Since the 1960s the UK has never faced such drastic changes in electricity system planning than it does today until 2050 and beyond [22–25]. Policies, environmental awareness, and system constraints push for a rigorous change of direction.

Figure 2.1 visualises which sources dominate electricity supply today and in the following decades based on seven scenarios for the UK's future electricity generation mix.

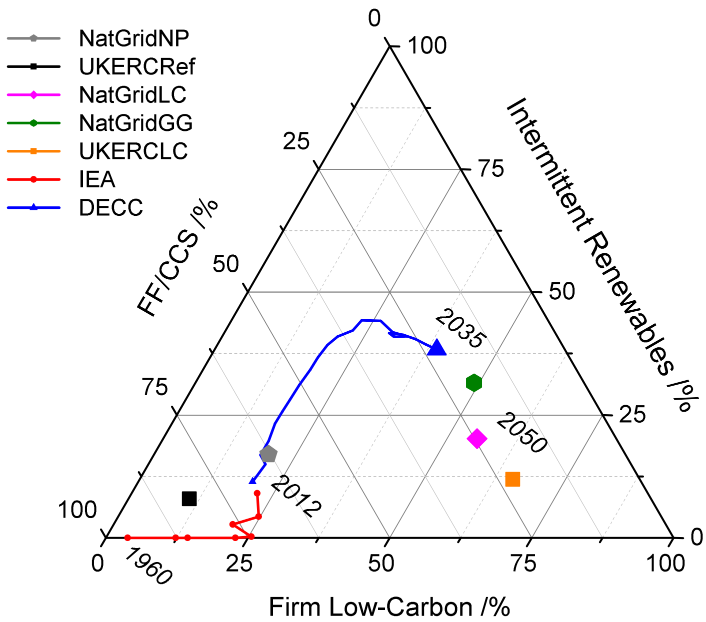

Figure 2.1: Trajectories for electricity generation by fuel in a technology ternary, 1960 to 2012 according to the IEA [26], and 2012 to 2035 to DECCâĂŹs reference scenario [27]. Other scenarios are shown with large markers for the respective 2050 fuel mix [23, 25]. Firm Low-Carbon generation refers to nuclear, imports, biomass and geothermal, energy storage technologies; Intermittent Renewables are represented by wind power; Fossil Fuels without and with CCS (FF/CCS) include coal (cofired/non-cofired, w/o CCS), natural gas (w/o CCS), oil. Data is normalised to total electricity generation for each year or according to the time discretisation of the given set. Based on analyses in Heuberger et al. [28].

2.1 Integration and Balancing Challenges

It is not CCS alone that will achieve the decarbonisation of the power sector, but rather a well-balanced combination of technologies. Intermittent renewable energy generators can provide an important source of low-carbon electricity, however their power output depends on the fluctuating energy source (wind or insolation).

The Capacity Factor (CF) is defined as electricity output over a certain time horizon, typically one year, as a fraction of nominal installed capacity. A typical conventional thermal power plant operating in a base-load merit order position has a CF value of 85 - 90 %. However, the power output of intermittent generators depends on the project site. For instance, the CF of a wind power plant is related to the locational power potential and ranges between 5 - 45%. In addition to its locational dependence the Capacity Factor of wind power plants varies over time as a function of the locational wind speeds [29, 30], classifying such power plants as non-dispatchable.

Besides transmission grid expansion, a sufficient level of balancing capacity is required to accommodate their large-scale integration into the electricity grid. Balancing capacities can include energy storage technologies, demand-side mechanisms, and conventional firm capacity such as nuclear or fossil fuel power plants. As both sides of the electric system, the supply and demand, are changing this will further complicate the balancing challenge [31–33]. In the absence of an inertia-based grid frequency control, operability requirements will become a restricting factor for renewable power capacity deployment [34].

Strategies trying to make use of intermittent power generation in frequency response propose "synthetic inertia"[1] as service for wind power plants. In this way, power generators which are traditionally almost inertialess can perform inertial services by rapidly increasing their power output from a part-load operation point [37]. However in the UK, this type of service is not yet specified by the Grid Code[2] [40].

On a practical level, the increasing penetration of intermittent power generation is stressing the electric grid's operability to its limits and is causing present ancillary requirements for reserve and frequency control to advance [37, 41]. Solving the trilemma between carbon avoidance, cost, and security of electricity supply therefore requires a delicate balance [42, 43].

[1] Synthetic inertia refers to the implementation of an additional electronic controller on the wind power generator side which during operation is able to restrain power output and increase rapidly if needed. This power boost can then counteract a frequency excursion and reduce the RoCoF [35–37]. Although, the inertial response from wind power generators has a positive effect on system inertia it only acts momentarily and might not be able to replace other security measures [35].

[2] This framework sets out the technical requirements for a reliable system operation; the Balancing and Settlement Code company ELEXON Ltd. defines the electricity trading arrangements [38, 39].

2.2 System Emission, Operability, and Economics

Intermittent renewable sources and CCS-equipped power plants are considered in the technology mix today due to their distinguishing mark of providing low-carbon electricity. However, for intermittent renewable capacity balancing mechanisms are required when integrating large amounts of intermittent capacity into the power system. The idea of "associated carbon" refers to the carbon emissions caused implicitly by "clean" electricity generators which require CO_2 emitting back-up capacity. As the load hours per year for conventional plants decrease with the inclusion of wind power, their CI increases and the combined system emissions remain significant. Additionally, balancing operation forces back-up power plants to operate off their nominal load point, reducing efficiency and increasing carbon intensity further.

The major effects a growing share of intermittent energy sources has on electricity market dynamics is described in the work of Ueckerdt et al. [44]. First, the reduction of full-load hours for conventional power plants imply an increase in average generation costs. Secondly, there is almost no reduction in necessary back-up capacity, hence capital expenses on conventional power plants remain, due to a low capacity credit of intermittent generators. Thirdly, a reduction in CF of intermittent generators due to overproduction (which increases with their share in the mix) induce higher specific energy costs for these generator types [44].

The common LCOE calculation accounts for the life-time expenses and revenues levelised by the generated electricity from the respective technology. However, the LCOE metric assumes that generated electricity is a "homogeneous product" [45]. This is not the case for intermittent technologies which necessitate back-up or energy storage capacity in order to provide electricity as reliably as conventional power plants. The traditional concept of LCOE is also lacking a systemic perspective when comparing electricity generation costs of different technologies. Omission of the additional costs to accommodate intermittent power generators can lead to inadequate results. Ueckerdt et al. define these additional costs as "profile costs", which consist of back-up costs (also referred to as integration cost), full-load hour reduction costs, and overproduction costs, accounting for the above mentioned mechanisms [44].

There are at present no evident market incentives, apart from individually contracted agreements with the system operator, to promote high-inertia generator types. Renewables are often supported using a fixed premium for energy generated regardless of how "useful" this is to the system, which offers no reward for availability or dispatchability [46]. Furthermore, renewables can operate at the expense of conventional generators where support schemes include an export guarantee with preferential grid access [47].

Given the system-wide constraints ensuring operability, reliability, and adequacy there is no alternative to a whole system approach when comparing technologies regarding their benefits to the energy system. It is essential to determine the optimal combination of technologies, concerning the amount of installed capacity as well as their interaction within the energy system providing the required services to meet our demand for reliable low-carbon electricity. The importance of evaluating technologies in the context of the electricity system within which they are operating as opposed to on an individual basis is the underlying principle of this study.

Chapter 3

Carbon Capture and Storage in Power Generation

The following sections provides a review on economic and operational features of different CCS technologies based on research by Heuberger et al. [28], and provides a brief outlook on the potential of this technology to operate in a flexible manner.

3.1 CCS – Key to a Low-Carbon Energy System

CCS has been identified as a key factor to a low-carbon electricity generation, environmentally and economically [48]. The costs arising from mitigating CO_2 emissions have been shown to be significantly lower when CCS technologies are available compared to estimations including only solar, wind or nuclear power generation [49]. The IPCC finds that in scenarios aiming for a 450 ppm CO_2-eq atmospheric concentration by the end of the century the global total discounted mitigation costs are 138 % higher without CCS relative to the default set of technologies [17]. The Low Carbon Innovation Coordination Group (LCICG) estimate a reduction in energy system costs between 2010 and 2050 by £100-500 billion when ensuring CCS availability [19, 50].

Current CCS deployment is mostly limited to the power generation and gas processing sector, however, also industry (e.g. cement and steel industry) is expected to deploy CCS technology [51, 52]. Experiences in the power sector can drive down costs and accelerate the deployment in industry. The IPCC predicts an investment increase in CCS almost on par with renewable power technologies (+100 % by 2029 compared to 2010). Unabated fossil fuels could see a divestment trend (-20 % by 2029 compared to 2010) [17].

The electricity generation costs of CCS-equipped power plants in the UK expressed as Levelised Cost of Electricity (LCOE) are estimated to range at £70 - 150/MWh[1] depending on the type of technology [53–55]. The cost of CO_2 avoided are estimated to range at £20 - 70/t-CO_2 [56, 57].

The capital costs of a CCS plant are estimated to be between 40 - 80 % greater than of unabated plants [58]. These costs, however, are expected to decrease as the technology deployment accelerates [54]. The IEA's World Energy Outlook projects a CAPEX reduction between 10 - 20 % by 2035 [59], the LCICG sees a decrease of 30 % by 2020 [50]. Outside the UK studies evaluate cost reduction rates of 5 - 20 % depending on the technology type [60–62]. The LCOE is expected to drop from £150/MWh in 2015 to just below £100/MWh in 2029 [63]. Nevertheless, transitions in the energy sector are slow as the existing asset-base has long lifetimes. It generally takes 30 years for a new technology to progress from first concept to "materiality" where it provides 1 % of global energy [64].

The LCOE is an intuitive metric for the technology-specific cost of electricity generation. It includes investments, operation and maintenance, and fuel costs and is widely used to assess the cost competitiveness of different types of generators. Nevertheless, the LCOE analyses has limitations as it does not account for price and production variability or give an indication for the impact a technology has on the energy economics [45]. In an LCOE comparison, DECC sees CCS to be on par with offshore wind for projects starting in 2019 in the UK [54]. However, when making strategic capacity planning decisions a straightforward comparison of technology prices is lacking an integral view and could cause systemically uneconomical results. At peak times wind power plants might not be able to generate electricity and cannot provide any other service to the energy system. A conventional energy system might therefore opt to provide back-up capacity for this intermittent capacity. Traditionally, this back up has been in the

[1] The International Energy Agency (IEA) states the LCOE for CCS at £62 - 68/MWh in 2011 [53]; DECC publishes figures of £90 - 130/MWh in 2013 [54]. Bassi et al. estimate a range of CCS LCOE of £70 - 80/MWh in 2015 [55]

form of unabated coal or gas-fired power plants. By contrast, power provided by CCS plants is both available and low-carbon, and the combination of CCS and intermittent renewable power should be investigated in detail as an alternative to the conventional combination of intermittent renewables and unabated fossil plants.

3.2 Flexibility in CCS Power Plants

Additionally to its important role in decarbonisation, CCS holds another feature which is and will become increasingly valuable: flexibility. Traditionally flexibility in energy engineering is understood on the process level where plant engineers manage the unit operation in order to provide a particular service such as delivering electricity or spinning reserve. The flexibility of a plant is then indicated by operational parameters defined as ramping rates, stay times in certain operational modes, and so forth.

In our understanding the term flexibility has two aspects. The first assumes the perspective of the power plant operator as described above. Flexibility in this context enables the plant to follow the load and participate in market schemes demanding high response rates. Consequently, it allows power plants to operate in sympathy with intermittent renewable generators as to balance their relative unreliability. The second takes the perspective of the electricity grid, or system operator, which is required to connect and balance power supply with power demand. Here the ability of a power generator to provide the required service is the main concern – what the power plant has to do in order to provide this service is less important. Hence, a power plant which the system operator could call upon at any time for any type of service would be particularly valuable to the electricity system. Then flexibility of a power plant is not simply the fastest possible adjustment in power output but the ability to provide the service which is of greatest value to the electricity system at any given point in time. The implications of this second perspective are underpinning to this paper as they highlight how the value of a specific feature of a particular technology depends on the system the technology is operating within.

Considering flexibility from the first perspective identified above, CCS can impose constraints on the operation compared to conventional power plants [65]. The degree to which different variants of CCS technology (amine scrubbing, oxy-combustion etc.) can operate in a flexible manner is a function of the design and operability of the individual technology elements of which the CCS plant is composed. A restriction applicable to all CCS options is for example the part load behaviour of the CO_2 compressors but other, possibly stronger limitations arise from the individual processes in pre-combustion, post-combustion, and oxy-combustion CCS [65]. Crucial for oxy-combustion CCS is the ramp rate (ramp-up 3 -5 %/minute) of the air separation unit (ASU) [65, 66]; whereas for post-combustion processes the solvent regeneration or column turn-down ratios can become limiting factors.

Analysis of how to increase CCS flexibility have historically been divided between options for reducing CO_2 removal and those keeping the CO_2 capture rate constant also when operating off the nominal load point. Hydrogen storages for pre-combustion, solvent storage for post-combustion or bypassing are currently the most studied techniques [5, 9, 67–70]. Another source of flexibility in the post-combustion process could be time varying solvent regeneration [10, 11]. Table 3.1 summarizes the effect bypass or storage can have on the processes for pre-/oxy- and post-combustion CCS.

Strategies to overcome the operational limitations are ample (although not tested in large-scale) and we do see that CCS power plants can operate just as flexibly as their CO_2 emitting counterparts [3, 65, 71–73].

Although the importance of CCS is clear, only economic measures defined through coherent long-term policies can convince the industrial and energy end-use sector to invest and deploy this technology. Using technology prices or LCOE measures have major shortcomings regarding system integration costs. Investments in supposedly cheap technologies can entail unplanned expenses at other ends but also environmental damage and grid instability. The overall value to the electricity system can only be understood when technologies are assessed together, not in isolation. In the following, we therefore analyse the current state and changes of the electricity system in general and in particular for the UK.

CCS option	Bypass Integration	Storage Integration
Pre-combustion	• Gasification process remains main source of energy penalty • Solvent regeneration and compressor work are reduced	• Hydrogen storage to decouple gasification and capture from power generation
Oxy-combustion	• Compressor work can be saved • Plant can run on air instead of oxygen	• ASU has to operate continuously
Post-combustion	• Reduced energy consumption in heat exchanger and stripper	• Large quantities of rich and lean solvent needed • Steam turbine, stripper, and compressor have to be sized accordingly

Table 3.1: Engineering requirements and effects of flexibility increasing process adjustments for CCS power plants [5, 6]

Chapter 4

Systemic Technology Valuation

Electricity cannot not be treated as a temporally homogeneous product [45] or a physical commodity [44]. Even more in a deregulated market, various services are based on electricity generation with a value to its consumers which is distinct from the electricity price. The growing share of intermittent renewable power generators disarranges traditional merit order energy economics. Previously discussed cost metrics, such as LCOE or Short-Run Marginal Cost (SRMC), lack to account for system integration and interaction which is identified to be indeed a relevant proportion of the overall system cost [44].

The U.S. Energy Information Agency (EIA) highlights the shortcomings of the LCOE metric in comparing dispatchable and intermittent power generation technologies. Factors besides the individual technology cost, such as the project region and the existing capacity mix can impact the investment viability and technology competitiveness [74].

This chapter reviews existing ideas to a system-wise evaluation of technologies and introduces the here developed approach of the System Value (SV).

4.1 Previous Approaches to Technology Valuation

Boston et al. advocates for a whole-systems perspective in capacity planning and presents the Balance Energy, Reserve, Inertia and Capacity (BERIC) model [75].

In brief, the BERIC model is a linear program (LP) minimising SRMC and determining the unit operational schedule of a predefined capacity mix of technologies. A technology value is then calculated as the impact that the addition of an incremental amount of capacity of that technology has on the total electricity generation cost. This value is observed to depend on the existing system configuration, and in particular on the amount of already installed capacity of the examined technology.

Another recent concept by Moore et al. is the "Cost of New Entry" (CONE), where a plant operators' costs (fixed cost minus energy market profits) per sold unit of electricity are used to quantify competitiveness between renewables and CCS capacities [76, 77].

The EIA introduces the Levelised Avoided Cost of Electricity (LACE) metric, which quantifies the annualised cost avoided by the integration of the respective technology capacity to the electricity grid levelised via its annual average power output [74, 78]. This metric requires a tool for simulation of the power system the technology is integrated with. By comparison of the LCOE with the LACE of a technology in a particular region and year the investment can be determined as attractive if its value exceeds the cost.

Ueckerdt et al. presents the "System LCOE" which strongly relates to the concept of SV [44]. The common LCOE calculation accounts for the life-time expenses and revenues levelised by the generated electricity from the respective technology. However, the LCOE metric assumes the homogeneity of electricity. Criticising the LCOE for its inadequacy when assessing intermittent renewables, the System LCOE includes generation and integration costs which are "all additional cost for accommodating intermittent renewables" in the electricity system [79]. A new component, the "profile cost", account for the effects of intermittent power generation on the system requirements. These show potential to become an "economic barrier" for the deployment of intermittent sources [44].

Where the System LCOE compares the economic feasibility of electricity systems with and without intermittent renewables, this study aims to progress this area by introducing a technology specific measure.

4.2 The System Value of Technologies

The System Value (SV) of a particular technology is the marginal change in total electricity generation cost (capital, energy, ancillary services) from integrating an additional unit of that technology. The relative SV is specified as reduction in annual total system cost (TSC) per unit of installed capacity, £/kW. We consider the value of a technology as a function of the existing capacity mix and consequently try to overcome the shortcomings of traditional cost metrics in a whole-system perspective.

The first capacity unit of a certain technology in a given capacity mix has a different value than the n$^{\text{th}}$ capacity unit. For example, the first unit capacity of wind power is extremely valuable to a system given its low SRMC and its manageable impact on system operability and stability. In contrast, in a wind-rich generation mix, increasing the wind capacity further could actually increase system costs and CO_2 emissions owing to the requirement for large back-up volume [80]. Therefore, a significant advantage of the SV metric is the ability to distinguish between FOAK and NOAK technologies, even specifically to quantify the value added by the n$^{\text{th}}$ capacity unit of the respective technology. A key feature of the SV approach is that the SV of a particular technology is firstly a function of the composition of the incumbent system into which that technology is installed and secondly that the SV itself evolves with increased deployment of that technology. This functionality is completely absent in cost-based metrics such as the LCOE.

The centrepiece of the SV approach is a mixed-integer linear program (MILP) which simultaneously optimises the electricity system design as well as the unit-wise schedule. We extend a general unit commitment formulation [30, 81] by environmental and security aspects as well as a model capturing the detailed unit operation.

The objective is to minimise total system cost subject to system design and whole-system constraints, as well as component-wise constraints. We account for reserve and inertia requirements to ensure system operability and reliability. An overall emission limit restrains the environmental impact of electricity generation. The ensuing section 5 introduces the model formulation in detail.

The SV procedure is summarised in figure 4.1. A whole system optimisation regarding the system design as well as the unit scheduling is performed for a reference system o. In this case, $N_o(i)$ units of each technology i are available (upper bound) to be installed in order to meet system demands. We stepwise increase the upper bound $N_k(i)$ for one technology i and perform the analogous calculation for K perturbed systems. From each set of results the total system cost are compared between system k and the reference system o. This allows the evaluation of the marginal change in total system cost by increasing the availability of the respective technology i taking the whole system dynamics into account.

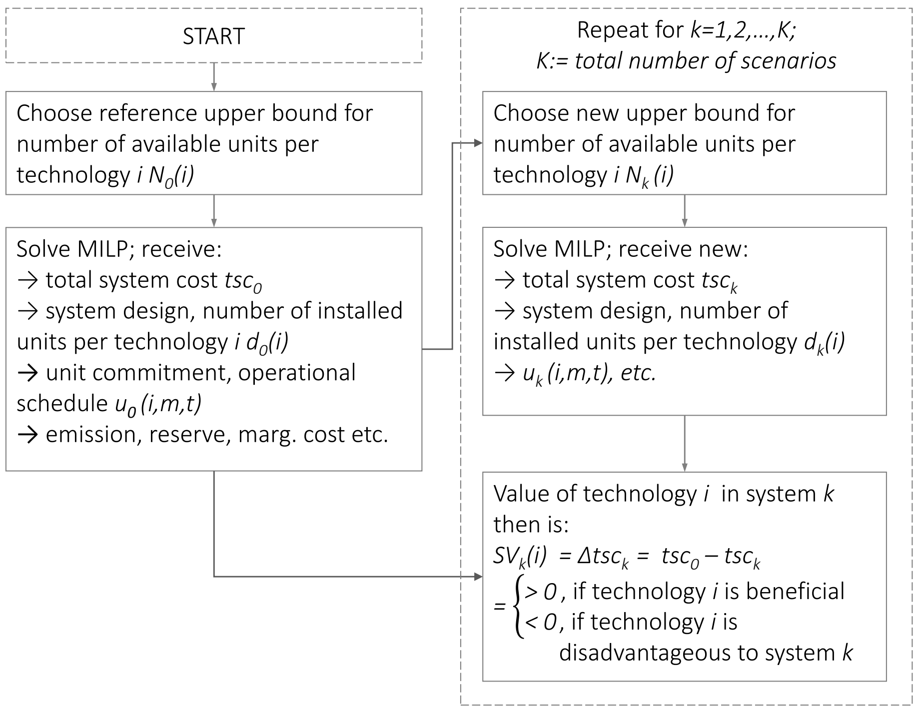

Figure 4.1: The System Value algorithm is based on the difference in total system cost (£/year). Mentioned parameters and variables in italic are described in detail in section 5.2.

Hence, the algorithm determines the System Value of a given technology i as a function of the prevalent system conditions, e.g., the other available power generating technologies, their operational and environmental characteristics, the overall system emission targets, and the amount of available capacity ($N_k(i)$) of the evaluated technology i. Consequently, it explicitly takes integration challenges and costs into account and addresses the value change as a function of capacity deployment.

This concept of evaluation and technology analysis is intended to create a general understanding for the system synergy and challenges. Firstly, the SV metric covers socio-economic aspects, taking a consumer's viewpoint when valuing available low-carbon electricity. Secondly, the SV can be used as tool for sustainable system design. Additionally, the SV estimates the value of a technology's feature (e.g. flexibility, firmness, low emission rates) within the electricity system which can imply economic changes in technology design.

Chapter 5

Optimisation Model of an National-Sized Electricity System

A coherent and integral optimisation model of the electricity system is the focal point of the System Value (SV) approach. In order to reach an understanding about the basics of energy systems modelling we review a special case of optimisation models, or more specifically of optimal scheduling: unit commitment. We then introduce the model derived in this study and emphasis on the differences and extensions to existing formulations.

5.1 Review of Unit Commitment Models

Every power network with more than one power generator faces the problem of unit commitment (UC) [82]. In brief, UC then refers to a dispatch strategy of power generating units in terms of time and level of output. Caused by consumer behaviour, the demand for electricity fluctuates considerably. In order to minimise fuel consumption, and ultimately costs, the determination of an optimal operation schedule for each power generating unit has been practised for many years.

The idea to approach this task by means of mathematical optimisation was introduced as early as in the 1920s [82, 83]. Industry, in particular electricity system operators, have pushed forward the research in this area [84, 85]. Until today, operator and transmission organisations are solving UC problems every day for dispatch planning to real-time control. Even commercial software is now available for automated UC [86, 87].

The goal of solving a UC model is to find a power dispatch strategy for the generating units to meet electricity demand in the most economic way. The dispatch strategy includes the on/off schedule as well as the level of production for each power unit. Obvious parameters are the operational costs of the units as well as the electricity demand which has to be satisfied. There are two main perspectives from which the unit commitment problem is typically examined. The first, is a societal view where the objective is to minimise total system or total electricity generation cost. In the second, one takes the perspective of a power plant operator who aims to maximise his individual profit by optimal production planning. In this case the constraint of meeting total electricity demand is soft.

A concept very close to UC is economic dispatch (ED). Originally UC and ED differ in their time dependency as well as their technical granularity and underlying perspective [88, 89]. A UC plans in advance for a certain time horizon (typically one day/week in hourly discretisation) so that sufficient generators are on-line. An ED on the other hand, without any time dependency determines the exact dispatch strategy based on more detailed cost structures in real-time (e.g. every minute). ED is typically formulated as simple linear program (LP) or non-linear program (NLP); the UC is formulated as mixed-integer linear program (MILP) including discrete decisions for the on/off status of the units. The solution of the ED problem implicitly determines the on/off status by assigning the level of power output to the individual power generating units. Traditionally, UC and ED programs are solved only for thermal power generators where fuel expenses are the dominant operating costs. More recently, efforts have been made to incorporate renewable power generators into the mathematical scheme. Zhu provides examples of ED for conventional power plants and Hetzer et al. for a network including wind power generation [88,90]. Necessary assumptions from an electrical engineering point of view are: constant current flow, constant generator voltages and angels, constant power factor (VAr/Watt ratio) [82].

The simplest version of a unit commitment problem is stated by equations and inequalities (1)-(5), where the symbols are defined as below. Throughout this work we follow the convention of capitalising parameters and using lower case names for all variables.

Type	Symbol	Unit	Description
Set	t	h	time periods, $t \in T = \{1,...,T_{end}\}$
	i	-	technologies, $i \in I = \{1,...,I_{end}\}$
Parameter	$Pmin(i)$	%-MW	minimum power output of technology i
	$Pmax(i)$	%-MW	maximum power output of technology i
	$OPEX(i)$	£/MWh	operational costs of technology i
	$SD(t)$	MWh	system electricity demand at time period t
Variable	$n(i,t) \in [0,1]$	-	1, if technology i is online (= generating power) at time period t
	$p(i,t) \in \mathbb{R}^+$	MWh	power output of technology i in time period t
	tsc	£	total system cost, objective

$$min\ tsc = \sum_{i \in I, t \in T} OPEX(i) \cdot p(i,t) \tag{1}$$

$$s.t. \quad \sum_{i \in I} p(i,t) = SD(t) \qquad \forall t \tag{2}$$

$$p(i,t) \geq n(i,t) \cdot Pmin(i) \qquad \forall i,t \tag{3}$$

$$p(i,t) \leq n(i,t) \cdot Pmax(i) \qquad \forall i,t \tag{4}$$

$$n(i,t) \in [0,1] \qquad \forall i,t \tag{5}$$

Here the total system cost tsc are represented purely by operational expenses caused by power output (e.g. fuel consumption) of technology i at time period t. The minimisation of tsc is the objective function (1) of this problem. It is further subject to the electricity balance (2), as well as the upper and lower bounds for power output from technologies i. The binary variable $n(i,t)$ determines the on/off status of each technology operating within the electricity system. Only if $n(i,t)$ equals 1 power output from technology i in time period t can contribute to meet the system electricity demand $SD(t)$.

In this study, we take the typical UC structure as basis for our model. However, the formulation we derive combines UC and ED ideas, as both detailed fuel consumption (as in ED) and time dependency (as in UC) are taken into account. We extend the scope and formulation based on the work of Staffell and Green [30] and as outlined in section 5.2. There are many variations of the UC problem emphasising different characteristics of the power system. Table 5.2 summarizes the most common types of UC and ED problems and provides some references for further reading.

Type of UC	Description	References
Network constrained (NCUC)	Additional constraints for sizing, location, and state (flow vs. congestion) of transmission lines	[81, 82]
Security constrained (SCUC)	Includes reserve requirements, spinning and non-spinning reserves	[82,91,92], with wind power [93]
Residual, Reliability UC (RUC)	Schedules reserve capacity for system reliability	[87, 94, 95]
Locational ED	Includes location of power generators	[82]
Environmental UC	Considered greenhouse gas emissions by power generating technologies	[82, 96, 97]
Detailed operation UC	Includes detailed generator constraints like ramp constrained and up/down times	[81, 92, 98–100]
Stochastic, Robust UC	Considers uncertainty in demand, power production, etc. and provides reformulation as stochastic or robust program	[101–103]

Table 5.2: Variations of unit commitment (UC) and economic dispatch (ED) problem.

Solving techniques for UC and ED problems continue to be a active field of research and have been constantly advancing to reduce computational effort and solution time. There are two main approaches to solving these types of optimisation problems: mathematical programming and heuristics. The first approach aims to find the optimal solution (or the optimal set of solutions) by means of rigorous mathematical procedures. A very well known technique, which was also the first to be applied to UC problems, is Lagrangian Relaxation. It approximates the solution in an iterative fashion by incorporating hard constraint into the objective function weighted by the Lagrangian multipliers which are repeatedly updated until the solutions suffices the defined tolerance. Wang, Zhu, and Frangioni give examples for LR approaches in UC modelling [88,96,99]. Dynamic programming is another technique which makes use of decomposition procedures and is often applied in a multi-stage decision making process. Examples for DP in unit commitment problems can be found in Li et al. [83]. State-of-the-art techniques are the Interior point method [98] and Branch & Bound, Branch & Cut [92]. Modern commercial solvers apply these procedures achieving short execution times at low computational effort.

The second approach uses heuristics, typically to improve solution time by potentially sacrificing accuracy and completeness of the solution. Heuristics can outperform mathematical programming where a problem cannot be posed in a closed mathematical form. The solution algorithms are often motivated by nature, biology, or engineering. The most common ones are priority listing, simulated annealing, particle swarm, tabu search, evolutionary and fuzzy algorithms [94,99,104–106]. For this work we aim at determining the mathematically optimal solution within a constrained space and choose mixed-integer linear programming as solution approach.

5.2 Model Formulation and Extension

The model we derive here is based on the simple unit commitment model (equations (1)-(5) section 5.1). We derive the final model formulation by consecutively increasing the complexity and size from the original UC. The following section presents the modelling assumptions and the model formulation [1a] according to the categories in figure 5.1 to create a general understanding for the UC structure in this report. The final model [3c] is presented in detail in the appendix A, as [3c] is the underlying model for all following results and analyses. The running procedure, scenarios, and outcomes are explained in detail in sections 6, 7, and 9.

Model categorisation		Basic MILP	Security constrained	Detailed operation
		a	b	c
Design + UC	1	[1a]	[1b]	[1c]
+ Environment	2	[2a]	[2b]	[2c]
+ CCS availability	3	[3a]	[3b]	[3c]

CONSTRAINTS + COMPLEXITY

SYSTEM + SIZE

Figure 5.1: Categorisation of MILP model; formulation increases with constraint and in complexity moving from the basic UC to the security constrained and finally the expression capturing detailed operational behaviour. The scope of the modelled electricity system increases by including environmental considerations on technology and system side as well as including a larger set of available technologies such as CCS.

5.2.1 Modelling Assumptions

Several assumptions and simplification are made to increase the computation tractability of the power systems model.

- We do not account for energy storage technologies as a choice in the range of technologies captured by the electricity systems model
- We assume electricity demand and prices to be perfectly inelastic.
- The national electric transmission system is represented as a single-node network. We do consider overall transmission losses.
- Electric interconnectors are modelled as one-way import option at constant cost rather than accounting for an hour-by-hour electricity market price.
- Uncertainty in the input parameters is not considered. The model is deterministic.
- We assume direct current power flow from the generating units to the electricity consumer, constant generator voltages and angels, and constant power factor.
- Since the time discretisation is hourly ($\Delta t = 1$ h) power and energy values are equivalent.

The integration of energy storage technologies in the systems analysis could smoothen the intra-day and seasonal intermittency of power generation by wind and solar and increase the viability of these power sources to the electricity grid [31]. However, the deployment of new grid-level energy storage capacity in the UK is estimated by the Department of Energy and Climate Change (DECC)[1] to be at most 3 GW by 2035 [27]. We note that these shortcoming can influence the numerical results in this report. The developed methodology and general trends found in this analysis, however, we believe to be unaffected by these aspects.

5.2.2 The Basic Energy System Model

In the following we introduce nomenclature and model formulation of the basic MILP model [1a]. In principal, any type of technology (set I) can be made available for power generation within the energy system. Model category [1] and [2] are defined to exclude CCS as available technology.

Type	Symbol	Unit	Description
Set	t	h	time periods, $t \in T = \{1,...,T_{end}\}$
	i	-	technologies, $i \in I = \{1,...,I_{end}\}$
Parameter	$N(i)$	-	number of available units of technology i
	$D(i)$	MW/unit	nominal capacity per unit of technology i
	$Pmin(i)$	%-MW	minimum power output of technology i
	$CF(i,t)$	%-MW	capacity factor (= maximum momentary power output) of technology i
	$CAPEX(i)$	£/unit	annualised investment costs of technology i
	$OPEX(i)$	£/MWh	operational costs of technology i
	$SD(t)$	MWh	system electricity demand at time period t
Variable	$d(i) \in \mathbb{Z}^+$	-	number of units of technology i designed (= units installed)
	$n(i,t) \in \mathbb{Z}^+$	-	number of units of technology i online (= generating power) at time period t

[1]Now integrated into the Department of Business, Energy & Industrial Strategy.

$p(i,t) \in \mathbb{R}^{+}$	MWh	power output of technology i in time period t
tsc	£	total system cost, objective

$$min\ \ tsc = \sum_{i \in I, t \in T} CAPEX(i) \cdot d(i) + OPEX(i) \cdot p(i,t) \tag{1a.1}$$

$$s.t. \qquad 0 \leq d(i) \leq N(i) \qquad \forall i \tag{1a.2}$$

$$n(i,t) \leq d(i) \qquad \forall i,t \tag{1a.3}$$

$$\sum_{i \in I} p(i,t) = SD(t) \qquad \forall t \tag{1a.4}$$

$$p(i,t) \geq n(i,t) \cdot D(i) \cdot Pmin(i) \qquad \forall i,t \tag{1a.5}$$

$$p(i,t) \leq n(i,t) \cdot D(i) \cdot CF(i,t) \qquad \forall i,t \tag{1a.6}$$

Equation (1a.1) represents the aggregate of all capital and operational expenses of technologies i throughout the time horizon T. We choose the minimization of the total system cost tsc to be the objective function for the proposed formulation. Inequalities (1a.2)-(1a.3) ensure the cost-optimal configuration and sizing of the power system.

Variable $d(i)$ is determined as the number of units of technology i to be installed. Consequently, the operational schedule (the number of units in on/off status $n(i,t)$) is limited by the number of available (installed) units. The power balance, upper, and lower bound for the power output of technologies i at time step t are described in equality/inequality constraint (1a.4)-(1a.6). The capacity factor $CF(i,t)$ for conventional technologies is constant, whereas for intermittent power generators such as wind power plants CF is subject to strong (here hourly) fluctuations according to the wind availability.

5.2.3 The Technical, Environmental, and Security Extended Formulation

We tailor the traditional UC model to address the questions posed in this study and implement a number of changes and extensions. Some of these variations have been studied before and can be found in table 5.2; others are as to the best of our knowledge not yet present in the open literature. A key contribution of this work is the development of an optimisation model for the simultaneous design and scheduling of an electricity system. We include constraints accounting for environmental impact as well as the reliability and operability of the electric grid. Changes to the original UC are listed below:

1. Security constrained; 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 t to secure dynamically against failure of the largest firm and intermittent unit.
2. Environmental 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 optimizer.
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.

This model can be applied to investigate optimal and sustainable capacity expansion planning as well as power unit scheduling, hence optimal unit commitment and economic dispatch. We incorporate the optimisation model into the SV algorithm to ultimately investigate and quantify the value provided by the availability of a certain technology to the capacity mix.

The mathematical formulation of the fully extended model [3c] can be found in the appendix A. All presented results in ensuing chapters are based on this model form.

Chapter 6

Computational Model Set-up and Data Clustering

Due to the relatively high complexity of this project, we here aim to comprehensively structure the model run procedure and visualise where different software platforms and computational tools integrate. We then introduce a data clustering method, which has been especially developed for this work in the context of energy systems modelling.

6.1 Model Structure and Interfaces

As discussed in section 1.2 we make use of three main software tools: Excel as data carrier, R for data pre-processing, and GAMS for the actual modelling and solving of the optimisation program. Figure 6.1 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. The scenarios evaluated in this report are described in the ensuing section 7.3.

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 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 section 6.2, 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 section A. The data output from GAMS is then transferred back to the Excel interface for post-processing and archiving.

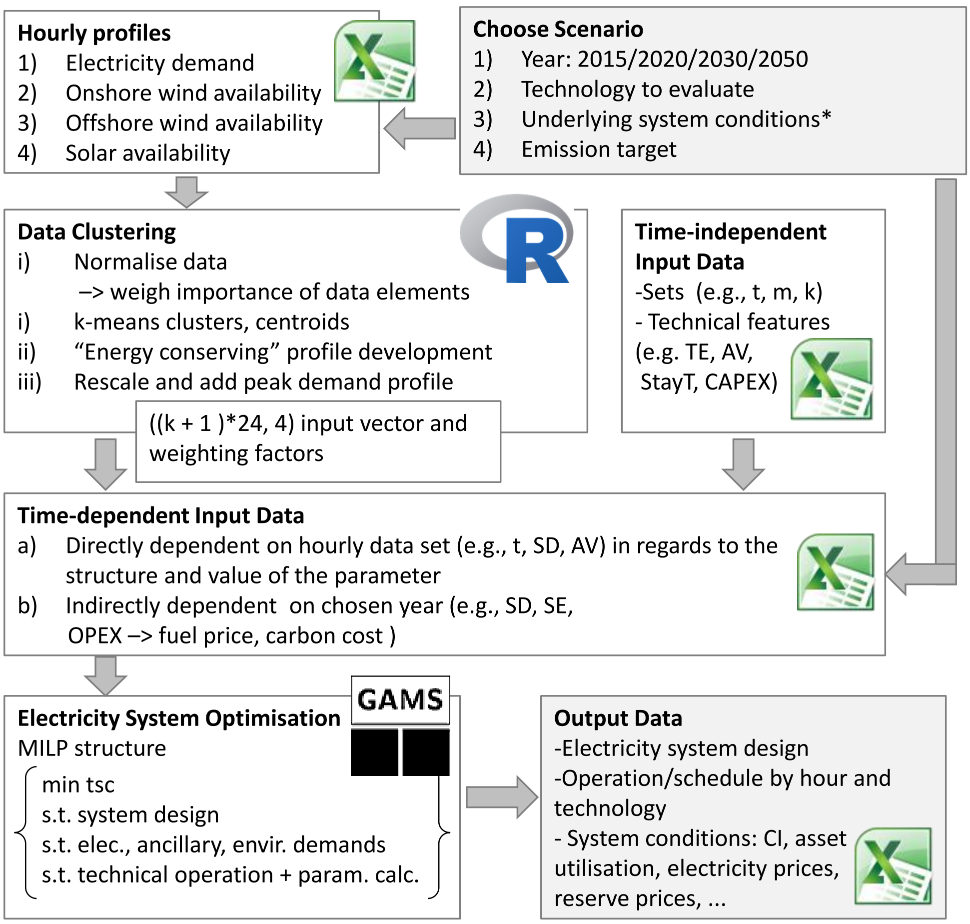

Figure 6.1: Model integration and solution process for the "Solve MILP" block in figure 4.1. The choice of scenario influences the input data on different levels and in direct (the length/structure of the vector) and indirect ways (the value of the parameters, for some of those we have not yet decided if and how they should vary). The final data output is followed by post-processing steps to retrieve the relevant information and visualise it accordingly. * The underlying system conditions for example refer to the type and amount of installed capacities,the system emissions targets, reserve and reliability requirements.

6.2 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 [107]. 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 6.2 gives an example for the clustered data for electricity demand, on-shore wind, off-shore wind, and solar power availability across the UK. 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 6.3 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.

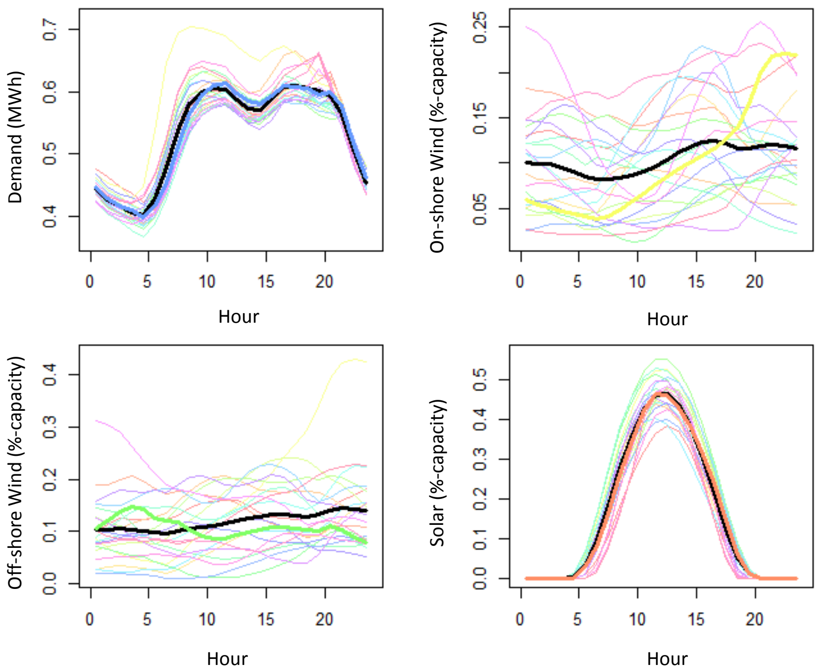

Figure 6.2: Example of 4-dimensional data space, in electricity demand, on-shore wind, off-shore wind, and solar availability, assigned to the same cluster; The thin colourful lines represent all profiles that were clustered into cluster 11. The thick black line represents the mean of the cluster, and the thick colourful lines are the specific profile chosen to comply with the "energy preserving" profiling method.

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 6.3. 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

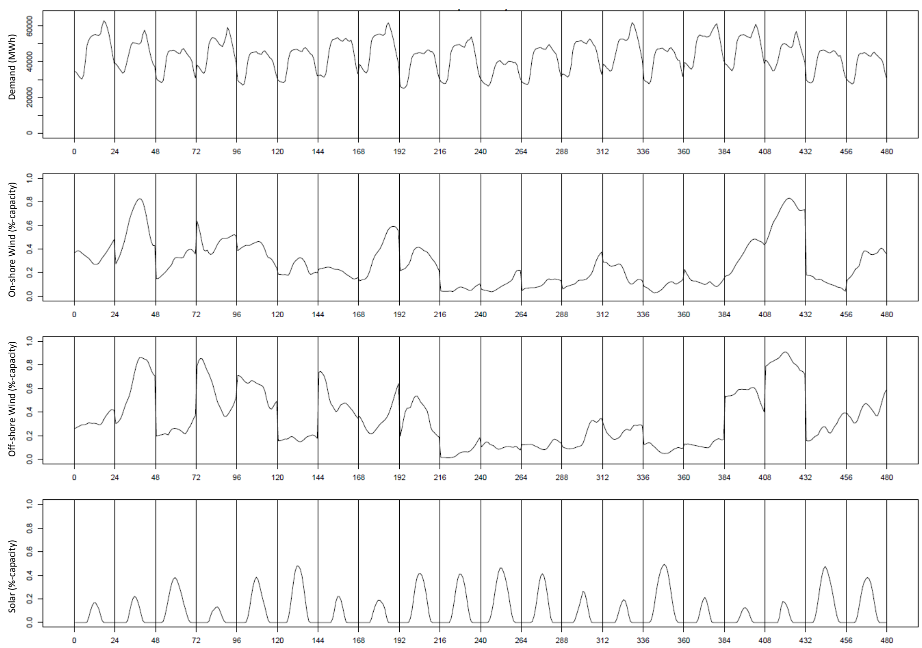

Figure 6.3: Specific profiles according to the "energy preserving" profiling method for k clusters; The on-shore and off-shore wind profiles show most clearly the importance of preserving a realistic hourly pattern by applying the "energy preserving" profiling as opposed to using the cluster mean. The resulting smoothness of a mean-value profile would significantly misstate a wind power plants behaviour and strongly underestimate operational challenges laying herein.

(derived from half hourly data provided by National Grid [108]) reached 4.8 GW. However, a smoothing of these unusually large data jumps, as proposed for example by Green and Staffell [107], 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.

Chapter 7

Data Assumptions and Scenario Sets

This chapter introduces the underlying assumptions on the input data and the scenario sets which are evaluated and presented in this report. A document summarising the entire underlying data set for the system and technology parameters is available as complementary document to this report "FlexEVAL_ModelInputData.xlsx".

7.1 Assumptions on Future Data

The forecast of future market data is highly uncertain and a research field of its own. This work does not question existing future fuel prices estimates or CAPEX learning rates, and does not aim at generating its own projections. Wherever possible, estimates from governmental bodies and the IEA are utilised.

1. Half hourly electricity demand data from National Grid is averaged to hourly values [108]. Hourly electricity demand data is scaled up from 2014 values [27] by 22 % for 2030 conditions (resulting in a peak demand of 62.14 GW), in compliance with projections from DECC, UKERC, and National Grid [23, 25, 27]. We investigate two electricity demand scenarios for 2050. The first scenario is characterised by a 45 % scale-up of 2014 values (resulting in a peak demand of 74.5 GW) while the pattern of the hourly demand profiles remain unchanged. The second scenario represents an increased electricity demand with a more extreme hourly pattern, assuming a growing discrepancy in electricity demand between non-peak and peak hours.

This scenario is based on increased electrification (e.g., transport through electric vehicles) and produced using the DESSTinEE model, which is described in [109].

2. Fuel prices are stated in 2015 prices and converted to £/MWh values from DECC's future price scenarios [4]. Table 7.1 summarises the coal and gas price assumptions for the years of 2015 to 2050.
3. All capital costs include an Interest During Construction (IDC) rate of annual 7.5 % according to the assumed construction time and are annualised with a discount rate of 7.5 % according to their assumed economic lifetime. We do not assume learning rates in the CAPEX of the modelled technologies.
4. The system emission constraint is parametrised in accordance with the UK's emission targets for the power sector in 2030, being 29 $\mathrm{Mt}_{\mathrm{CO_2}}$ [110], and 2050, being 12.8 $\mathrm{Mt}_{\mathrm{CO_2}}$[1] [23], respectively.
5. Hourly data for on-shore and off-shore wind availability factors for 2014 as fraction of installed capacity is made available from [30]. We do not assume a change in the potential power generation profiles for intermittent renewables over the observed time horizon from 2015 to 2050.

7.2 Non-Flexible and Flexible CCS Technologies in the Modelling Framework

The analyses in this report focusses on four types of CCS technologies and their respective flexible counterparts:

- coal post-combustion – flexible coal post-combustion (bypass)
- coal oxy-combustion – flexible coal oxy-combustion (storage)
- IGCC pre-combustion – flexible IGCC pre-combustion (storage)
- CCGT post-combustion – flexible CCGT post-combustion (bypass)

The flexible CCS options are conceptually modelled with the ability to bypass the CO_2 capture train or to be equipped with hydrogen/oxygen storages as to enhance operational flexibility as was described in detail in section 3.2. In order to

[1]As sectoral breakdown of the UK's 2050 emission reduction target of 80 % across all sectors compared to the 1990 emission level, we choose the UKERC's "Low Carbon" scenario resulting in an additional 27 % reduction for emissions caused by power stations compared to the 2030 level.

	Gas (p/therm)				Coal (USD/tonne)		
	Low	Central	High		Low	Central	High
2015	38.5	46.5	54.6	2015	53.0	59.9	66.8
2020	29.5	52.3	75.6	2020	54.1	69.3	85.7
2025	37.8	66.8	98.9	2025	70.6	82.8	99.3
2030	46.1	68.3	98.9	2030	70.6	87.0	109.6
2035	46.1	68.3	98.9	2035	70.6	87.0	109.6
2040	46.1	68.3	98.9	2040	70.6	87.0	109.6
2050	46.1	68.3	98.9	2050	70.6	87.0	109.6

	Gas (£/MWh)				Coal (£/MWh)				Carbon price (£/tCO2)
	Low	Central	High		Low	Central	High		
2015	13.1	15.9	18.6	2015	4.8	5.4	6.0	2015	15.0
2020	10.1	17.8	25.8	2020	4.9	6.3	7.8	2020	30.0
2025	12.9	22.8	33.8	2025	6.4	7.5	9.0	2025	30.0
2030	15.7	23.3	33.8	2030	6.4	7.9	9.9	2030	70.0
2035	15.7	23.3	33.8	2035	6.4	7.9	9.9	2035	70.0
2040	15.7	23.3	33.8	2040	6.4	7.9	9.9	2040	70.0
2050	15.7	23.3	33.8	2050	6.4	7.9	9.9	2050	100.0

Table 7.1: Data assumptions for gas and coal [4]; The conversion to £/MWh values makes use of the following parameters: exchange rate GBP/USD = 1.585; gas heat rate = 105.5056 · 10^{-6} therm/J; coal calorific value = 6,000 Kcal/kg.

capture the power plants' characteristics we reduce the large amount of technical data to the set of parameters presented in table 7.2 and model the operation according to the constraints presented in section A.

Figure 7.1 visualises a typical operational profile for thermal power plants and the modal representation in the energy systems model derived in this report. The *off* mode is modelled as discrete operation points, whereas the start-up (*su*) and running (*inc*) modes enable continuous power output between the respective bounds. We model the transition between the operational modes as discrete decisions in the optimisation framework (switching variable $z(i,m,m',t)$).

The amount of time necessary for a power plant start-up and shut-down are decisive parameters describing a power plants flexibility. We explicitly model the power plants transition times in the parameter $StayT(i,m,m')$, indicating the time a power plant has to remain in mode m' after transition from mode m to m', where m,m' can be the modes *off*, *su*, or *inc*. We do not distinguish between hot, warm, and cold start-up times and assume a warm start-up behaviour for all technologies.

The start-up phase for power plant operation, is defined between the power output level of zero and MSG, which is the minimum output level the power plants can continuously operate at (modelled as $TE(i,m,Pmin)$). In the regular operating band between MSG and maximum power output the residual of maximum power output and current power output (modelled as $p(i,m,t)$) can be offered as reserve capacity. Once the power output drops below the MSG level the power plant must shut down.

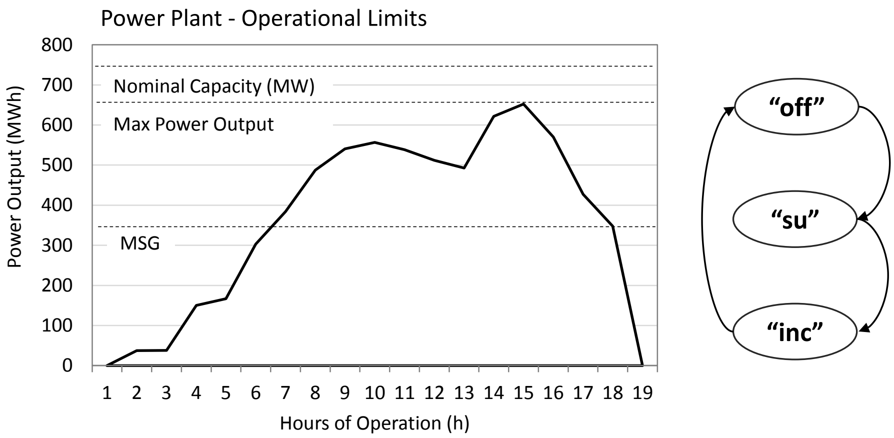

Figure 7.1: Continuous power plant operation is constrained between the minimum stable generation (MSG) and the maximum output level. This operational profile was obtained from the hourly output of a CCGT power plant in scenario "A_GF" described in section 7.3.

The presented data for the different CCS technologies is derived from an extensive literature review as well as through collaboration with our industrial partners. Table 7.2 summarised the CCS related input data and visualises the parameter differences between non-flexible and flexible CCS options. The colour code highlights the occurrence of high and low values between the different technologies for salient economic and technical features.

The underlying data for the remaining power generating technologies present in the energy systems model can be found in the complementary data sheet <FlexEVAL_ModelInputData.xlsx>.

7.3 Scenario Sets

In order to understand the important parameters and sensitivities of the presented energy systems model, we define and investigate the model on a range of scenarios. These are categorised on the highest level into scenario A, representing

Parameter	Mode	Unit	CCS				Flex CCS			
			Coal-PostCCS	Coal-OxyCCS	IGCC-PreCCS	CCGT-PostCCS	Coal-PostFlexCCS	Coal-OxyFlexCCS	IGCC-PreFlexCCS	CCGT-PostFlexCCS
Num(i)	-	#	-	-	-	-	-	-	-	-
Des(i)	-	MW/unit	500	500	500	750	500	500	500	750
CAPEX(i)	-	£/kW	2648.42	2638.80	3017.32	1327.66	2751.71	2741.71	3018.83	1404.67
OPEXNL(i)	-	£/h	4228.6	4228.6	5040.0	2337.3	4393.5	4393.5	5042.5	2472.9
OPEX(i,m)	su	£/h	250145.28	250145.28	360000	83542.2	216584.12	259900.95	360180	88387.65
	inc	£/MWh	41.09	40.81	45.64	60.53	43.6	43.3	46.14	61.08
Pmin	su	%-MW/unit	0.35	0.35	0.35	0.35	0.2	0.2	0.2	0.35
	inc		0.7	0.7	0.7	0.7	0.4	0.4	0.4	0.7
Ip	su	MW.s/MW	5	5	5	5	5	5	5	5
	inc		10	10	10	10	10	10	10	10
Rp	su	%-MW/unit	0	0	0	0	0	0	0	0
	inc		1	1	1	1	1	1	1	1
Ems	su	tCO2/MWh	0.0977	0.0968	0.1009	0.0447	0.0994	0.0986	0.1018	0.0450
	inc		0.0930	0.0922	0.0926	0.0410	0.0947	0.0939	0.0934	0.0413
StayT(i,m,m)	-	h*	*5,1,4*	*5,1,4*	*4,3,2*	*3,2,2*	*1,1,1*	*1,1,1*	*1,1,1*	*1,1,1*
AV(i,m,t)	su	%-MW/unit	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	inc	%-MW/unit	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Efficiency HHV	-	%	0.336	0.341	0.339	0.4554	0.3078	0.3124	0.3051	0.4518
Fixed OPEX	-	£/MWh	2.8	3	3	2.8	2.9	3.1	3.1	2.9
Construction	-	years	4	4	4	4	4	4	4	4
Lifetime	-	years	25	25	25	25	25	25	25	25

Table 7.2: Model input data for non-flexible and flexible CCS technologies; Parameter abbreviations can be found in table A.1. Main data sources are [1–3, 54, 65, 67, 111, 112], as well as collaboration with Capture Power Ltd. + Values shown refer to the 2030 central fuel price scenario [4]. All CCS power plants are assumed to operate at 90 % capture rate. * The $StayT(i,m,m')$ parameter captures the time delay for power plant behaviour when switching between operational modes (see section A). The three presented numbers refer to the transition time between the modes: *off* to *su*, *su* to *inc*, and *inc* to *off*.

all data in 2030 conditions, and scenario B, which is set in 2050. The reference scenario A and B represents the base case and benchmark for the remaining scenarios. They are characterised by DECC's central fuel price projections[2] [4] and DECC's and UKERC's generating capacity projections [23, 27] for 2030 and 2050.

Within the two scenario branches we vary the cost related data (lower fuel prices are represented in the "LowFP" scenarios) and the upper bound for available capacities (a green field case with relaxed upper bounds on the technology capacities[3] is represented by the "GF" scenarios).

For the modelled CCS technologies and their flexible counterparts as described in section 7.1 we obtain the System Value (SV) as a function of their available capacity in the mix of power generating technologies. Following the SV algorithm as outlined in section 4.2, we gradually increase the upper bound for available capacity $Num(i)$ of technology i. This procedure is repeated for the CCS technologies individually, while no other CCS options are available (sensitivities on scenario A_Ref_CCS in 7.2). Additionally, we evaluate which of the CCS options is systemically most competitive by enabling the optimizer to choose from all possible CCS options, and flexible CCS options, respectively.

In scenario set B, we conduct the analogous calculations for 2050 system conditions. As outlined in more detail in figure 6.1, this impacts the input data in terms of the hourly electricity demand vector, the carbon price, and consequently the technology specific OPEX, the emission target and the upper bound of available capacities for the reference scenarios (B_Ref). The fuel prices for 2030 and 2050 are assumed to be equal, since any estimates are subject to large uncertainties.

[2] Note that fuel price estimates for 2050 are not available from DECC or similar sources and subject to high uncertainties. In this report we therefore continue to utilise the 2040 data provided by DECC for the presented 2050 scenarios, resulting in p46.1/therm (low) - p68.3/therm (central) for gas and USD70.6/tonne (low) - USD87/tonne (central) for coal. The price for carbon emissions in 2050 is obtained from a comparative review and chosen from the lower end of the range of available values (£100/t_{CO_2} - £260/t_{CO_2}) to £100/t_{CO_2} [113–116].

[3] If the upper bound on the technology capacity availabilities ($Num(i)$) is non-binding/relaxed the optimisation can obtain the "truly" optimal system set-up. The green field case assumes no restrictions on the amount or type of power generating technology to be build. Hence, there are no assumptions on existing power plants or the availability of new technologies. The green field scenarios present the theoretically optimal system design without any "real world" restrictions on capacity availabilities.

Scenarios A - 2030	Notes	Outcomes	Variations	# Runs
A_Ref - UB for capacities according to UKERC/DECC scenario - Central DECC fuel price scenario	- Governmental emissions target - Including CCS/BECCS according to the UKERC/DECC 2030 projections, where "Coal CCS" is represented by Coal-PostCCS, and "Gas CCS" by CCGT-PostCCS in our model - The remaining (6) CCS/FlexCCS options are not considered	- Optimal capacity mix - Example operational schedule - System parameter: TSC, electricity price, CI, etc. - "reality check" for planned energy systems	*A_LowFP* - Low DECC fuel price scenario *A_GF* - "green field" scenario -> No upper bounds (UBs)/relaxed UBs for any technology capacity	3
A_Ref_NoCCS	- Without any CCS availability -> all CCS capacity UB = 0	- Delta cost, CI, etc. for system without CCS compared to projected CCS availability	- Central and Low fuel price scenario	2
A_Ref_CCS	- With CCS availability of all non-flexible CCS options (Coal-PostCCS, Coal-OxyCCS, IGCC-PreCCS, CCGT-PostCCS)	- Which CCS option/options are most competitive - How their individual SV (absolute reduction in TSC and per installed kW) changes with increasing penetration into the system	- Central and Low fuel price scenario CCS System Values (SV)* for: - Coal-PostCCS, Coal-OxyCCS, IGCC-PreCCS, CCGT-PostCCS if only the respective technology is available	2 + (4*10) (~10 runs to vary the capacity UB for each CCS technology)
A_Ref_FlexCCS	- With CCS availability of all flexible CCS options (Coal-PostFlexCCS, Coal-OxyFlexCCS, IGCC-PreFlexCCS, CCGT-PostFlexCCS)	- Which CCS option/options are most competitive - How their individual SV (absolute reduction in TSC per installed kW) changes with increasing penetration into the system	- Central and Low fuel price scenario Flexible CCS System Values (SV)* for: - Coal-PostFlexCCS, Coal-OxyFlexCCS, IGCC-PreFlexCCS, CCGT-PostFlexCCS if only the respective technology is available	2 + (4*10)
Total # Runs				89

Figure 7.2: Categories of scenario set A; * This refers to the evaluation of the System Value (SV) according to the SV algorithm as a function of the technology availability as presented in section 4.2. Analysis of the SV includes the investigation of the capacity type which is replaced by the respective CCS options if applicable, as well as the change in marginal total system cost (TSC).

Scenarios B - 2050	Notes	Outcomes	Variations	# Runs
B_Ref - UB for capacities according to UKERC/DECC scenario - Central DECC fuel price scenario	- Governmental emissions target - Including CCS according to the UKERC/DECC 2050 projections, where "Coal CCS" is represented by Coal-PostCCS, and "Gas CCS" by CCGT-PostCCS in our model - The remaining (6) CCS/FlexCCS options are not considered	- Optimal capacity mix - Example operational schedule - System parameter: TSC, electricity price, CI, etc. - "reality check" for planned energy systems	*B_LowFP* - Low DECC fuel price scenario *B_GF* - "green field" scenario -> No upper bounds (UBs)/relaxed UBs for any technology capacity	3
B_Ref_NoCCS	- Without any CCS availability -> all CCS capacity UB = 0	- Delta cost, CI, etc. for system without CCS compared to projected CCS availability	- Central and low fuel price scenario	2
B_Ref_CCS - UB for capacities adjusted to receive feasible system without CCS availability	- With CCS availability of non-flexible CCS options (Coal-PostCCS, CCGT-PostCCS)	- Which CCS option/options are most competitive - How their individual SV (absolute reduction in TSC and per installed kW) changes with increasing penetration into the system	- Central and low fuel price scenario CCS System Values (SV)* for: - Coal-PostCCS, CCGT-PostCCS if only the respective technology is available - SV for Coal-PostCCS, CCGT-PostCCS for different demand scenarios: BAU, ExP	2+(2*10*2) (~10 runs to vary the capacity UB for each CCS technology)
B_Ref_FlexCCS - UB for capacities adjusted to receive feasible system without CCS availability	- With CCS availability of flexible CCS options (Coal-PostFlexCCS, CCGT-PostFlexCCS)	- Which CCS option/options are most competitive - How their individual SV (absolute reduction in TSC and per installed kW) changes with increasing penetration into the system	- Central and low fuel price scenario Flexible CCS System Values (SV)* for: - Coal-PostFlexCCS, CCGT-PostFlexCCS if only the respective technology is available - SV for Coal-PostFlexCCS, CCGT-PostFlexCCS for different demand scenarios: BAU, ExP	2 + (2*10*2)
Total # Runs				89

Figure 7.3: Categories of scenario set B; * This refers to the evaluation of the System Value (SV) according to the SV algorithm as a function of the technology availability as presented in section 4.2

Chapter 8

Electricity Systems Model Validation

In order to validate the electricity systems model which has been developed for this study and derived in detail in chapter 5, we evaluate the model outputs under today's electricity system conditions.

In an initial scenario, we replicate the UK's current mix of generating capacity and obtain the optimal operational schedule. Here, we can observe if the power plant behaviour is well reflected, hence, if the technology-specific operational patterns are modelled correctly. The amount of installed generating capacity in the UK in 2014 totalled approximately 85 GW[1], comprised of 20 GW coal fired power stations, 2.5 GW oil or dual fired power stations, 32.6 GW of CCGT power plants, 10 GW nuclear power stations, 1.7 GW of gas or oil engines, 4 GW of electric hydro stations, 5.5 GW of wind capacity[2], 4.7 GW of other renewable capacity such as solar, wave, tidal, and bioenergy [117]. Additionally, 4 GW of high voltage interconnection capacity are available for electricity import.

In a next step, we analyse DECC's future reference scenarios for the power generation capacity mix for the years 2020, 2030, and 2050. These scenarios put the model to test with a tightening of the emission target, a increased penetration of intermittent renewable capacity, which impacts the demand for operational and

[1] In this figure, the capacity of small-scale hydro capacity are derated by factor 0.365, wind capacity by 0.43, and solar capacity by factor 0.17 to account for intermittency as indicated by DECC (see table 5.6 "Plant Capacity: United Kingdom" in [117]).

[2] Non-derated wind capacity would amount to 12.8 GW when scaled back to nominally installed capacity with factor 0.43 as provided by DECC [117].

capacity balancing and reserve mechanisms. Additionally, we can evaluate the feasibility of DECC's proposed electricity systems design on the future security and environmental requirements.

8.1 Today's Electricity System - Capacity and Operation

We fix the design variable $d(i)$, representing the number of installed capacity units of technology i, in constraint (3c.2) of the electricity systems model as described in section A, to the amount of installed capacity for each technology according to the values by DECC as stated above[3]. Hereby, the variable $d(i)$ becomes a parameter indicating the fixed level of installed capacities for the individual technologies in the energy systems model.

The fuel prices are chosen according to table 7.1, the system emission level is set to 129 $\mathrm{Mt}_{\mathrm{CO_2}}$ for power stations [110], half hourly electricity demand data is averaged to hourly values [108]. Remaining system parameters and underlying data on the individual technologies is made available in the complementary data file (<FlexEVAL_ModelInputData.xlsx>).

The topmost image in figure 8.1 visualises the installed capacity of 2014 and the generated power output as result of the presented energy systems model. As main model outputs we receive:

1. The number of installed units per technology i, resulting in the total installed capacity (GW) for each power generating technology,
2. The total system cost of the resulting electricity system, including annualised capital cost, operational cost (divided into costs associated with star-ups and running cost),
3. The overall Carbon Intensity (CI) of the electricity generation,
4. The power output (GWh) provided by each power generating technology i in each mode m (starting up, running) at every given hour t,
5. The amount of reserve capacity (GW) provided by each power generating technology i in each mode m (starting up, running) at every given hour t,

[3]The amount of capacity of technologies not represented in the modelling framework are distributed to the modelled technologies according to their type of power generation. 4.7 GW of "other renewables" are in equal parts to on-shore wind, off-shore wind, and solar capacity.

6. The detailed operational schedule, indicated the number of operating units and the number of mode transitions of each power generating technology i in each mode m at every given hour t,
7. The asset utilisation of each power generating technology i,
8. The resulting theoretical electricity price to the consumer in every hour t,

where values are rescaled accordingly to annual levels by the data weighting factors as described in section 6.2.

In comparing these model outputs to the best of our abilities with the respective statistics for the 2014 UK electricity system, we aim to validate the functionality of the presented energy systems model. The total system cost (TSC) as defined above and by the objective function (3c.1) in section A amount to £1.8 billion for the 2014 electricity system.

We define the utilisation rate of a power technology type as the actual annual power output divided by the installed capacity. A curtailment of intermittent renewable capacity for instance would results in a utilisation rate below the capacity factor. The utilisation rates accumulated from all power units per technology arrive at 80 % for nuclear power plants, 5% for OCGT's, 29 % on-shore wind, 35 % off-shore wind, 10 % solar, and 0.05 % for interconnection capacity. We note that electric interconnectors are modelled simplified without taking a time-varying electricity price from the import market into account. This causes the utilisation rate of interconnection in the model to be low if possible, which does not necessarily reflect actual operation. For the remaining technologies, the determined figures are in good agreement with typical power plant operation and indeed reflect the UK's electricity generation in 2014 [117]. The utilisation rate for coal fired power stations reaches 70 %, which is high compared to approximately 50 % for coal fired power stations in the UK in 2014. The results for the CCGT capacity utilisation are with 20 % relatively low, compared to 30 % in 2014. However, the trade-off between thermal power generation from dominantly coal or gas fired power stations is highly dependent on the given fuel prices. We use annually averaged fuel prices for incremental operational costs for coal at £24.5/MWh, and electricity from CCGT power stations at £30.1/MWh [4].

The underlying emission rates for the individual power generating technologies do not reflect emissions rates from effectively installed power plants in the UK, but rather from state-of-the-art power plants as stated in the relevant literature basis 7.2 (and references according to technologies in <FlexE-

VAL_ModelInputData.xlsx>). The overall system CI as derived from the energy systems model achieves 0.397 t_{CO_2}/MWh, which lays well in the CI range of UK electricity generation of the past years, of 0.35 to 0.45 t_{CO_2}/MWh [110].

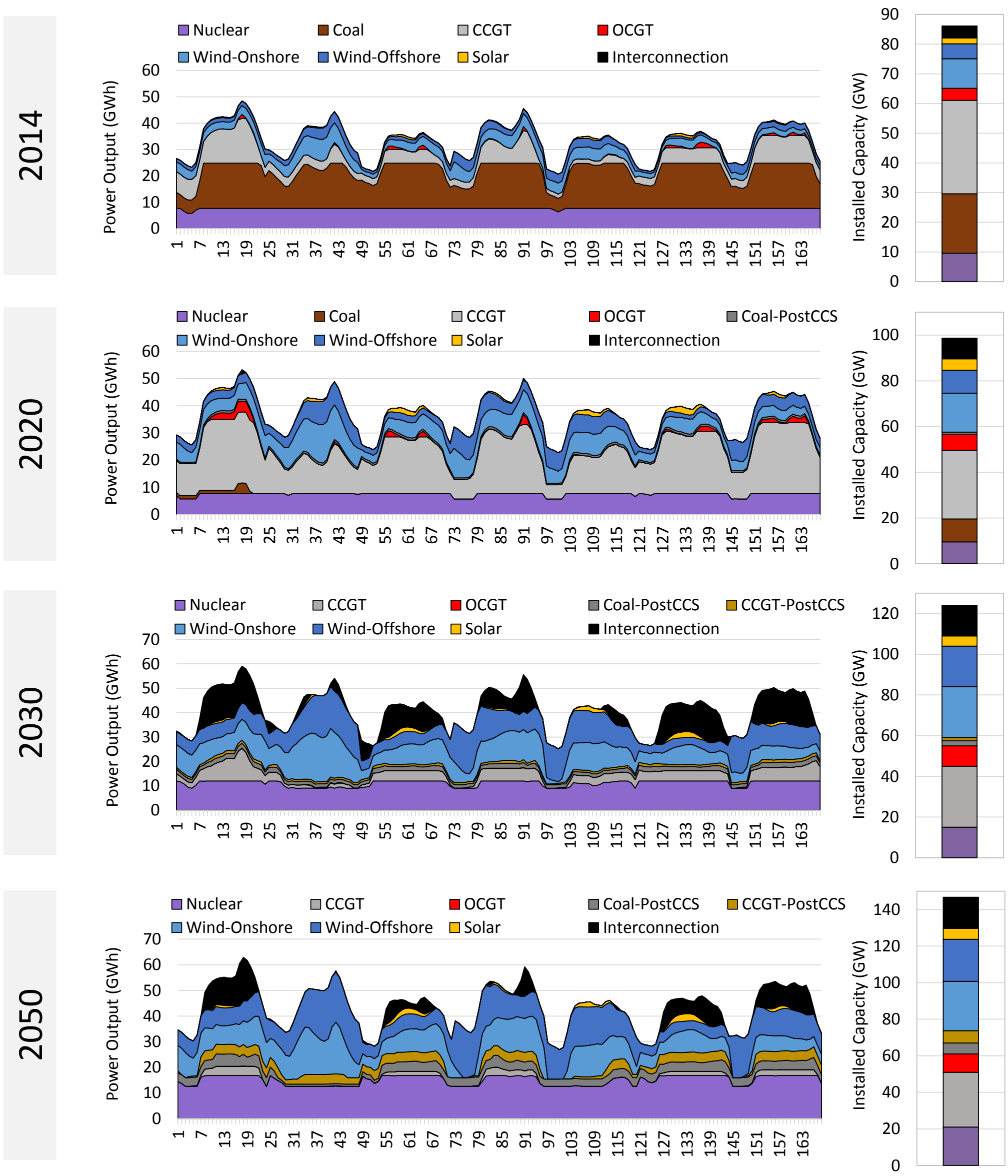

Figure 8.1: Power output (GWh) for one exemplary week and installed power generating capacities (GW) for today and DECC's future UK energy scenarios for 2020, 2030, and 2050 [27]; The amount of installed capacity per technology was fixed to the published values, the operating schedule is obtained from the energy systems model. Demand profiles, emissions and reliability constraints are adjusted according to the assumptions made for each year 7.1. The presented results take DECC's low fuel price scenarios as basis [4].

8.2 Electricity System Transition

In addition to the UK's current electricity system, figure 8.1 visualises possible future electricity systems for the years of 2020, 2030, and 2050. The installed capacities are stated according to DECC's reference scenario [27], the power generation profiles for the individual technologies are the result of the energy systems model.

This analyses enables us to observe the system changes and validate the model outputs under tightening emission constraints, increasing demand and fuel prices, the set of future parameter assumptions as described in section 7.1. In each of the future systems the respective emission target can be achieved with the DECC proposed systems designs. The optimal power generation in the presented scenarios would result in CI's of 0.202 t_{CO_2}/MWh in 2020, at TSC of £1.97 billion, a CI of 0.074 t_{CO_2}/MWh in 2030, at TSC of £3.27 billion, and a CI of 0.0308 t_{CO_2}/MWh in 2050, at TSC of £3.53 billion.

In 2020, a large amount of power generation from CCGT's (50 %) enables an initial reduction in carbon emissions, providing electricity at 0.3480 t_{CO_2}/MWh, as opposed to 0.7458 t_{CO_2}/MWh for coal fired power stations. The contribution from nuclear power stations to total electricity provided remains constant compared to 2014 at approximately 20 % of annual electricity demand. Electricity provided from intermittent renewables, including on-shore wind, off-shore wind, and solar power plants, increases from 14 % in 2014 to to 23 % in 2020, adding to the amount of low-carbon power generation.

The presented electricity system in 2030 would already meet 33% of its electricity demand from intermittent renewable sources. However, in this system configuration also 17 % of electricity would be provided via the electric interconnectors. These made up for less than 1% of electricity provided in 2014[4].

[4]1 % of electricity would be provided by interconnectors according to the energy model results for the 2014 system. Effectively, 6 % of the UK's electricity consumption was met by electricity provided through interconnectors. The actual electricity transfer via interconnectors is subject to the electricity markets in the connected countries and thus more complex than the modelling scope in this national energy systems model allows. In the presented model, interconnectors are represented as one-way (import only), infinitely flexible, and zero-emission electricity source. The first two assumptions on import (UK is net electricity importer) and flexibility are sufficient. The omission of emissions caused by electricity production abroad is a marked simplification, however common practice in UK carbon emissions balance sheets. Results from the here presented model are always cost-optimal solutions under the set constraints and cannot account for temporarily market specific characteristics. We assume a constant elec-

In 2050, the picture has changed significantly, in terms of generation capacity and patterns of power generation. Intermittent renewables now account for 38 % of installed capacity and 33 % of generated power. Nuclear capacity has more than doubled from 2014 values and provides 36 % of annual electricity demand. CCS technologies[5] start to play a major role, at combined 12.75 GW and high utilisation rates of over 50 %.

Bearing in mind that here the amounts of installed capacity are not the result of the energy systems model, but set to the DECC reference scenario values, the utilisation rates can give us information about the profitability of the different power generating units. CCGT utilisation is with 4 % very low and would not necessarily present an economic investment. Consequently, less CCGT capacity would be needed to meet the demand for electricity from CCGT power stations in a 2050 systems under the assumed conditions.

Generally, the integration of high wind power outputs anticipate the ability of flexible operation for thermal power plants. Providing electricity low-carbon becomes essential in 2050. Interconnection[6] plays a very important role possibly providing 12 % of electricity consumption.

tricity import price of £80/MWh at 52 % efficiency. However, the possible amount of electricity which can be imported via interconnectors is captured correctly by the systems model.

[5]Note, that coal post-combustion CCS and CCGT post-combustion CCS are here chosen arbitrarily as CCS technologies in the 2050 capacity mix. DECC's reference scenario does not specify the type of CCS technology, but only the amount of CCS capacity to be deployed by 2050.

[6]Note, that we do not account for carbon emissions caused by power generation of the interconnectors.

Chapter 9

Results from the Electricity Systems Optimisation

The following chapter presents the results from the electricity systems optimisation for the two main scenario branches A and B, representing 2030 and 2050 system conditions, respectively. An overview of the different scenario runs and sensitivities tested is provided in section 7.3.

9.1 Scenarios A - 2030

In a first step, we obtain results on the general system performance and characteristics under a range of boundary conditions. We analyse the impact of capacity upper bounds, the fuel price, and CCS power plant efficiency. Subsequently, we evaluate the difference between the deployment of non-flexible and flexible CCS technologies at the capacity level of DECC's 2030 reference scenario.

Secondly, we derive the System Value (SV), the reduction in total systems cost, individually for each CCS technology as a function of their deployment within the electricity system. Additionally, we quantify the most economic level of capacity deployment and understand what generator types could be displaced by the introduction of CCS technologies.

9.1.1 A: Reference and Green Field Scenario

The reference scenario A is based on DECC's central fuel price and DECC's proposed amounts of installed capacities in 2030 [4, 27]. In figure 9.1 we compare the results of the optimal dispatch, where capacities are fixed (compare figure 8.1), with the results of the simultaneous electricity system structure and dispatch optimisation, where the DECC capacity levels serve as upper bound for technology deployment (*A_ Ref*). In the green field scenario (*A_ GF*), the upper bound on the design constraint is relaxed entirely, so that we receive the system which is able to meet all constraints in the most economic way without taking realistic technology deployment potentials into account.

We depict the power dispatch over the complete set of evaluated time periods (504) and the corresponding capacity stack. All scenarios can reach the emission limit when following optimal dispatch schedule. The TSC for the fixed system amount to £3.35 billion (in the low fuel price the TSC are £3.27 billion 8.2). The reference system with DECC's capacity projections as upper bound shows little difference and achieves annual TSC of £3.3 billion. All technologies, including the available CCS options, are deployed to their maximum available capacity level (the DECC scenario) with the exception of CCGT power plants. Under the given conditions, 20 GW is the optimal level of CCGT deployment, showing an 8 % increase in utilisation rate as opposed to 30 GW proposed by DECC's reference scenario.

The green field scenario achieves TSC of £2.55 billion, being significantly lower than the previous two scenarios. This is due to the fact that 38 % of power generation and capital expenses are minimal, installing only as much capacity as necessary to meet the system requirements. In this green field scenario, where also all modelled types of CCS technologies (non-flexible and flexible) are available and their deployment level is not constrained, CCGT post-combustion CCS is the one CCS technology chosen in the most economic mix of technologies. The low capital cost compared to the other CCS options contribute in grater parts to the TSC and outweigh the higher operational expenses. A deployment of CCGT post-combustion CCS is economical up to 10.5 GW and shows an average utilisation rate of 51.5 %.

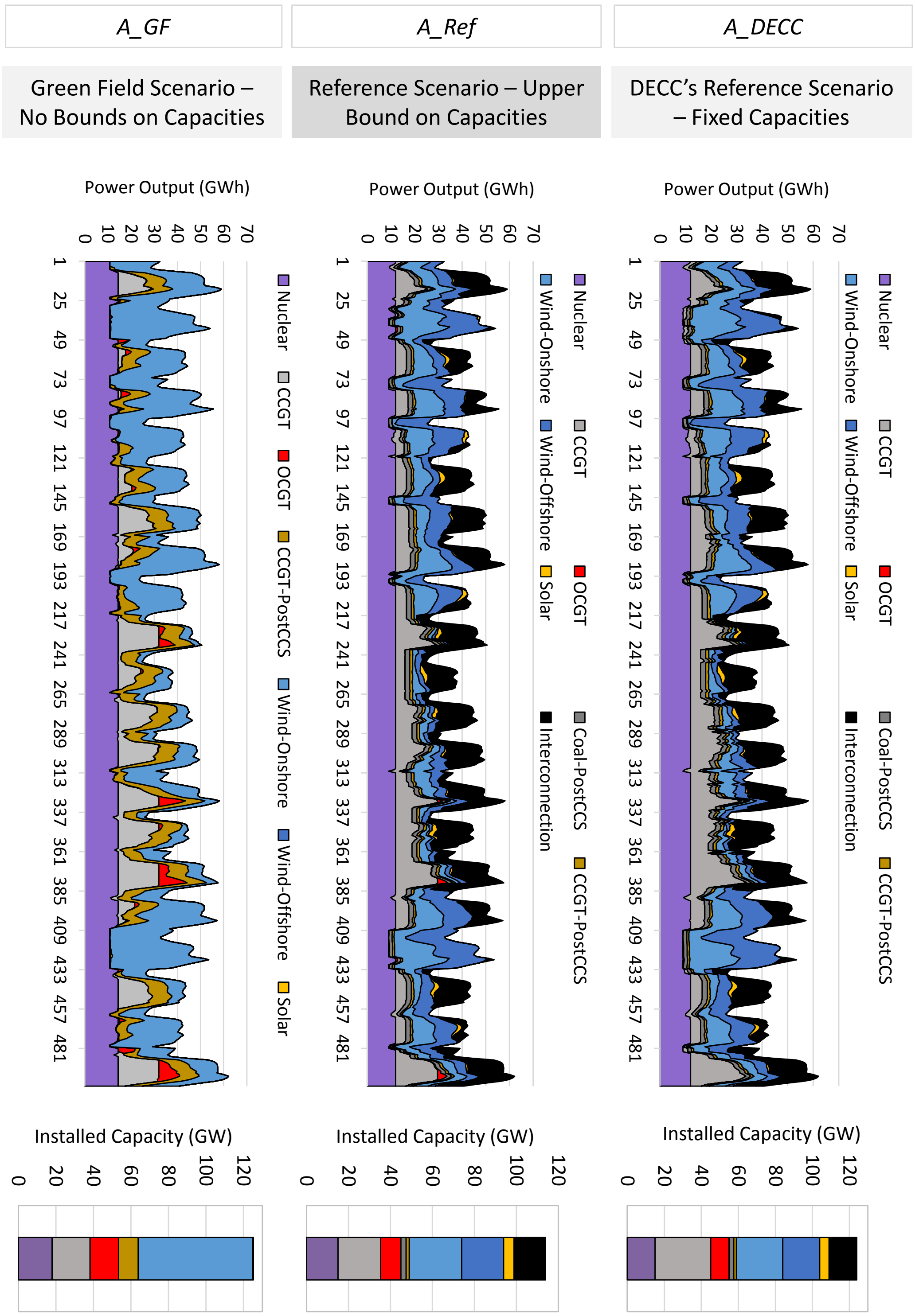

Figure 9.1: Comparison of installed capacity (GW) and power output (GWh) by technology type for DECC's reference scenario in 2030, the reference scenario in this study, and a green field scenario, as described in section 7.3. Presented values are based on DECC's central fuel price assumptions 7.1.

The asset utilisation across all types of power generating technology in the green-field scenario is lower (31 % compared to 40 % in *A_Ref*), since the amount of installed intermittent renewable capacity with low capacity factors is higher (10 GW more on-shore wind). The total installed capacity amounts to 125.27 GW, as opposed to 113.95 GW in the *A_Ref* scenario. very large amounts of on-shore wind capacity (61 GW) are proposed to be deployed in the *A_GF* scenario, demanding for more flexible OCGT capacity (15 GW compared to 10 GW in *A_Ref*).

The amount of nuclear capacity aimed for in DECC's reference scenario (15 GW) is close to the optimal amount evaluated in the green field case (18 GW). A green field scenario under today's conditions does not include any nuclear. Only the emission target makes nuclear a necessary low-carbon and evidently part of the lowest cost solution. Interestingly, interconnectors are not economical and a partial electricity dependency from other energy systems can be entirely avoided. However, we note again, that the upper bounds for capacity installation in this scenario are in no relation to factually possible deployment rates.

9.1.2 A: Fuel Price Sensitivity

We evaluate the dependency of the system design and operation on the coal and gas fuel price for DECC's low, central, and high prices on the *A_Ref* scenario [4]. Scenarios are subject to the same emissions targets; beside the fuel price, all other parameters and constraints remain the same.

The amount of installed capacity per technology is independent of the fuel price variation. However, the utilisation rates are sensitive to fuel prices, and differ according to the change rates of the price scenarios. According to DECC's estimates, the difference between the low and high gas prices compared to the central price is -32.6 % and +45.1 %, where as for coal the range covers -19 % to +25.3 % to the central coal price, respectively. Hence, in an economically optimal schedule gas fired power plants are utilised less in high fuel price scenarios and production from coal fired power plants is increased.

Intermittent renewables are dispatched more at high fuel price values, however, are tightly constrained by their relatively low availabilities. Figure 9.2 summarises the changes in utilisation rates depending on the fuel price scenario. Overall TSC are 2.6 % less in the low fuel price scenario, and 3.5 % higher in the high fuel price scenario compared to the central scenario.

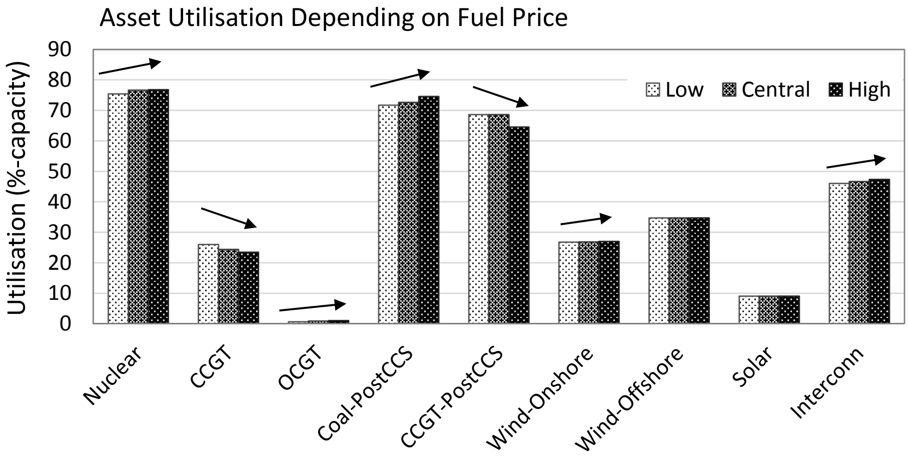

Figure 9.2: Utilisation rates for each power generating technology for low, central, and high fuel price scenario [4].

9.1.3 A: Sensitivity of Power Plant Efficiency

In this section, we analyse the model sensitivity regarding the CCS power plant efficiency. As an example, we study the effects of an increased efficiency for flexible coal post-combustion CCS and flexible coal oxy-combustion CCS at low fuel price values.

A higher efficiency reduces fuel consumption and operational cost, which effects the total system cost beneficially. The total system-wide amount of capacity is marginally dependent on the individual power plant efficiencies. Generally, OCGT and CCGT capacity can be displaced further in high efficiency cases. Also the optimal dispatch schedule changes and is able to marginally reduce utilisation from CCGT's and OCGT's. The economic capacity deployment level for the CCS technologies does not change and reaches 28 GW for both, coal po-combustion CCS and coal oxy-combustion, as we will see again in section 9.1.5.

In few cases it can be economical to reduce power output from high efficiency CCS plants in order to accommodate solar power output, which would be curtailed with low efficiency power plants. Additionally, electricity from interconnectors can be reduced.

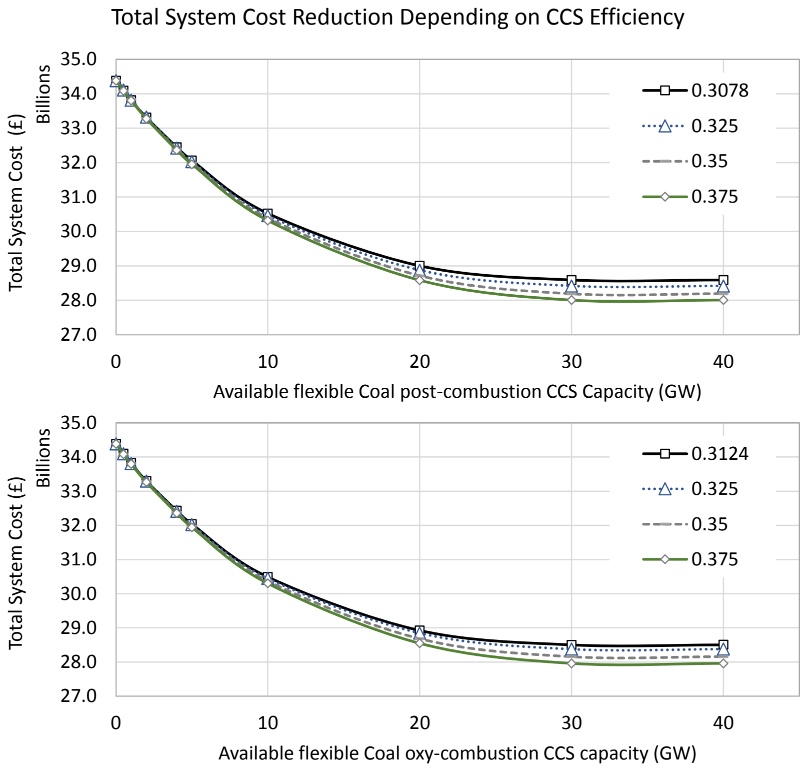

Figure 9.3: Total system cost as a function of the power plant efficiency and available capacity of flexible coal post-combustion CCS and flexible coal oxy-combustion CCS, respectively. Lowest efficiency values represent the reference case parametrisation.

9.1.4 A: Non-Flexible and Flexible CCS Technologies

This section deals with the comparison of non-flexible and flexible CCS technologies, where non-flexible refers to the CCS options which do not make use of any flexibility enhancing equipment 7.2. Detailed parametrisation of all types of CCS technologies can be found in table 7.2.

Figure 9.4 visualises on the left hand side the composition of the total system cost for the different system configurations. Scenario *A_Ref* has previously been discussed in sections 9.1.1, and represents the model output on structural and dispatch optimisation taking the capacities from DECC's reference scenario as upper bound for the system design variable. Scenario *A_Ref_NoCCS* is equal to *A_Ref* without any CCS availability. The reduced capacity (4 GW) is not compensated for with increased availability of another power generating capacity.

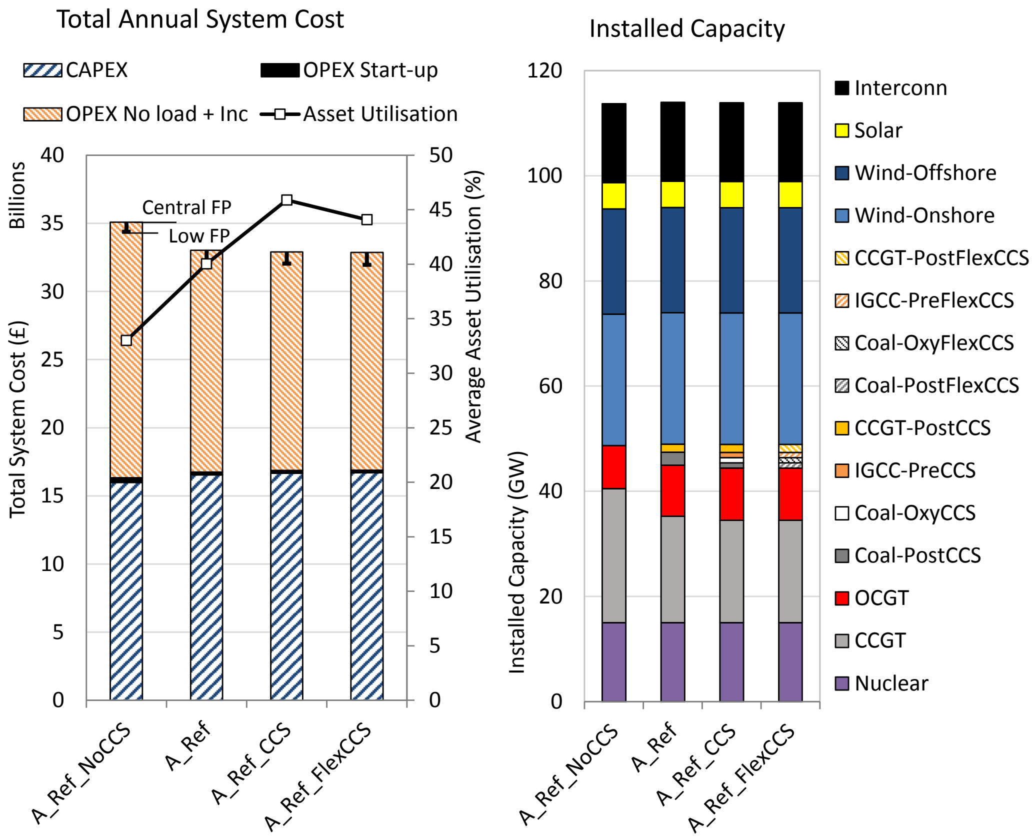

Figure 9.4: On the left hand side: Total System Cost (TSC) for reference scenario omitting CCS capacities *A_Ref_NoCCS*, the reference scenario *A_Ref*, a technology independent scenario distributing the CCS capacity across all available CCS technologies *A_Ref_CCS*, and a scenario as the latter distributing the capacity across all available flexible CCS capacities *A_Ref_FlexCCS*; On the right hand side: The capacity mix resulting from the structural optimisation for each scenario.

In order to remove the bias for a particular CCS technology, scenario *A_Ref_CCS* distributes the amount of CCS capacity deployment (4 GW) envisaged by DECC evenly across the four non-flexible CCS options. The upper bound for capacity availability for each technology is set to two power units, resulting in 1 GW for coal post-combustion CCS, 1 GW for coal oxy-combustion CCS, 1 GW for IGCC pre-combustion CCS, and 1.5 GW for CCGT post-combustion CCS. The scenario *A_Ref_FlexCCS* sets these same upper bound for the respective flexible CCS options and the non-flexible CCS options to zero.

We observe a significant cost reduction of 5.9 % in TSC between the case without CCS (*A_Ref_NoCCS*) and the scenario deploying CCS (*A_Ref*). This underpins the findings of the IPCC, ETI and other research institutions who state that achieving future emission targets with CCS deployment will be less costly [17, 19, 50]. The error bars indicate the difference between the central and the low fuel price scenario. The average asset utilisation increases from the scenario without CCS to the one including CCS capacity *A_Ref_CCS* predominantly by the reduction in CCGT capacity.

In the technology independent analyses, all CCS capacities are deployed to their maximum possible capacity level of 1 GW and 1.5 GW, respectively. TSC are marginally reduced compared to the *A_Ref* scenario (- 0.3 %). The transition from the non-flexible to flexible CCS technologies again reduces the TSC marginally (- 0.1 %). In detail, we find that the costs associated with the starting-up of units reduces by 2%, the fixed running (no load) cost and the cost for fuel reduce by 0.4 %. The CAPEX of the system incorporating the flexible CCS options, however, is 0.2 % more expensive.

The average asset utilisation which has been increasing from scenario *A_Ref* to *A_Ref_CCS* as smaller capacity sizes could be deployed more efficiently, now reduces in scenario *A_Ref_FlexCCS* slightly from 45 to 44%. Utilisation rates of the individual technologies differ between the non-flexible and flexible CCS case differently. When flexible CCS capacity is deployed the utilisation from wind, solar, and CCGT power plants is higher. However, the utilisation of the CCS capacity itself is higher for the non-flexible case than for the flexible case (1-10%).

Besides the annual system statistics as model output, we analyse the exact hourly dispatch schedule to understand the differences in cost and utilisation. We observe low demand time periods, where power plants have to shut-down and wind power plants have to be curtailed in order to maintain grid stability. Interestingly, non-flexible and flexible CCS power plants show different operational patterns in situations where demand following is necessary.

Figure 9.5 visualises such a case by summarising the direct model output on the optimal modal schedule for each power generating unit. The tables indicate for an exemplary time span from hour 93-103 the number power units of each technology type operating in each mode. The sum over all modes per technology results in the total number of installed units of the respective technology. The upper table shows the operational schedule of all power generating units for scenario *A_Ref_FlexCCS*, the lower table for scenario *A_Ref_CCS*.

NUMBER OF UNITS												
TECHNOLOGY	MODE	TIME PERIOD										
		93	94	95	96	97	98	99	100	101	102	103
Nuclear	inc	25	25	25	25	25	25	25	25	25	25	25
CCGT	off	10	11	14	21	26	26	26	23	17	17	17
	su								3	9	9	6
	inc	16	15	12	5							3
OCGT	off	99	99	99	99	99	99	99	99	99	99	99
	su											
	inc											
Coal-PostFlexCCS	off											
	inc	2	2	2	2	2	2	2	2	2	2	2
Coal-OxyFlexCCS	off											
	inc	2	2	2	2	2	2	2	2	2	2	2
IGCC-PreFlexCCS	off											
	inc	2	2	2	2	2	2	2	2	2	2	2
CCGT-PostFlexCCS	off					2	2	2	2	2		
	su										2	
	inc	2	2	2	2							2
Wind-Onshore	off					792	919	976	1067	950	313	
	inc	1250	1250	1250	1250	458	331	274	183	300	937	1250
Wind-Offshore	inc	200	200	200	200	200	200	200	200	200	200	200
Solar	off	250	250	250	250	250	250	250	250	250	250	
	inc											250
Interconn	off	12	22	30	29	30	30	30	30	30	30	29
	inc	18	8		1							1

		93	94	95	96	97	98	99	100	101	102	103
Nuclear	inc	25	25	25	25	25	25	25	25	25	25	25
CCGT	off	9	11	14	21	26	26	26	23	17	17	17
	su								3	9	9	6
	inc	17	15	12	5							3
OCGT	off	99	99	99	98	98	99	99	99	98	98	99
	su				1					1		
	inc					1					1	
Coal-PostCCS	off											
	inc	2	2	2	2	2	2	2	2	2	2	2
Coal-OxyCCS	off											
	inc	2	2	2	2	2	2	2	2	2	2	2
IGCC-PreCCS	off											
	su											
	inc	2	2	2	2	2	2	2	2	2	2	2
CCGT-PostCCS	off					2	2					
	su							2	2	2		
	inc	2	2	2	2						2	2
Wind-Onshore	off					886	1010	1077	1166	1046	500	
	inc	1250	1250	1250	1250	364	240	173	84	204	750	1250
Wind-Offshore	inc	200	200	200	200	200	200	200	200	200	200	200
Solar	off	250	250	250	250	250	250	250	250	250	250	
	inc											250
Interconn	off	14	22	30	29	30	30	30	30	30	30	29
	inc	16	8		1							1

Figure 9.5: On the top: Operational schedule for unit-wise operation in different mode in the scenario deploying flexible CCS technologies *A_ Ref_ FlexCCS*; on the bottom: The unit-wise schedule for the scenario with non-flexible CCS technologies *A_ Ref_ CCS*. Technologies can operate in all three mode (*off*, *su*, *inc*), here shown are the modes that are occupied by the respective technology between hours 93-103. Both cases are based on the DECC's low fuel price scenario.

The drop in demand from hour 96 to 97 forces CCGT power plants to shut-down. Additionally, power transmission from interconnectors is turned off and on-shore wind power generation is curtailed. Also the two CCGT post-combustion CCS power plants are forced to shut-down in the flexible and non-flexible CCS case. All other CCS options run flat out, and show high asset utilisation of > 60% for the flexible and > 70 % for the non-flexible options. As the electricity demand increases again in time period 102 to 103, power plants have to start-up again and increase their power output sufficiently ahead of time so demand, reserve, and inertia requirements in hour 103 can be met.

Flexible CCS power plants are able to transition from the off to start-up mode, and from start-up to the regular operating band in one hour (compare flexibility concepts in section 3.2). We can observe this behaviour, in the time periods from 101 to 103. The non-flexible CCS power plants on the other hand, show longer start-up times and transition from the off to the running mode in a total of 4 hours, compared to 2 for the flexible options. This stiff behaviour forces non-flexible CCGT post-combustion CCS power plants to start-up earlier (at $t = 99$) as to provide full power output in hour 103. Consequently, a larger number of on-shore wind power plants have to be curtailed (in sum 5685 versus 5017 wind power plants are turned off from hour 97-102; maximum curtailment at $t = 100$ of 23.32 GW versus 21.34 GW of on-shore wind power units turned off). Additionally, OCGT power plants are turned up to provide electricity and reserve capacity. With less wind power output reserve requirements reduce slightly and momentarily, however, at the same time more electricity from conventional power generators is necessary to meet demand, calling for peak-load OCGT power plants to turn on.

We observe a similar behaviour again in time periods 480-482, where an initial demand decrease of 4 GW and a subsequent large increase of 9.6 GW in electricity demand occurs[1]. The largest proportion of rapid electricity generation increase is provided by interconnectors. Interconnectors is modelled as being inherently zero-carbon and highly flexible, however, at relatively high operational costs (see

[1]A steep increase/reduction in electricity demand of $\geq$10 GW is a result of the non-smoothness between the individual data clusters. In the UK electricity system in 2014, the largest drop in electricity demand was approximately 5 GW. We note, that the magnitude of electricity demand change in the presented data does exceed a currently realistic and yet observed demand behaviour. However, an analysis on the basis of a more challenging electricity demand profile can help us understand how the observed set of power plants would operate together most economically in an integrated system. We describe this in detail in section 6.2.

detailed data in <FlexEVAL_ModelInputData.xlsx>). Similarly to the previously discussed time period, the flexible CCS case causes less wind power plants to be curtailed in the electricity demand drop as flexible CCS power plants can reduce their power output further (40 % versus 70 % turn-down) and start-up quickly as soon as the demand increases.

What has been said thus far means that the additional operating flexibility of flexible CCS power plants (here specifically CCGT post-combustion CCS) increases the possibility to incorporate higher levels of intermittent renewable power generation. The shorter mode transition times enable flexible CCS power plants to reduce and increase their power output quickly. The higher turn-down rates expand the operational space and allow flexible CCS plants to adjust power generation to lower output levels. Over the entire clustered data set, wind power plants provide more power, interconnectors less in the flexible CCS case. This increases low-carbon power production and reduced electricity dependency. However, the non-flexible CCS power plants provide more electricity in absolute terms and less unabated power is needed. Nuclear power generation shows marginally lower values in combination with non-flexible CCS power plants than with the flexible counterparts.

The operational advantages of flexible over non-flexible CCS power plants have not been observed frequently (twice over the clustered data set). However, an increasing amount of intermittent power sources could indeed evoke the need for more volatile generation patterns from previously declared base-load power plants. The observed cases give evidence for the operational capabilities of flexible CCS power generators and the clear benefits to the overall system performance if we aim to increase low-carbon power generation, while maintaining supply reliability and grid stability at minimum cost.

9.1.5 A: System Value of CCS Technologies

We now derive the System Value (SV) as previously defined in section 4.2 individually for each non-flexible and flexible CCS technology, respectively. The SV represents the annual total system cost reduction by deployment of the given technology and is visualised as a function its capacity availability. We note, that the analysis depending on available capacity is not based on actual expected deployment rates, but rather aims at determining the optimal level of deployment for each technology under the given parametrisation.

System Value of Coal Post-combustion CCS

The maximum deployment level of coal post-combustion CCS power plants is determined to be 28 GW in a system under 2030 conditions as outlined in section 7. In the top part, figure 9.6 visualises the amount of CCS capacity installed as a function of the capacity availability, being the upper bound $Num(i)$ in the optimisation framework as presented in section A. Additionally, we find the total system cost (TSC) reducing as more CCS capacity gets deployed. A system deploying 28 GW of coal post-combustion CCS could reduce TSC by 18 % compared to a case without any CCS capacity installed.

As a mirror image of the TSC reduction, we find the System Value (SV) of coal post-combustion CCS increasing with the amount of installed capacity. The flattening of the SV indicates that a further increase in CCS capacity is no longer economical. This point we call the "economic limit" of capacity deployment.

The lower part of figure 9.6 depicts the reduction in TSC, being the percentage SV. The marginal reduction in TSC gives us information about the most valuable capacity addition of coal post-combustion CCS power plants. The marginal reduction curve is not monotonous as it depends on the corresponding capacity mix which shows discrete changes as certain technologies are displaced entirely. In accordance to the economic limit of capacity deployment the marginal value drops to zero as no further capacity is installed.

As more coal post-combustion CCS capacity becomes available and is deployed the amount of necessary CCGT capacity reduces and at levels > 20 GW eventually causes off-shore wind and solar power plants to become uneconomic. The amount of interconnection capacity is more than halved (11 GW to 4 GW) as the intermittent capacity of off-shore wind and solar are displaced. The need for high-flexibility balancing capacity and electricity from interconnectors is reduced. Thus, the total amount of required capacity (initially 113.7 GW) reduces from 107.2 GW to 95.5 GW as off-wind and solar are entirely faded out.

The utilisation rate for CCS capacity increases by 5 % points from minimum to maximum deployment, however, overall average asset utilisation remains nearly constant. The utilisation rate for flexible coal post-combustion CCS power plants is lower (64 %) compared to the non-flexible CCS plants (68 %). Utilisation of all

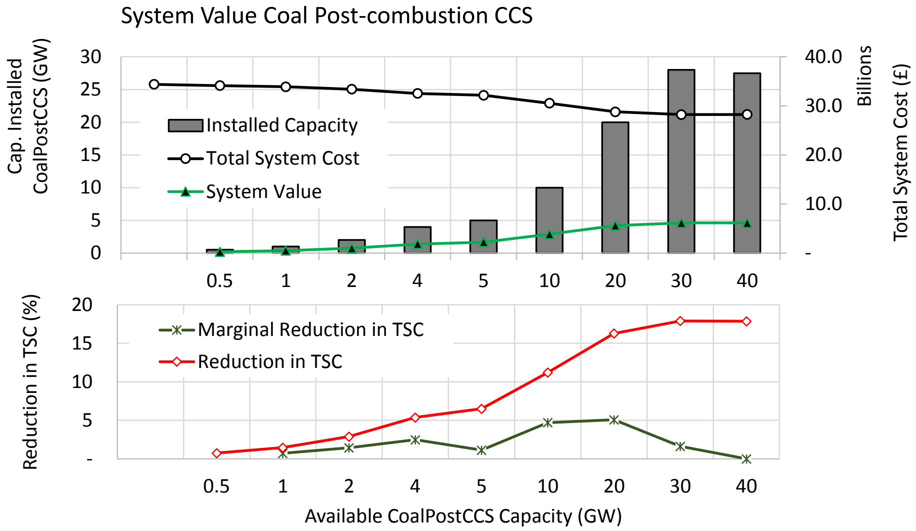

Figure 9.6: Top: Installed capacity, TSC, and System Value of coal post-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as describer in 7.

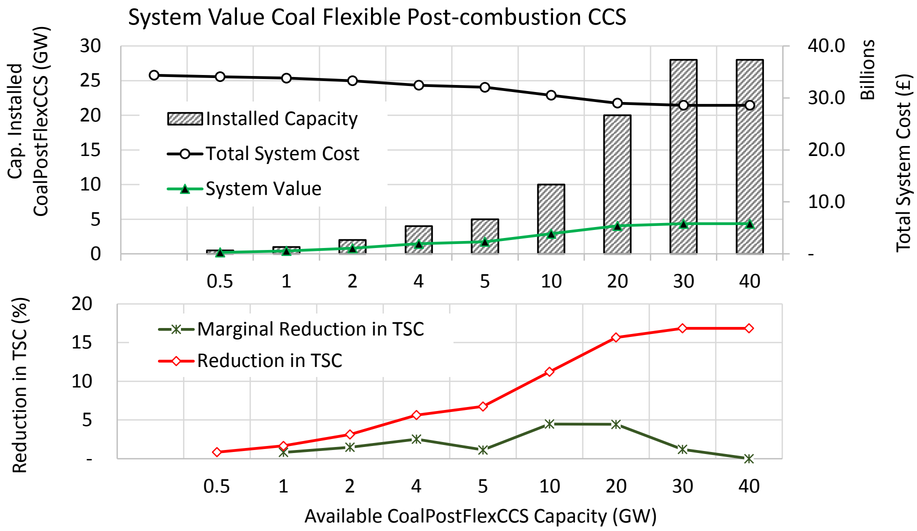

Figure 9.7: Top: Installed capacity, TSC, and System Value of flexible coal post-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as describer in 7.

intermittent capacities and nuclear power plants is greater with flexible CCS, as the operational agility can balance easier between the stiff and volatile generators. Interconnectors are utilised significantly less, CCGT power plants marginally less in the flexible CCS case.

Overall, the flexible coal post-combustion CCS shows a higher SV for the first 10 GW. As installation rate increases further the non-flexible CCS technology become more valuable as it can deliver greater amounts of low-carbon and firm electricity. The savings in capital expenses for non-flexible capacity over flexible capacity then outweighs the operational savings in incorporating low-cost renewable technologies.

System Value of Coal Oxy-combustion CCS

Under the given scenario conditions, the economic level of capacity deployment for non-flexible and flexible coal oxy-combustion is achieved at 28 GW. This results in a maximum TSC reduction of 18 % in the non-flexible case versus 17 % in the flexible case, as capital and operational expenses for the flexible CCS options are higher according to table 7.2. Figure 9.8 and 9.9 illustrate the capacity installation, TSC reduction, and marginal TSC reduction.

The power system including the flexible coal oxy-combustion CCS option is able to deploy a greater amount of intermittent renewable capacity at high CCS capacity installation levels. In the case of a system composition including 20 GW of flexible coal oxy-combustion CCS capacity, 35.8 GW of combined on-shore wind and off-shore wind capacity are part of the optimal mix. In the case of a system including non-flexible CCS capacity, 33.9 GW of intermittent renewable capacity can be deployed. The increased flexibility in operational behaviour allows for higher integration rates of intermittent capacity and power production. However, this comes with the disadvantage of higher operational costs associated with the start-up phases, and lower average utilisation rates for all thermal power plants.

The availability of non-flexible and flexible coal oxy-combustion CCS capacity gradually displaces unabated CCGT capacity from an inital amount of 25.5 GW to 15 GW. Intermittent renewables become uneconomic at once, and are displaced entirely at CCS deployment rates greater than 20 GW. At a CCS capacity integration level of 20 GW of, the case of flexible coal oxy-combustion CCS is able to reduce interconnector capacity to 7.5 GW, whereas the non-flexible CCS

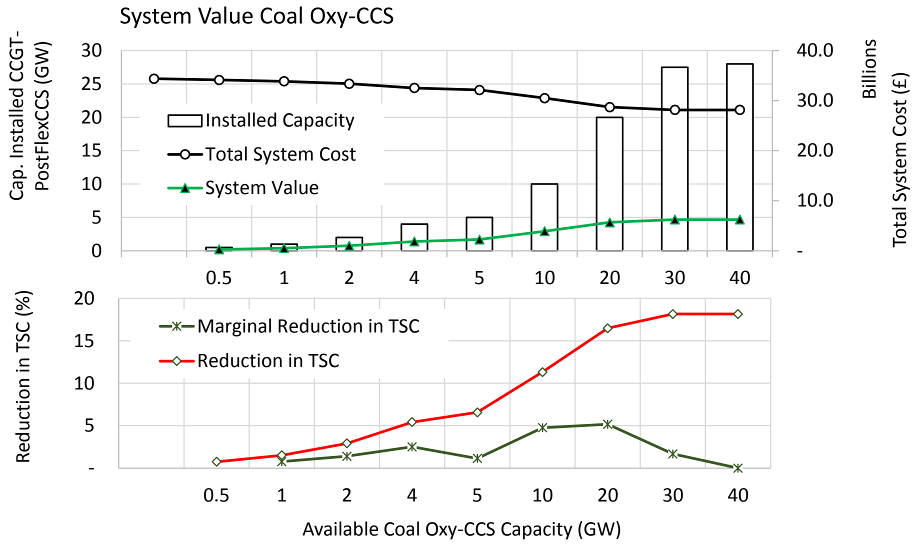

Figure 9.8: Top: Installed capacity, TSC, and System Value of coal oxy-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

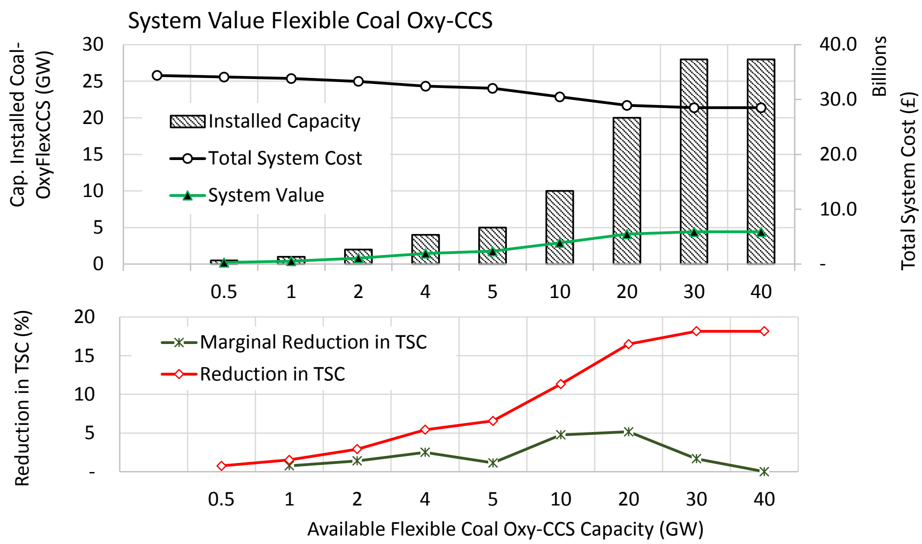

Figure 9.9: Top: Installed capacity, TSC, and System Value of flexible coal oxy-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

case still requires 11.5 GW of interconnection. For both CCS options, interconnector capacity can be reduced from initial 15 GW to 2.5 GW at maximum CCS deployment.

System Value of IGCC Pre-combustion CCS

The reduction in TSC for non-flexible and flexible IGCC pre-combustion CCS at maximum deployment levels arrive at 14.25 % and 13.9 %, respectively. Due to high capital cost and low efficiencies, the achieved TSC reduction is low compared to the other CCS technologies. Figures 9.10 and 9.11 illustrate the economic level of deployment, which is marginally higher for the flexible case (26.5 GW) compared to the non-flexible case (26 GW).

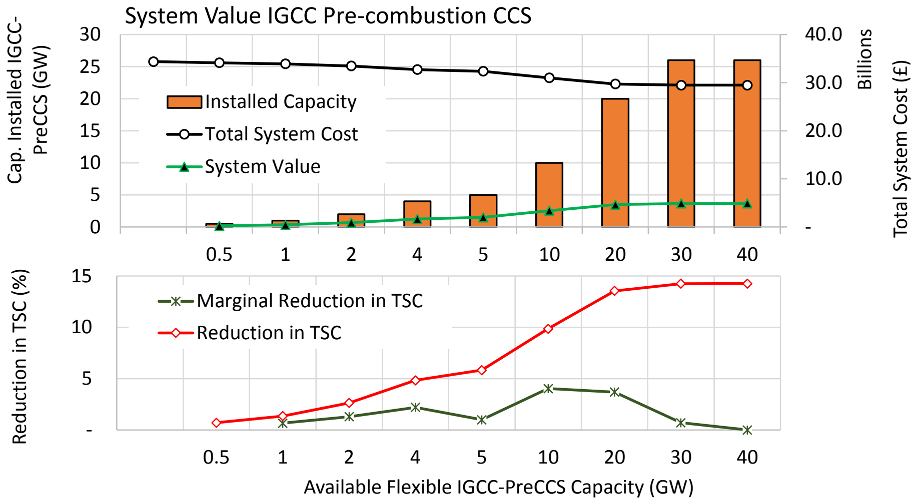

Figure 9.10: Top: Installed capacity, TSC, and System Value of IGCC pre-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

Analogously to the previous scenarios, a larger proportion of off-shore wind capacity is profitable in a system with flexible CCS capacity. Whereas off-shore wind capacity is displaced entirely at maximum deployment levels of 26 GW on non-flexible CCS, 2 GW of off-shore wind capacity remain valuable at 26.5 GW deployment level of flexible CCS capacity. Interestingly solar capacity, which is less intermittent but less efficient, remains part of the optimal capacity mix when

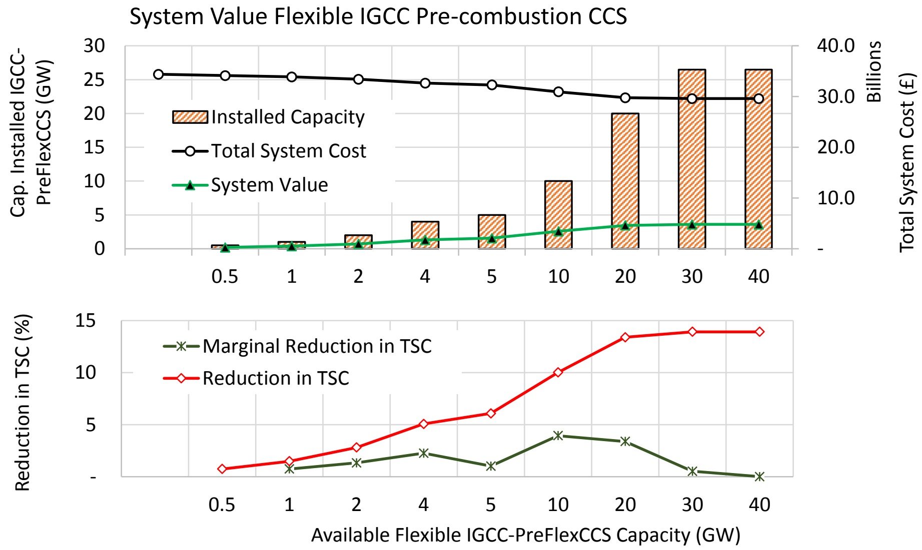

Figure 9.11: Top: Installed capacity, TSC, and System Value of flexible IGCC pre-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

non-flexible CCS is deployed. In the case where flexible CCS is available, more intermittent and efficient off-shore wind capacity can be integrated.

Figure 9.12 illustrates the capacity displacement structure as more CCS capacity becomes available to the electricity system. The flexible CCS option reduces dependency on electricity imports, as only 3.5 GW of interconnection capacity is needed compared to 6.5 GW in the non-flexible case at a maximum deployment level. The total installed capacity differs between 96.9 GW including flexible CCS versus 98.18 non-flexible CCS, resulting in an infrastructurally more efficient system design.

The power output from on-shore wind is higher if flexible CCS capacity is available. Contribution to meet power demand via interconnectors and the flexible IGCC pre-combustion CCS itself is less.

System Value of CCGT Post-combustion CCS

The economic level of capacity deployment for non-flexible and flexible CCGT post-combustion CCS capacity is reached at 40.5 GW. The non-flexible option

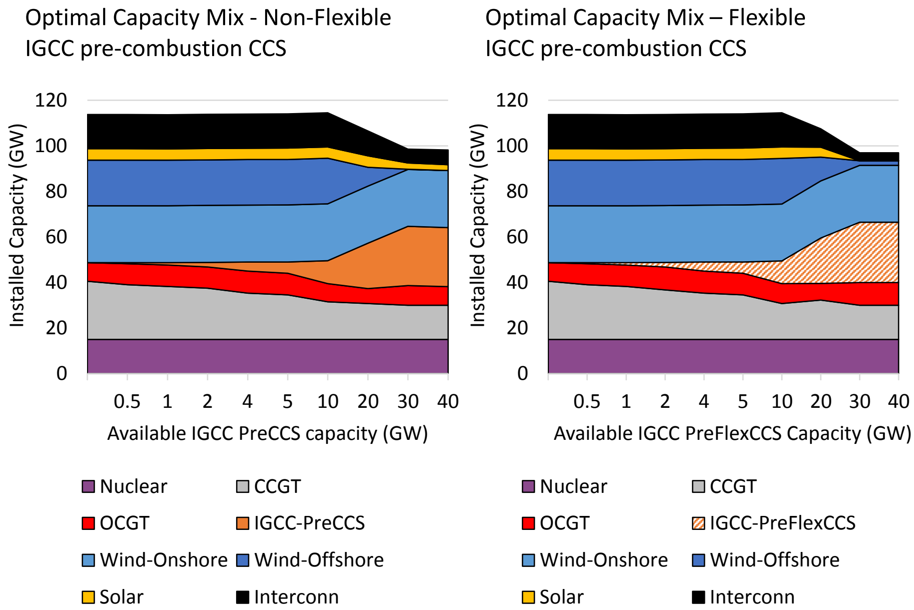

Figure 9.12: Comparison of capacity mix and replacement for non-flexible and flexible IGCC pre-combustion CCS deployment as a function of available CCS capacity. Underlying assumptions are DECC's low fuel price scenario [4] and system conditions as described in 7.

reduces TSC by 31 %, and total capacity from 113.7 GW to 95.5 GW. The flexible option, achieves a TSC reduction of 30 % at maximum deployment level compared to the case without CCS capacity; total system capacity is reduced to 95.4 GW. Figure 9.13 and 9.14 illustrate the CCGT post-combustion CCS capacity deployment and TSC reduction. The marginal reduction curve provides information about the most valuable capacity addition, indicating the integration of 7.5 GW of flexible capacity versus 15.8 GW of non-flexible capacity as largest incremental contribution to TSC reduction.

The flexible and non-flexible CCGT post-combustion CCS power plants show utilisation rates of 62 % and increase with growing deployment rates up to 71 %. As previously observed, the scenarios including flexible CCS integrate higher levels of off-shore wind capacity. For example, at a CCS deployment level of 15 GW a system using non-flexible CCGT post-combustion CCS can combine 12.4 GW of off-shore wind; a system deploying flexible CCGT post-combustion CCS 13.4 GW.

Figure 9.15 compares the capacity displacement order of the power systems deploying non-flexible and flexible CCGT post-combustion CCS capacity. In the

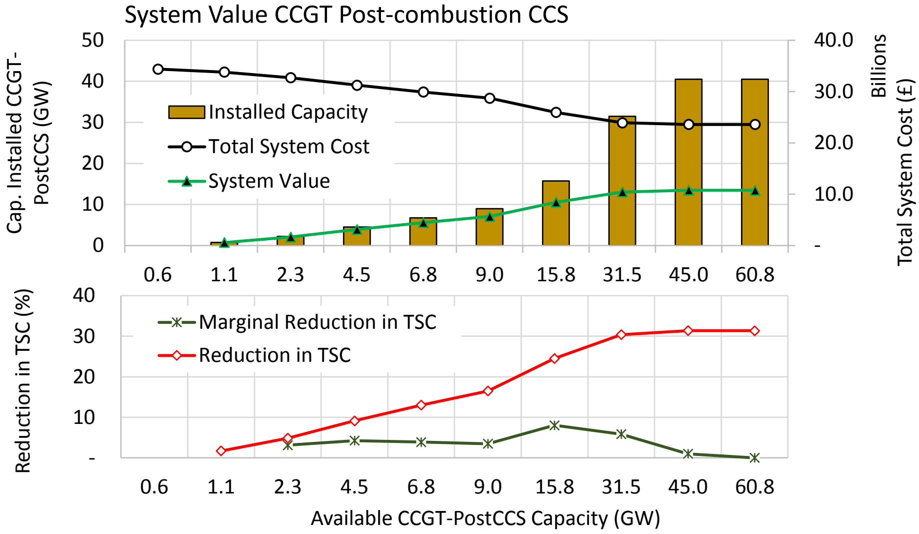

Figure 9.13: Top: Installed capacity, TSC, and System Value of CCGT post-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

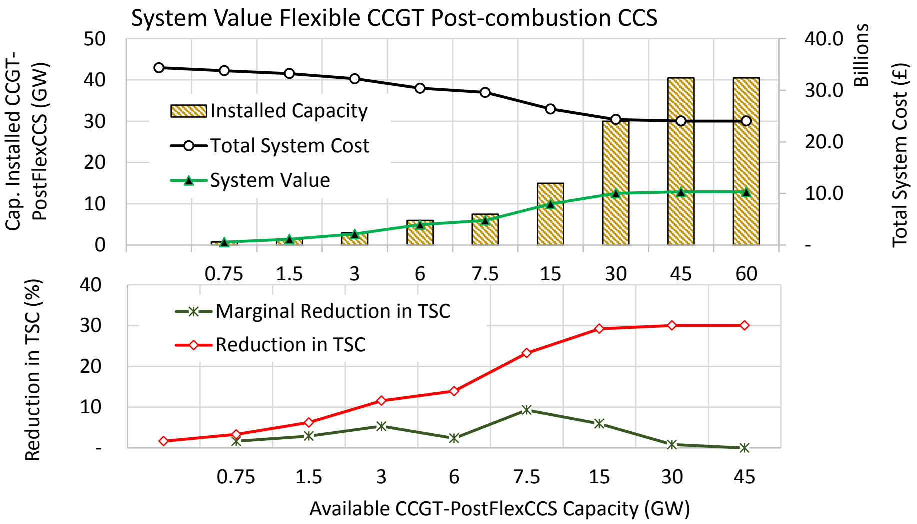

Figure 9.14: Top: Installed capacity, TSC, and System Value of flexible CCGT post-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition as a function of the available CCS capacity. Calculations are based on DECC's low fuel price scenario [4] and underlying system conditions as described in 7.

non-flexible case, off-shore wind becomes uneconomical as more than 15.75 GW CCS capacity is present in the capacity mix. Consecutively, nuclear capacity is displaced as 31.5 GW of CCS capacity is available. However, 5 GW of interconnection, and 10 GW OCGT capacity remain necessary.

In the scenario deploying flexible CCS, off-shore wind is only fully replaced after more than 30 GW of CCS, as shorter start-up phases and a lower MSG allow for more intermittent power generation to be incorporated. Nuclear and interconnection capacity evolves analogously to the non-flexible CCS case; whereas OCGT capacity experiences a marginally improved reduction to 9.9 GW. The enhanced flexibility of the CCS capacity can reduce the necessity for OCGT further.

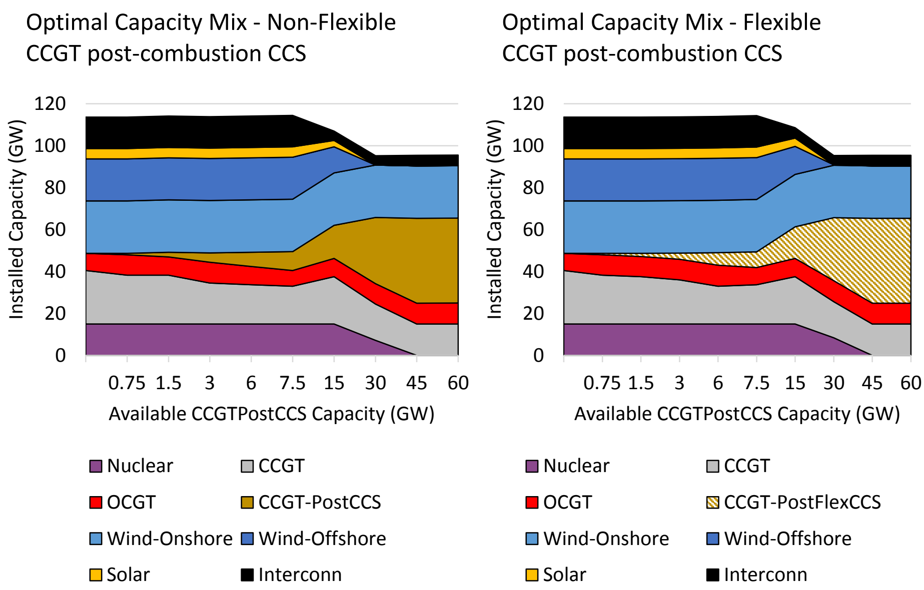

Figure 9.15: Comparison of capacity mix and replacement for non-flexible and flexible CCGT post-combustion CCS deployment as a function of available CCS capacity. Underlying assumptions are DECC's low fuel price scenario [4] and system conditions as described in 7.

Summary of System Value for Non-flexible and Flexible CCS Technologies

We define the relative System Value as the reduction in total system cost caused by the deployment of the respective technology per amount of installed capacity, £/kW. This metric enables us to compare the presented CCS technologies regardless of their individual economic level of deployment.

Figure 9.16 contrasts the relative SV functions for all discussed CCS options and summarises the findings from the previous sections. In agreement with the results on the SV of CCGT post-combustion CCS, the relative SV shows a clear lead of CCGT CCS compared to the other technologies. The relatively low capital cost, low emission rates, and high efficiency gives explanation for this outcome. Coal post-combustion and coal oxy-combustion differ marginally on a system level in this comparison. Due to high capital expenses and relatively a low efficiency, IGCC pre-combustion CCS is outperformed by the other technologies and provides the lowest level of system benefits.

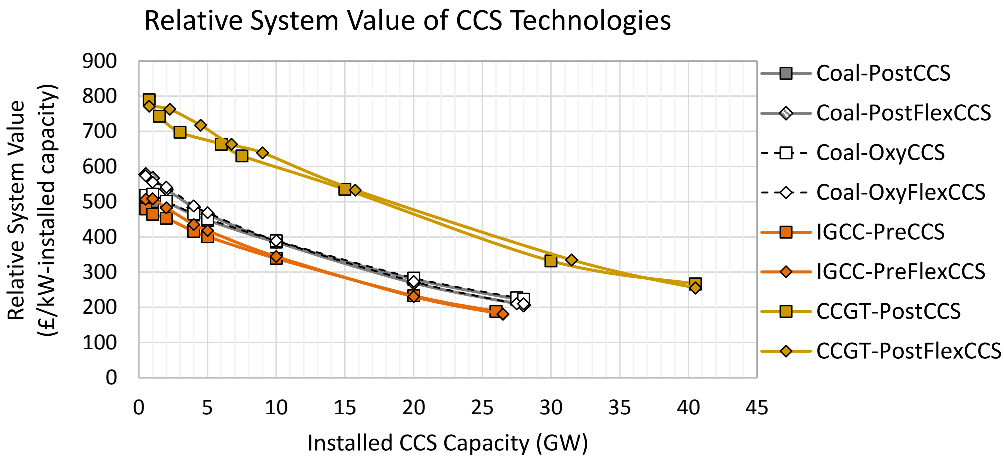

Figure 9.16: Summary and comparison of relative System Values for non-flexible and flexible CCS technologies. Underlying assumptions are DECC's low fuel price scenario [4] and system conditions as described in 7.

A comparison between the flexible and non-flexible CCS options reveals the initially higher relative SV for the flexible CCS technologies in all cases. At high deployment rates, however, non-flexible CCS capacity overtakes the flexible options again. Figure 9.17 illustrates the difference in Relative System Value (£/kW) between the flexible and corresponding non-flexible CCS technology. Non-flexible CCGT post-combustion CCS shows initially a great SV than its flexible counterpart. On the whole, all CCS options, however, follow the same trend line of reduced value to flexible capacity as the deployment rate increases.

The initial reduction in operational cost, by the ability to integrate higher levels of renewable capacity through deployment of flexible CCS capacity, is overwhelmed with higher capital expenses at an installation level of more than 10 GW. However, flexible CCGT post-combustion CCS remains more economic compared to the non-flexible option.

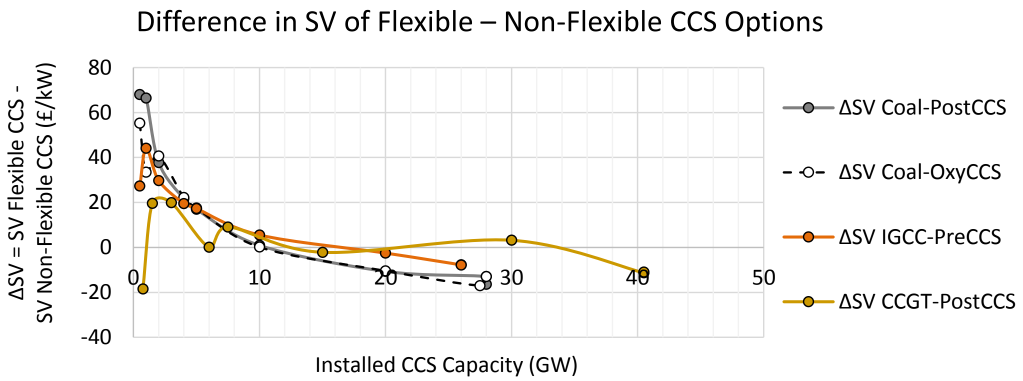

Figure 9.17: Summary and comparison of relative System Values for non-flexible and flexible CCS technologies. Underlying assumptions are DECC's low fuel price scenario [4] and system conditions as described in 7.

9.2 Scenarios B - 2050

In scenario set B, we undertake analyses on the value of non-flexible and flexible CCS technologies under 2050 power system conditions. We choose coal post-combustion CCS and CCGT post-combustion CCS as sample technologies and investigate the influence of different future electricity demand profiles on their System Value. The underlying scenario assumptions are described in section 7.

9.2.1 B: Reference and Green Field Scenario

Due to the lack of studies on the planned capacity mix for 2050, we present a reference scenario which is composed of the 2035 reference scenario by DECC [27] and the 2050 low-carbon scenario by UKERC [23]. Both scenarios show a similar amount of renewable capacity, unabated thermal, and nuclear capacity. The scenario from DECC, however, reports more interconnection capacity; UKERC states higher levels of CCS capacity. The benchmark power system we compose is denoted with *B_DECC*, and contains 21 GW of nuclear, 40 GW unabated thermal, 12.75 GW CCS-equipped thermal, 56 GW intermittent renewables, and 17 GW interconnection capacity.

Figure 9.18 illustrates the power output by technology for the 2050 reference scenario of this study (*B_Ref*), which utilises the capacity amounts as stated for the *B_DECC* scenario as upper bounds in the optimisation framework. Hence, the determined technology mix in scenario *B_Ref* is the optimal combination if the maximum possible capacity expansion is defined by the *B_DECC* level. We find that a system with 30 % less gas power plants can provide the equivalent services in terms of electricity and reserve demand, reliability and operability constraints. We achieve the identical emission target, and due to reduced capital expenditure the annual TSC are more than half a billion pounds less in the *B_Ref* scenario. Additionally, the thermal asset utilisation in the *B_DECC* scenario is less the large amounts of gas capacity cannot be utilised and make way for intermittent power generation.

The greenfield scenario *B_GF* illustrates the optimal capacity mix without constraints on the amount of capacity built-up. The scenario complies to the same reliability, operability, environmental, and technical constraints as the previous cases. Rather then representing a realistic scenario, *B_GF* gives insight into

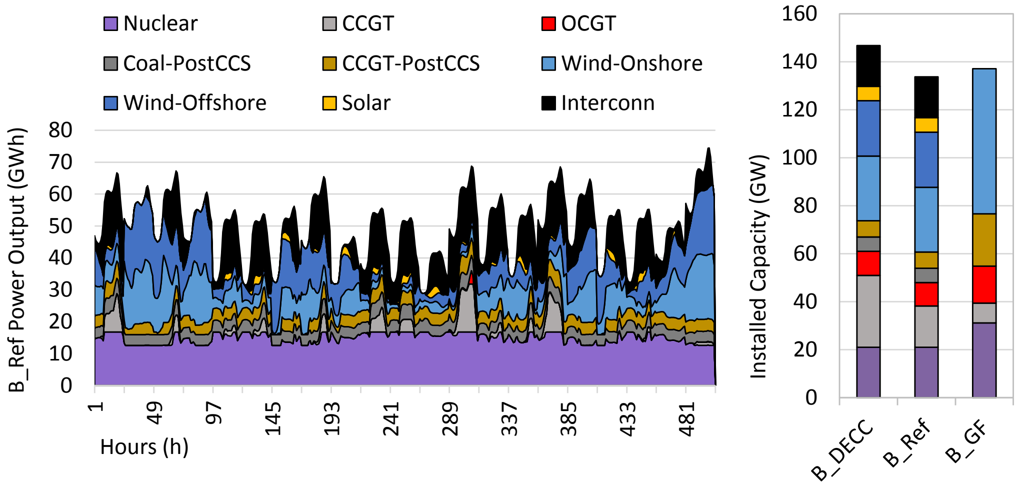

Figure 9.18: Power output (GWh) for the 2050 reference scenario in this study, and comparison of installed capacity (GW) by technology type for a UKERC/DECC scenario in 2050, the reference scenario in this study, and a green field scenario. The presented results are based on DECC's central fuel price scenario 7.1 and the business-as-usual scale-up of electricity demand profiles as explained in section 7.1; all assumptions are described in section 7.3.

the actual cost-optimal power system under 2050 constraints. All zero-carbon or low-carbon technologies are highly valuable, resulting in a system with large amounts of nuclear and wind capacity. CCGT post-combustion CCS capacity is deployed up to 21.75 GW and utilised when power generation from intermittent wind is insufficient. Unabated thermal power plants provide reserve and balancing services and show low utilisation rates of less then 15 %. With a sufficient amount of low-carbon and firm capacity, electric interconnection becomes uneconomical. The greenfield scenario results in annual TSC of £3.75 billion, which is equivalent to a reduction of 25 % compared to the *B_DECC* case (£4.21 billion), or 23 % compared to the *B_Ref* case (£4.15 billion).

9.2.2 B: Non-Flexible and Flexible CCS Technologies

In order to understand the differences between non-flexible and flexible CCS technologies and their impact on system-wide characteristics, we conduct the analogous calculations to section 9.1.4, here under 2050 conditions.

As CCS capacity now makes up for 8.7 % of the total available capacity, a scenario where no CCS capacity is made available (*B_NoCCS*) results in an in-

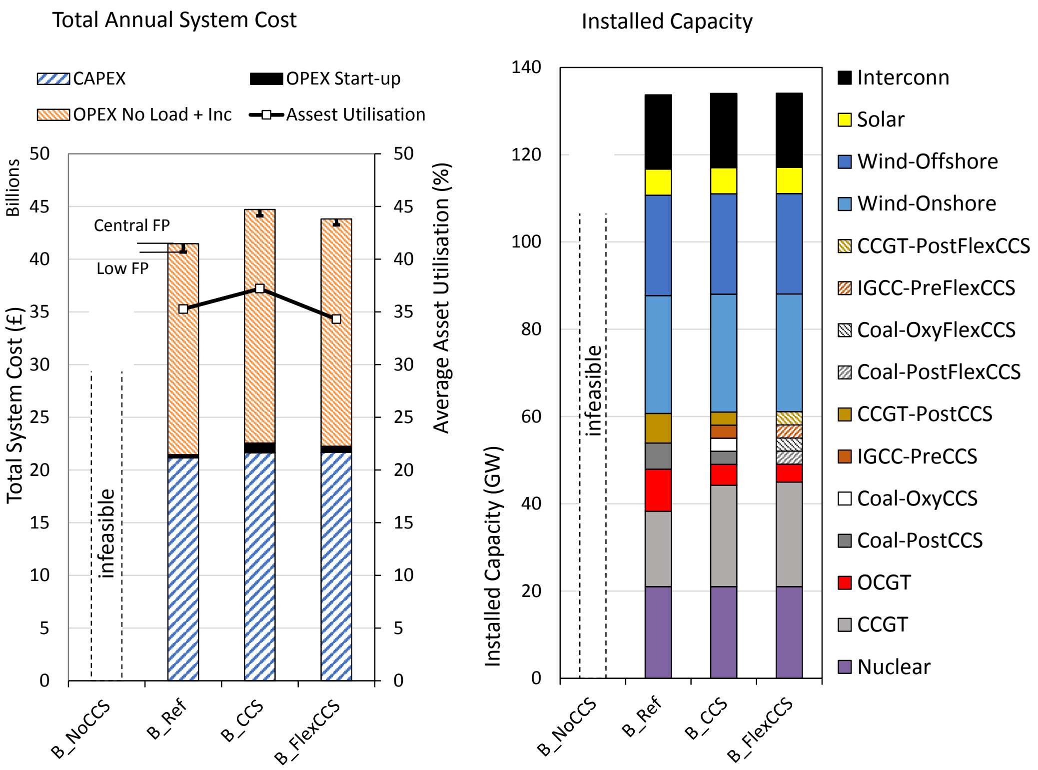

Figure 9.19: On the left hand side: Total System Cost (TSC) for reference scenario omitting CCS capacities *B_Ref_NoCCS*, the reference scenario *B_Ref*, a technology independent scenario distributing the CCS capacity across all available CCS technologies *B_Ref_CCS*, and a scenario as the latter distributing the capacity across all available flexible CCS capacities *B_Ref_FlexCCS*; On the right hand side: The capacity mix resulting from the structural optimisation for each scenario.

feasible system. The available power capacity assets are not sufficient to meet electricity demand and reserve requirements alongside emission targets and reliability constraints.

The previously discussed scenario *B_Ref*, deploys the maximum amount of available CCS capacity, which is limited to a combined 12.75 GW across coal post-combustion CCS and CCGT post-combustion CCS. The annual TSC amount to £4.15 billion with DECC's central fuel price scenario [4]. The error bars indicate a difference in TSC of 2 % in the case of the low fuel price scenario. For the scenarios *B_CCS*, and *B_FlexCCS* the difference to the low fuel price scenario is 1.3 %.

Similarly as for the 2030 scenarios, the technology neutral case *B_CCS*, where the equal CCS capacity amount is distributed evenly across all non-flexible CCS technologies, shows higher TSC. This is due to higher CAPEX and OPEX of coal oxy-combustion and IGCC pre-combustion CCS, which are nevertheless valuable in the absence of greater coal post-combustion and CCGT post-combustion capacity availability. In the cost-optimal operational schedule, power generation from CCS power plants in the *B_CCS* case is less then in scenario *B_Ref*. The CCS power plants show increased cycling, causing 67 % increased start-up cost, but operate at a lower average utilisation rate compared to the *B_Ref* scenario. However, mainly driven by the on-shore wind and interconnection capacity, the overall average asset utilisation increases from 35 % to 37 %.

Comparing the scenario where flexible CCS technologies are available (*B_FlexCCS*) instead of the non-flexible CCS technologies, figure 9.19 visualises the marginal difference in the optimal capacity mix. In the flexible CCS case the amount of necessary OCGT capacity is reduced by 700 MW, however, an additional 750 MW of unabated CCGT capacity become part of the cost optimal solution. Both cases integrate the maximum available CCS and intermittent renewable capacity.

Despite increased CAPEX and OPEX of the flexible CCS options compared to the non-flexible options, the TSC in the *B_FlexCCS* case is less, comparing £4.47 billion for *B_CCS* to £4.38 billion for *B_FlexCCS*. This is due to the reduced operational expenses including no load and fuel costs from thermal power plants and interconnection. The utilisation of the non-flexible to the flexible CCS power plants drops from an average of 50 % to 40 %. Although, the same amount of capacity is required, the scenario deploying flexible CCS technologies is able to reduce electricity dependency on interconnectors slightly. The annual interconnection utilisation is decreases from 65.9 % to 64.3 %.

Additionally to the reduced power output from flexible CCS power plants, we find that their operational pattern differ greatly from the non-flexible CCS power plants. Under system conditions with tight emission targets and a high penetration of intermittent capacity, rather the non-flexible than the flexible CCS power plants are forced into increased cycling behaviour. Due to the tighter operating envelope of the non-flexible CCS power plants (MSG of 70 %), they experience shut-down and start-up phases twice as often compared to the flexible options (MSG of 40-70 %). Hence, the operational costs associated with power plant start-up for the non-flexible technologies are 1.7 times greater than for the flexible technologies. This is driven by the start-up frequency as well as the longer start-up times for the non-flexible options.

Figure 9.20 gives an example for the operational differences between the non-flexible and flexible CCS power plants. The table on the top of the figure shows the unit-wise and mode-specific schedule for the power generation in the flexible CCS case. All CCS power plants, especially the coal-fired power plants, remain online, however reduce their power output to the MSG level of 40 % compared to full load.

The non-flexible coal post-combustion and coal oxy-combustion CCS power plants, which are depicted in the bottom table of figure 9.20, are forced to shut down all or most of their units, as the MSG power level is not low enough (70 %). The low-cost and low-carbon electricity from on-shore and off-shore wind is highly valuable, and is prioritised in the dispatch order. Furthermore, a greater amount of interconnection capacity is utilised in the non-flexible CCS case as to compensate for the power loss from the abated thermal power plants. Caused by relatively long start-up periods (3-5 hours), the non-flexible CCS power plants enter the start-up phase in time period 124 although their full power output is only needed in hour 130, when demand reaches it's first daily high and wind availability is low.

9.2.3 B: System Value of CCS technologies Under Different Electricity Demand Scenarios

In the following we compare the System Value of coal post-combustion CCS and CCGT post-combustion CCS under two different future electricity demand scenarios which are described in more detail in section 7. The scenario referred to as business-as-usual (BAU) scenario, is characterised by a linear scale-up of the hourly electricity demand profile, whereas the scenario assuming a widening of the spread between demand minima and peaks is in the following denoted as extreme peak (ExP) scenario.

In order to determine the SV of the CCS technologies within the 2050 electricity system, we assess its impact on system dynamics as its capacity deployment increases from zero to the economic limit. However, as the amount of CCS capacity in the base 2050 system of the *B_ Ref* scenario makes up for 9 % of installed capacity, a system design without this amount of firm low-carbon capacity is infeasible to comply with the required system-wide constraints. In particular

NUMBER OF UNITS											
TECHNOLOGY	MODE	TIME PERIOD									
		116	117	118	119	120	121	122	123	124	125
Nuclear	inc	35	35	35	35	35	35	35	35	35	35
CCGT	off	25	30	31	31	31	31	31	31	31	31
	su										
	inc	6	1								
OCGT	off	48	48	48	48	48	48	48	48	48	48
	su										
	inc										
Coal-PostFlexCCS	off										
	su										
	inc	6	6	6	6	6	6	6	6	6	6
Coal-OxyFlexCCS	off										
	su										
	inc	6	6	6	6	6	6	6	6	6	6
IGCC-PreFlexCCS	off										
	su										
	inc	6	6	6	6	6	6	6	6	6	6
CCGT-PostFlexCCS	off										
	su										
	inc	4	4	4	4	4	4	4	4	4	4
Wind-Onshore	off										
	inc	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
Wind-Offshore	inc	230	230	230	230	230	230	230	230	230	230
Solar	off		300	300	300	300	300	300	300	300	
	inc	300									300
Interconn	off			6	15	24	27	28	27	26	24
	inc	34	34	28	19	10	7	6	7	8	10

		116	117	118	119	120	121	122	123	124	125
Nuclear	inc	35	35	35	35	35	35	35	35	35	35
CCGT	off	26	31	32	32	32	32	32	32	32	32
	su										
	inc	6	1								
OCGT	off	41	41	41	41	41	41	41	41	41	41
	su										
	inc										
Coal-PostCCS	off			6	6	6	6	6	6		
	su									6	6
	inc	6	6								
Coal-OxyCCS	off			4	5	5	5	5	5		
	su									5	5
	inc	6	6	2	1	1	1	1	1	1	1
IGCC-PreCCS	off										
	su										
	inc	6	6	6	6	6	6	6	6	6	6
CCGT-PostCCS	off										
	su										
	inc	4	4	4	4	4	4	4	4	4	4
Wind-Onshore	off										
	inc	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
Wind-Offshore	inc	230	230	230	230	230	230	230	230	230	230
Solar	off		300	300	300	300	300	300	300	300	
	inc	300									300
Interconn	off				7	15	18	20	19	19	17
	inc	34	34	34	27	19	16	14	15	15	17

Figure 9.20: Top: Operational schedule as unit-wise and mode-specific operation in the scenario deploying flexible CCS technologies *B_FlexCCS*; bottom: Operational schedule for the scenario with non-flexible CCS technologies *B_CCS*. Technologies can operate in all three mode (*off*, *su*, *inc*), here shown are the modes that are occupied by the respective technology between hours 116-125. Both cases are based on the DECC's central fuel price scenario.

the emissions target constraints cannot be met if for instance CCS capacity is replaced by unabated CCGT capacity. To determine the SV functions for the different CCS technologies, we therefore increase the capacity availability within the BAU scenarios by an additional 7 GW of nuclear capacity, and 7 GW of on-shore wind capacity. We chose to increase the availability of these two power generating technologies as both provide zero-emission electricity during their operation. The first being modelled as dispatchable, and the second as intermittent power source, this enables us to capture the trade-off and competition between the generation capacities and observe the economic capacity displacement when introducing CCS availability.

The extreme peak scenario shows an annual peak demand of 74.5 GW, and total demand of 424.5 TWh, compared to 62.1 GW and 354.4 TWh in the BAU scenario, respectively. This again causes an electricity system which is designed according to the *B_Ref* capacity availabilities to be infeasible under the prevalent emission constraints. Analogously, we increase the capacity availability for the ExP demand scenario by an additional 7 GW of nuclear capacity, 7 GW of on-shore wind capacity, and 10 GW of interconnection capacity. We appreciate that this draws a skewed picture of capacity availability in 2050, however, the amount of uncertainty inherent to long-term energy systems planning might well exceed the presented capacity estimates.

System Value of Coal Post-combustion CCS

In both demand scenarios coal post-combustion CCS capacity reaches its economic deployment level at 21 GW of deployment. Beyond this point, an increased availability of CCS capacity does not increase the optimal amount of capacity installed as result of the optimisation problem under 2050 conditions.

Figure 9.21 visualises how the deployment of CCS capacity in the BAU and ExP case reduces TSC by 9.7 % and 7.2 %, respectively. The marginal value of the 10^{th} GW of coal post-combustion CCS capacity is the most prominent as solar capacity can be fully displaced at this level of CCS deployment.

In the case where the future electricity demand does not only increase in magnitude but also the spread between minimum and peak hours widens (ExP), a larger amount of unabated CCGT capacity remains necessary even at high deployment rates of coal post-combustion CCS. An additional 6-8 GW of CCGT

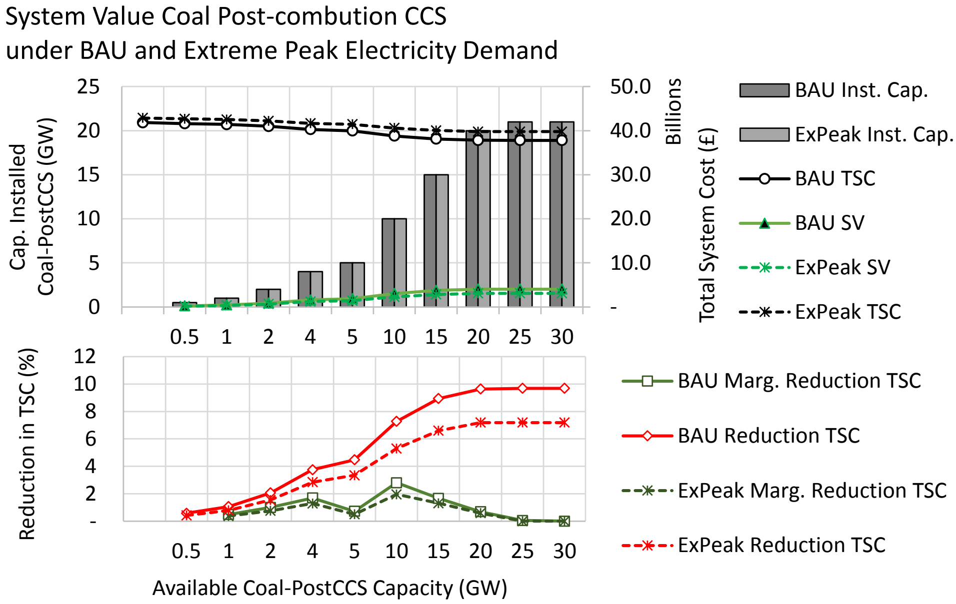

Figure 9.21: Top: Installed capacity, TSC, and System Value of coal post-combustion CCS as a function of capacity availability and the electricity demand scenario BAU vs. extreme peak; Bottom: The absolute and marginal reduction in TSC for each incremental CCS capacity addition.

capacity is necessary throughout all stages of CCS capacity availability in the ExP case compared to the BAU scenario. This results in a less pronounced TSC reduction in the ExP case compared to the BAU scenario.

The ExP scenario, however, is able to incorporate higher amounts of intermittent off-shore wind capacity. At maximum CCS capacity deployment of 21 GW, the BAU scenario incorporates as optimal solution 5.6 GW off-shore wind, whereas the ExP case includes 7 GW.

In both cases, the TSC reduction upon CCS deployment is due to a decrease in the utilisation of CCGT power plants, OCGT power plants and electricity from interconnectors. In the BAU and extreme peak scenario, the interconnectors utilisation drops by over 20 % at maximum CCS capacity deployment levels compared to the situation without CCS availability.

Additionally, the operational cost associated with power plant start-up is significantly reduced at hight levels of CCS deployment as the intermittent renewable asset base is displaced by dispatchable low-carbon CCS capacity. The no load and fuel cost of operation are reduced according to the utilisation, most significantly for CCGT, OCGT, and interconnectors.

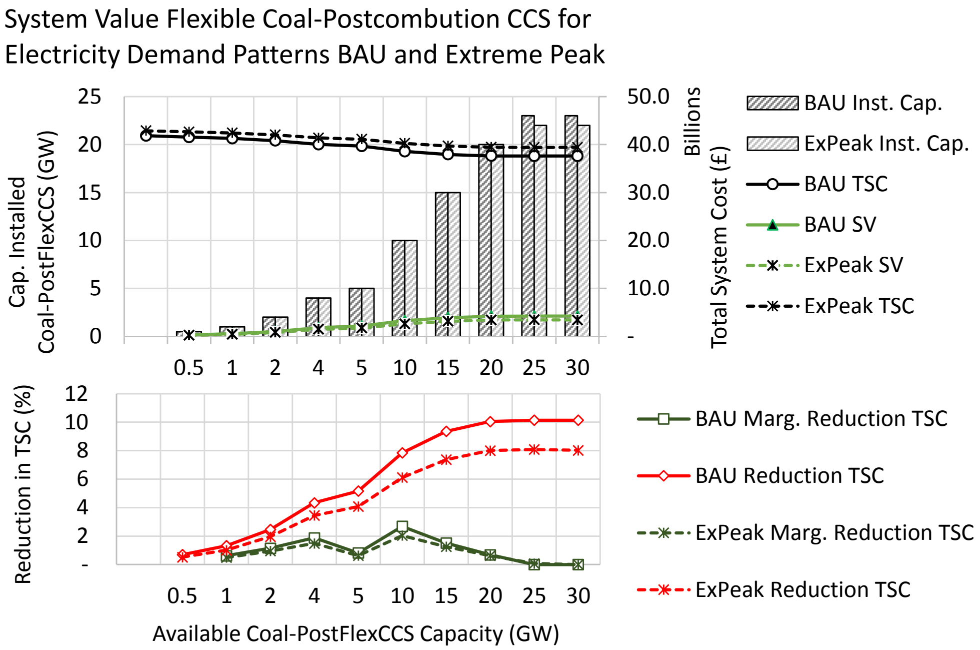

Figure 9.22: Top: Installed capacity, TSC, and System Value of flexible coal post-combustion CCS as a function of the available capacity as the upper bound in the energy systems model; Bottom: The reduction in TSC and the marginal reduction in TSC for each incremental CCS capacity addition.

Figure 9.22 presents the results in the case of flexible coal post-combustion CCS deployment. Under the BAU scenario flexible coal post-combustion CCS reaches its economic deployment level at 23 GW, and under the ExP scenario at 22 GW. The TSC reduce by 10 % in the BAU scenario, and 8 % in the ExP scenario at maximum CCS deployment levels.

As previously discussed, the flexible CCS power plants show fewer start-up times, and higher on-times. The accumulated power output, however, is less than for the non-flexible CCS technologies, such that their utilisation rates differ between 55 (52) % (non-flexible) versus 49 (48) % (flexible), both at 21 GW of deployment in the BAU (ExP) scenario. Non-flexible CCS power plants cycle more often in order to include electricity from the low-cost intermittent renewables. Consequently, the non-flexible CCS options show less operating hours at an higher power output level, whereas the flexible CCS options show on in sum more operating hours, however, a lower power output.

This causes the start-up cost for non-flexible coal post-combustion CCS power plants to be more than four (five) times higher compared to the start-up cost of flexible CCS power plants in the BAU (ExP) scenarios. The deployment of flexible CCS capacity reduces interconnection utilisation further than non-flexible CCS. In the BAU scenario for example, the utilisation rate of interconnectors drops from 60 % to 28 % upon non-flexible CCS deployment, whereas flexible CCS capacity reduces the interconnection utilisation to 24 %. In both cases, however, the same amount of interconnector capacity is necessary to ensure the security of electricity supply.

System Value of CCGT Post-combustion CCS

The economic limit of capacity deployment of CCGT post-combustion CCS is reached at 31.5 GW in the BAU, and 33 GW in the ExP scenario. At this deployment level TSC are reduced by 22 % in the BAU case, and 20 % in ExP case. In both scenarios, off-shore wind and solar capacity is fully displaced at CCGT CCS deployment rates over 22.5 GW. Higher amount of unabated CCGT capacity remain necessary in the ExP scenario compared to the BAU demand profile. At maximum CCS deployment levels, however, the equivalent amount of unabated CCGT capacity of 9 GW remains part of the optimal solution. As opposed to coal post-combustion CCS capacity, the high deployment levels of CCGT post-combustion CCS enable a replacement of interconnection capacity. In the BAU case, interconnection capacity is reduced to 1 GW at maximum CCS deployment rates, whereas in the ExP case 20.5 GW remain valuable to the capacity mix. We again note, that the initial capacity availability for interconnectors in the ExP case in higher than in the BAU case (27 GW vs. 17 GW at zero CCA availability). Where in the BAU case, the total required amount of capacity is reduced by 25 GW (139.2 to 114.2), in the ExP scenario only 20.35 GW of capacity assets are displaced (155.55 to 135.2). The larger amount of required capacity in the ExP scenarios causes the TSC reduction to be less pronounced.

Figure 9.23 visualises the TSC reduction upon CCGT post-combustion CCS deployment in the BAU and ExP scenario. The CCS capacity, in both demand scenarios, experiences a reduction in average asset utilisation as the amount of CCS capacity installed increases. At maximum deployment levels CCGT CCS utilisation reaches 49 % in the BAU case, and 46 % in the ExP scenario.

As interconnection capacity is displaced, also its capacity utilisation can be reduced significantly, however, causing OCGT power plants to higher power output levels. Nuclear capacity remains highly valuable at average factors of 77 %.

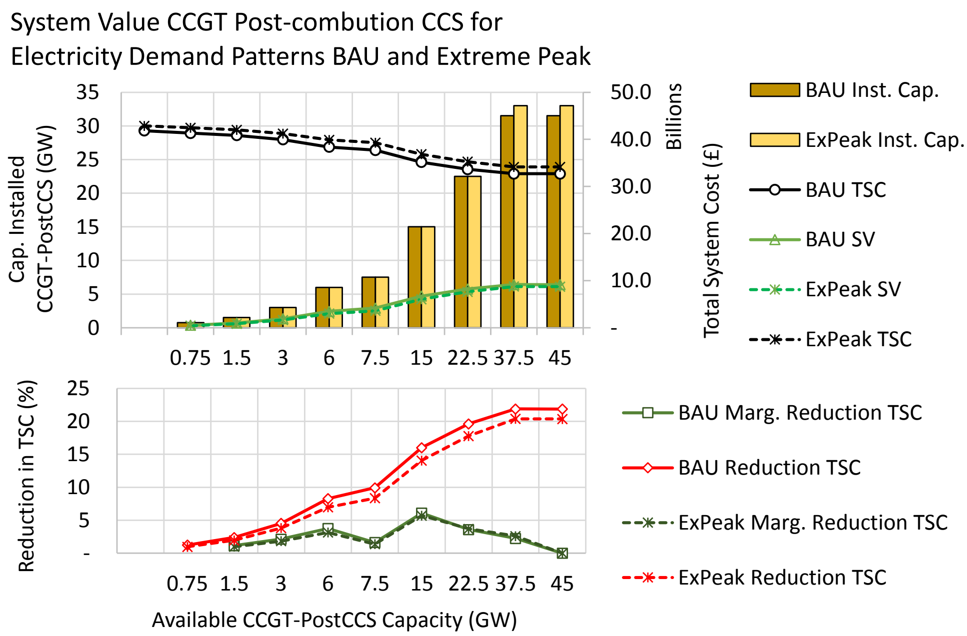

Figure 9.23: Top: Installed capacity, TSC, and System Value of CCGT post-combustion CCS as a function of capacity availability and the electricity demand scenario BAU vs. extreme peak; Bottom: The absolute and marginal reduction in TSC for the incremental CCS capacity addition.

Flexible CCGT post-combustion CCS reaches its economic capacity limit at 30.75 GW in the BAU, 32.25 GW in the ExP scenario. Figure 9.24 visualises the optimal capacity levels for flexible CCGT CCS capacity as well as the reduction in TSC cost caused by its deployment.

In both demand scenarios, solar capacity and the intermittent off-shore wind capacity is fully displaced at CCS capacity deployment of 15 GW and 22.5 GW, respectively. However, in the ExP scenario larger amount of off-shore wind capacity are utilised at high CCS installation levels. With 22.5 GW of CCGT post-combustion CCS present in the capacity mix, 4.6 GW of off-shore wind are profitable in the BAU case, whereas 13 GW are utilised in the ExP scenario. This indicates an increased potential for intermittent capacity in scenarios with more extreme electricity demand profiles.

The interconnection capacity is reduced from 17 GW to 1 GW in the BAU, and from 27 GW to 20.5 GW in the ExP case. A decrease in energy dependency remains one of the advantages of flexible CCS capacity deployment.

The integration of flexible CCGT post-combustion CCS capacity to its maximum

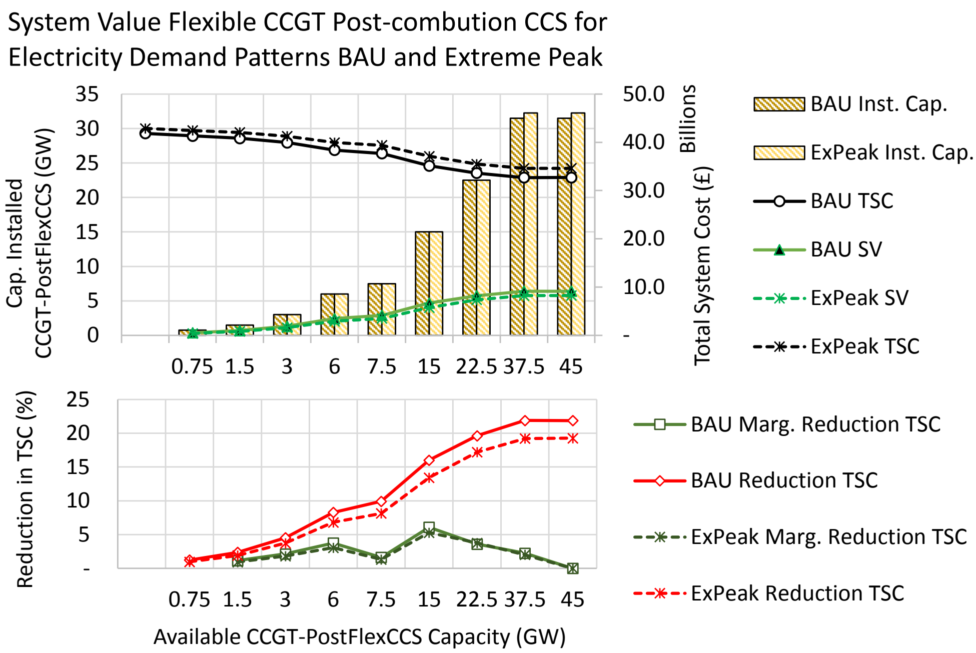

Figure 9.24: Top: Installed capacity, TSC, and System Value of flexible CCGT post-combustion CCS as a function of capacity availability and the electricity demand scenario BAU vs. extreme peak; Bottom: The absolute and marginal reduction in TSC for the incremental CCS capacity addition.

economic deployment level is able to reduce TSC by 21 % in the BAU, and 19.3 % in the ExP scenario. As figure 9.24 suggests, the marginally greatest reduction is generated at a CCS installation level of 15 GW. At this point, solar capacity is entirely displaced, causing a beneficial discontinuity in the marginal TSC reduction curve.

The average asset utilisation behaves analogously to the non-flexible CCGT CCS capacity deployment, causing interconnection and CCS utilisation to decrease. Unabated CCGT capacity however, reaching equivalent capacity levels of 10.5 GW at maximum CCS deployment rates in the BAU and ExP case, show a higher utilisation factor in the latter demand scenario. This causes greater levels of total power output and higher OPEX for start-up operation in unabated CCGT power plants.

Summary of System Value for Coal Post-combustion CCS and CCGT Post-combustion CCS

In order to compare the non-flexible and flexible coal post-combustion CCS and CCGT post-combustion CCS technologies under the different electricity demand scenarios BAU and ExP, we present their relative System Values in annual TSC reduction per installed capacity unit, £/kW.

Figure 9.25 summarises on the left-hand side the relative SV for coal post-combustion CCS, and concludes that in the BAU and ExP scenario the flexible technology option is more valuable. This tendency is more visible at low installation levels, where the flexible option can reduce TSC approximately £100/kW further than the non-flexible CCS options.

This is explained by the different optimal operational strategies of the non-flexible and flexible CCS technologies in the 2050 scenarios. Due to a higher MSG point, non-flexible CCS power plants show more start-up and shut-down periods in order to enable the integration of intermittent renewables. This cycling behaviour increases the operational cost associated with start-up to more than twice the cost compared to flexible CCS. Total operational cost including fuel expenses are on average 10 % higher for non-flexible coal post-combustion CCS power plants compared to the flexible ones at a deployment level of 20 GW.

The relative SV levels which are achieved by a non-flexible or flexible coal post-combustion CCS deployment in 2050 range from £480-580/kW to £180-190/kW, resulting in generally similar figures to the 2030 scenario in figure 9.16.

The electricity demand scenario with more extreme peaking patterns leads to an overall lower relative SV for coal post-combustion CCS. Approximately 12 % more total capacity is needed to reliably meet system requirements. However, under equivalent emission, security, and operability constraints, the challenging demand profile in the ExP scenarios cause higher TSC and a reduced potential for the CCS power plants.

The right-hand side of figure 9.25 visualises the relative SV for CCGT post-combustion CCS and how it evolves depending on its deployment level. Analogously to coal post-combustion CCS, non-flexible and flexible CCGT post-combustion CCS power plants can achieve larger TSC reductions in the BAU demand scenarios than in the scenarios where the electricity demand show extreme peaks in its daily variation.

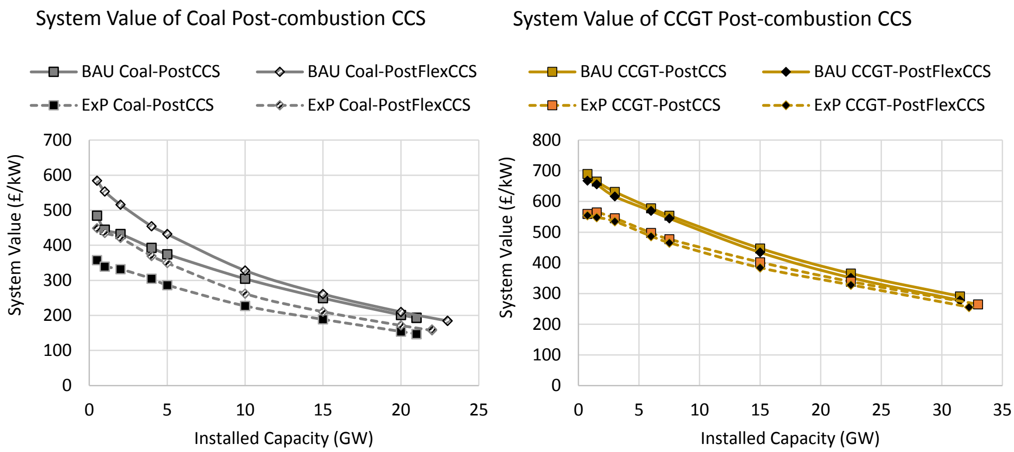

Figure 9.25: Left: Relative System Value of coal post-combustion CCS; right: Relative System Value of CCGT post-combustion CCS as a function of the amount of capacity installed.

CCGT post-combustion CCS power plants show only a marginal spread in the relative SV between the non-flexible and flexible options. As opposed to coal post-combustion CCS, the non-flexible technology achieves greater TSC reductions at marginally higher utilisation rates. Although the non-flexible power plants show increased cycling behaviour (approximately 50 % more start-up operations), the total benefits of greater overall power output at lower operational cost outweigh the additionally incurred start-up cost. These benefits might be lessened by additional costs owing to higher maintenance requirements.

Overall, the relative SV for CCGT CCS ranges from £560-690/kW to £260-290/kW from low to high deployment rates depending on the BAU and ExP scenario; respective values for flexible CCGT CCS range from £550-670/kW to £260-280/kW. Hence, due to its comparatively low upfront cost, low emission rates, and high efficiencies, CCGT post-combustion CCS outperforms coal post-combustion CCS in reducing TSC under the BAU and ExP scenario.

Chapter 10

Conclusions from the FlexEVAL Project

The FlexEVAL project has aimed at analysing the value of flexible CCS power plants to a future UK electricity system. We categorise the main findings in qualitative and quantitative results and list these in the same order.

- All studied CCS technologies provide a value to a 2030 and 2050 UK electricity system as they reduce the total system cost (TSC) when being deployed in the mix of power generating capacity.
- A cost-optimal future electricity system contains large amounts of intermittent renewable capacity. In order to integrate the intermittent power generation, thermal power plants are forced to increased cycling operation.
- Scenarios without restrictions on the amount of capacity that can be installed, indicate that CCGT post-combustion CCS in combination with onshore wind power is part of the economically and environmentally optimal solution under 2030 and 2050 conditions.
- Flexible CCS technologies provide an additional value in being able to accommodate higher levels of intermittent renewable capacity, reducing TSC further through increased electricity dispatch from intermittent renewables with low operational cost.
- Non-flexible and flexible CCS power plants show different optimal operational strategies. Under 2030 conditions, flexible CCS power plants show more frequent start-up/shut-down behaviour than non-flexible CCS power plants to enable intermittent renewable power generation. Under 2050 con-

ditions, with larger amounts of renewable and CCS capacity, non-flexible CCS power plants are forced into cycling operation due to their tighter operating envelope (higher MSG, longer start-up times, etc.) causing higher start-up cost.

- Non-flexible CCS power plants show a higher utilisation than flexible CCS power plants with regards to absolute power output, but a lower utilisation in terms of on-times.
- Flexible CCS technologies reduce the necessity for interconnectors compared to non-flexible CCS options and are able to lower the dependency on electricity imports.
- In 2030, the level of economically optimal deployment for the different CCS options is: 28 GW for coal post-combustion, 28 GW for coal oxy-combustion, 26 GW for IGCC pre-combustion, 40.5 GW for CCGT post-combustion CCS.
- In 2050, the level of economically optimal deployment under the business-as-usual/extreme peak electricity demand scenario is: 21/23 GW for coal post-combustion, 31.5/33 GW for CCGT post-combustion CCS.
- The economic level of deployment is marginally affected by the flexibility of the power plants.
- The relative System Value for the different CCS options indicates the generated reduction in TSC per installed capacity unit and is a function of the system conditions and amount of capacity deployment. It ranges from £500-800/kW at low deployment rates to £150-300/kW at maximum deployment rates and illustrates clearly the value difference between FOAK and NOAK power plants.

The FlexEVAL project has been able to provide evidence for the additional value flexible CCS power plants can provide to the electricity system of the future. The increased ability of flexible CCS power plants to incorporate intermittent renewable capacity and power generation is systemically beneficial and critical for system cost reduction.

Future work could involve studying how the business case of flexible CCS-equipped power plants is effected by the lower utilisation rates and capacity factors in future years. Additionally, the consideration of advanced energy storage technologies as part of the future capacity mix, to assist non-flexible CCS power plants or for integration with intermittent renewables and flexible CCS could provide further insight to potential operation patterns of CCS power plants in the future. Finally, we hope this work assists subsequent research on adequate policy support mechanisms to incentivise flexible CCS-equipped power plant deployment.

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Appendix A

Model Formulation [3c]

Mathematically model formulation [2c] and [3c] are equivalent; they differentiate solely in the available set of technologies I. Model [3c] does include CCS technologies whereas the available selection for model [2c] is defined to exclude CCS. A detailed definition of the investigated scenarios can be found in section 7. The nomenclature for the extended model formulation is listed below.

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 section 6.2. Hence, the obtained total system cost tsc are scaled back to represent annual construction cost and one year of operation.

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

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.

$$
\begin{aligned}
& 0 \leq d(i) \leq Num(i) && \forall i && \text{(3c.2)} \\
& \sum_{m \in M} n(i,m,t) = d(i) && \forall i,t && \text{(3c.3)}
\end{aligned}
$$

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" $TE(i,m,\textit{IP})$ 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.

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

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

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

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

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.

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

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

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

The provision of spinning reserve service is further constrained according to the mode-dependent "reserve potential" $TE(i,m,\mathit{RP})$ 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 $TE(i,m,\mathit{RP})$ 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.

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

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.

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

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 following sections. 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 $d(i) \geq 0$:

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

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