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Resilient UK Energy System

Research Report

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This work was carried out as part of the cross-Centre UKERC Energy 2050 project. It has engaged researchers from: the Infrastructure and Supply Theme located at Cardiff, Imperial College and Manchester; the Energy Systems and Modelling theme then located at Kings College London and now at UCL; and staff from UKERC Headquarters at Imperial College.

Executive Summary

Introduction

1. Climate change and energy security have come to dominate the energy policy agenda. Concerns about energy security in the UK have been driven by the loss of self-sufficiency in oil and natural gas and a growing dependency on imports.

2. This report explores ways of enhancing the “resilience” of the UK energy system to withstand external shocks and examines how such measures interact with those designed to reduce carbon dioxide (CO_2) emissions. The concept of resilience is explored and a set of “indicators” is developed to define quantitatively the characteristics of a resilient energy system. In the report we systematically test the response of the UK energy system under different scenarios to hypothetical shocks. These are all assumed to involve the loss of gas infrastructure. We then assess mitigating measures which can help to reduce the impact of these shocks and test their cost effectiveness using an insurance analogy.

3. The report covers one workstream in the larger *UK Energy 2050* project conducted by UKERC. The wider project is described comprehensively in a Synthesis Report (Skea et al., 2009) and in a book exploring the project and a wider range of policy issues (Skea et al., 2011). In particular, the scenarios describing broad energy system change which frame the analysis in this report are covered only briefly. Readers interested in underlying assumptions about energy demand and supply are referred to these other publications.

4. We have used three energy models to conduct this analysis. The first is the MARKAL-MED model, a linear optimisation model which covers the entire UK energy system and can address interactions between different parts of the energy system.

5. The second is the WASP electricity generation planning model originally developed by the International Atomic Energy Agency (IAEA). It is used to explore, in more detail, the levels of generation investment needed to maintain reliable supplies. It is a cost minimising model. The WASP model is fed electricity demand assumptions from MARKAL-MED.

6. The third model is the geographically explicit Combined Gas and Electricity Networks (CGEN) model which is used to assess where electricity generation capacity should be located and how much gas and electricity infrastructure (wires, pipes, gas storage, import terminals) should be constructed. It is another cost-minimising model which is fed results from both MARKAL-MED and WASP.

The analytical approach

7. It is has been argued that policies and measures that help to reduce CO_2 emissions will help to promote energy security and vice versa. This is clearly the case for energy efficiency which reduces both CO_2 emissions and our dependence on energy. But fossil fuels will play an important role in our energy mix for some time to come.

Energy sources such as coal may contribute to diversity of supply and thereby enhance security, but deploying them works against our climate change goals. Increasingly ambitious plans to deploy intermittent renewable energy pose challenges for the reliability of electricity supplies without corresponding investment in “back-up” capacity.

8. This work is based on four “core” scenarios, organised on a 2x2 matrix, for the development of the UK energy system out to 2050. One dimension of the matrix refers to the level of ambition for CO_2 reduction, the other to the “resilience” of the energy system to external shocks.

9. A *Reference* scenario which assumes no policy measures other than those contained in the 2007 Energy White Paper is the starting point. Under the *Low Carbon* scenario, CO_2 emissions are constrained so that they fall 36% below 1990 levels by 2025 and 80% by 2050. Our *Resilient* scenario embodies a number of constraints that enhance the ability of the energy system to withstand shocks, but has no CO_2 constraints. A *Low Carbon Resilient* scenario includes both sets of constraints.

Characterising Resilience

10. The advantage of focusing on *resilience* as the key concept is that it can be seen as an intrinsic characteristic of the energy system. It does not require us to think about the underlying causes of a particular shock, for example a prolonged interruption of gas supply.

11. Drawing heavily on the ecological sciences, we used the following working definition of energy system resilience:

> *“Resilience is the capacity of an energy system to tolerate disturbance and to continue to deliver affordable energy services to consumers. A resilient energy system can speedily recover from shocks and can provide alternative means of satisfying energy service needs in the event of changed external circumstances.”*

12. To ensure that boundaries were clearly defined, we also adopted the following working definition of the UK energy system:

> *“the set of technologies, physical infrastructure, institutions, policies and practices located in and associated with the UK which enable energy services to be delivered to UK consumers”.*

13. The UK Government has identified three elements of energy security:

- *physical security*: avoiding involuntary physical interruptions to consumption of energy (i.e., the lights going out or gas supplies being cut off);
- *price security*: avoiding unnecessary price spikes due to supply/demand imbalances or poor market operation (e.g., market power);

- *geopolitical security*: avoiding undue reliance on specific nations so as to maintain maximum degrees of freedom in foreign policy.

14. To address these, we identify three key elements of a resilient energy system: lower levels of imports and hence energy demand; diversity of supply; and robust physical infrastructure. A resilient energy system needs to deliver energy services reliably in the light of outcomes to which probabilities can be attached (plant outages, weather variability) but must also be resilient to larger scale "shocks" to which it is difficult to attach probabilities. Less work has been carried out on this latter aspect.

Macro-indicators of resilience

15. The following quantified indicators of resilience were arrived at by assessing their practical feasibility and by conducting a variety of sensitivity analyses using the MARKAL-Med model. These are applied as constraints in the *Resilient* and *Low Carbon Resilient* scenarios.

16. ***Energy demand and imports.*** We have set a constraint that final energy demand should fall by about 3.2% per annum relative to GDP, or about 1% per annum in absolute terms, from 2010 onwards. These were benchmarked against bottom-up estimates of the potential impact of energy efficiency measures out to 2020 made by Government in the most recent carbon and energy projections available at the time the analysis was conducted. Our assumptions about constrained final energy demand correspond roughly to the assumption of *high* impact of energy efficiency measures up to 2020. We then assume that the same pace of improvement will continue thereafter. This constraint is therefore at the upper end of the plausible range in terms of energy demand reduction.

17. ***Primary energy demand***. We have constrained primary energy demand so that no single energy source (e.g. natural gas, nuclear) gains more than a 40% market share. The constraint on maximum share for primary energy supply ensured supply diversity in the economy as a whole.

18. ***Electricity generation.*** We have constrained the electricity generation mix so that no single energy source gains more than a 40% market share. Generation mix was constrained because the electricity sector was found to play a key role in shifting the primary energy mix.

19. With these constraints applied in the resilient scenarios, the energy system develops rather differently from the *Low Carbon* case. The *Low Carbon* scenario is dominated by rapid de-carbonisation on the supply side, especially in the electricity sector. The sector is virtually de-carbonised by 2030 and electricity enters new markets through electric and plug-in hybrid vehicles and heat pumps in the residential sector. In the *Resilient* scenario, electricity de-carbonisation takes place more slowly. In the *Low Carbon Resilient* scenario, the electricity system de-carbonises by 2050 but the pace of de-carbonisation is about 10-15 years behind the *Low Carbon* scenario.

20. The main theme in the resilient scenarios is the driving down of energy demand. This happens in respect of demand for gas in the residential, services and industrial sectors. This translates directly into reduced imports.

21. The key conclusion is that the low carbon agenda contributes to meeting some resilience objectives, especially those relating to diversity but it still leaves the UK much more import dependent. The *Resilient* scenario reduces CO_2 emissions by 52% by 2050, well short of the UK's target.

Physical Infrastructure

22. The MARKAL-MED model determines how much electricity generating capacity it installs by applying a capacity margin on top of exogenously specified peak demand.[1] However, as more intermittent renewable capacity (e.g. wind) is added to the system, this simple approach may not meet recognised security standards. The WASP and CGEN models were run to ensure that sufficient investment is made.

23. The models use a number of key parameters combined with statistical analysis to ensure adequate investment in electricity capacity. These include: value of lost load (£5/MWh for residential electricity; £40/kWh for industrial electricity; £5/therm for industrial gas; and loss-of load expectation for electricity (maximum 4 hours per year or 0.05% of the time). Disconnection of residential gas is not permitted.

24. Applying these reliability standards adds to electricity system costs. The maximum annual increase across the scenarios is £354m in 2020 (*Low Carbon Resilient* scenario), £575m in 2035 (*Low Carbon* scenario) and £457m in 2050 (*Resilient* scenario).

25. To meet gas reliability standards, the CGEN model adds LNG terminals and gas storage capacity in addition to facilities that are currently planned. In the *Reference* scenario, 160 mcm/d of LNG terminals and 2,000 mcm of storage capacity are added by 2030. In the *Low Carbon* scenario, the same investment in LNG terminals is made, but the need for additional storage capacity is reduced to 1,000 mcm. The *Resilient* and *Low Carbon Resilient* scenarios require less capacity because gas demand is lower and the demand profile is less "peaky". In these two scenarios,140 mcm/d of LNG terminals are added by 2030 but no additional gas storage.

System shocks

26. We have hypothesised a set of shocks to the gas system and investigated the impacts. We do not attribute any specific cause to these shocks, but they are compatible with previous events caused by major accidents rather than politically motivated supply interruptions. There is a system response which adds to costs, but with the most severe shocks supply curtailments are inevitable. The model predicts the following sequence of responses: a) invoking interruptible gas contracts with industry; b) re-dispatching the power system to use less gas; c) use of back-up distillate oil in CCGTs; and d) involuntary interruptions to industrial customers.

[1] However, intermittent renewable capacity is down-rated using a "capacity credit" to ensure investment in "back-up" plant.

27. The “shocks” were all assumed to take place in mid-winter (1 January in 2025) during a spell of “average cold spell” demand. We tested the consequences of losing the Bacton or Easington gas terminals or the Milford Haven LNG terminal for periods of 5, 40 or 90 days. This is broadly consistent with past “shocks” in the gas sector.

28. The costs associated with the shocks were much lower in the *Resilient* and *Low Carbon Resilient* scenarios. This is because gas demand is much lower. The loss of Easington or Milford Haven does not entail any costs at all in the 5 and 40 days cases.

29. The loss of the largest terminal, Bacton, which affects both imported and domestic gas supplies, has the largest impact in the other scenarios.

30. The energy system can ‘ride through’ the loss of Easington or Milford Haven under the *Resilient* and *Low Carbon Resilient* scenarios – and the impact of losing Bacton is much diminished. This is because these two scenarios are characterised by lower levels of seasonal gas demand. The system can cope better when demand is less ‘peaky’. Demand reduction demonstrably contributes to energy system resilience

31. The imputed value of unserved energy (in £bns) is an order of magnitude larger than the changed system costs. System costs generally rise as more expensive gas is sourced and coal substitutes for gas in electricity generation. This however does not take account of the response in energy spot markets that would be expected following such events, which would tend to increase costs to consumers further.

32. The patterns of response are complex because the facilities play different roles in the gas network. In none of the scenarios is it necessary to curtail electricity supplies. Response is taken up entirely by exercising interruptible gas contracts, re-dispatch of the electricity system, use of distillate oil at certain CCGTs and non-contracted industrial gas interruptions.

Mitigating the shocks

33. We tested the effectiveness of a set of infrastructure investments, over and above those required to meet normal reliability standards, in mitigating the hypothesised shocks. These included: gas storage; LNG terminals; new gas interconnectors; and storage of distillate oil back-up at CCGT plant.

34. We focus on the loss of Bacton, the most severe shock, for a 40-day period and assess the impact of these mitigating investments in the *Low Carbon* scenario. The biggest impact in terms of reducing the volume of energy unserved comes from the expansion of import facilities, be they new LNG terminals or a new interconnector. Dedicated gas storage and 40 days distillate storage have half to two thirds the impact of more import facilities.

35. The effectiveness of gas storage is critically dependent on how much gas is in store at the time of the shock. If a storage facility is used as strategic storage and kept completely full for emergencies it will be much more effective in mitigating shocks.

36. Making a mitigating investment can be regarded as taking out insurance against the eventuality of adverse events. If a rate of return of 10% real is required on investment in two LNG terminals, then the 40-day Bacton outage would need to take place more than once every 35 years to pay off. Given the severity of the event, and the improbability of its happening as frequently as this, it is almost impossible to conceive of this as a good investment in a market context.

37. On the other hand, the mitigating measures could be regarded as strategic investments taken in the public interest. At a rate of return on investment of only 3.5% real, the Treasury "social" discount rate, investing in LNG terminals might still 'pay off' if the event were to occur as infrequently as once in 100 years.

The Costs of Resilience

38. There are costs and benefits associated with moving from the *Low Carbon* to the *Low Carbon Resilient* scenario. Most of these are associated with the macro-indicators of resilience, especially bearing down on final energy demand. Energy system costs are £5bn lower in 2025 simply because the energy system is smaller. However, there is an implied loss of welfare of £15bn associated with the loss of consumer surplus as consumers respond to higher energy prices.

39. In practice, it may be possible to mitigate some or even all of these welfare losses. If 25% of the demand reduction is achieved through low cost conservation measures the welfare loss is reduced by £2.3bn. We also explored a scenario where people voluntarily reduce their energy use as a result of social and cultural change. This may involve no welfare loss at all – and it reduces the energy system cost by £35bn in 2025.

40. The costs of ensuring electricity system reliability and reinforcing gas infrastructure are orders of magnitude less than the costs associated with driving the macro-structure of the energy system in different directions. Enhanced electricity reliability appears to cost around £10-15 per household per year while additional investment in gas storage or import facilities appears to run at around £2 per household.

Policies for resilience

41. Achieving the macro goals of reduced imports and greater supply diversity can be achieved through the vigorous pursuit of fairly conventional policy instruments. The key is a very strong emphasis on policies to improve energy efficiency in buildings and transport. The emphasis on the demand side needs to be much stronger than in a pure *Low Carbon* scenario. Keeping up the pace of investment in renewables and nuclear will also contribute.

42. As regards reliability and redundancy in the electricity system, current UK Government policy is to deliver an adequate capacity margin by having a licensing obligation on power companies to meet energy demands, and then relying on markets, through price signals, to deliver capacity that may only be rarely used. There is now a widespread view that current market arrangements may not be

sufficient to guarantee reliable energy supply while ambitious low carbon targets and renewable energy goals are pursued. Consultation on the Government's proposals for Electricity Market Reform concluded in March 2011.

43. This report suggests that there is potentially a case for investment in further "strategic" gas infrastructure beyond that which the market would deliver if we pursue the supply-led energy strategy embodied in the *Low Carbon* scenario. By itself, that investment would be relatively modest and would add little to consumer costs.

44. There are three possible models for stimulating such investment: Government provides the appropriate framework for the market to make the investment; the regulator permits the investment through price reviews, but the investment is provided by the regulated companies; Government carries out the investment itself. The latter model appears unlikely. The key policy question is whether the benefits of driving this investment through rate of return regulation outweigh the disadvantages of driving out investment made on a purely market basis.

Future Research Directions

45. In taking work on energy system resilience forwards, we consider the following lines of inquiry:

- Examining a wider range of contingencies relating to oil, electricity and renewables (including bio-energy)

- Examining market responses to shocks as well as possible physical responses costed in a bottom-up manner

- Attempting to attach probabilities to various types of shock. This may not be possible for "geopolitical" events, but many of the historic shocks that we reviewed resulted for insurable weather or accident-related incidents for which evidence may be available.

- Producing new or "reduced" models of system responses to energy shocks that could be operated in Monte-Carlo mode. The current models are too cumbersome to operate in this way.

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1. Introduction

1.1 Background

UK energy policy has four objectives: to put the UK on a path to cutting greenhouse gas (GHG) emissions by some 80% by 2050, with real progress by 2020; to maintain the reliability of energy supplies; to promote competitive markets in the UK and beyond; and to ensure that every home is adequately and affordably heated. Climate change, affordability and the reliability of energy supplies have come to dominate the energy policy agenda. Chapter One of the 2007 Energy White Paper (DTI, 2007a) bore the title Energy and climate security; speeches by the previous Secretary of State for Energy and Climate Change have emphasised these goals particularly in light of new evidence about the seriousness of climate change and the UK's increasing dependence on energy, especially gas, imports (Miliband, 2008). In October 2008, the ambition of the UK's 2050 GHG reduction target was raised from 60% to 80%. The Low Carbon Transition Plan (DECC, 2009a) sets out an ambitious policy agenda for starting to realise this ambition. In August 2009, a report by the Prime Minister's Special Representative on International Energy argued for a more strategic approach to energy security issues (Wicks, 2009).

It has become a commonplace notion, prevalent in both policy-making and academic circles (Grubb et al., 2006), that technologies and measures that reduce CO_2 emissions contribute to energy security and vice versa. This is clearly the case for energy efficiency which reduces both CO_2 emissions and our dependence on energy. But fossil fuels will play an important role in our energy mix for some time to come. Energy sources such as coal may contribute to diversity of supply and thereby enhance security, but deploying them works against our climate change goals. Increasingly ambitious plans to deploy intermittent renewable energy pose challenges for the reliability of electricity supplies without corresponding investment in "back-up" capacity.

The work described in this report forms part of the *UKERC Energy 2050* project whose overall concern is the development of a resilient low-carbon energy system. This report focuses on energy security and resilience, but does so within the wider context of an energy policy which is also concerned with radical CO_2 emissions reductions. In assessing energy security and resilience we concentrate on the electricity and, more particularly, the gas systems. This reflects the rapidly changing balance in the UK's supply-demand balance for natural gas and the interconnectedness of the gas and electricity systems.

1.2 The analytical approach

Progress in reducing the energy sector's impact on the climate can be measured through a single metric, tonnes of carbon dioxide (CO_2) equivalent emitted. The energy security agenda responds to anxieties and insecurities about a range of contingencies which are often not well thought through or are ill-defined. These include adequacy of investment in electricity generation capacity, loss of critical infrastructure whether through deliberate action or by accident, or politically motivated interruptions to supply in global markets.

The objective in this report is to think through this agenda in a more systematic manner and, specifically, to assess the pay-off from measures which could serve to mitigate against some of the contingencies which we face. This has been achieved by considering two broad sets of scenarios as to how the UK energy system might develop over the coming decades.

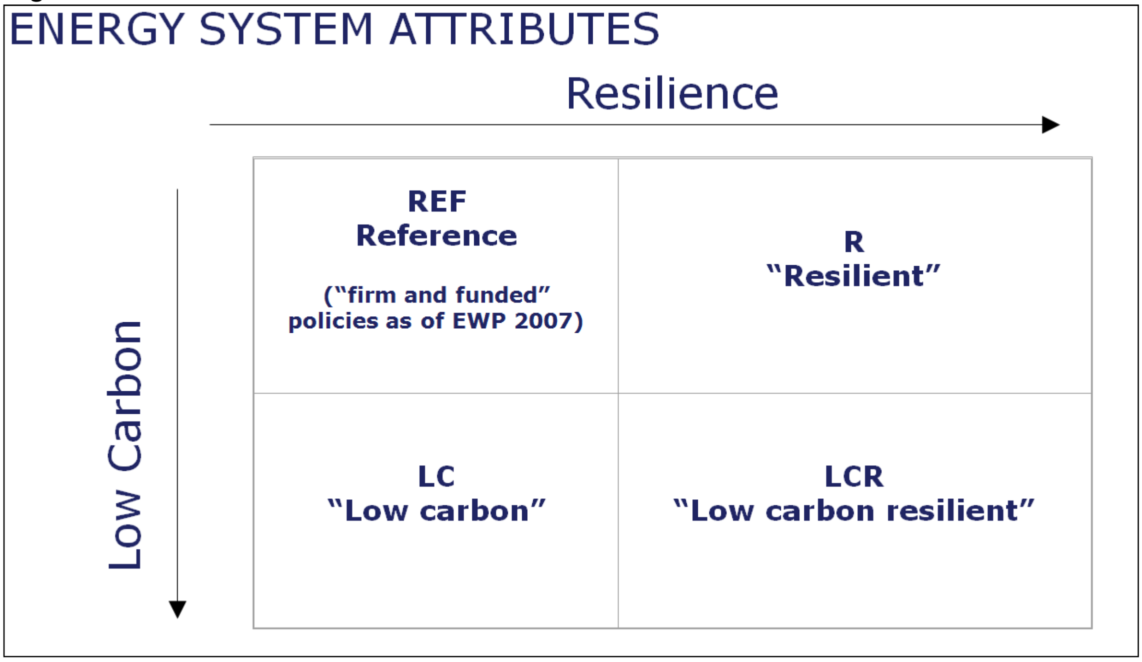
We are particularly concerned to take into account "low probability, high impact" events to which it is extremely difficult to attach probabilities. Some types of contingency, which can be characterised in formal probabilistic terms, can be considered in a full cost-benefit framework. This applies particularly to the reliability of electricity and gas systems where the probability of failing to meet demand depends on the underlying probability distributions associated with weather-related demand variations and the availability of generating plant. Using concepts like the "value of lost load" or "expected energy unserved" a formal cost–benefit approach is possible. DECC's Energy Markets Outlook (DECC, 2008a) relies heavily on this approach and this is indeed built into our framework. However, this report starts to open up methods for considering the larger scale contingencies alluded to in policy documents (for example, Wicks, 2009).

The analysis is based on a set of four scenarios depicting the development of the UK energy system over the next 40 years. In the first set of two scenarios, we assume that the energy system will develop in a "business-as-usual" manner reflecting the approach adopted over the last twenty years during a period of self-sufficiency and increasing market liberalisation. We consider developments both with and without carbon constraints. In the second set of scenarios, we consider patterns of development that would make the UK energy system more resilient to various risks and shocks, again with and without carbon constraints.

Linking the two principal themes of carbon constraints and energy system resilience we arrive at the set of four "core" scenarios that frame the *UKERC Energy 2050* project, as shown in Figure 1. The wider project and the construct of the core scenarios is described comprehensively in a Synthesis Report (Skea et al., 2009) and in a book exploring the project and a wider range of policy issues (Skea et al., 2011). A *Reference* scenario assumes no policies other than those in place at the time of the 2007 Energy White Paper. A *Low Carbon* scenario assumes that the UK is on a pathway to an 80% reduction in CO_2 by 2050. The *Resilient* scenario ignores CO_2, but incorporates a set of measures mitigating against different types of energy shock. The final *Low Carbon Resilient* scenario combines the two attributes.

UKERC does not pretend to have expertise in the geo-political aspects of the global energy system. The advantage of focusing on *resilience* as the key concept is that it can be seen as an intrinsic characteristic of the energy system itself. It does not require us to think about the underlying causes of a particular shock, for example a prolonged interruption of gas supply. We only need to know that a particular kind of shock is possible. Building in resilience can be achieved only by bringing together a number of different mitigating measures. Broadly, these involve bearing down on energy demand, ensuring adequate capacity, diversifying supply and making greater investments in infrastructure. The value of different mitigation measures obviously depends on the nature of the contingencies for which we are preparing.

Figure 1: The UKERC Core Scenarios



We have analysed records of disturbances or shocks to electricity and gas systems, most of which can be attributed to weather, accidents and catastrophic equipment failures rather than politically motivated supply interruptions. Based on this analysis, we have defined a small number of hypothetical shocks to the UK gas system which would then ripple through to the electricity supply sector. The shocks are within the range of historical experience and are assumed to occur in the year 2025. This year was selected so as to be beyond immediate energy policy concerns for the 2010-2020 period, but to be well within the lifetime of current investments. The impacts of the shocks against the background of each of our core scenarios are tested. This serves to test the impact of macro-developments in the energy sector on system resilience and vulnerability. Under each of the scenarios we than test the degree to which a number of "mitigating measures", mainly infrastructure investments, can reduce the impact of the hypothetical system shocks. This serves to test the possible security and resilience benefits of more specific policies.

1.3 Structure of the report

The first main section of the report, *the resilience of an energy system*, first explores the concept of resilience, drawing on the use of the concept in other fields, and proposes a working definition as applied to an energy system. We note that "reliability" in the context of statistical variations in energy system variables (demand, weather, equipment availability) can be distinguished from "resilience" to high impact and low probability events. The section then moves on to identify a candidate set of resilience indicators for the energy system. Finally, a small set of indicators is selected and quantified to help define the *Resilient* and *Low Carbon Resilient* core scenarios.

The following section describes in brief the *modelling tools* used to conduct the analysis. The models cover the energy system as whole (MARKEL-MED), investment in electricity generation capacity (WASP), and the development and operation of the gas and electricity networks (CGEN).

The following section, *energy systems resilience: the macro picture*, summarises the *Resilient*" and *Low Carbon Resilient* core scenarios and identifies the key features of energy system development associated with each. By systematically comparing all of the four core scenarios, the interplay between resilience and CO_2 emissions reduction is explored.

The section on *reliability of gas and electricity supply* identifies the level of investment in electricity generation capacity and gas infrastructure needed to maintain reliability of supply at the levels specified as part of the set of resilience indicators. This analysis uses the WASP and CGEN models and goes in to greater depth than is possible with the MARKAL model which covers the entire energy system. This highlights the need for sufficient investment to “back-up” intermittent renewable electricity and the need for investment in import and gas storage facilities in the light of the UK’s declining self-sufficiency in natural gas.

The section, *resilience to energy system shocks*, first reviews historical disturbances to gas and electricity supplies, in the UK and elsewhere. Based on this review, a small number of hypothetical shocks to UK gas supply are postulated. These, as described above, are assumed to take place in 2025 and are within the range of historical experience. The impacts of the shocks under each of the core scenarios are then assessed in terms of cost and levels of energy unserved. Finally, the benefits of infrastructure investments which will mitigate the impacts of the shocks are considered.

The last section of the report, *policy implications, key messages and future research*, first summarises, in broad terms, the costs and benefits associated with the different approaches associated with the four scenarios and the mitigating investments. It then sets out policy options for promoting the different elements of energy system resilience. These are promotion of demand reduction, supply diversity and infrastructure investment. This section also reflects on the implications of policy development subsequent to the finalisation of the analysis. The government has published two key policy documents since the work underpinning this report was completed: the Wicks report on energy security referred to above and the Low Carbon Transition Plan (DECC, 2009a) which establishes concrete and more ambitious policies to meet the UK’s climate change goals. We therefore consider the robustness of the conclusions in light of these subsequent developments. Finally, we anticipate further research challenges relating to energy resilience which UKERC may pursue in Phase II of its operations 2009-14.

2. The resilience of an energy system

2.1 Overview

In this section, we identify a set of indicators that can be used to define the "resilience" of an energy system. The section starts from a theoretical perspective, establishing a working definition of the UK energy system, in terms of its scope, to which the concept of resilience will be applied. The application of resilience and the related concept of "vulnerability" at the systems level in other fields, notably ecology, is explored and a working definition of energy system resilience is then established. Resilience is typically defined with reference to "shocks", and the nature of the shocks to which an energy system might be exposed is discussed. Moving to a more practical level, we then look at policy approaches to energy security in the UK and the EU and deduce from this the nature of the shocks to which energy policy might be sensitive and conclude with a set of resilience indicators which are used to underpin the subsequent analysis.

2.2 Defining the Energy System

The following working definition of the UK energy system was used in undertaking this work:

> *"the set of technologies, physical infrastructure, institutions, policies and practices located in and associated with the UK which enable energy services to be delivered to UK consumers".*

This definition covers all of the equipment along the energy supply chain that is located in the UK – extraction of non-renewable resources, electricity generation, energy conversion, transportation, transmission, storage, distribution and end-use equipment. It excludes physical infrastructure located outside the UK. It covers UK institutions (government at the national, regional and local levels, other statutory and non-statutory public bodies and private companies), UK policies, regulatory frameworks (economic and environmental) and operating practices.

The definition is built round the concept of delivering "energy services" to consumers rather than energy *per se*. This allows for the fact that technologies and practices on the energy demand side can help to ensure a reliable supply of energy services. For example a well-insulated house will make the occupants more resilient against supply interruptions during cold weather. At a more sophisticated level, advanced technologies such as micro-generation and private grids could also promote resilience. We are going beyond the simple "security of supply" aspects of energy security and resilience.

The UK energy system is bounded by what is in the sphere of influence of UK institutions. It excludes energy infrastructure outside UK jurisdiction and supra-national (EU) or international (e.g. International Energy Agency) institutions. There is necessarily some blurring at the edges. The UK has an influence over EU energy policy for example, but it shares responsibility with the European Commission, the European Parliament and 26 other Member States. Its influence cannot therefore be said to be decisive. However, it does include infrastructure in which the UK has a major share, e.g. gas and electricity inter-connectors.

It is also helpful to draw some boundaries within the UK. For example, homeland security and defence policy can be seen as having an impact on the resilience of the UK energy system. However, such policies relate to a range of sectors and types of critical infrastructure such as water, transport and telecommunications. These are therefore excluded from the definition, although it may be useful for the energy research community to interact with those operating in other policy domains.

This definition of the energy system provides a foundation for exploring resilience in many more ways than are possible in this report. The final section of the report briefly discusses possible future research directions.

2.3 Resilience and vulnerability

The concept of "resilience" has acquired a long pedigree in the field of ecology since the seminal work of Holling (1973).[2] It is helpful to draw on the substantial amount of systematic thinking that has been invested over the last 35 years.

Resilience is seen to be a key concept in ecology because:

> *"A resilient system, in a desirable state, has a greater capacity to continue providing us with the services that support our quality of life while being subjected to a variety of shocks" (Walker & Salt, 2006).*

The analogy with the delivery of energy services and the maintenance of quality of life is a helpful one. A classic definition of "*ecological resilience*" focuses on maintaining existence of function and is defined as:

> *"the capacity of a system to absorb disturbance; to undergo change and still retain essentially the same function, structure and feedbacks"* (Walker et al., 2004).

The ability to bounce-back is the key focus under this definition. A second type of definition refers to *"engineering resilience*". It considers ecological systems to exist close to a stable steady state, where resilience is defined as:

> *"the ability to return to the steady state following a disturbance, and focuses on maintaining efficiency of function. Here the major measure is return time where the speed of the bounce-back is the most important factor."* (Holling, 1996).

In terms of an energy system both the ability to bounce-back and the speed of bounce-back will be important for industry and consumers.

[2] This section has been informed by helpful discussions with the UKERC Phase I Energy and Environment team about resilience and ecosystem services. UKERC's "whole systems" approach to research has allowed us to get "read over" from one area of science to another when considering concepts such as resilience.

Building on the definition of the energy system suggested above, the following definition of energy system resilience is proposed:

> *"Resilience is the capacity of an energy system to tolerate disturbance and to continue to deliver affordable energy services to consumers. A resilient energy system can speedily recover from shocks and can provide alternative means of satisfying energy service needs in the event of changed external circumstances."*

This is not offered as a universal definition of resilience in energy systems, but as a broad-brush, working definition which provides a basic platform for identifying more specific resilience "indicators" for use in this specific piece of research. The indicators are identified in Section 2.7 and quantified for illustrative purposes in Section 4. By introducing the concept of "affordable" energy services we are highlighting the question of resilience to high or volatile external energy prices. If we were concerned only with physical resilience, the concept of "affordability" would not be necessary.

In the field of climate change impacts and adaptation, resilience has been characterised as the "flip side of vulnerability" (IPCC, 2001). The concept of vulnerability is also helpful in the energy field. IPCC described climate vulnerability as being "a function of the sensitivity of a system to changes in climate (the degree to which a system will respond to a given change in climate)". The following working definition of the vulnerability of an energy system has been adopted:

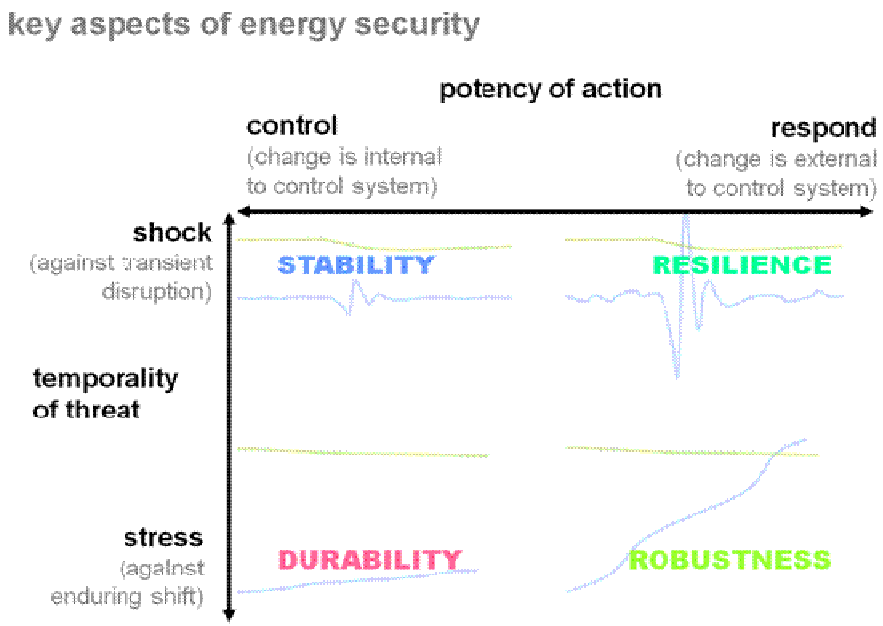
> *"Vulnerability is the sensitivity of an energy system to external disturbance or internal malfunction. A vulnerable energy system lacks the capacity to recover speedily from shocks and may not be able to satisfy energy service needs affordably in the event of changed external circumstances."*

2.4 Risk, resilience and security

Although the concepts of "security" and "security of supply" are frequently (and often loosely) used in the energy domain, the concept of "resilience" has had relatively little usage. Stirling (2009a) has made an interesting attempt to locate the concept of resilience within a wider conceptualisation of energy security. In Figure 2, security is characterised as the ability to mitigate against threats which may take the form of transient disruptions ("shocks") or more permanent shifts ("stress").

The discussions of energy security and resilience in this report focus specifically on transient threats ("shocks"). In Stirling's scheme, resilience is the ability to respond to shocks that are external to the system. However, given the broad definition of the energy system that we have adopted, our definition of resilience also encompasses what Stirling describes as stability, the ability to respond to shocks that are internal to the energy system. This would apply, for example, with reference to the adequacy of electricity generation capacity to meet levels of demand caused by low probability outages of plant.

Figure 2: Conceptualising Energy Security



Source: Stirling, 2009a

Stirling (2009b) has also addressed the question of how much we can know about the nature of the shocks to which we would like to be resilient. He identifies three broad types of incertitude:

- ***Risk:*** the nature of the shock can be defined and a quantitative probability can be attached to it. Unplanned outages of electricity generating equipment fall into this category.
- ***Uncertainty:*** the nature of the shock can be described but no probability can be attached to it. An example would be the interruption of gas supplies from Russia.
- ***Ignorance:*** we cannot characterise the nature of the shocks and no probabilities can be attached. Some types of terrorist attacks could fall into this category.

Broadly speaking, energy policy has dealt far more rigorously with those types of incertitude to which probabilities can be attached and that are more amenable to a formal risk-based assessment.

2.5 Policy approaches to energy security

UK and EU approaches are briefly discussed at a high-level.

In the UK, DECC (2008a) identifies three elements of energy security:

- *physical security*: avoiding involuntary physical interruptions to consumption of energy (i.e., the lights going out or gas supplies being cut off);
- *price security*: avoiding unnecessary price spikes due to supply/demand imbalances or poor market operation (e.g., market power);

- *geopolitical security*: avoiding undue reliance on specific nations so as to maintain maximum degrees of freedom in foreign policy.

Government policy to address these challenges to energy security (DTI 2007a, p.35) consists of "promoting open, competitive energy markets" in the EU and other regions; planning for unforeseen contingencies such as major disruptions (perhaps, in the case of gas, through ensuring that enough storage is available; "driving investment" in a diverse range of (low-carbon) technologies (although from the above it is clear that the investment itself will actually take place through market decisions); and "promoting policies to improve energy efficiency".

In practice, UK policy to date has focused almost exclusively on "risk": "measuring security of supply is primarily about measuring the risk … of involuntary interruptions to supply" (DECC, 2008a). This focuses primarily on *supply* security and specifically the adequacy of capacity:

> *"Our analysis suggests that the single most important influence on expected energy unserved[3] is the overall balance, the margin, between demand and physical supply capacity".*

The EU (CEC, 2008) takes a broader approach. The Commission has proposed a five-point Action Plan which implicitly responds to concerns about price and geo-political security:

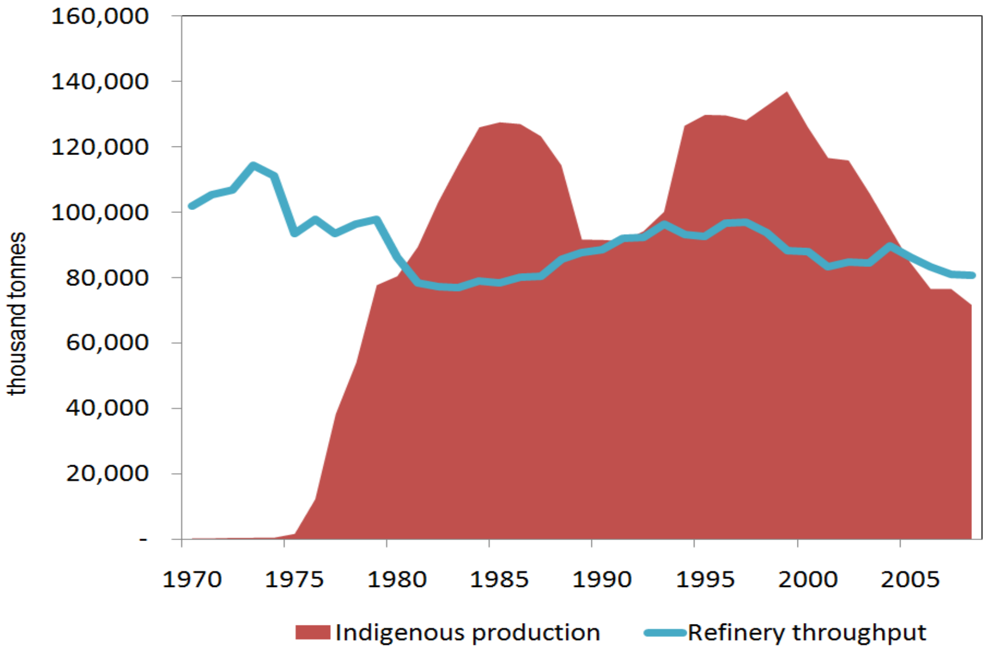
- Infrastructure needs and the diversification of energy supplies
- External energy relations
- Oil and gas stocks and crisis response mechanisms
- Energy efficiency
- Making the best use of the EU's indigenous energy resources

Although the UK has taken a narrower view of energy security in recent years, the recent loss of self-sufficiency in oil and gas (Figures 3 and 4) is encouraging a greater degree of sensitivity to geo-political uncertainties, price shocks and supply interruptions. For example, In August 2009, a report by the Prime Minister's Special Representative on International Energy argued for a more strategic approach to energy security issues (Wicks, 2009). However, supply interruptions need not be associated with overseas developments, as the UK miners' strikes in the 1970s and 1980s and the tanker drivers' dispute in 2000 demonstrate.

Attacks on infrastructure are also addressed through generic homeland security policies (CPNI, 2009). Security measures (surveillance, protection etc) that could be implemented in respect of any piece of critical infrastructure have intentionally been defined as being outside the scope of energy system "resilience". Measures to enhance energy system resilience would allow the energy system to recover in the event of generic security measures failing.

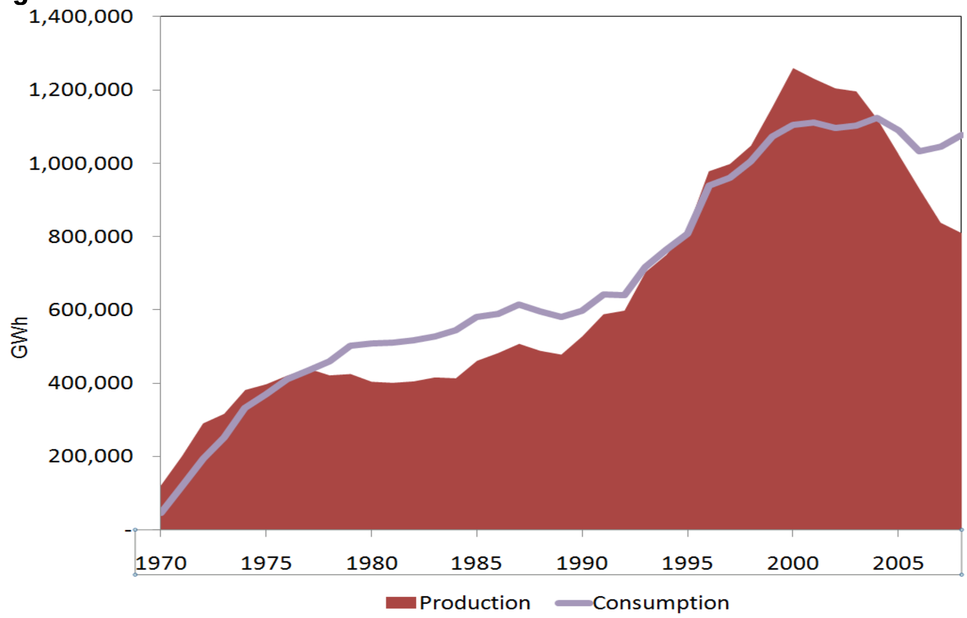
[3] The key security of supply indicator under UK policy

Figure 3: UK Crude Oil Production and Demand



Source: DECC

Figure 4: UK Natural Gas Production and Demand



Source: DECC

Other commentators have pointed out that, in practice, most interruptions of supply to final consumers, whether in the gas or electricity sectors, can be attributed to local technical failures rather than to wider political events (Stern, 2004). This is documented in Section 6. A key question is whether technical failures can be treated probabilistically or not. The rate of failure of individual pieces of equipment may be treated in this way. For example, in the electricity sector, the “availability” of plant, which reflects the probability that it will not be available for technical reasons, is routinely built into planning processes. This approach underpins the WASP model described in Section 3.

However, the events documented in Section 6 are, for the most part, beyond probabilistic analysis because they are the result of extreme weather, multiple/co-incident technical failures or catastrophic accidents whose nature was not anticipated. The consideration of failures that are amenable to probabilistic analysis is built into the models described in Section 3. Other types of event, that are subject to uncertainty and ignorance, are dealt with through the "stress-testing" analysis in Section 6.

In this report, we intentionally take a broad perspective. A set of resilience indicators needs to be comprehensive in terms of covering the energy supply chain, the types of external disturbance to which we want to be resilient and the types of response that might be appropriate.

2.6 Classifying "shocks" to the energy system

Table 1 describes a range of possible external events that would threaten the operation of the UK energy system, locating them within the risk-uncertainty-ignorance framework.

Table 1: Events Impacting on the Energy System

Type of Event	Type of Incertitude
Technical equipment failure/unplanned outages	Risk
Weather-related risks	Risk
Volatility in global energy prices	Risk
Energy price "shocks"	Uncertainty
Interruption of a major supply source	Uncertainty
Attack on energy infrastructure	Ignorance

Some of these events are already routinely factored into energy decision-making, notably those associated with simple technical failures and weather. Energy price volatility refers to measurable price variability over periods of months or years. A small but growing literature is using portfolio approaches from finance theory to address energy policy (Bazilian and Roques, 2008).

The *vulnerability* of the energy system can be seen as falling into three main areas, each implying different management approaches. The coverage of the three areas and the range of the management approaches reflect our definition of the energy system which focuses on the delivery of energy services to consumers:

1. *the availability and cost of primary energy supplies*. Vulnerability can be managed partly through domestic energy policy and the choice of primary energy supplies (as measured by supply diversity, import dependence etc). Vulnerability can also be managed through foreign or defence policies, or through energy-sharing agreements struck via the EU or International Energy Agency (IEA), but these are beyond the scope of this paper.

2. *transformation, conversion, storage and distribution systems* which allow primary energy to be converted and made available to final consumers when and where

they want it. Domestic energy policy has a major role to play here by ensuring the reliability of transmission and distribution systems and the provision of sufficient margins between potential supply and demand. Current UK energy policy centres on this area of vulnerability, but homeland security policies also have an important role to play in protecting critical infrastructure from attack. Note that a wide conception of energy policy is required as it can be argued, for example, that markets are sufficient to produce adequate margins between potential supply and demand, i.e. that the optimum policy in this respect is non-intervention.

3. *disruptions to supplies and fluctuating prices*. Here, measures to reduce vulnerability include reducing energy demand to minimise the economic impacts of supply interruption or price fluctuations, stand-by electricity generation capacity, installing multiple-fuel capabilities or maintaining energy stocks at industrial or commercial premises.

Reducing the vulnerability of the energy system from the perspective of final consumers is key. Vulnerabilities for final consumers run right through the energy system. The important policy questions concern which types of measure, applied at different points in the energy system, can most easily and cost effectively be deployed to protect consumers. In addressing these questions, consideration must be given as to which types of incertitude (risk, uncertainty, ignorance) specific measures address. A measure that reduces quantifiable risk should be assessed differently from a measure which addresses events about which we may be “ignorant”.

2.7 Selecting Indicators of Resilience in an Energy System

Tables 2 - 4 propose a set of candidate resilience indicators for the three main areas of vulnerability: primary energy supply, energy infrastructure and energy usage. These derive from consideration of both the theoretical insights into resilience and the practical concerns of policymakers. The tables also note the type of external disturbance to which the resilience indicators apply and the nature of the incertitude.

Table 2 covering primary energy supply includes some possible indicators relating to energy mix. These include novel indicators based on recent work deriving from financial portfolio theory and diversity theory (Bazilian and Roques, 2008) as well as simpler and more conventional indicators such as import dependence and the degree of dependence on the largest single source.

Table 3, addressing infrastructure issues, focuses heavily on adequacy of capacity as advocated by DECC. It includes standard measures used in statistical assessments of system reliability (loss-of-load probability; loss-of-load expectation; value of lost load) but also storage capacity and indicators relating to redundancy in network infrastructure.

Table 4 looks at demand side indicators. Most of these address the amount of energy used or financial exposure to energy dependence. They also cover the availability of back-up arrangements or alternative sources of supply for energy sensitive users, e.g. hospitals and banks.

The challenge is to identify a usable set of indicators from the wide range identified in Tables 2-4 that can be practically applied in energy analysis and, ultimately in energy policy. For the analysis in this report, we need indicators that can be easily applied in the modelling tools available to us. The small set of resilience indicators which we have worked with are as follows:

Reliability indicators for electricity: value of lost load (VOLL) expressed in £/MWh and loss-of-load expectation (LOLE) expressed in hours per year.

Reliability indicators for gas: value of lost load (VOLL) for industrial gas[4].

Infrastructure investment: we assess the implications of different levels of gas storage and diversity of import options.

Level of final energy demand: used as an operational indicator in EU energy policy (e.g. the Energy Efficiency and Energy Services Directive) serving as a proxy for import dependence and expenditure on energy. This is the easiest demand related indicator to implement in the models.

Diversity of primary energy supply. A constraint on maximum market share of major supply sources, e.g. coal, oil or gas. This has been selected because it is simple to implement in the models and, at an intuitive level, matches well with policy aspirations.

Diversity of generation mix in electricity supply. We focus on electricity supply because, as shown later in the report, this sector turns out to offer some of the lowest cost options for enhancing diversity. A constraint on the maximum market share of major generation types (coal, gas, nuclear) is applied.

We have also striven to ensure that the indicator set is coherent and does not lead to perverse outcomes. Annex A describes the analysis that was undertaken to ensure that this is so. For example, we investigated putting a constraint on the level of final primary energy demand rather than one on final energy. However, the current conventional definition of primary energy values renewable electricity (other than that produced through biomass) on the basis of the energy content of the electricity generated. Nuclear and biomass are measured according to the energy content of the heat used to generate electricity. Constraining aggregate primary energy demand thus creates perverse biases between different types of electricity generation. In practice, a constraint on maximum *market share* in primary energy supply generally bites on the supply of fossil fuel and sidesteps this perversity.

In theory, constraining final energy demand could also introduce perversities because of the treatment of electricity vis-a-vis fossil fuels. However, in practice it turns out that this was not the case when we conducted sensitivity tests.

We return to the exact quantification of the constraints in Section 4. In Section 3, the modelling tools used to conduct the detailed analysis are described.

[4] Loss of load not allowed for household supplies.

Table 2: Possible Resilience Indicators for Primary Energy Supply

Indicator	Type of Event	Type of Incertitude	Notes
Import dependence	Supply interruption	Uncertainty Ignorance	Could be for the whole economy or specific sectors.
Largest single source of supply	Supply interruption	Uncertainty Ignorance	Could be for the whole economy or specific sectors.
Diversity/concentration of energy supply (e.g. Herfindahl-Hirschman Index)	Supply interruption Price shocks	Uncertainty Ignorance	HHI is used by the Office of Fair Trading to assess market concentration.
Energy Portfolios	Price volatility	Risk	Energy mixes which are efficient in terms of volatility/cost along a frontier have been explored by Awerbuch and Roques using financial portfolio theory. Could be for the economy a whole or specific sectors.

Table 3: Possible Resilience Indicators for Energy Infrastructure

Indicator	Type of Event	Type of Incertitude	Notes
Statistical probability of supply interruption in network industries (gas and electricity)	Technical equipment failure Weather-related risks Inadequacy of investment	Risk	Specify as a security standard (i.e. a probability). to allow for the greater use of intermittent supply sources. Intermittent wind is assumed to have a lower capacity credit which requires higher capacity margins if the probability of interruption is to be kept below a threshold.
Expected number of annual hours in which energy is unserved	As above	Risk	
Value/level of unserved energy	As above	Risk	
Energy storage capacity and/or stocks by fuel and market	Interruption of supply	Uncertainty	Could be measured in hours/days/weeks
Largest single source of supply in a market energy	Interruption of supply	Uncertainty	Expressed as a percentage of supply in any given market
Redundancy in network architecture	Attack on infrastructure	Ignorance	The number of pinch points/critical nodes which would need to go down to cause interruption of supply to consumers. The networks could include gas, electricity and distribution of refined oil products

Table 4: Possible Resilience Indicators for Energy Users

Indicator	Type of Event	Type of Incertitude	Notes
Energy demand level	Supply interruption Price shocks	Risk Uncertainty	Often taken as proxy for exposure to supply interruptions and price shocks in policy formulation. This could be applied to specific sectors e.g. residential housing, critical transport or types of business
Energy intensity	Supply Interruption	Uncertainty	kWh/£ for industry (output) and economy as a whole (GDP). kWh per household in the domestic sector. This indicator should represent the capacity for some degree of energy service needs to be met in the event of supply interruption.
Energy costs	Price volatility Price shocks	Risk Uncertainty	% energy expenditure as proportion of output, expenditure and GDP for industry, households and economy as a whole respectively. This indicator points to the broader economic impact of price shocks.
Back-up arrangements for energy sensitive users, e.g. hospitals, banks	Supply interruption	Uncertainty	

3. Analytical tools

3.1 Modelling overview

Quantitative modelling of the UK energy system has been carried out using three separate models with complementary characteristics. These models have been "soft-linked" – i.e. the output of one model has been used as input to another rather than attempting to solve the models simultaneously.

The three models used have been: the MARKAL-MED model of the entire UK energy system described in previous reports in this series (Strachan et al., 2008); the Wien Automatic System Planning (WASP) model developed by the International Atomic Energy Agency (IAEA) which determines electricity generation expansion plans at the national level (IAEA, 2001); and the Combined Gas and Electricity (CGEN) model developed by Manchester University through UKERC (Chaudry et al., 2008). This latter model determines geographically specific investments in new gas and electricity infrastructure (gas pipelines, terminals and storage facilities; transmission lines; and power stations) given assumptions about final demand for gas and electricity and patterns of investment in electricity generation capacity at the national level.

The common feature is that they are all optimisation models programmed to minimise the total discounted cost over time[5] of the particular part of the energy system that they cover. In general, we use a real discount rate of 10%, reflecting the rate of return required by an investor exposed to market risk. However, we explore the use of a social discount rate (3.5%) where this is policy relevant.

Table 5 summarises key characteristics of the three models. Note that the scope of the MARKAL-MED model includes the ground covered by the WASP electricity model. However, the WASP model addresses the electricity system in considerably more detail and can pick out issues, especially those related to reliability, that MARKAL cannot. Specifically: WASP has a far more detailed characterisation of the load duration curve (which summarises electricity demand at different levels throughout the year); WASP's use of mixed integer programming means it takes account of the "lumpiness" of investment in power plant; and WASP can use a more sophisticated set of indicators to ensure reliability of electricity. Whereas MARKAL assumes a fixed plant margin in excess of peak demand,[6] WASP uses three reliability indicators: the number of years in a century in which demand is expected not be met fully; a "value of lost load" (VOLL) measure in £/kWh; and loss of load expectation (LOLE) the maximum number of hours in which load is not met in any year. In general, this results in WASP building more capacity than MARKAL, especially when there are large quantities of intermittent renewable energy on the system.

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[5] Or maximise welfare in the case of MARKAL-MED
[6] Strictly speaking a capacity margin over the highest load step

Each of the *UKERC Energy 2050* scenarios addressing resilience is characterised using the three models operating in tandem. Figure 5 shows the way that information flows between the three models. MARKAL-MED is run first. Depending on technology assumptions, price assumptions and other constraints such as those on carbon, it determines the extent to which energy service demands are met through electricity or gas. Electricity demand is then passed to WASP which generates a more refined picture of the need for and operation of generation capacity at the national level. The CGEN model then takes electricity and gas demands directly from MARKAL-MED and national electricity generation capacity from WASP in order to determine the location of generation plant and other infrastructure.

Figure 5: Operation of the three models in tandem

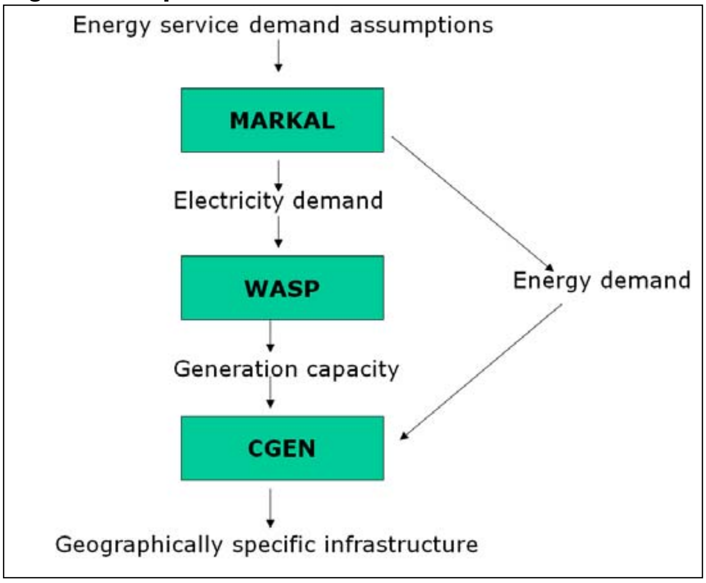


Table 5: Key Characteristics of the Modelling Tools

	MARKAL-MED	**WASP**	**CGEN**
Scope	The entire UK energy system	Electricity generation at the national level	Gas and electricity infrastructure including geographical distribution
Objective	Maximising discounted welfare by deploying available technologies in order to meet energy service demands which adjust in response to energy price changes	Minimising discounted cost by investing in and dispatching plant in order to meet specified levels of electricity demand and levels of reliability.	Minimising discounted cost by locating new plant and infrastructure to meet specified final gas and electricity demands.
Method	Linear programming	Mixed integer programming	Non-linear optimisation
Key inputs	• Baseline energy service demands • detailed characterisation of technology performance and costs, • elasticity of energy service demands with respect to price. • Key constraints such as carbon emissions	• Annual and peak electricity demand, • profiles of existing and committed plant • performance and cost of new plant, reliability measures.	• Final gas and electricity demands, • geographical characterisation of the gas and electricity systems • costs and performance of plant and infrastructure •
Key outputs	Energy demand and supply by sector, energy source and technology	Levels of investment in and operation of plant by type.	Selection, location and operation of plant and infrastructure

3.2 Energy system: The MARKAL Model

MARKAL portrays the entire energy system from imports and the domestic production of energy, through fuel processing and supply, explicit representation of infrastructures, conversion to secondary energy carriers (including electricity, heat and hydrogen), end-use technologies and energy service demands of the entire economy. As a perfect foresight partial equilibrium optimisation model, standard MARKAL minimises discounted total system cost by choosing the investment and operation levels of all the interconnected system elements. It is not a forecasting model, but rather a 'what-if' framework that provides a systematic exploration of least-cost energy system configurations under a broad, integrated set of input assumptions. MARKAL models have been used around the world for policy relevant analytical work (BERR, 2008c; Smekens, 2004), including the International Energy Agency's Global Energy Technology Perspectives (IEA, 2008a).

The UK MARKAL model optimally solves from year 2000-2070 in 5-year time steps. For this exercise, the model has been calibrated in its base year (2000) to data within 1% of actual resource supplies, energy consumption, electricity output, installed technology capacity and CO_2 emissions (BERR, 2006). A first key input parameter is resource supply curves (see Table 4 in Anandarajah et al., 2009). From these baseline costs, multipliers are used to generate both higher cost supply steps as well as imported refined fuel costs.

A second key input is dynamically evolving technology costs which are based on expert assessment of technology vintages or, for less mature electricity technologies, via exogenous learning curves derived from an assessment of learning rates combined with global forecasts of technology uptake (Winskel et al., 2009).

A third key input is an explicit depiction of infrastructures, physical and policy constraints. A wide range of peer reviewed data sources inform the model and have been supplemented by a series of stakeholder workshops. A complete description of all input parameters is given in the model documentation (Kannan et al., 2007). All costs are in year 2000 £ sterling. The model uses a global discount factor of 10% to reflect commercial UK market rates of return. The model uses a higher hurdle rate for advanced end-use technologies like plug-in hybrid/hydrogen vehicles and heat pumps. All currently UK legislated environmental and economic “firm and funded” policies as of the 2007 Energy White Paper are included. In addition, considerable attention is given to near-term (2005-2020) convergence of sectoral energy demands and CO_2 emissions with the econometric outputs of the DECC energy model. The imposition of a range of policy and physical constraints, implementation of all taxes and subsidies, and inclusion of base-year capital stocks and flows of energy, facilitates realistic evolution of the energy system under alternate scenarios.

A final key input for the UK MARKAL model is exogenous demand for various energy services. The MARKAL elastic demand (MED) version is used to account for the response of energy service demands to prices. This is implemented at the level of individual energy service demands using linear programming. Hence, each demand has a constant own-price elasticity. The MED model calculate welfare losses from reduced demands -

i.e. if consumers give up some energy services that they would otherwise have used if prices were lower, there is a loss in utility to them which needs to be accounted for. The sum of consumer and producer surplus (economic surplus) is considered a valid metric of social welfare in microeconomic literature. A full description of MED function and its input assumptions are given in the low carbon pathway report (Anandarajah et al., 2009).

A full description of the UK MARKAL model is given in the model documentation (Kannan et al., 2007) and in peer reviewed publications (Strachan et al., 2008; Strachan and Kannan, 2008; Kannan and Strachan, 2009).

3.3 Electricity generation: The WASP Model

The Wien Automatic System Planning (WASP) model (version IV) developed by the International Atomic Energy agency (IAEA) is designed to determine medium to long-term economically optimal expansion policy for a power generation system within user-specified constraints. WASP has been distributed to more than 75 countries and has become the standard approach to investment planning in many of the IAEA and World Bank's member countries (ESMAP, 2007). Many IAEA member states have applied the model in their national and regional studies to analyse the issues of electric power system expansion planning. One recent study has been commissioned by European Union to identify and prioritize investment in power generation and related electricity infrastructure for the Balkan's region (REBIS, 2004).

Timely and optimal development of adequate electricity generating capacity is vital for maintaining security of supply while meeting desired policy objectives regarding energy supplies, environment and affordable energy prices. Overbuilding generating capacity increases the reliability of the system but the average price of electricity will also increase because the costs of that excess capacity will be borne by customers. On the other hand, under-building capacity will result in some portion of demand not being served. The economic costs of this unserved energy are significant and are added to the generation cost, this summed cost of generation also increases as the degree of under-building becomes more severe. Thus, an appropriate level of reliability for the generating system is required which depends on a large number of system characteristics.

The optimal expansion plan for a power generating system in WASP model is evaluated in terms of minimum discounted total costs within the system reliability constraints given by the planner. System reliability is evaluated on the basis of three indices: reserve margin, loss-of-load-expectation (LOLE), and un-served energy. Each possible sequence of power generating units added to the system (expansion plan or expansion policy) meeting the constraints is evaluated by means of a cost function (the objective function) which is composed of capital investment costs (which can be assumed to change over time), salvage value of investment costs, fuel costs, fuel inventory costs, non-fuel operation and maintenance costs and cost of the energy not served.

The model applies probabilistic simulation to evaluate the electricity generation system's production costs and costs associated with un-served energy and reliability. It uses a linear programming technique for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by specified plants. The dynamic programming method is then applied for comparing and optimising the costs of alternative system expansion policies that would serve the future electricity demand with a desired level of system reliability (IAEA, 2001).

The model provides options for introducing constraints on environmental emissions, fuel usage and energy generation. These constraints are handled by a multiple group-limitation technique wherein a group of plants are constrained and plants can be included in more than one type of constraint. Environmental emissions for each year and for each period within a year are based on the electricity generated by each plant and the user specified characteristics of fuels used. These options are extremely useful for real life planning in view of the increasing importance of environmental concerns as well as the fact that in many cases availability of some fuels for power generation may be limited or energy generation from some plants may need to be restricted.

In the WASP model, the changing nature of the load from one year to another is taken into account by specifying the peak demand forecast demand for each year. In order to consider the seasonal changes of the load characteristics, the year is sub-divided into a number of equal periods. For long-range planning studies, such as the ones presented here, the chronological hourly load curves (LDC) are transformed into load duration curves for each period and scaled to represent future electricity demand projections. The LDC, with area under the curve representing the electricity demand, characterises the load in each period of every year. The demand load factor (the ratio of average to peak demand) is assumed to stay constant.

The WASP model can be applied in two modes.

Evaluation of a *Fixed Plan* – This mode is applied to investigate the reliability, cost and environmental performance of a predefined expansion plan.

Search for the *Optimal plan* – In this mode the model is allowed to determine the economically optimal expansion plan or plans within used defined constraints. However, if required, the appropriate year and range of capacity addition of candidate technologies can be defined.

We have applied the model in the latter mode, using the future UK electricity demand projections obtained from the output of the MARKAL model. MARKAL determines the future electricity sector demand based on a least cost optimisation of the overall energy system for the designed energy scenarios.

Thermal plants are described by maximum and minimum capacities, heat rate at minimum capacity and incremental heat rate between minimum and maximum capacity, maintenance requirements (scheduled outages), failure probability, emission rates and specific energy use, capital investment cost (for expansion candidates), variable fuel cost, fuel inventory cost (for expansion candidates), fixed component and variable component of (non-fuel) operating and maintenance costs and plant life. The schedule of annual maintenance of the plants in the system can also be specified.

The types of hydroelectric projects that can be modelled include run-of-river, daily peaking, weekly peaking and seasonal storage regulating cycle. They are defined by identifying for each project the minimum and maximum capacities, energy storage capacity of the reservoirs, energy available per period, capital investment cost (for projects considered as expansion candidates), fixed operation and maintenance costs and plant life. The stochastic nature of the hydrology is treated by means of hydrological conditions, defined by its probability of occurrence and the corresponding available capacity and energy of each hydro project in the given hydro-condition.

Some recent studies have introduced new approaches to model wind generation in WASP (Koritarov et al., 2005). In this study wind generation is represented in a simplified way, similar to the behaviour of a run-of-river hydro plant. The average behaviour of wind power output (available wind energy and its seasonal variation) from future on- and off-shore wind farms is adopted from the historical wind speed data.

The key outcomes of the application of model under the given constraints include:

- Build schedule; i.e., which capacities to install to ensure an appropriate level of reliability, best combination among the different technologies at hand now and in future, appropriate time to incorporate new plant in the system.
- Costs: investment costs and cost of system operation that includes fuel, operation and maintenance and cost of energy not served.
- Expected generation of plants
- Fuel requirements
- Emissions

3.4 Gas and electricity infrastructure: The CGEN Model

The Combined Gas and Electricity Network (CGEN) model describes gas and electricity infrastructure. The objective of the CGEN model is to minimise total discounted costs related to the combined operation and expansion of the gas and electricity networks whilst meeting demand requirements over the entire planning horizon. Energy demand requirements are taken from the MARKAL model runs which determine, for a given scenario, how energy service demands are met, for example through conventional vehicles or electric cars in the transport sector.

The model consists of a DC load flow analysis for the electricity network and detailed modelling of the gas network including facilities such as gas storage and compressor stations. The interaction between the two networks is through gas turbine generators connected to both networks (Chaudry et al, 2008).

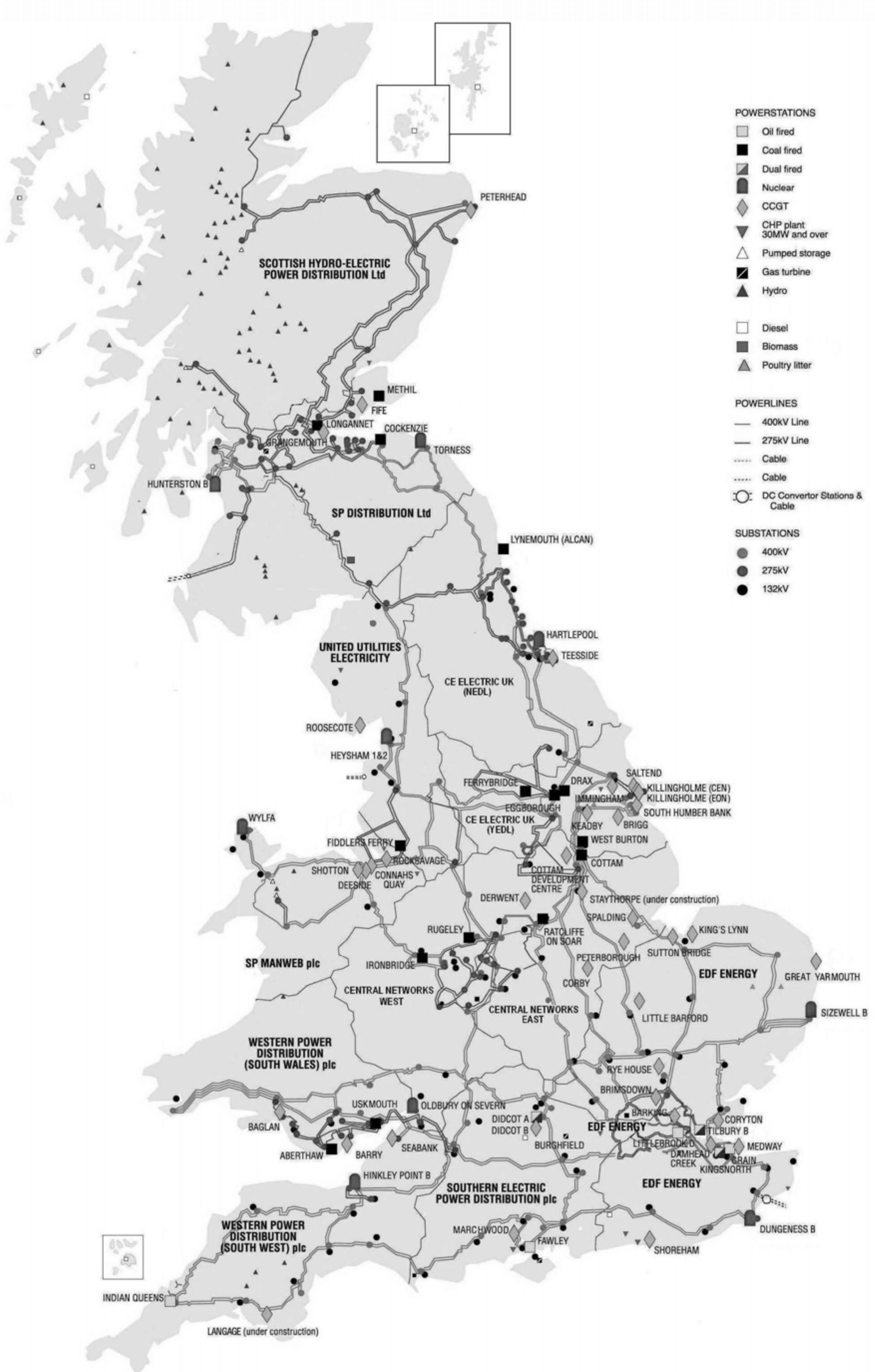
CGEN is a geographical model, thus, the connection of gas pipes and electricity transmission wires in a network is explicitly modelled. This geographical element allows a realistic picture of network flows and the physical constraints that are present in both networks. Figures 6 and 7 show the current shape of the Great Britain electricity and gas networks which CGEN seeks to represent in a simplified form. The components modelled within CGEN are illustrated in Figure 8.

The components are arranged into distinct categories, describing energy supply, energy transportation (networks), generation technologies, and energy end use.

Resource supply: This includes bounds on the availability of primary energy supplies (gas, coal, oil etc) and electricity imports. For gas, CGEN uses the same assumptions as the MARKAL model (Kannan et al., 2007). This allows for nine separate tranches of domestic gas supply, three tranches for LNG, three tranches for Russian supply (via the continent) and one tranche for Norway. Gas import interconnectors are modelled as gas pipes with maximum transport capacities. For pipeline terminals, six separate entry costs are modelled ranging from zero at Barrow to £0.06/GJ at St Fergus. Details are provided in Annex C.

Networks: The gas network includes the detailed modelling of pipelines, compressors, and storage facilities. The gas flow in a pipe is determined by employing the Panhandle 'A' gas flow equation that calculates the gas flow rate given the pressure difference between upstream and downstream nodes. A DC power flow model is used to represent the electricity network. The DC power flow formulation enables the calculation of MW power flows in each individual transmission circuit. Gas turbine generators provide the linkage between gas and electricity networks. They are considered as energy converters between these two networks. For the gas network, the gas turbine is looked upon as a gas load. Its value depends on the power flow in the electricity network. In the electricity network, the gas turbine generator is a source.

Figure 6: Great Britain Electricity Network

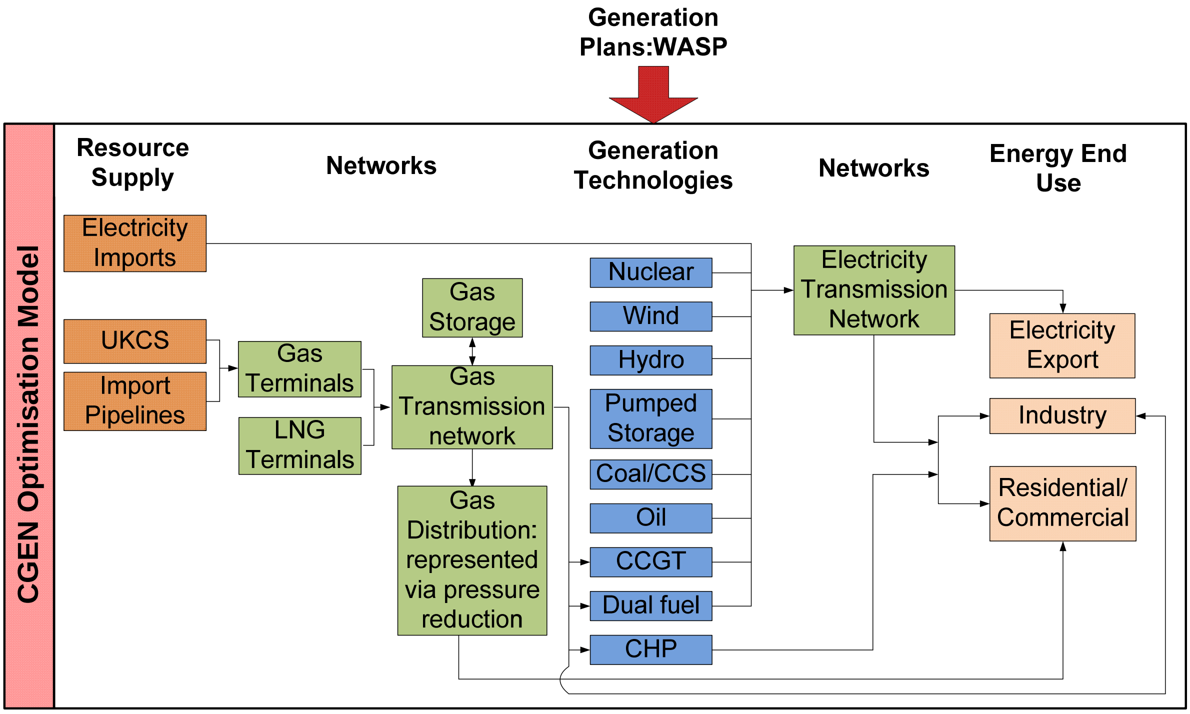


Source: DECC

Figure 7: UK Gas Network

Source: DECC

Figure 8: CGEN optimisation model



Generation technologies: CGEN includes models for all the conventional generation technologies such as CCGT, coal, and nuclear. Generation technologies are described by a number of characteristics such as ramp up/down, maximum generation and thermal efficiencies. CGEN introduces new power generation plants according to the generation capacity plan schedule developed in WASP. To capture the spatial nature of the wind resource, wind power is modelled using average wind load factors for different locations around the UK. The geographic wind power variation influences energy balancing in the electricity network, and the location of new wind power generation capacity.

Energy end use: Gas and electricity energy demand is fed into CGEN from MARKAL demand outputs. The demand is split into residential and industrial/commercial components for gas and electricity. Gas used for electricity generation is determined endogenously within CGEN.

Location of generation plants: CGEN does not endogenously build generation capacity to satisfy future demand. Generation plans from the WASP model are used as an input into to the CGEN model. Since WASP is a non-geographical generation planning model, it does not provide location specific information on new generation capacity. Using the concept of minimising costs (operational + infrastructure), CGEN optimally places these generation plants around the electricity network. Figure 9 describes an example of how CGEN would deal with the location of a CCGT plant. CGEN calculates the cost associated with placing the CCGT plant at every location. For instance, if the CCGT plant were located in Scotland this would incur a reinforcement cost of £ A and £ B for new gas pipes and electricity transmission lines respectively. If the CCGT plant is located in the Southeast the total investment cost is £ C+D for new gas and electricity transmission lines. CGEN would intuitively choose the Southeast option, but once operational costs are included, the Southeast option may well turn out to be more expensive. The CCGT plant is placed at a location that minimises both gas and electricity operational and infrastructure expansion costs.

Transmission capacity: For both gas and electricity networks, transmission capacity is added to satisfy peak demand requirements. Figure 10 illustrates how the optimisation routine within CGEN will explore all possible solutions to satisfy peak demand. This ranges from building additional network capacity to the re-dispatching of energy. The model will select the cheapest solution over the entire time horizon. By balancing gas supply and demand, CGEN mimics trades at the National Balancing Point (NBP) and the costs associated with the cash-out procedure. This is achieved by minimising total costs associated with gas production, compression (own fuel used) and storage operation.

Electricity network expansion: Electricity transmission capacity expansion is assumed to be carried out on a radial network.

Figure 9: Location of a CCGT plant

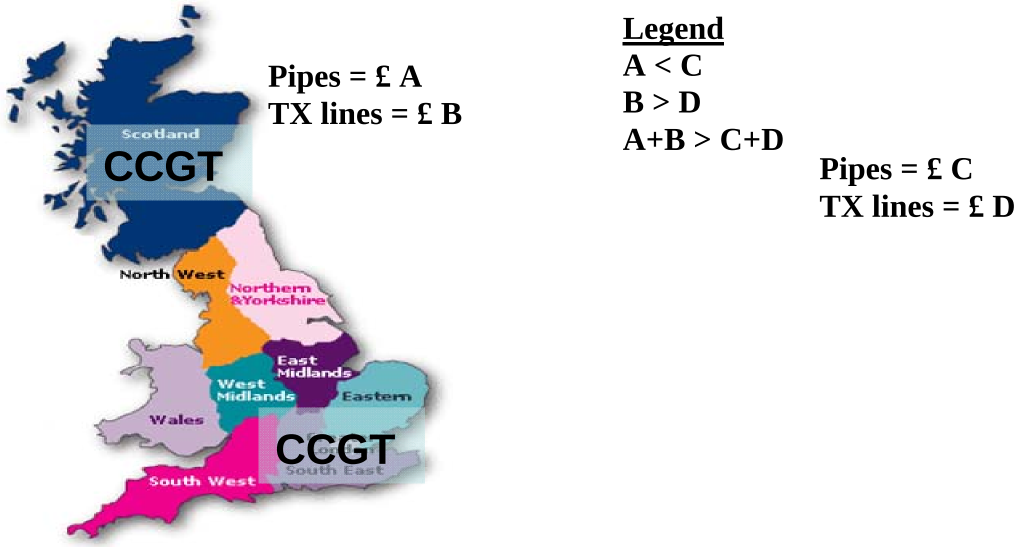
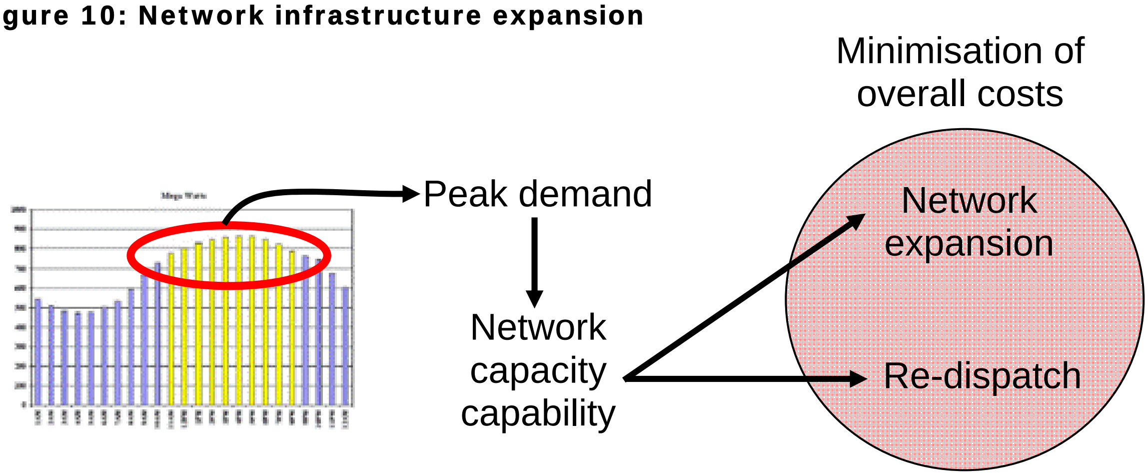


Figure 10: Network infrastructure expansion



Gas network expansion: Gas pipe capacity expansion is based on building additional pipes in parallel to existing pipes. The Panhandle 'A' equation is used is determine the flow rate through a pipe. In addition to increasing gas pipe capacity, CGEN allows capacity expansion of import pipelines, LNG terminals, storage facilities and compressor stations.

The key outputs of the model are:

- Location of electricity generation capacity
- The volume and location of investment in electricity transmission capacity and gas infrastructure (interconnectors, pipelines, LNG terminals and storage facilities)
- Utilisation of electricity generation capacity and infrastructure
- System costs
- The amount of energy unserved and its monetary value

CGEN can operate in two modes:

Planning mode: infrastructure additions are made to an initial network over a time horizon in order to satisfy demand and network related constraints (pressure, electricity flow constraints etc). CGEN was used in this mode to model the "core" *UKERC Energy 2050* scenarios

Operational mode: A user-specified network is used to test various scenarios (prices increases, shocks etc). CGEN was used in this mode to assess the benefits of investment in infrastructure aimed at increasing resilience.

4. Resilient energy systems: the macro picture

4.1 Quantifying a resilient energy system

The three macro-level indicators that we adopted for a resilient energy system in Section 2 relate to final energy demand and diversity of primary energy supply and electricity generation mix. The quantified assumptions are shown in Table 6.

Table 6: Macro-level Resilience Indicators

Indicator	Quantified assumption
Final energy demand	Final energy demand falls 3.2% pa relative to GDP from 2010 onwards.
Primary energy supply	No single energy source (e.g. gas) accounts for more than 40% of the primary energy mix from 2015 onwards
Electricity generation mix	No single type of electricity generation (e.g. gas, nuclear) accounts for more than 40% of the mix from 2015 onwards

Reducing energy demand is a key element of EU energy security strategy. It will reduce vulnerability to all types of insecurity – physical, price and geopolitical. The 3.2% decoupling of final energy demand from GDP is equivalent to an annual reduction of 1.2% in absolute terms (assuming GDP growth of 2% p.a.). The falling trajectory of final energy demand was used to apply a set of constraints in MARKAL-MED, measured in PJ, for each five-year time step out to 2050. The MARKAL model then selected the welfare-maximising mix of measures that allowed these constraints to be met. The constraints shown in Table 7 were applied in the *Resilient* and *Low Carbon Resilient* scenarios. Final energy demand is down by 17% relative to the *Reference* scenario by 2025 and 41% by 2050.

Table 7: Final energy demand constraints in the *Resilient* Scenario

Year	2000	2005	2010	2015	2020	2025	2030	2040	2050
GDP index	100.0	112.9	129.3	143.5	158.4	174.9	193.1	235.4	286.9
Final energy (PJ)									
Reference	6189	6321	6300	6260	6288	6287	6312	6401	6455
Resilient	6189	6318	6291	5933	5567	5224	4902	4316	3801
Final energy / GDP (% pa)									
Reference		-1.99%	-2.74%	-2.18%	-1.87%	-1.96%	-1.88%	-1.86%	-1.92%
Resilient		1.99%	2.76%	3.20%	3.20%	-3.20%	-3.20%	-3.20%	-3.20%

In deriving the final energy demand constraints, we considered rates of decline in the final energy demand/GDP ratio ranging from 2.4% to 3.6% per annum. These were benchmarked against bottom-up estimates of the potential impact of energy efficiency measures out to 2020 made by DECC in the most recent carbon and energy projections (DECC, 2008b) available at the time the analysis was conducted. The full analysis is set out in Annex A, *Detailed Analysis of Resilience Indicators*. Our assumptions about constrained final energy demand correspond roughly to the assumption of *high* impact of energy efficiency measures up to 2020. We then assume that the same pace of improvement will continue thereafter. This *Resilient* scenario can therefore be said to be at the upper end of the plausible range in terms of energy demand reduction.

We explored diversity constraints relating to primary energy supply, the electricity generation mix and the mix of installed electricity generating capacity. This exploration is also described in Annex A. The diversity constraints were formulated in terms of maximum market shares because: a) this is a simple and intuitive characterisation; and b) such constraints are easily implemented in the MARKAL-MED model. Only a non-linear model could deal with diversity indices such as Herfindahl-Hirschman. In each case we explored a 40% constraint on the market share of the largest source and tested interactions with different levels of constraint on final energy demand. The 40% figure was intended to prevent any single energy source from dominating the market.
The way that different combinations of constraint affected welfare losses as imputed by the MARKAL-MED model was a key consideration.

The final, and relative simple, selection of diversity constraints was made for the following reasons:

- The constraint on maximum share for primary energy supply ensured supply diversity in the economy as a whole.

- Generation mix was constrained because the electricity sector was found to play a key role in shifting the primary energy mix. The availability of alternative generating options at similar costs means that diversity can be achieved at a relatively low cost in the electricity sector. The generation mix constraint helps guarantee security of electricity supply and prevents the electricity sector being used to compensate for imbalances elsewhere in the energy sector.

- Constraints on installed electricity generation capacity were found to produce perverse outcomes. These drove investment in low capital cost plant (specifically CCGT) which was subsequently used at a low load factor and failed to prevent high market shares (60%+) for other forms of generation. Constraints on installed capacity, if combined with constraints on generation mix, did not substantively change the outcomes.

A fuller description is provided in Annex A.

4.2 Key features of a resilient energy system

This section highlights the consequences of constraining the development of the energy system using the quantified resilience indicators. In general, this produces quite different patterns of development, both when 80% CO_2 reductions by 2050 are required, and when no carbon constraint is applied. The comparison between the four core scenarios – *Reference*, *Low Carbon*, *Resilient* and *Low Carbon Resilient* - focuses on 2025 representing the mid-term and 2050 representing the long-term. In practice, when we start to explore the impact of shocks to the energy system in Section 6, the analysis focuses entirely on 2025. Annex B, *The Resilient and Low Carbon Resilient Scenarios in Detail*, provides a fuller comparison of the four core scenarios.

Energy demand

Tables 8 and 9 compare primary energy demand, final energy demand, final electricity demand and residential energy demand in each of the four core scenarios for 2025 and 2050 respectively. Final energy demand is formally constrained in the model in the *Resilient* and *Low Carbon Resilient* scenarios. Without these constraints, final energy demand rises very modestly in the Reference scenario and falls by 2% by 2025 and 29% by 2050 in the *Low Carbon* scenario (all measured from a year 2000 baseline). However, in the resilient scenarios demand falls much more, by 16% by 2025 and 40% by 2050.

Out to 2025, the higher falls in energy demand in the resilient scenarios are explained by declines across the residential, services and industrial sectors. Taking the residential sector as an example, demand holds steady, or increases slightly, out to 2025 in the *Reference* and *Low Carbon* scenarios but falls by 20%+ in the resilient energy systems. Figure 11 shows clearly that this is also associated with a squeezing of natural gas demand. This has the consequence of directly reducing energy imports.

The pattern is different out to 2050 (Table 9). Residential energy demand is down by roughly 50% in all but the *Reference* scenario and, as Figure 12 shows, natural gas demand actually falls faster in the two low carbon scenarios. The same is the case for oil demand, mainly associated with the transport sector.

In all scenarios, and over both time horizons, primary energy demand falls relative to final energy demand. This is because of the adoption of more efficient technologies in the energy transformation sector, mainly electricity generation. Primary demand, as would be expected, falls most rapidly in the *Resilient* and *Low Carbon Resilient* scenarios with declines of 20% by 2025 and 45-50% by 2050.

The role of electricity of in the energy economy is interesting, and a subject we will return to. In the *Reference* scenario electricity expands its role, with demand rising by 14% by 2025 and 26% by 2050. By 2050, the electrification of the energy economy is even more pronounced in the *Low Carbon* scenario with electricity demand rising by 39% by 2050. In the *Resilient* scenario, electricity demand changes little throughout the projection period. However, in the *Low Carbon Resilient* scenario, electricity demand falls 8% by 2025, but has risen by 16% by 2050 compared to year 2000 levels, again as a result of some electrification of the energy economy.

Table 8: Changes in energy demand by 2025 with respect to a 2000 baseline

Low carbon	Reference		Resilient	
	Primary Energy Demand	-7%	Primary Energy Demand	-20%
	Final Energy Demand	+2%	Final Energy Demand	-16%
	Electricity Demand	+14%	Electricity Demand	+1%
	Residential Demand	+5%	Residential Demand	-23%
	Primary Energy Demand	-13%	Primary Energy Demand	-20%
	Final Energy Demand	-2%	Final Energy Demand	-16%
	Electricity Demand	+6%	Electricity Demand	-8%
	Residential Demand	+0%	Residential Demand	-20%

Table 9: Changes in energy demand by 2050 with respect to a 2000 baseline

Low carbon	Reference		Resilient	
	Primary Energy Demand	-4%	Primary Energy Demand	-44%
	Final Energy Demand	+4%	Final Energy Demand	-38%
	Electricity Demand	+26%	Electricity Demand	+2%
	Residential Demand	-2%	Residential Demand	-50%
	Primary Energy Demand	-32%	Primary Energy Demand	-49%
	Final Energy Demand	-29%	Final Energy Demand	-40%
	Electricity Demand	+39%	Electricity Demand	+16%
	Residential Demand	-55%	Residential Demand	-50%

Figure 11: Primary Energy Demand in 2025

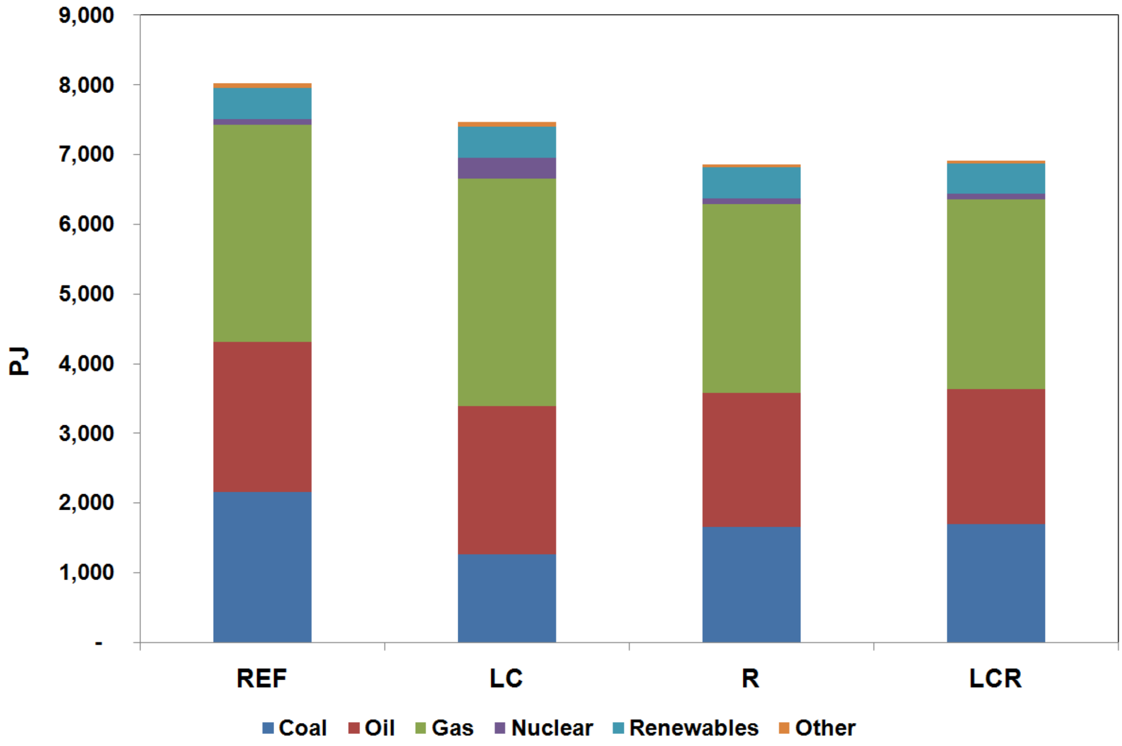
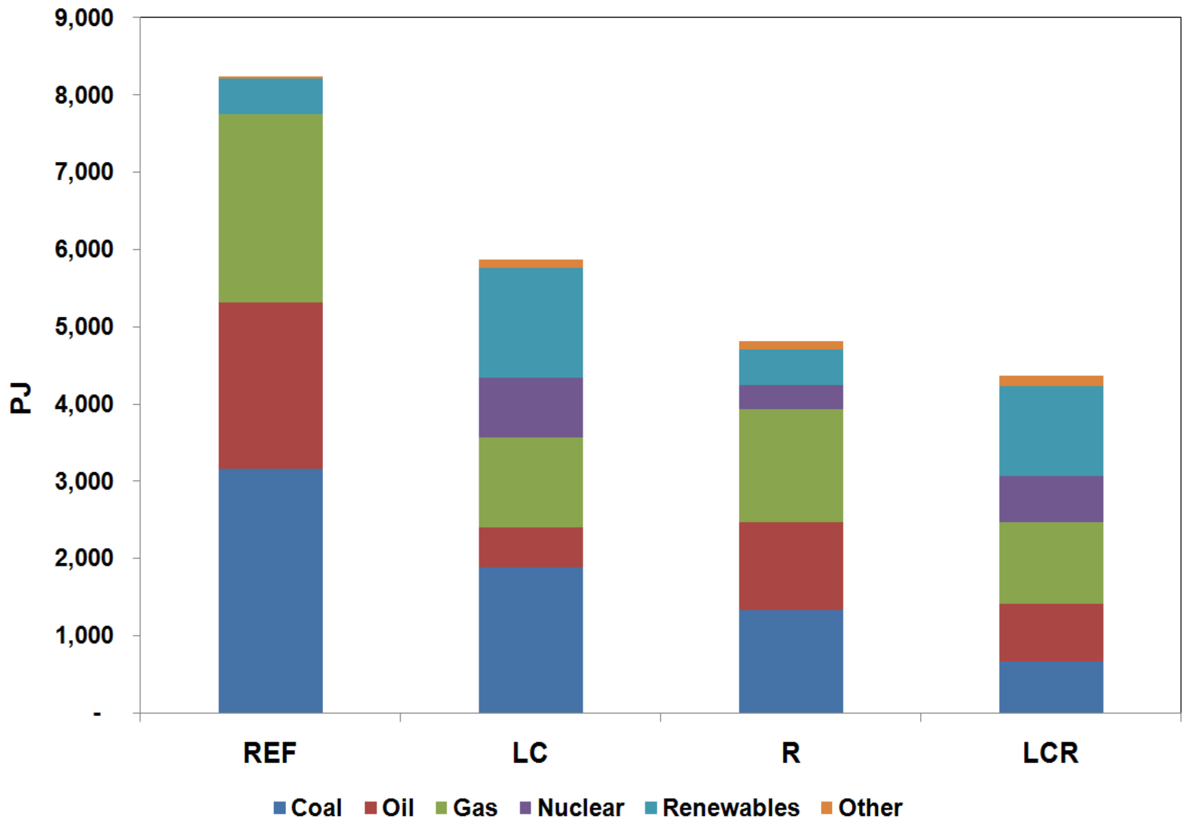


Figure 12: Primary Energy Demand in 2050



Diversity of energy supply and the electricity generation mix

Tables 10 and 11 show that the *Low Carbon* scenario and even more so the *Reference* scenario breaches the diversity constraints set in the resilience scenarios. In the *Reference* scenario, the primary energy mix is compliant but coal attains 54% of the electricity generation mix by 2025 and 81% by 2050. In the *Low Carbon* scenario, the primary energy mix includes 44% gas in 2025 and the electricity generation mix includes 41% coal in 2050. The resilience constraints are barely breached in the *Low Carbon* scenario which, consequently, can be said to perform relatively well in diversity terms. In the two resilient scenarios, the only constraint that bites relates to the maximum share in the electricity generation mix. It is generally coal that tends to run up against the constraint, but for the *Low Carbon Resilient* scenario in 2050, nuclear power is constrained off.

Note that coal gains market share in the unconstrained *Reference* scenario because of the underlying price assumptions made when prospects for natural gas supply were less optimistic than is currently the case. In general, the diversity constraints tend to hold coal back rather than to enhance its role.

Table 10: Changes in diversity indicators in 2025 with respect to a 2000 baseline

	Reference →		**Resilient**	
	Max primary energy share (gas)	39%	Max primary energy share (gas)	39%
	Max electricity share (coal)	54%	Max electricity share (coal)	40%
	Max electric capacity share (coal)	33%	Max electric capacity share (gas)	29%
↓ **Low carbon**	Max primary energy share (gas)	44%	Max primary energy share (gas)	39%
	Max electricity share (gas)	31%	Max electricity share (coal)	40%
	Max electric capacity share (gas)	27%	Max electric capacity share (gas)	29%

Table 11: Changes in diversity indicators in 2050 with respect to a 2000 baseline

	Reference →		Resilient	
↓ Low carbon	Max primary energy share (coal)	38%	Max primary energy share (gas)	31%
	Max electricity share (coal)	81%	Max electricity share (coal)	40%
	Max electric capacity share (coal)	51%	Max electric capacity share (coal)	27%
	Max primary energy share (coal)	32%	Max primary energy share (gas)	24%
	Max electricity share (coal)	41%	Max electricity share (nuclear)	40%
	Max electric capacity share (coal)	25%	Max electric capacity share (wind)	29%

CO_2 intensity and economic indicators

Tables 12 and 13 cover a range of indicators relevant to CO_2 emissions and economic aspects of the four core scenarios. In the two low carbon scenarios, CO_2 emissions are constrained to fall by 36% by 2025 and 80% by 2050 relative to 1990 levels. In the *Reference* scenarios, unconstrained emissions fall by 12% by 2025 but by only 2% by 2050. In the *Resilient* scenario, emissions fall by 29% by 2025 and 52% by 2050 as a result of constraining final energy demand.

The tables also cover the average carbon intensity of grid electricity measured in grams CO_2/kWh generated. Figure 13 expands on this by showing the trajectories of carbon intensity for each of the scenarios through to 2050. In the *Reference* (unconstrained) scenario, carbon intensity increases due to a switch from gas and nuclear to coal partly compensated for by increases in renewable generation. In the *Resilient* scenario, carbon intensity declines gradually because of investment in nuclear and renewables which is, however, partly compensated for by a switch from gas to coal as noted above. The dramatic, and early, reduction in carbon intensity in the *Low Carbon* scenario is the result of large scale investment in coal plant fitted with carbon capture and storage (CCS)[7], nuclear and wind generation. Carbon intensity declines significantly in the *Low Carbon Resilient* scenario but lags about a decade behind the *Low Carbon* Scenario. Electricity demand is lower in the *Low Carbon Resilient* scenario. Nuclear's market share is similar to that in *Low Carbon* while there is a significant switch from coal CCS to renewables. The expansion of markets for electricity in the *Low Carbon* scenario is largely explained by the combined effect of the de-carbonisation of electricity and the application of the carbon constraint.

[7] The system-wide scenarios that frame this analysis were constructed before the demonstration of CCS on gas-fired plant became UK policy. Later runs of the MARKAL model have included the option of gas CCS.

Tables 12 and 13 also show annual energy system costs (including amortised capital, fuel and operating costs) change relative to the *Reference* scenario. Costs rise in the *Low Carbon Scenario* because much of the CO_2 abatement occurs on the energy supply side, notably through de-carbonisation of electricity. However, in the two resilient scenarios, system costs generally fall as a result of reduced demand for energy. The exception is in the *Low Carbon Resilient* scenario in 2050 where system costs rise slightly as de-carbonisation costs offset savings from reduced energy demand.

There are always welfare losses associated with constraining energy system development away from the *Reference* scenario. Tables 12 and 13 suggest that the welfare loss associated with building in resilience are much higher than those associated with pursuing the low carbon economy. This needs interpreted carefully. The largest contribution to the welfare loss in the two resilient scenarios is associated with reduced energy demand in the residential sector. This is driven by a price elasticity assumption which stands as a proxy for both investment in energy efficiency and reductions in energy service demand (mainly for heating). To the extent that available energy efficiency measures are low cost, the welfare loss figures may be biased upwards to a considerable degree.

Table 12: CO_2 and economic indicators in 2025

	Reference →		**Resilient**	
↓	CO_2 emissions[+]	-12%	CO_2 emissions[+]	-29%
	CO_2 intensity of electricity (g/kWh)	513	CO_2 intensity of electricity (g/kWh)	464
	Change in annual energy system cost* (£bn)	0	Change in annual energy system cost (£bn)	-2
	Change in economic welfare* (£bn)	0	Change in economic welfare (£bn)	-19
Low carbon	CO_2 emissions[+]	-36%	CO_2 emissions[+]	-36%
	CO_2 intensity of electricity (g/kWh)	188	CO_2 intensity of electricity (g/kWh)	360
	Change in annual energy system cost (£bn)	+2	Change in annual energy system cost (£bn)	-3
	Change in economic welfare (£bn)	-4	Change in economic welfare (£bn)	-19

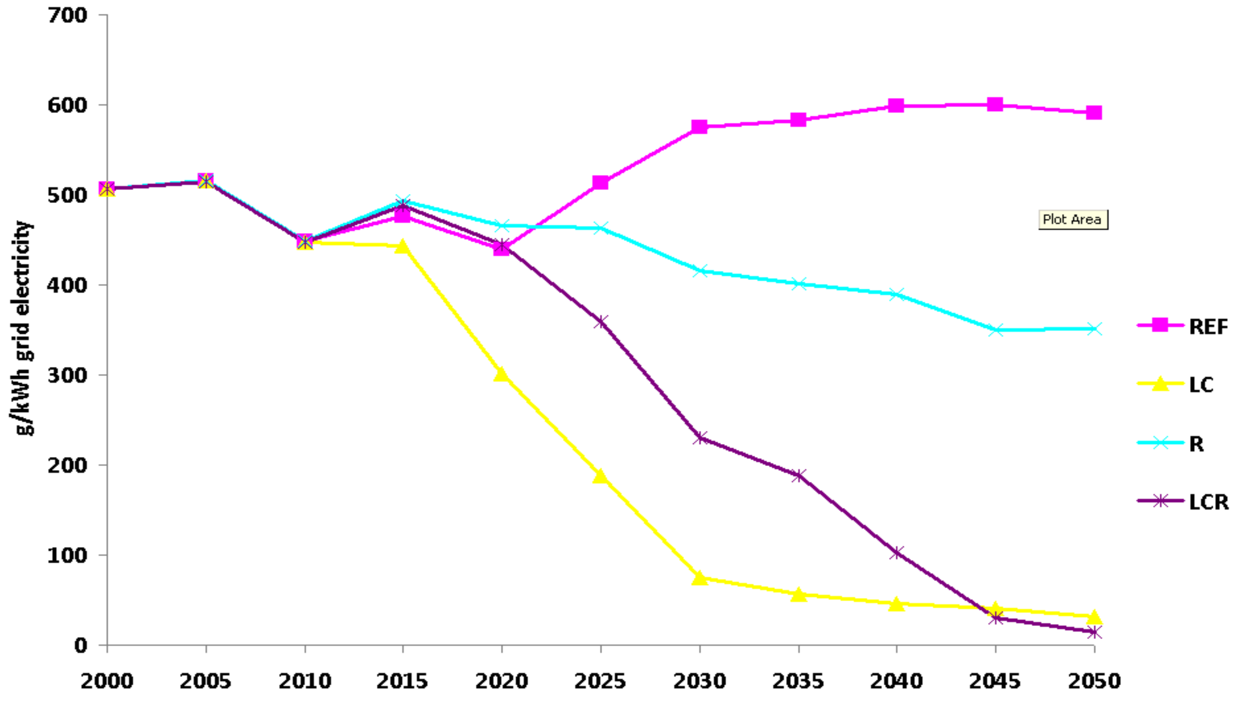
Note: [+] - with respect to a 1990 baseline; * - with respect to the Reference scenario

Table 13: CO_2 and economic indicators in 2050

	Reference →		Resilient	
↓	CO_2 emissions+	-2%	CO_2 emissions+	-52%
	CO_2 intensity of electricity (g/kWh)	591	CO_2 intensity of electricity (g/kWh)	352
	Change in annual energy system cost* (£bn)	0	Change in annual energy system cost (£bn)	-11
	Change in economic welfare* (£bn)	0	Change in economic welfare (£bn)	-49
Low carbon	CO_2 emissions+	-80%	CO_2 emissions+	-80%
	CO_2 intensity of electricity (g/kWh)	31	CO_2 intensity of electricity (g/kWh)	15
	Change in annual energy system cost (£bn)	+17	Change in annual energy system cost (£bn)	+1
	Change in economic welfare (£bn)	-38	Change in economic welfare (£bn)	-59

Note: + - with respect to a 1990 baseline; * - with respect to the Reference scenario

Figure 13: Carbon Intensity of Grid Electricity



Demand Side Technology Choice

The contribution of technology selection to the de-carbonisation of the electricity sector was noted above. On the demand side, technology choices in the transport and residential sectors play a significant role in differentiating the scenarios.

The surface transport sector in the *Reference* scenario is dominated by conventional petrol and diesel engines right out to 2050, though goods vehicles switch to diesel hybrid engines from 2015-20 onwards. However, in the *Low Carbon* scenario, petrol engine vehicles are switched to a mixture of plug-in electric hybrids and bio-ethanol around 2035. Bio-ethanol fails to emerge in the *Resilient* scenario where a switch to hybrid and plug-in hybrid cars takes place, again from 2035 onwards. The *Low Carbon Resilient* scenario resembles the *Resilient* scenario, but there is some take-up of bio-ethanol cars. Hydrogen is used to a limited extend by goods vehicles in the *Low Carbon* and *Low Carbon Resilient* scenarios, but only by 2050.

In the residential sector, gas heating dominates the *Reference* scenario right through the projection period. In the *Low Carbon* scenario, electric heat pumps start to replace gas around 2040 and have done so almost completely by 2050. Biomass heating plays a transient role in the period 2035-45. However, electric heat pumps and biomass fail to come through in the two resilient scenarios. Here, the main contributions to CO_2 reduction come from reduced heat demand and the emergence of some district heating, to a somewhat greater extent in the *Low Carbon Resilient* scenario.

4.3 Resilience and the Low Carbon Economy: Synergies and Trade-offs

A key message emerges from the comparison of the resilient and the other two core scenarios. Although there are synergies between the low-carbon/resilience agendas, they are far from being synonymous with each other. The key theme in the *Low Carbon* scenario is de-carbonisation of electricity supply with demand reduction making a modest contribution. The key theme in the *Resilience* scenario is demand reduction with only a modest reduction in the carbon intensity of electricity generation by 2025. The *Low Carbon* scenario contributes to reduced energy dependence, but does not go far enough to meet overall security goals; the *Resilient* scenario reduces CO_2 emissions, but does not go far enough to stay on the pathway to the 2050 80% reduction goal.

Reducing energy demand, and thereby import dependence, is the key to achieving both the *Resilient* and *Low Carbon Resilient* scenarios. This different emphasis has consequences for the selection of demand side technologies. In the built environment, electric heating plays a far bigger role in the *Low Carbon* scenarios but is absent in the resilient scenarios. There are also more varied, and subtle, changes in technology choice for transport.

The significant reductions in residential energy demand in the *Resilient* and *Low Carbon Resilient* scenarios appear to incur a major loss in welfare through a reduction in consumer surplus. As noted earlier, this should be kept in perspective as there are more low-cost energy efficiency opportunities available than the modelling has implied.

5. Reliability in the network industries

5.1 Overview

This section is concerned with the adequacy of investment in supply capacity and infrastructure to ensure that electricity and gas are supplied reliably to consumers. It covers risks, as defined in Section 2, to which probabilities can be assigned. These include variability in demand, including those related to weather, and the probabilities of plant outages through technical failure. Reliability standards are set so as to ensure that the risk of outages is kept to acceptable levels. There can be no guarantee that demand can be met at all times.

The MARKAL-MED model used in Section 4 uses a simple "planning margin" approach[8] to determine the adequacy of generation capacity in the electricity sector. Planning margins are "rules of thumb" based on more fundamental statistical analyses. The loss-of-load probability (LOLP) – the number of winters per century in which demand will not be fully met - is another intermediate indicator. A capacity margin of around 20% and a LOLP of nine winters per century were the standards used by the former Central Electricity Generating Board (CEGB).

If new types of plant, particularly intermittent renewables, take a large share of the electricity market then the old assumptions about LOLP and capacity margin may break down. When demand is not fully met, periods of interruption may be longer and more load may be lost. There is a need to adopt a more fundamental statistically-based approach to reliability.

The basic approach is to assess the value of gas or electricity to customers and multiply by the probabilities of outages occurring to obtain the expected welfare cost of unserved demand. Both the WASP model of the electricity system and the CGEN model of gas and electricity infrastructure use the concept of value-of-lost-load (VOLL)[9] to balance the cost of outages against the cost of investment in additional capacity to improve reliability. In addition, the WASP model applies a constraint on the loss-of-load expectation (LOLE) – the number of hours per year in which demand is expected not to be met. Where there is substantial investment in intermittent wind generation, using the LOLE and VOLL constraints will increase the capacity needed to meet reliability standards in the electricity sector.

The input assumptions about VOLL and LOLE are shown in Table 14. These derive largely from the work of Kariuki and Allan (1996). Industrial VOLL varies from £10-255/kwh and domestic VOLL from £0.26-6.3/kWh. More recent research from van der Welle and van der Zwann (2007) concluded that figures for VOLL lie in the range $4-40/kWh for developed countries. Taking account of these two studies allows us to differentiate between customer types. The VOLL in Table 14 reflect a typical four hour outage.

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[8] For intermittent generation, such as wind, adjustments are made to allow for the "capacity "credit", i.e. the proportion of the capacity that can be counted on at times of peak demand.
[9] "Lost load" corresponds to the concept of "energy unserved" used by DECC.

Other approaches are possible. Redpoint (2010) used a single VOLL of £10/kWh across all customer types in work underpinning UK Electricity Market Reform proposals.

Table 14: Reliability indicators for gas and electricity

Value of lost load	• £5/kWh (residential electricity) • £40/kWh (industrial electricity) • £5/therm (industrial gas) • Lost load not allowed (residential gas)
Loss-of-load expectation (LOLE)	• 4 hours per year (0.05% of year) for electricity

This section first considers the approach to reliability in the electricity sector then goes on to look at gas.

5.2 Reliability of electricity supply

Applying the reliability indicators in Table 14 to the electricity system using the WASP model shows that the conventional capacity margin approach used in MARKAL will lead to increasingly unreliable supply if significant amounts of intermittent renewable capacity comes on to the system. Figure 14 shows how the required system capacity margin (the fraction by which installed capacity exceeds peak demand) changes between 2005 and 2050 under the *Low Carbon* scenario if the more formal reliability approach based on VOLL and LOLE is applied. The difference relates mainly to the degree of renewables on the system. With intermittent renewables electricity shortages tend to become longer, involving deeper load cuts, even if the frequency of such events remains the same.

Figure 15 shows how, in the same *Low Carbon* scenario, the loss of load expectation (LOLE) exceeds accepted norms if the conventional capacity margin approach is adopted. Accepted loss-of-load expectations under current conventional systems range between 2 and 8 hours per year. With more intermittent renewables on the system, the conventional approach could lead to loss of load as high as 150 hours per year by 2040. In the later part of the projection, nuclear forms an increasing part of the mix and LOLE falls off.

The WASP model installs additional conventional, mostly CCGT/open cycle gas turbine (OCGT) capacity, to compensate for intermittency. Storage is not the least cost option. “Back-up” capacity meets short-term operational requirements and ensures the long-term reliability of the system in order to maintain acceptable levels of LOLE while minimising overall system costs.

Figure 14: Capacity margin using different reliability approaches, Low-Carbon scenario

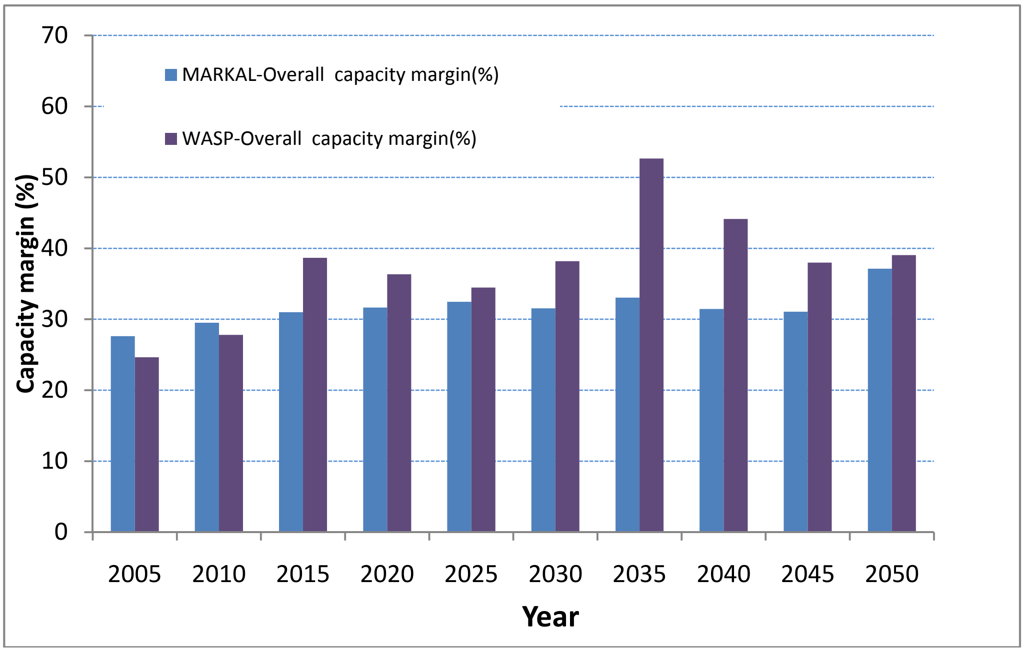
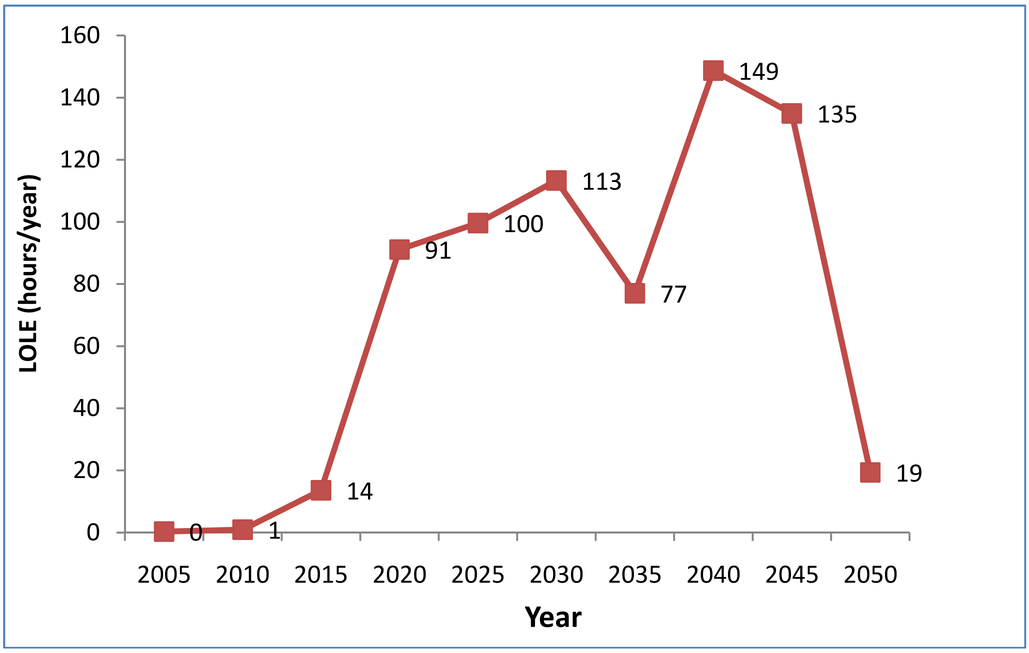


Figure 15: Loss-of-load expectation using capacity margin approach, *Low Carbon* scenario



The additional capacity and electricity system costs associated with the more formal reliability approach is shown in Table 15. Beyond 2020, the additional capacity required on the system to maintain reliability is in the range 5-10 GW depending on the scenario and the precise point in the projection. The cost of maintaining this capacity, which would be seldom used, is largely associated with capital costs and could run into several hundreds of millions of pounds per year. As an indicator, the £354m incurred in the *Low Carbon Resilient* scenario in 2020 is equivalent to £1.03/MWh of all electricity generated and £9.85/MWh of wind energy generated. The modelling suggests just over 12 GW of wind on the system at this point.

Table 15: Additional Capacity and System Costs to Ensure Reliability

	Additional System Capacity (GW)			Additional System Cost (£m pa)		
	2020	2035	2050	2020	2035	2050
Reference	1.3	5.5	5.5	67	274	277
Low-Carbon	3.7	11.5	4.4	187	575	219
Resilience	6.8	5.9	9.1	341	296	457
Low-Carbon Resilience	7.1	5.4	6.2	354	269	312

5.3 Reliability of Gas Supply

When the UK was self-sufficient in gas supplies, the response to uncertainty in the gas market largely came down to turning the tap on and off. With the prospect of the UK becoming largely dependent on imports, other measures are required to ensure reliability of gas supplies. These include greater interconnection with Europe, opening up to global LNG markets and investing in storage.

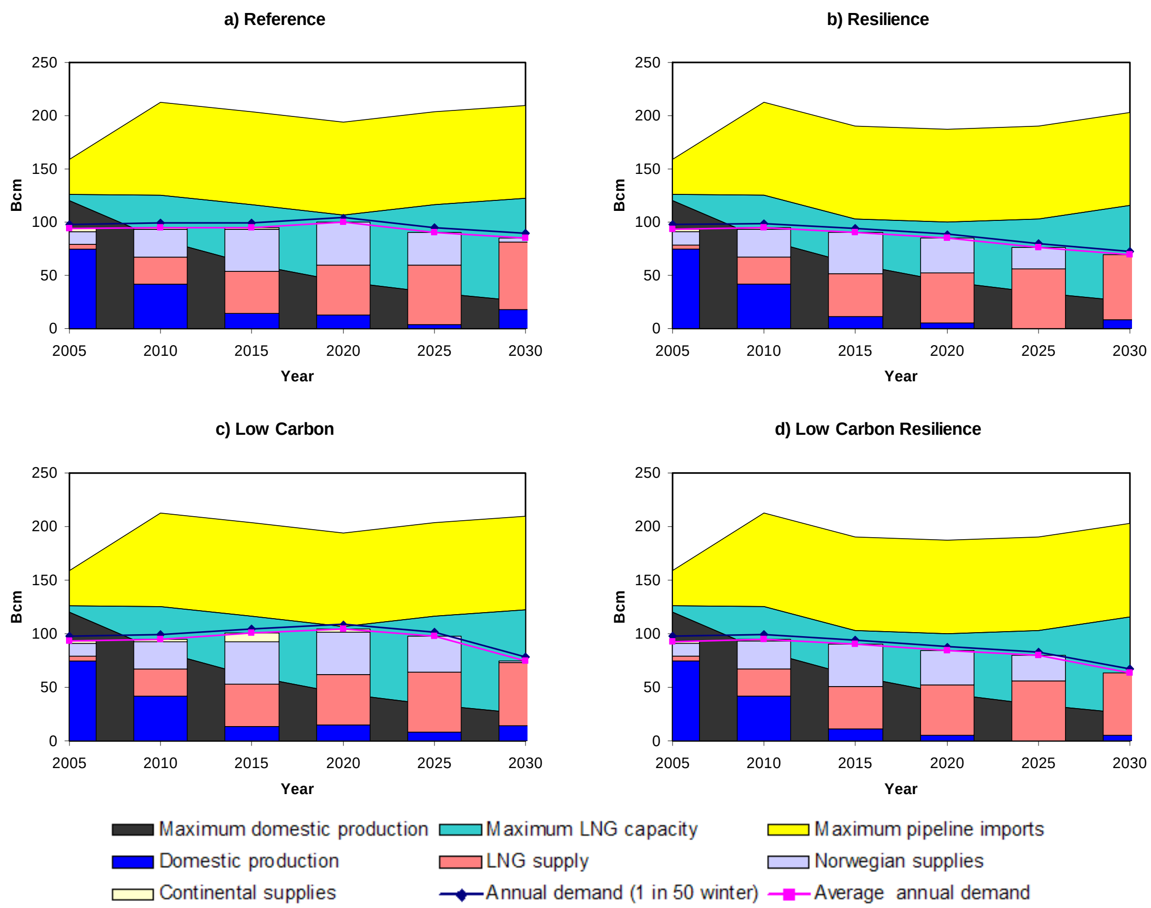
We have operated the CGEN model using the indicators from Table 14 to assess the investments needed to ensure reliable gas supply through to 2050 under each of the four core scenarios. After taking account of current and committed projects, the CGEN model chooses between additional pipeline interconnectors, LNG terminals and gas storage facilities. Table 16 shows investments selected under the four core scenarios in addition to current and committed capacity. New interconnectors are not selected but there is considerable investment in new LNG terminals to compensate for declining domestic supply. This is largely driven by assumptions about the relative cost of continental gas and gas available through LNG markets. New, additional storage is selected in the *Reference* and *Low Carbon* scenarios but not in the resilient scenarios where final gas demand is much lower. As explained above, intermittent wind generation is handled in the WASP model which identifies “back-up” CCGT and open cycle gas turbine plant (OCGT), rather than storage, as being the least cost way to deal with intermittency.

Table 16: Gas infrastructure investments

	Reference (REF)	Low Carbon (LC)	Resilient (R)	Low Carbon Resilient (LCR)
Interconnectors	No additional	No additional	No additional	No additional
LNG terminals	40 mcm/d 2015 20 mcm/d 2020 60 mcm/d 2025 40 mcm/d 2030	40 mcm/d 2015 20 mcm/d 2020 60 mcm/d 2025 40 mcm/d 2030	40 mcm/d 2020 40 mcm/d 2025 60 mcm/d 2030	40 mcm/d 2020 40 mcm/d 2025 60 mcm/d 2030
Storage	2000 mcm 2015	1000 mcm 2015	No additional	No additional

Figure 16 shows the gas market balance out to 2030 under each of the four core scenarios. This illustrates starkly the degree to which the UK will become import dependent. The broad pattern across all scenarios is that LNG capacity substitutes for UK domestic production and, in the 2020s, for Norwegian imports. In the two resilient scenarios, where gas demand is lower, Norwegian imports are reduced more quickly.

Figure 16: gas supply/demand balance in the four core scenarios



6. Resilience to energy system shocks

6.1 Overview

This section addresses the resilience of the UK energy system to shocks or disturbances to which it is difficult or impossible to attach probabilities. It responds to concerns about the UK's growing import dependence and perceived underinvestment in infrastructure. The focus is largely on natural gas supply.

The section starts with a review of the historical experience of "shocks" or "events" that have caused disruption to energy markets round the world over the last 10-20 years (electricity and gas) or 50 years (oil). We use this evidence to define a set of hypothetical shocks to the UK energy system. These all relate to natural gas supply.[10] We assume that these shocks occur towards the beginning of winter, in the year 2025, under each of the four core scenarios. Using the CGEN model, we assess the impact of these shocks in terms of the additional costs associated with re-balancing the energy system to maintain supplies to consumers (e.g. by re-dispatching power stations) and the imputed costs associated with "lost load" if supply curtailments prove necessary.

The final stage is to test a set of measures that would help to mitigate the impacts of the shocks. These measures take the form of investments in physical assets such as gas storage, LNG terminals or additional interconnectors additional to those needed to meet the reliability standards described in Section 5. We assess the extent to which these measures mitigate the costs of the various shocks to the energy system. As noted in Section 2.5, the shocks that we hypothesise are not susceptible to probabilistic treatment as they may be caused, *inter alia*, by extreme weather, unanticipated catastrophic accidents or multiple/coincident events. Without being able to assign probabilities to the shocks, we cannot place this analysis in a formal cost-benefit framework. However, if the mitigating investments are regarded as insurance against the shocks taking place, we can calculate how often the shocks would have to recur (the "return period"[11]) before investments can be justified.

6.2 Energy system shocks: historical experience

Overview

Shocks associated with electricity, gas and oil are assessed. A general finding is that electricity shocks have tended to last for hours-days, gas shocks for weeks-months, and oil shocks for months-years in the some cases.

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[10] We prioritised gas because: a) there are well-established requirements for major consuming countries to maintain significant quantities of oil stocks under International Energy Agency (IEA) and EU rules; and b) shocks to the electricity system tend to be of a much shorter duration and can be mitigated by addressing the reliability issues considered in the previous section.

[11] The "return period" does *not* relate to the financial rate of return on capital

Electricity

Table 17 shows major electricity blackouts and disturbances over the last 20 years. Electricity supply accidents have occurred more frequently in the last 10 years, partly reflecting rising energy demand and hot summer conditions.

Electricity blackouts have lasted for several hours up to several days. Compared to oil and gas shocks, electricity shocks have happened more frequently but the durations have been shorter. Almost of all the blackouts were caused by the extreme weather and the failure of major infrastructure assets. However, the California power crisis in 2000 and 2001 is an exception. The series of blackout and service interruptions were mainly attributable to inefficient market policy and market manipulations by some energy companies.

Gas

Table 18 shows that there have been no massive global gas supply disruptions in the last 20 years. Most disruptions occurred in specific locations. Some can be attributed to extreme weather events, such as hurricanes in US in late 2005. Others were caused by poor or aging gas transmission infrastructure. For example, the gas supply crisis in Australia in 1998 was caused by a fractured vessel in a gas plant (AGD, 1998). There have been several events affecting major UK gas facilities in the last decade: Bacton, Easington, the UK CATS pipeline and the UK interconnector.

Some gas supply disruptions have arisen for political reasons. The most obvious one in recent years has been the Russia/Ukraine gas supply crisis. Russia cut off natural gas supplies to Ukraine in 2002, 2006 and 2009 in an attempt to increase gas prices and force the payment of debts.

Depending on the reasons for disruption, gas supply disruptions have generally lasted from several days up to a couple of weeks. It has taken between one and four days to reach an agreement to resolve the various Russia/Ukraine gas crises. However, US gas supply disruptions attributable to hurricanes lasted for 4 months in 2005.

Table 17: Major electricity blackouts and disturbances

Date	Place	Duration	Cause	Loss
23 - 25 July 2007	Barcelona	More than 3 days	The blackout began when a broken substation cable caused a chain reaction failure in other substations.	Around 350,000 households and businesses lost power at some point, and more than 100,000 remained powerless at night on 25th July.
16 – 29 July, 2006	Queens, New York	About 10 days	Intense heat wave	More than 3 million Americans were affected, some for hours, others for ten days.
23 – 24 October, 2005	South Florida, Naples, Ft. Myers, Miami, Ft. Lauderdale, West Palm Beach and Martin county	1 day	Hurricane Wilma	10,000MW loss and 3.2 m Americans were affected.
12 July, 2004	Athens and southern Greece	70% of the region had no power for an hour. Power was restored to all of Athens in 3 hours. Remote areas were affected longer.	Many of the planned new upgrades were not integrated in the system until after the yearly peak, which occurred on Monday, July 12, and the high demand due to a heat wave led to a cascading failure.	Several million people were affected.
28 September, 2003	The entire Italy with the exception of the island of Sardinia	9 hours	The problem was blamed on a fault on the Swiss power system, which caused the overloading of two Swiss internal lines close to the Italian border.	Almost all of the country's 57 million people were affected.
23 September,	Denmark and southern Sweden	Half day	The power failure occurred as a consequence of a number of faults in	4 million businesses and homes were affected. A total loss to the grid of 3000

Date	Place	Duration	Cause	Loss
2003			the South Swedish power system.	MW or about 20% of Sweden's electricity consumption at the time.
14 August 2003	The states of Ohio,Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario	Almost one week	It was caused by deficiencies in specific practices, equipment, and human decisions by various organizations that affected conditions and outcomes.	An estimated 50 million people and 61,800 megawatts (MW) of electric load were affected.
Several occasions between Summer 2000 and summer 2001	California	Several hours to two days	Attributed variously to significant supply shortfalls, flawed market design and market manipulation.	Several hundred thousand consumers suffered blackouts and service interruptions Wholesale electric prices were significantly raised,
10 August 1996	8 US western states	About 10 hours	A major transmission line was failed due to a period of high temperatures and high demand for electricity.	4 million people were affected.

Sources: BBC (2007); Berizzi, A. (2004); BreakingNews (2007); EIA (2006); Elkraft System (2003); Freeman, M. J. (2006); Northwest Power and Conservation Council (1996); U.S.-Canada Power System Outage Task Force (2004); Vournas,C (2004); World Energy Council (2003); FERC (2003)

Table 18: Gas supply crisis and accidents

Date	Place	Duration	Cause	Loss
Sep 2010 – Jan 2011	Norway's Kollsnes gas plant	Several months	Technical problems related to recovering natural gas liquids from two fields	Operations of Kollsnes was reduced dramatically.
April - June 2010	UK	Several months	Qatari liquefied natural gas (LNG) producers ran an extensive summer maintenance programmes reducing global supplies	Forward British gas prices for the following winter 2010/11 rose significantly as a result.
Several times in 2002, 2006 and January 2009	Ukraine	1 to several days	Russian companies cut off natural gas supplies to the Ukraine and Georgia to force payment of debts.	The gas supplies in many European countries depending on Russian natural gas were threatened.
28 Feb 2008 – 3 March 2008	UK Bacton terminal	4 days	The terminal was shut down due to a fire breaking out at a waste water treatment plant.	An instantaneous reduction in supply of around 30 mcm
July 1, 2007 – mid Sept. 2007	UK CATS pipeline	About 2 months	The pipeline’s protective casing was damaged by the anchor of a large vessel in June 2007.	Some oil and gas fields, such as J-block and Armada, had to stop producing.
February 16, 2006	The Bravo rig, in Centrica's Rough field, UK	About 4 months	There was an apparent failure of a cooler unit in one of four dehydration units and an explosion occurred in that vicinity.	Two people were injured. The main consequence of the Rough incident was higher prices after the event.
Sept. – Dec. 2005	US	4 months	Hurricanes	10% of US gas production was reduced during the last four months of 2005.
Nov. 2005	UK Interconnector	Early part of the winter 2005/2006	Possible reasons include infrastructure bottlenecks, legal restrictions and lack of transparency about gas movements in the EU and Norwegian markets	The UK failed to attract gas from continental Europe through the Interconnector even though UK prices were higher than those in Europe.

Date	Place	Duration	Cause	Loss
17 and 18 June 2003	Bacton, UK	2 days	A number of localised system balancing actions taken to address a supply deficit in the south of Great Britain failed to result in a sufficient physical response.	National Grid Transco (NGT) interrupted 10.5 mcm of National Transmission System (NTS) load on 17 June and 11 mcm of NTS and Local Distribution Zones (LDZ) loads on 18 June, as well as flows to the Belgian interconnector.
15 December, 1999 **Error! Bookmark not defined.**	Easington terminal, UK		Easington terminal was struck by lightning, limiting the operation of the Rough subterminal and other facilities	This reduction in flows contributed to a sharp increase in prices
Sept. 25 - Oct. 14 1998	Victoria, Australia	19 days	A vessel in a natural gas processing plant fractured, releasing hydrocarbon vapours and liquid.	1.3 million households and 89,000 businesses were affected. The commercial/ industrial cost was AUD \$1.3bn. Two people were killed.

Sources: AGD (1998); Centrica (2006); IEA (2006); Ofgem (2003); Ofgem (2004); Reuters (2007); National Grid (2008); House of Commons (2008); LNG World News (2010); Reuters (2011)

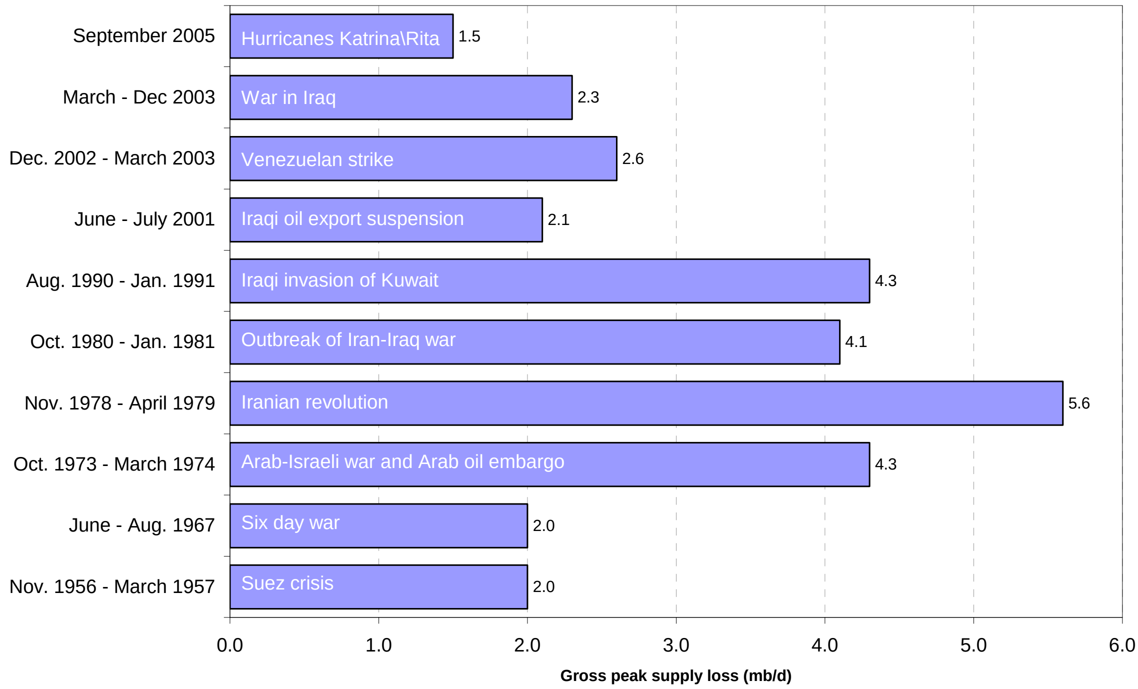
Oil

There have been ten major world oil supply disruptions in the last 50 years (IEA, 2007). There have been four major disruptions in the last decade. Before that, there had been disruptions roughly once in every ten years.

Among the major disruptions, only one is attributable to severe weather. This was also the shortest disruption lasting one month. All the others were caused by economic disruptions, political developments at the national/international level, and/or wars in the Middle East. These always lasted more than two months. Five out of the ten disruptions lasted for more than six months.

If both loss of supply and global production are considered, the most significant disruption in the last 50 years was the Suez crisis in late 1956 and early 1957. The loss in peak supply was about 11.4% of global crude oil production (Table 19). Figure 17 shows that most disruptions were due to events in the Middle East. The largest loss of supply was associated with the 1979 Iranian revolution.

Figure 17: Major world oil supply disruptions in the last 50 years



Source: IEA (2007)

Table 19: Global crude oil production and peak supply loss in each disruption

	1957	**1967**	**1974**	**1979**	**1981**	**1991**	**2001**	**2003**	**2003**	**2005**
Crude Oil production (mb/d)	17.6	37.1	59.0	66.6	60.6	66.9	77.1	79.5	79.5	84.2
Gross peak supply loss (mb/d)	2.0	2.0	4.3	5.6	4.1	4.3	2.1	2.6	2.3	1.5
Ratio	11.4%	5.4%	7.3%	8.4%	6.8%	6.4%	2.7%	3.3%	2.9%	1.8%

Source: Earth Policy Institute (2009) and IEA (2007)

6.3 Hypothetical System Shocks

We have hypothesised three possible 'shocks' to the UK energy system that impact on gas supply facilities (Table 20). We have assumed that the impact of each shock is experienced over three different durations - 5, 40 and 90 days. In each case we have assumed that the shock occurs in mid-winter, nominally 1 January 2025, during a period of 'average cold spell' demand. We do not attribute any specific underlying cause to these events, but note that Table 18 suggests that severe accidents rather than politically motivated acts would be the more likely cause.

These are deliberately severe events. However, they are within the range of recent experience. As shown in Table 18, an explosion at the Bravo rig in the Rough field took the storage facility out of service for two months in 2006. Gas supplies through Easington were interrupted for five days after it was struck by lightning in 1999.

Note that, as CGEN is an engineering-economic model which minimises cost it does not provide real insight into the impacts of a shock on spot prices for gas. The gas price implied by CGEN will rise to reflect the most expensive supply option at the margin, or the cost of customer interruption if this is required. A model like CGEN provides insight into resource costs but not necessarily the way that these costs are shared between consumers and producers. A rise in spot prices does not by itself alter the underlying resource cost, but does transfer money from consumers to producers. Experience has shown that supply interruptions can have considerable impacts on spot prices. For example, the loss of the Rough Field referred to in line 6 of Table 18, coupled with cold weather, led wholesale gas prices to spike at 250 pence/therm (Centrica, 2007).

Table 20: Description of facilities

Facility	Description	Size
Easington gas terminal	Connects the UK gas system to the Rough storage facility and the Langeled pipeline from Norway	Can deliver 120 mcm/day (equivalent to 35% of UK winter demand). Rough can store 3.3 bcm of gas, equivalent to 10 days average winter demand
Bacton gas terminal	Connects the UK to continental Europe via Zeebrugge and Balgzand. Also links to some domestic production	Can deliver 144 mcm/day (equivalent to >40% of UK winter demand). Also used for export
Milford Haven LNG terminal	Two terminals commissioned in 2009	Milford Haven can currently deliver 75 mcm/day (equivalent to > 20% of winter demand)

Table 21 shows the impact of the three events against the background of each of the core scenarios. The key messages are:

- The loss of the largest terminal, Bacton, which affects both imported and domestic gas supplies, has the largest impact.

- The energy system can 'ride through' the loss of Easington or Milford Haven under the *Resilient* and *Low Carbon Resilient* scenarios – and the impact of losing Bacton is much diminished. This is because these two scenarios are characterised by lower levels of gas demand which is also less seasonal. The system can cope better when demand is less 'peaky'. Demand reduction demonstrably contributes to energy system resilience.

- The imputed value of unserved energy (in £bns) is an order of magnitude larger than the changed system costs. System costs generally rise as more expensive gas is sourced and coal substitutes for gas in electricity generation. This however does not take account of the response in energy spot markets that would be expected following such events, which would tend to increase costs further.

- The patterns of response are complex because the facilities play different roles in the gas network. In none of the scenarios is it necessary to curtail electricity supplies. Response is taken up entirely by exercising interruptible gas contracts, re-dispatch of the electricity system, use of distillate oil at certain CCGTs and non-contracted industrial gas interruptions.

Table 21: Impact of 40-day shocks in the four core scenarios

	Energy unserved (mcm)	Value of energy unserved[1] (£m)	Change in system operating costs[2] (£m)
Reference (REF)			
- Bacton	1839	3404	-7
- Easington	1049	1942	+137
- Milford Haven	866	1604	+104
Low Carbon (LC)			
- Bacton	1718	3179	+29
- Easington	1155	2138	+144
- Milford Haven	1015	1878	+89
Resilient (R)			
- Bacton	244	452	+203
- Easington	-	-	-
- Milford Haven	-	-	-
Low Carbon Resilient (LCR)			
- Bacton	704	1303	+135
- Easington	-	-	-
- Milford Haven	-	-	-

Notes: 1) using the values of lost load in residential and industry from Table 14; 2) this does not allow for the likely rise in spot prices for gas

Table 22 shows in more detail the actions taken during the 40 day shock at Bacton terminal and the costs associated with voluntary gas demand reduction.

Table 22: System response to 40-day shock at Bacton in the four core scenarios

	Change in CCGT/OCGT gas demand (mcm)[1]	Cost of voluntary gas response (£m)[2]
Reference (REF)	-386	341
Low Carbon (LC)	-690	391
Resilient (R)	-620	379
Low Carbon Resilient (LCR)	-598	375

Notes: 1) refers to the change in power station gas demand determined by CGEN relative to the situation where no shock occurs; 2) The cost of voluntary gas response compared with no shock. This includes switching from gas to distillate oil, the re-dispatching of CCGTs and industrial response.

In all cases the following procedures are initiated during a shock before involuntary energy measures are required:

Voluntary industrial gas response. The response from the industrial sector is fixed at 5.5 bcm/y for 2025. This is based on the value used in the analysis conducted by National Grid and Global Insight (National Grid, 2006; Global Insight, 2005). The response loosely represents industrial users on interruptible contracts who have the capability to switch to other fuels at an average cost of £8.34/GJ or ~ 3p/kWh (OXERA, 2007).

Voluntary power sector response. It was assumed that there are 3GW CCGT power plants (JESS, 2006) with distillate back-up for up to 120 hours operation in 2025. In a gas emergency it is assumed that all these plants will switch to distillate. The cost of distillate fuel is set at the price of crude oil and assumes that CCGT plants running on distillate have a thermal efficiency of 50%.

Additional CCGT response. This is determined endogenously by CGEN through least cost dispatch for a particular shock and scenario. The response depends on the levels of demand for gas and electricity, CCGT capacity, electricity generation capacity mix, operational costs and VOLL.

Due to higher peak demand for both gas and electricity, a lack of alternative electricity generating capacity and transmission capacity constraints it was difficult to reduce CCGT gas demand in the *Reference* scenario. There is greater CCGT demand response in the *Resilient* and *Low Carbon* scenarios resulting in higher costs attributable to voluntary gas response.

Table 23 assesses how different lengths of interruption could affect outcomes. The loss of Easington is taken as an example. The clear message is that shorter periods of interruption, of the order of days, can be accommodated through system adjustments with very little loss of load. Beyond a certain threshold, costs increase rapidly, but they are less than linearly related to the length of the interruption.

Table 23: Impact of the loss of Easington for different periods

	Energy unserved (mcm)	Value of energy unserved (£m)	Change in system operating costs (£m)
Reference			
- 5 day	14	26	+29
- 40 day	1049	1942	+137
- 90 day	1857	3438	+294
Low-Carbon			
- 5 day	12	23	+32
- 40 day	1155	2138	+144
- 90 day	2127	3937	+242

6.4 Mitigating the Shocks

The analysis above is based on the assumption that investment takes place to meet the reliability standards set out earlier. It is also possible to undertake additional infrastructure investment that would help to mitigate the impacts of major shocks. This section investigates the benefits that such investment might bring and sets them against the costs. Table 24 shows seven possible projects which would increase the resilience of the gas supply network. The costs for storage are based on Oxera (2007) for gas and ILEX (2006) for distillate oil.

The costs of cushion gas are included for salt cavity storage facilities. Although more cushion gas is needed for seasonal depleted gas storage facilities, we would expect these depleted gas reservoirs to contain a large amount of economically unrecoverable gas that can be used as cushion gas. Additional gas may be needed to keep storage facilities pressurised to maintain gas flow rate. This is included in the model as an operational cost. The cost of distillate storage refers only to the costs of the tanks and associated equipment. The cost of distillate oil stocks are treated separately in the modelling.

Table 24: Gas infrastructure projects

Project	**Capacity**	**Capital Cost (£m)**
Storage facility similar to Rough	3000mcm delivering 40 mcm/d, located near St Fergus	475
Two storage facilities	Salt cavities each with a capacity of 500mcm delivering 40 mcm/d	550
Expansion at one LNG terminal	40mcm/d at Teesside	400
Expansion at two LNG terminals	20 mcm/d at each of Teesside and Isle of Grain	405
New gas interconnector	40 mcm/d through Theddlethorpe	340
Backup distillate storage at CCGTs	5 days storage at 6GW plant	15
Major distillate storage at CCGTs	40 days storage at 6GW plant	215

We focus on the loss of Bacton, the most severe shock, for a 40-day period and assess the impact of these mitigating investments in the *Low Carbon* scenario. The pay-off from these investments will manifestly be less under the *Resilient* and *Low Carbon Resilient* scenarios under which the electricity/gas system is much more able to ride through shocks. The 40-day Bacton shock stands as a good proxy for other shocks, periods and scenarios as the pattern of impacts is similar.

Table 25 shows the degree to which each individual mitigating investment would reduce the volume of energy unserved. The biggest impact comes from the expansion of import facilities, be they new LNG terminals or a new interconnector. Five days distillate storage has little impact (as might be expected for a 40 day outage) but dedicated gas storage and 40 days distillate storage have half to two thirds the impact of more import facilities.

The conclusion about the impact of gas storage is critically dependent on how much gas is assumed to be in store at the time of the shock. For the major storage facility we have considered two options: a) that the facility is half full in mid-winter; and b) that it is used as strategic storage and kept completely full for emergencies. This has a significant effect on the conclusions. Note also, as described above, that the analysis does not explicitly take into account changes in spot market prices.

Making a mitigating investment can be regarded as taking out insurance against the eventuality of adverse events. If the event is expected to occur regularly, taking out the investment could reduce costs in the longer term. If it were extremely rare it might be better to forego the insurance costs and accept the consequences. The ‘return period’ in Table 25 refers to the frequency with which the event would need to take place for each of the mitigating investments to pay off in the long run. It is based on a simple calculation that involves dividing the expected loss as a result of the adverse event by the annualised capital cost of the mitigating investment. Table 25 shows, for example, that if the investor requires a market rate of return of 10 per cent real, investing in two new LNG terminals might be expected to pay off in the long run if a 40-day outage at Bacton were to occur more frequently than once every 35 years. Given the improbability of its happening as frequently as this, it is almost impossible to conceive that market players would undertake this investment. Note that our scenarios anticipate new market-driven investment in gas infrastructure as shown in Table 16. Investment to mitigate against catastrophic shocks would be *additional* to the investments in Table 16.

On the other hand, investment in these mitigating measures could be regarded as strategic investments to be taken in the public interest. At a rate of return on investment of only 3.5 per cent real, the Treasury ‘social’ discount rate, the investment might still ‘pay off’ if the event were to occur as infrequently as once in 100 years. There might therefore be a case for the regulator to allow (or mandate) the costs of such an investment to be passed on to consumers, whereby companies would be prepared (or required) to accept a lower risk-free rate of return in exchange for revenue certainty. To ensure that the investment did deliver strategic security, they would need to be prevented from commercial arbitrage activities.

With lengthy return periods, the changing structure of the energy system in the long term becomes an issue. If an event is likely to occur only once every 50 years or so, it may not be desirable to invest in a project that appears to pay off using the insurance analogy, if gas use is virtually eliminated from the energy system over that time period. Further research would be needed to elucidate this question.

Table 25: Impact of Mitigating Investments: Bacton out for 40 days

			10% investor rate of return		3.5% regulated rate of return	
	Energy unserved (mcm)	Reduction in cost of shock (£m)	Additional annual costs (£m)	Return period (years)	Additional annual costs (£m)	Return period (years)
Baseline investment	1718	-	-	-	-	-
Additional:						
Storage facility[1]	1104	1093	52	21	17	63
Storage facility[2]	832	1598	52	31	17	93
Two storage facilities	1246	832	60	14	20	42
One LNG terminal	786	1572	44	36	15	108
Two LNG terminals	789	1569	45	35	15	105
Gas interconnector	790	1600	37	43	12	129
Distillate storage	1685	53	2	32	1	96
Major distillate storage	1246	767	24	32	8	96

Notes: 1) facility half full in mid-winter; 2) facility completely full

7. Policy implications, key messages and future research

7.1 Overview

This section draws together the key messages from the report, discusses the policy implications and suggests some future lines of research. It starts with an overview of the economic and financial implications of the analysis. It continues by briefly describing the current institutional framework for UK energy policy and then sets out policy options and opportunities for promoting resilience in three areas: promoting diversity; reducing energy demand; and building resilient infrastructure. Finally, some suggestions are made for future lines of research.

7.2 Adding up the Costs of Resilience

Ultimately, deciding how much to invest in and promote resilience in the energy system is a political decision that must be informed by evidence, albeit in the light of deep uncertainty. In this section we draw together evidence from the preceding analysis to assess the overall economic impact of investing in resilience.

Table 26 summarises how system costs and welfare costs change in moving from the *Reference* and *Low Carbon* scenarios to the *Resilient* and *Low Carbon Resilient* scenarios respectively. The high-level goals refer to the resilience constraints imposed on final energy demand and the energy mix. Electricity reliability costs refer to the additional system costs of maintaining capacity sufficient to meet reliability criteria over and above maintaining a conventional capacity margin. These costs are essentially associated with the greater use of intermittent renewables. Finally, infrastructure costs are those associated with mitigating the effects of major disruptions to the gas system.

Energy system costs change when the high-level constraints are applied, but so do welfare costs. It is important to note that the very high loss of welfare potentially associated with building in the high-level resilience goals (£15-19bn in 2025 – see Table 26) is very much an upper bound, and true welfare loss could be very much lower, or even non-existent. As discussed in Section 4, the response of residential consumers was modelled solely through a demand elasticity that caused them to reduce their demand for energy services, and did not allow conservation measures (which might be very low cost) to be chosen endogenously.

To get some insights into the possible effect of this assumption, we allowed certain residential conservation measures back into the model. These are relatively low cost and, as a result, a quarter of the demand reduction was achieved through conservation rather than a price-driven demand response. This lowered welfare losses by £2-3bn pa in 2025. If all of the demand reduction could be achieved through conservation then the welfare losses could be eliminated entirely.

In the main UKERC 2050 report (Skea et al., 2009), we considered a ‘lifestyles’ scenario resulting in demand reductions even greater than those in the resilience scenarios discussed in this report. These are underpinned by both a greater adoption of conservation measures and a reduction of energy service demands, for example through turning down of thermostats in the home or reducing travel. In 2025, the energy system cost is £35bn pa lower in the *Lifestyle Change Low Carbon* scenario than it is in the *Low Carbon* Scenario. This appears to be a classic win-win-win situation where energy conservation will bring economic, environmental and security benefits. However, the critical issue is whether reduced energy service demands are associated with welfare loss. If people are forced into discomfort through high energy prices the welfare loss is real. On the other hand, if thermostats are turned down though pro-active lifestyle choice then welfare might arguably increase.

The costs of ensuring electricity system reliability and reinforcing gas infrastructure are orders of magnitude less than the costs associated with driving the macro-structure of the energy system in different directions. Enhanced electricity reliability appears to cost around £10-15 per household per year while additional investment in gas storage or import facilities appears to run at around £2 per household.

Table 26: Estimated costs associated with different aspects of resilience in 2025

	Reference	**Low Carbon**
High-level goals	**Reference ↓ Resilient**	**Low Carbon ↓ Low Carbon Resilient**
- Change in annual system cost[1]	-£2.0bn	-£4.6bn
- Loss of welfare[2]	Up to £19bn	Up to £15bn
- Change in system cost through 25% conservation[3]	-	£0.9bn
- Mitigation of welfare loss through 25% conservation[3]	£3.1bn	£2.3bn
- Reduced system cost through lifestyle change[4]	£33bn	£35bn
Electricity Reliability		
- Cost of higher capacity margins[5]	~£300m	~£300m
Infrastructure		
- Enhanced gas import or storage capacity[6]	£45m	£45m

Notes: 1) from MARKAL runs; 2) change in consumer and producer surplus from MARKAL assuming a price-induced response in the residential sector; 3) mitigation of welfare loss when conservation measures (which deliver about 25% of residential demand reduction) are allowed in MARKAL; 4) the reduced cost of the energy system when adding lifestyle change to the *Reference* and *Low Carbon* scenarios respectively); 5) the cost of additional capacity determined by WASP as opposed to MARKAL. These additional costs vary considerably from one year to another; 6) annualised cost of two LNG terminals

A key point from Table 25 is that high-level resilience goals bring costs or benefits that are an order of magnitude higher than those associated with guaranteeing reliability of supply or insuring against infrastructure loss. The uncertainties associated with the costs of the high-level goals are equally large. However, as shown above, if the high-level goals are pursued then the case for infrastructure measures is considerably reduced.

7.3 Institutional Structure of the UK Energy System

The presumption underlying UK energy policy is that the first choice of delivery of energy services is through competitive energy markets (see, for example, DTI 2007a, p.137):

> "We believe the UK's energy needs are best delivered by a liberalised energy market. The Government's role is to set the overall market and regulatory framework that enables companies to make timely investments consistent with the Government's policy goals on climate change and security of energy supplies."

However, it is also clear that where there are market failures government intervention may seek to rectify these. Where the failures are in respect of inadequate competition, the intervention is likely to take the form of regulation. Where they involve externalities or public goods, public policy may seek to address them through regulation, economic instruments or some other intervention. To the extent that energy system resilience, or security, is a public good,[12] then public intervention to provide it to the desired extent is clearly justified. However, there is clearly room for debate over both the nature and extent of that intervention, the outcome of which will have a considerable influence on the institutional structure of the energy system and how public policy seeks to act through it.

In the UK energy system the supply of energy-using equipment, from machinery to vehicles to household appliances, has long been left almost entirely to a market regulated only in terms of health and safety characteristics (though some equipment is now environmentally regulated too). The retail supply of energy carriers (fossil fuels, biomass and electricity) was the subject of privatisation in the 1980s and these markets have been progressively deregulated, so that there is now no formal price regulation in these markets (although energy prices can be subject to substantial and overt political pressure). However, energy supply is subject to regulatory oversight by the gas and electricity markets regulator, Ofgem. Ofgem has a direct role in price regulation of the gas and electricity distribution and transmission companies, for whom competition is either very restricted or non-existent.

Ofgem's price regulation of gas and electricity distribution and transmission has important implications for energy system resilience because, to the extent that this resilience requires investment, on which the transmission and distribution companies need to make a return, this investment must be permitted by Ofgem in the regular price reviews relating to the companies, through which the companies are allowed to adjust their prices to generate the return. The following section explores the policy options in more depth.

[12] Helm (2003, p.260), for example has written with regard to the electricity system: "Security of supply ... is a system property with important public-goods characteristics."

7.4 Delivering Energy System Resilience

Policies for Diversity in Energy Supply

There are a range of options for energy and electricity supply. Primary energy sources include the fossil fuels (coal, oil, natural gas), uranium, various renewables (of which onshore and offshore wind, biomass and possibly large tidal seem likely to play the largest role, although microgeneration technologies may also make a contribution). In transport, oil is dominant, but for the future it is possible that electricity will have a major role, either directly or through the production of hydrogen by electrolysis. For heat, natural gas plays the largest role, but biomass could substitute for this to some extent, so that the substantial use of natural gas also for power generation may present issues of diversity and security of supply. Electricity may be generated by any of the above primary energy sources, although in a low-carbon world the use of fossil fuels for this will require effective carbon capture and storage (CCS) technology to be deployed as well. Clearly a carbon constraint in the absence of CCS will very substantially reduce the electricity options available and could lead to significant diversity issues.

In a centrally-driven energy system it would be relatively easy in principle to ensure energy system diversity by building capacity of different types of plant. In a market-driven context, such as that currently in place in the UK, such an outcome may be more difficult to ensure.

The first principle to encourage diversity is to ensure that there are no non-financial constraints to the deployment of the different desired capacity options. Such constraints are neither easy to identify nor easy to remove, as is clear from the analysis of the UK's experience with onshore wind energy in IEA 2008b (p.17). Despite having among the highest remuneration levels for onshore wind in Europe, the UK has among the lowest deployment levels, and this is put down to non-financial constraints. In BERR (2008a) some of the relevant issues are identified as the effectiveness of the financial incentives that are offered, planning issues, grid issues, supply chain issues, information issues, network issues, and market structure (for example, the appropriateness of the wholesale electricity market for smaller generators). Having identified these issues, it is far from clear whether the proposals being made will in fact lead to the step change in the deployment of renewable of different kinds that is required for them to achieve the 15% share in final energy demand by 2020 that is the UK's commitment under the EU Renewable Energy Directive. For example, The Government adopted a Microgeneration Strategy in 2006 (DTI 2006) which identified 25 actions to remove barriers to microgeneration, and by June 2008 was claiming (BERR 2008b, p.1) that 21 of these had been successfully completed, and the only action that remained outstanding (three having been overtaken by other events) would be completed by the end of the year. Yet it is still not at all clear that microgeneration is on a track to become more than an absolutely marginal contributor to UK energy supply (in the three years from the end of 2004 the number of microgenerators increased from 82,000 to only around 100,000, BERR 2008b, p.2).

For renewables more broadly, it is clear that time is running out if the 15% renewable energy share in final energy demand is to be achieved by 2020. For example, BERR (2008a, p.57) estimated that this could require around 3,000 extra offshore turbines of

5MW, a deployment rate of about 5 per week, from a base of 0.8GW at the end of 2008. The rate for extra onshore wind turbines is around seven 3MW machines per week, when at the end of 2008 the total operational capacity was only 1.7GW (BWEA 2009). The realisation of these numbers strains credibility in the absence of a completely transformed policy landscape that clearly addresses all the issues relating to both financial incentives and non-financial constraints. The Coalition Government's proposals for Electricity Market Reform (DECC, 2010) set out comprehensive changes to the incentive structure for low carbon generation that address the question of financial incentives.

Looking further into the future, the Government is keen to ensure that there is a favourable policy framework for a new generation of nuclear power stations, and DECC 2008a (p.51) declares confidently: "The Government is also ensuring that there are no unnecessary barriers to the deployment of new nuclear power, and the appropriate regulatory frameworks are in place for nuclear new build.", with the Nuclear White Paper (BERR 2008c, p.136) envisaging the start of construction in 2013 and power output from 2018, although DECC 2008a (p.51) gives a range of years, 2017-2020 for the latter. The issues set out in the White Paper as needing to be addressed include planning, site assessment, assessment of potential health impacts, design assessment and licensing, and review of the regulatory regime in general. The draft National Policy Statement on released in December 2009 could unlock some of the planning constraints associated with nuclear power (DECC, 2009c).

On the economics of nuclear, and therefore the potential need for public subsidy of new nuclear build, the Government has had a remarkable change of mind over the past five years. The Energy White Paper of 2003 said unequivocally "the current economics of nuclear power make it an unattractive option for new generating capacity" (DTI 2003, p.61), but the next Energy White Paper in 2007 stated in contrast "Based on this conservative analysis of the economics of nuclear power, the Government believes that nuclear power stations would yield economic benefits to the UK in terms of reduced carbon emissions and security of supply benefits" (DTI 2007a, p.191), although "it would be for the private sector to fund, develop, and build new nuclear power stations in the UK, including meeting the full costs of decommissioning and their full share of waste management costs" (DT1 2007a, p.17). This implies that new nuclear build would neither need nor get public subsidy. The wording in DTI 2007b (p.59) is slightly different: "As for any type of power station, energy companies would decide whether to propose, develop, construct and fund any new nuclear power stations. Private sector financing would also need to cover the full costs of decommissioning and full share of waste management costs.", and does not imply so strongly that there will be no public subsidy. Indeed, later on BERR 2008c (p.154) says: "It is not intended that incentives will be provided through the fiscal regime to invest in nuclear power generation in preference to other types of electricity generation. The Treasury and HMRC are, however, exploring the possibility that the timing of nuclear decommissioning could create a potential tax disadvantage for nuclear operators and, if so, whether it may be appropriate to take action to ensure a level fiscal playing field between nuclear power and other forms of electricity generation." This may open the door to some public subsidy of decommissioning costs at least.

The issue is important, because if nuclear power is an important element of UK energy system resilience, and if private companies decide that it is not in fact financially viable without public subsidy (as has been the fact in the past), then without public subsidy new nuclear stations will not be built and energy system resilience will not be delivered.

Policies for Reducing Energy Demand

In the *Reference* scenario, primary energy demand in 2025 is 7% below that in 2000, and, in the *Resilient* scenario, because of the imposed 3.2% p.a. reduction in energy intensity, it is 14% below the *Reference* case. The objective of the EU Energy Efficiency Action Plan (EC, 2006) is "to control and reduce energy demand and to take targeted action on consumption and supply in order to save 20% of annual consumption of primary energy by 2020 (compared to the energy consumption forecasts for 2020). This objective corresponds to achieving approximately a 1.5% saving per year up to 2020." In the *Low Carbon Resilience* scenario, primary energy demand falls by 18% between 2005 and 2020 compared to only 9% in the *Reference* scenario. Since the EU savings target is specified with reference to what primary energy demand would otherwise have been in 2020 without policy actions initiated prior to 2006, it is very hard to compare the scenarios with the EU target. Since the *Reference* scenario includes some policies set out in the 2007 Energy White Paper it can be assumed that it already embodies some policy effort. The *Resilience* and *Low Carbon Resilience* scenarios appear roughly compatible with the EU goal. As described in Section 4, the *Resilience* scenario assumptions require optimistic assumptions the efficacy of the policy measures specified in the 2007 White Paper as well as some defined subsequently. This scenario can therefore be described as stretching in policy terms.

In principle, there is little mystery in how the economy's energy intensity could be reduced: a combination of rising energy prices and measures to enhance the development and deployment of energy efficiency measures in the various end-use sectors of machinery, electric motors, buildings, vehicles and appliances. Achieving a 3.2% p.a. reduction would be challenging, and any number of devils will lurk in the policy details, but the generic policies themselves are reasonably well understood. The assumption that a 3.2% annual improvement can be achieved through to 2020 is perhaps safer than assuming that such improvements can be sustained indefinitely.

Delivering improvements in energy intensity beyond historic time trends has not often been achieved. Partly this has been because governments have been unwilling to increase energy prices above market rates to the extent that would be required. However, it has also been because of now well documented barriers to and constraints on the take up of energy efficiency measures that are cost-effective at prevailing prices (Sorrell et al., 2004).

The UK Government's Consultation on a Heat and Energy Saving Strategy (DECC 2009b) is couched resolutely in terms of 'helping people to change behaviour and take action' (the title of chapter 2) when, throughout, it is claimed that what is being proposed will save people money. Such a seeming paradox is commonly encountered in policy discussions about energy efficiency, and may be explained by one or all of the following reasons (again, see Sorrell et al. 2004 for a more detailed exposition): people are unaware of the price they pay for energy or what their energy bills are; even with recent energy price increases (and certainly before them), energy bills are a low proportion of most people's expenditure; energy efficiency technologies have a low profile and are of little interest to energy consumers; people (both consumers and installers) are unaware or sceptical of the technologies that would help save energy; consumers do not trust the expertise of the installers of energy efficiency technology; the installation of some energy efficiency technologies causes disruption to the household; consumers tend to have high discount rates for energy efficiency technologies, and therefore demand excessive rates of return which the technologies cannot deliver.

Now is not the place to go into detail about the wide range of complementary policies that are necessary in order to overcome these barriers to energy efficiency. For a step change in the take up of energy efficiency, the policies are likely to have to be stronger than in the case of energy supply, because consumers are less responsive to energy price incentives than energy businesses, and the barriers to energy efficiency are arguably higher and more pervasive. DECC (2009b) goes considerably further in seeking to address them that previous Government policy on household energy efficiency. It remains to be seen whether the concrete policies that emerge from the Consultation manage to achieve the very considerable increase in energy efficiency installations that is being sought.

Policies for ensuring reliability and adequacy of infrastructure

In the *UKERC Energy 2050* project the issues of reliability and redundancy in the electricity system (given the very limited current electricity storage options) are reflected in the capacity margin (the gap between generating capacity and peak power demand), which is an important parameter in all the models used. Current UK Government policy is to deliver an adequate capacity margin by having a licensing obligation on power companies to meet energy demands, and then relying on markets, through price signals, to deliver the capacity that may only be rarely used, but will then command a high price for power generated.

However, there is now widespread acceptance that current market arrangements may not be sufficient to guarantee reliable energy supply while ambitious low carbon targets and renewable energy goals are pursued. Ofgem is investigating the need, and options for, alternative market arrangements through Project Discovery (Ofgem, 2009). Meanwhile, the Government has accepted the Committee on Climate Change's recommendations that market arrangements may need to be changed if climate policy goals are to be met (HMG, 2010).

Explicit capacity payments for plant that may not be much used is one option that will need to be assessed in order to underpin incentives for adequate investment in capacity. The merits of this have been discussed by Oren (2000). The Coalition Government's Electricity Market Reform package (DECC, 2010) indeed includes a capacity mechanism.

In relation to policy for infrastructure investment for energy system resilience, there are three possible models:

1. Government provides the appropriate framework for the market to make the investment (the model through which electricity supply and gas storage and international pipelines are supposed to be provided);

2. The regulator permits the investment through price reviews, but the investment is provided by the regulated companies (this is the model for electricity and gas transmission and distribution);

3. Government carries out the investment itself (this was the principal model before privatisation).

The current approach of Ofgem and the UK Government is to expect market signals to provide the incentive to invest in such capacity. For gas, the fossil fuel over which there is the principal security of supply concern, National Grid break down supply into UK Continental Shelf (declining), imports (increasing) and storage, while imports are distinguished by supply type (Norway, Continent and LNG) and import route (the various pipelines to Norway and elsewhere on the European mainland, and LNG, but not, interestingly, by country of origin). The market approach to the provision of supply infrastructure has had some success over the past few years, with new pipelines to Norway (Langeled) and The Netherlands (Balgzand-Bacton) opening in 2006, and two large LNG facilities at Milford Haven opening in 2009. While storage has been slower to increase, there is expected to be very substantial construction over 2010-14, such that by 2018 there will be storage space for some 10% of UK projected annual demand (DECC 2008a, p.72), in line with the capacity expansion suggested through our work with the CGEN model.

Our modelling suggests that there is potentially a case for investment in further ”strategic” gas infrastructure beyond that which the market would deliver if we pursue the supply-led energy strategy embodied in the *Low Carbon* scenario as opposed to the demand-led strategy embodied in the *Low Carbon Resilient* scenario. By itself, that investment would be relatively modest and would add little to consumer costs. The key policy question is whether the benefits of driving this investment through rate of return regulation outweigh the disadvantages of driving out investment made on a purely market basis.

7.5 Future research directions

The work described in this report was motivated by increasing public concern about the vulnerability of the UK energy system to contingencies that go beyond extreme weather, demand variations that can be characterised statistically and “normal” outages of plant.

We are conscious of the fact that the work has only started to open up a new agenda in energy research. We are aware of the limitations:

- The main focus has been on the gas system

- The characterisation of energy “shocks” has looked only at the physical aspects - we have not addressed wider market outcomes, for example in terms of changes to energy spot prices

- We have not been able to attach any probabilities to the shocks that we have postulated

- We have not considered the vulnerability of the UK economy as a whole to fluctuations and/or shocks in world energy prices

In taking work on energy system resilience forwards, we would therefore consider the following lines of inquiry:

- Examining a wider range of contingencies relating to oil, electricity and renewables (including bio-energy)

- Examining market responses to shocks as well as possible physical responses costed in a bottom-up manner

- Attempting to attach probabilities to various types of shock. This may not be possible for “geopolitical” events, but many of the historic shocks that we reviewed resulted for insurable weather or accident-related incidents for which evidence may be available.

- Producing new or “reduced” models of system responses to energy shocks that could be operated in Monte-Carlo mode. The current models are too cumbersome to operate in this way.

Finally, by focusing on “resilience” as an intrinsic characteristic of the energy system we have, broadly, managed to avoid considering the fundamental causes of shocks and instabilities. In UKERC Phase II which started in May 2009, we will be assessing the development of future international gas markets, the stresses that radical de-carbonisation objectives place on the international energy system, and the adequacy of international governance arrangements for managing stress and change. The MARKAL model described in Section 3 is being supplemented by the TIMES global model which breaks out the UK as one region in a global market for energy.

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ANNEX A: DETAILED ANALYSIS OF RESILIENCE INDICATORS

This Annex describes in more depth the analysis underpinning the quantification of the *Resilient* and *Low Carbon Resilient* scenarios. It is divided into three main sections: 1) the rationale for the final demand constraint; 2) parametric analysis using MARKAL-MED which explores the interaction between the final energy demand and supply diversity constraints; and 3) the assignment of reliability indicators used in the electricity modelling in Section 5.

A.1 Final energy demand

An appropriate constraint on final energy demand needs to be ambitious while at the same time lying within the bounds of technical and economic feasibility. We have approached this from two angles. First, we conducted sensitivity tests on the MARKAL model constraining final energy demand to fall at increasingly large annual percentage rates with respect to GDP. This tested feasibility from the modelling perspective. Then we looked at the range of uncertainty associated with the delivery of energy efficiency embodied in the UK's Energy Efficiency Action Plan (DEFRA, 2007), as subsequently updated and quantified in the most recent DECC Updated Energy and Carbon projections (DECC, 2008b) available at the time the work was conducted.

The DECC projections and the sensitivity tests can be compared out to 2020. We have taken one of the MARKAL sensitivity tests which closely matches the DECC "optimistic" projection of the delivery of energy efficiency policies. The associated annual percentage improvements in energy efficiency (ratio of final energy demand to GDP) are then extrapolated out to 2050.

Table A-1 compares the development of final energy demand and GDP in the UKERC *Reference* scenario and under four other assumptions (Sensitivities A-D) about the development of the final energy demand/GDP ratio beyond 2010. The ratio is assumed to improve at rates between 2.4% and 3.6% per annum. The lower rate is slightly faster than in the UKERC Reference scenario. Option D (3.6% per annum) could not be solved in MARKAL and we have therefore assessed sensitivities B and C in more depth.

Sensitivities B and C are compared with the most recent official UK energy projections coupled with projections of the impacts of UK energy efficiency policy actions. The Updated Energy and Carbon Emissions Projections (DECC, 2008b) include a scenario out to 2020 which includes "firm and funded" policies in the 2007 Energy White Paper, those announced in the White Paper and included in the 2007 Energy Efficiency Action Plan (DEFRA, 2007) plus two further measures announced since the Energy Efficiency Action Plan was published.[13] Three separate estimates of the effectiveness of the post-White Paper policies were made – low, central and high.

[13] "Carbon neutral government" and the inclusion of domestic aviation in the EU Emissions Trading Scheme.

Table A-1: Projected GDP, Final Energy demand and energy intensity

Year	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
GDP index	100.0	112.9	129.3	143.5	158.4	174.9	193.1	213.2	235.4	259.9	286.9
PJ											
REF	6189	6321	6300	6260	6288	6287	6312	6367	6401	6441	6455
A	6189	6318	6291	6182	6045	5910	5779	5651	5525	5403	5283
B	6189	6318	6291	6056	5801	5557	5323	5099	4885	4679	4483
C	6189	6318	6291	5933	5567	5224	4902	4600	4316	4051	3801
D	6189	6318	6291	5811	5341	4909	4512	4148	3812	3504	3221
% pa											
REF/GDP		-1.99%	-2.74%	-2.18%	-1.87%	-1.96%	-1.88%	-1.79%	-1.86%	-1.84%	-1.92%
A		-1.99%	-2.76%	-2.40%	-2.40%	-2.40%	-2.40%	-2.40%	-2.40%	-2.40%	-2.40%
B		-1.99%	-2.76%	-2.80%	-2.80%	-2.80%	-2.80%	-2.80%	-2.80%	-2.80%	-2.80%
C		-1.99%	-2.76%	-3.20%	-3.20%	-3.20%	-3.20%	-3.20%	-3.20%	-3.20%	-3.20%
D		-1.99%	-2.76%	-3.60%	-3.60%	-3.60%	-3.60%	-3.60%	-3.60%	-3.60%	-3.60%

Table A-2 summarises the impact of the measures as estimated by DECC in $mtCO_2$ equivalent. These have been converted to final energy demand figures using sector specific ratios derived by DEFRA (2007).

Table A-2: Assumed Impact of Energy Efficiency Policies

	DECC mtCO2			DECC PJ		
	Lo	Central	High	Lo	Central	High
Carbon Reduction Commitment	3.6	3.6	3.6	38	38	38
Products policy	2.2	4.0	6.2	24	43	67
EPBD	1.4	2.2	3.6	19	29	48
Carbon neutral government	0.7	0.7	0.7	7	7	7
Smart Metering	0.4	0.7	0.7	5	9	9
Total business and public	**8.3**	**11.2**	**14.8**	**93**	**127**	**169**
Further improvements in vehicle efficiency	0.3	6.2	12.0	4	87	168
Domestic aviation included in EU ETS	0.7	1.1	1.5	9	15	20
Total transport	**1.0**	**7.3**	**13.5**	**13**	**101**	**188**
Better billing and metering	-	0.8	2.2	-	11	31
Product policy	1.5	3.3	4.8	16	35	51
Supplier obligation	11.0	12.8	14.7	155	180	207
DCLG- Zero carbon homes	4.0	4.4	4.4	74	81	81
Energy Performance of Buildings Directive	0.7	1.5	2.2	12	25	36
Total residential	**17.2**	**22.8**	**28.3**	**257**	**333**	**408**
TOTAL DEMAND SIDE	**26.5**	**41.3**	**56.6**	**363**	**562**	**765**

Based on: DEFRA (2007); DECC (2008b)

Figure A-1 then compares final energy demand in 2005 with DECC's central estimates of final energy demand in 2020. Figure A-1 includes columns referring to the low and high estimates of policy effectiveness, a "reference" case which backs out *all* post-White Paper policies and a "no policies" case. The "reference" case is relevant because the assumptions underlying it correspond to those underlying the UKERC *Reference* scenario. Finally, Figure A-2 compares the DECC final energy demand projections from Figure A-1 with those arising from UKERC sensitivities B and C as set out in Table A-2. There is a slight discrepancy between *actual* final energy demand in 2005 and that projected in the MARKAL *Reference* scenario (which starts from a year 2000 baseline) which needs to be taken into account. Allowing for this final energy demand, UKERC sensitivity C is almost identical to the DECC high impacts projection. We therefore set the final demand constraints in the UKERC *Resilience* scenario equal to those in sensitivity case C. This is equivalent to saying that ambitious policies, with a relatively high impact, are implemented through to 2020 and that the momentum of energy efficiency policy is maintained afterwards.

Figure A-1: Projections of Final Energy Demand after Allowing for Energy Saving

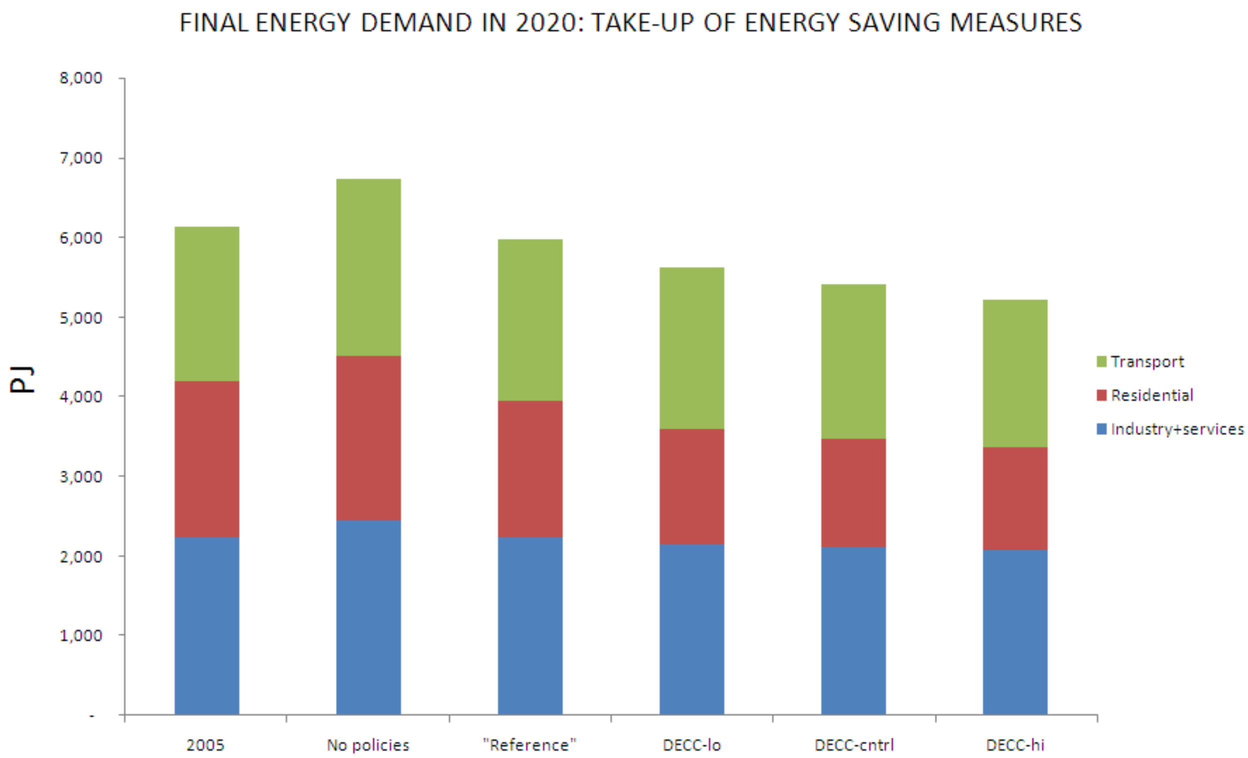
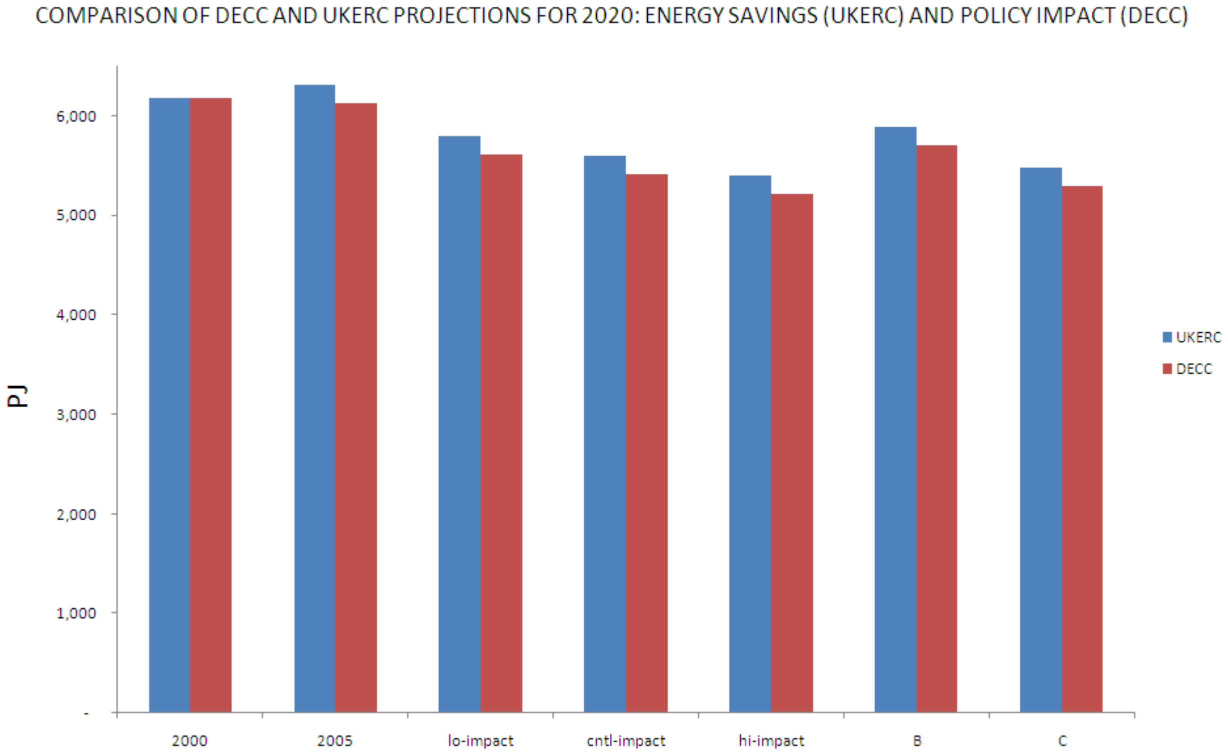


Figure A-2: Comparison of DECC Projections and UKERC Sensitivities



A.2 Resilient parametric analyses in MED

Definition of constraints

In this section, parametric constraints on diversity in primary energy supply and power supply, and reduction in final energy demand, are defined and analysed using the MARKAL-MED model. The parametric constraints and their rationale are given in Table A-3. Each constraint is applied in isolation. Insights from the analyses are summarised in the following sub sections. The results from the parametric runs are interpreted with respect to the *Reference* scenario (Anandarajah et al. 2009).

Table A-3: List of constraints in parametric analyses in MED

Criteria	Rationale	Name and description of constraints	
Diversity in primary energy supply	This criterion is intended to promote supply diversity in overall energy system.	R_PE	A maximum market share of 40%[1] is applied [2] to each fuel type. Import and domestic fuels are aggregated as a single category. Uranium for nuclear power generation is excluded in this constraint but nuclear generation is constraint through diversity in power supply.
Diversity in power sector	This criterion is intended to promote supply diversity specifically for the electricity sector.	R_P (PJ): Diversity in electricity generation mix	A maximum market share of 40% is applied[2] to electricity generation from each fuel sources. In general, fuel sources are aggregated as coal [3], gas [3], nuclear [4] and renewable [5].
		R_P (GW): Diversity in installed capacity	Similar to the diversity of electricity generation mix constraint R_P (PJ), but applied to installed capacity.
		R_POW: Diversity in both installed capacity and generation mix	Combination of the above two constraints, R_P (PJ) and R_P (GW)
Reduction of final energy demand	This criterion is intended as proxy for expenditure on final energy that would reduce the UK's economic exposure to volatility or enduring rises in global energy prices.	This final energy intensity constraint is aimed to reduce the final energy demand. The final energy intensity is unconstrained [2] up to 2010 and then falls [6] at the following annual rates.	
		R_FE-A	2.4% per annum
		R_FE-B	2.8% per annum
		R_FE-C	3.2% per annum
		R_FE-D	3.6% per annum.

[1] The 40% threshold is derived from an equivalent Herfindahl-Hirschman Index (HHI) of 30%. HHI is used by the Office of Fair Trading to measure excessive concentration when considering mergers and acquisitions

[2] Due to the existing capital stocks and near term policy constraints, all the above constraints are implemented from 2015

[3] Coal/gas with and without CCS is aggregated

[4] only to new build nuclear plants

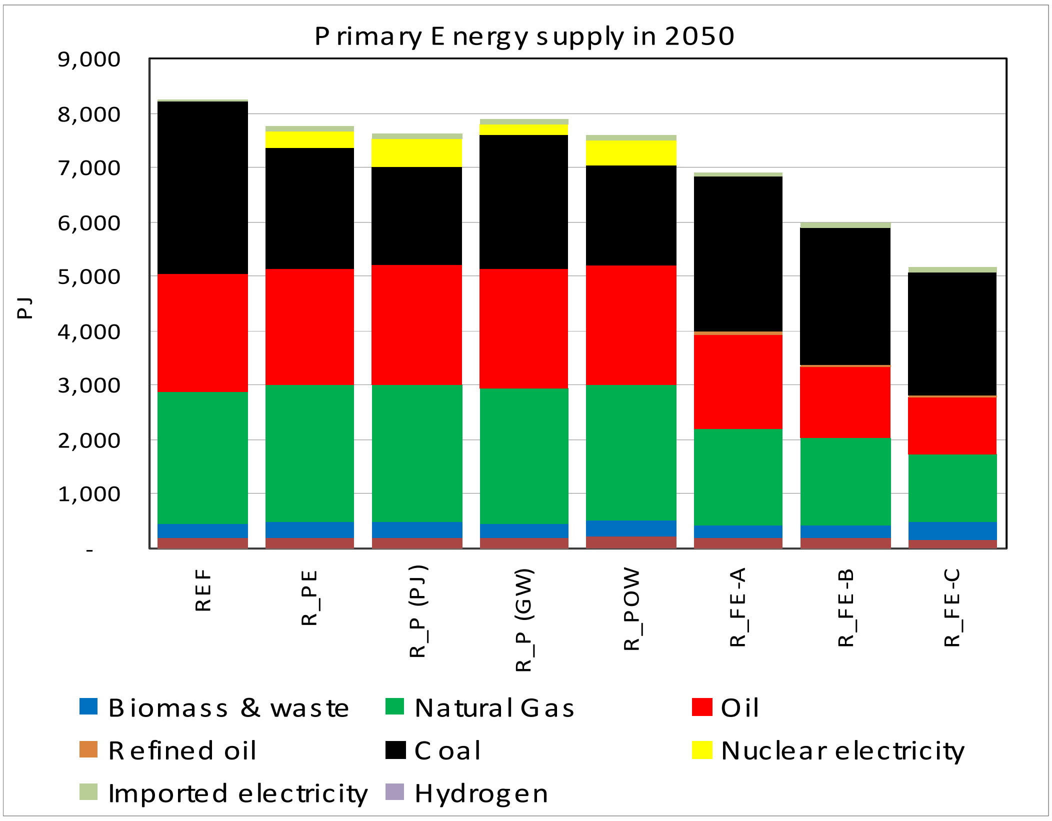
[5] offshore wind, tides, marine and wave

[6] In the reference scenario (REF), energy intensity reduces between 1.79% and 2.74% per annum during 2010-2050 (Anandarajah et al., 2009).

Diversity in primary energy supply

In the *Reference* scenario, gas dominates the primary fuel supply in 2025 and coal in 2050. The *R_PE* constraint bites from 2015 because of the oil market share and from 2030 because of the coal market share. However, there is no significant change to the energy system in 2025. In 2050, primary energy supply reduces to 7751 PJ versus 8243 PJ in the *Reference* scenario. The share of coal in primary energy supply reduces to 31% (vs. 39% in the *Reference* scenario). The reduction in coal is because of change in the power section. Coal based electricity generation reduces to 57% from 81% in the *Reference* scenario. In turn, nuclear based power generation fills the electricity gap and contributes 18% of the total electricity generation (vs. no nuclear in the reference scenario). It illustrates that the power sector is the cheapest sector to enhance diversity in primary energy supply. The high cost nuclear electricity (with respect to the cheaper coal) induces demand side response, particularly in electricity driven appliances in the residential and service sectors. The restriction of coal also reduces direct use of coal in industrial applications. These demand side responses reduce final energy demand, and thereby primary energy supply. The welfare cost is about £3.5 billion in 2050. The diversity in fuel supply, particularly driven by the power sector, reduces the CO2 emission by 26% in 2050 from the reference scenario or 16% from the 1990 level.

Figure A-3: Primary energy supply in parametric runs



Diversity in power supply: electricity generation mix

Figure A-4 shows power generation mix in 2025 and 2050. In the *Reference* scenario, coal dominates the electricity generation mix with 54% share in 2025 and 81% share in 2050. As the result of the *R-P(PJ*) constraint, coal based power generation in 2025 reduces to 40%. The gas share increases to 31% (vs. 19% in the *Reference* scenario). In 2050, the nuclear share rises to 33% (vs. zero in the *Reference* scenario). Diversifying electricity generation from coal to nuclear increases the cost of the energy system, and also induces demand reduction. For example, the residential electricity demand for appliances reduces by 5% in 2025. The combination of high energy system cost and the losses in consumer surplus results in a welfare loss of about £1.1bn in 2025 rising to £4bn in 2050. At the same time the diversification of electricity generation reduces CO_2 emissions by 22% from the 1990 level.

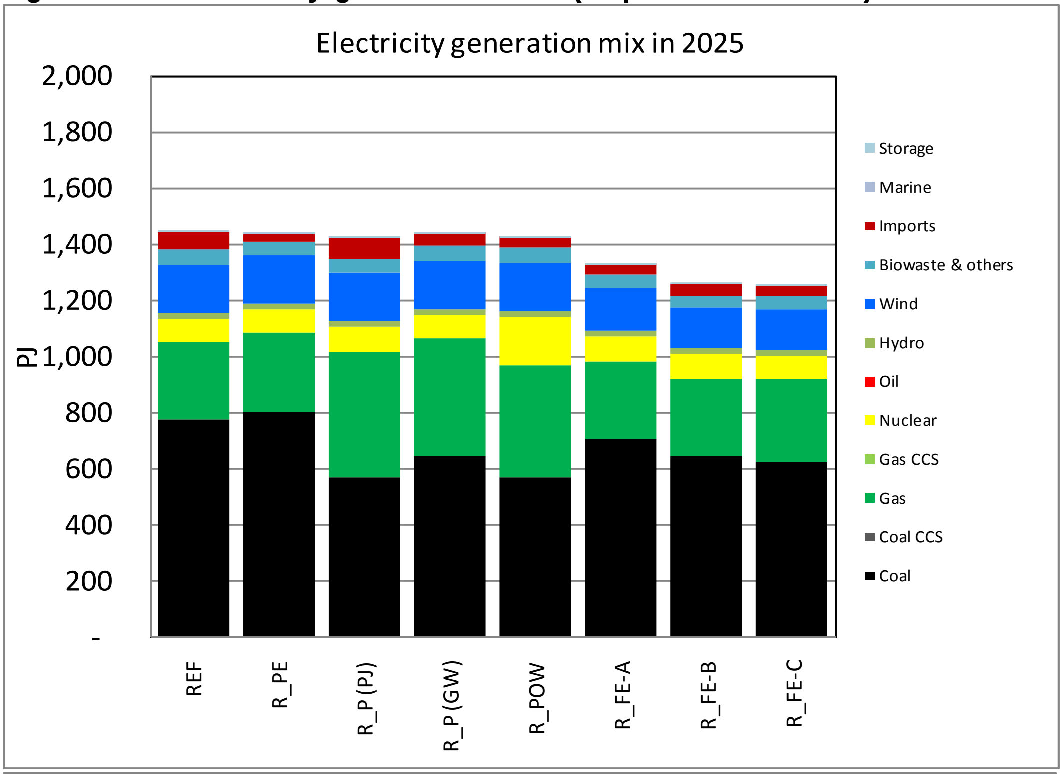
Diversity in power supply: installed capacity

The capacity constraint encourages investment in gas capacity in the short term because it is cheapest after coal, the unconstrained choice. Nuclear and wind benefit in the long term. In 2025, the installed capacity of gas plants doubles whereas generation increases by less than 50% (A-5). As coal based generation is cheapest, the investment in gas plant is simply to increase capacity diversity.

In 2050, the coal based generation capacity in *R_P(GW)* reduces to two-thirds of the level in the *Reference* scenario. It stimulates new investment in nuclear for base load generation. The model also chooses high wind capacity, which requires additional gas plant to cope with its intermittence nature. Thus, the investment in cheaper gas plant complements the intermittent wind capacity and also serves as reserve margin in addition to fulfilling the diversity constraints. Despite the diversity in capacity, electricity generation is still dominated by coal (60%). Therefore the demand side response is lower than in the R_P(PJ) run. The welfare costs are £0.8bn in 2025 and £2.5bn in 2050.

Applying the *R_P(GW)* constraint results in more coal based electricity generation (60%) and therefore it does not meet the criterion for diversity in generation. On the other hand, the *R_P(PJ)* run fulfils the criteria for capacity diversity. Combining the two constraints produces more or less a similar results to *R_P(GW)* in the short term and *R_P(GJ)* in the long term. Therefore its welfare cost in 2025 is slightly higher than in *R_P(PJ)*. However, the CO_2 emission reduction and welfare cost are similar to those in the *R_P(PJ)* run (see Table A-4).

Figure A-4: Electricity generation mix (in parametric runs)



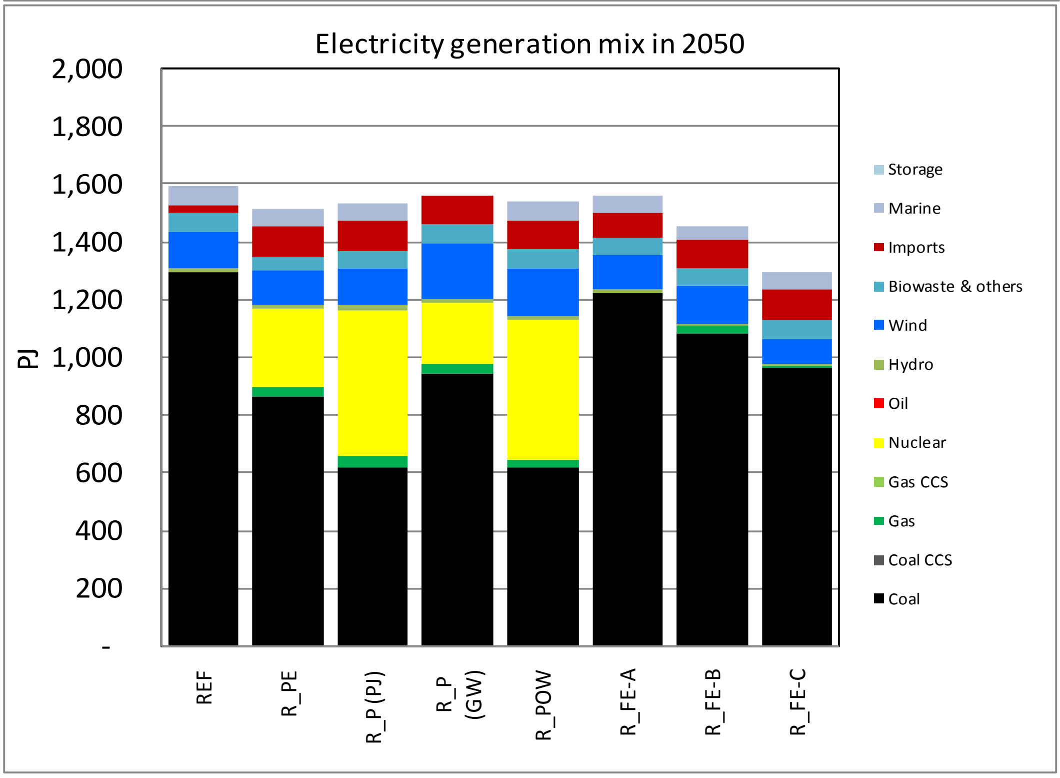
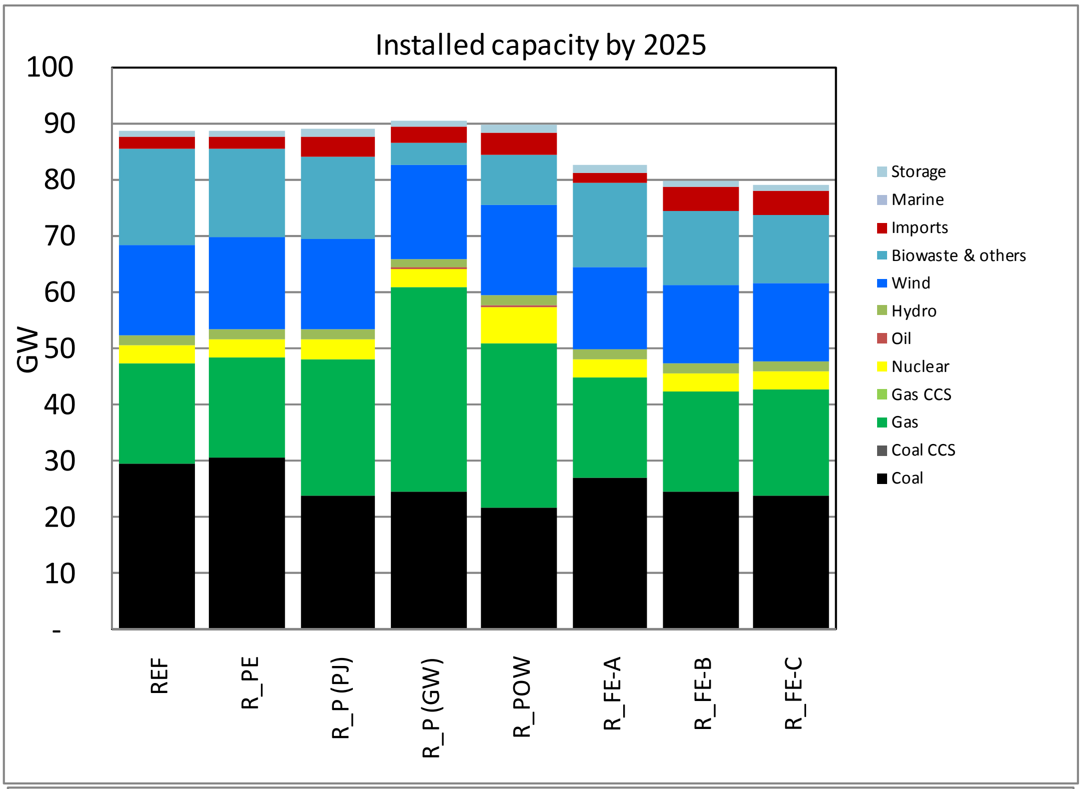


Figure A-5: Installed capacity (in parametric runs)



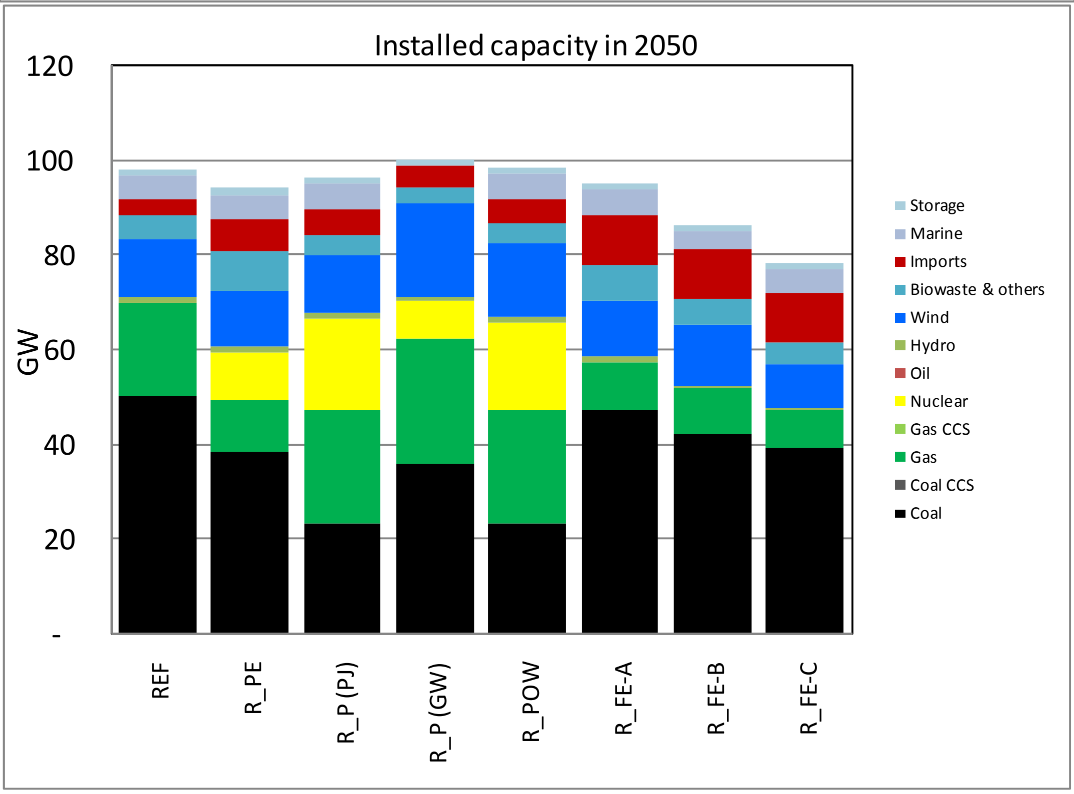
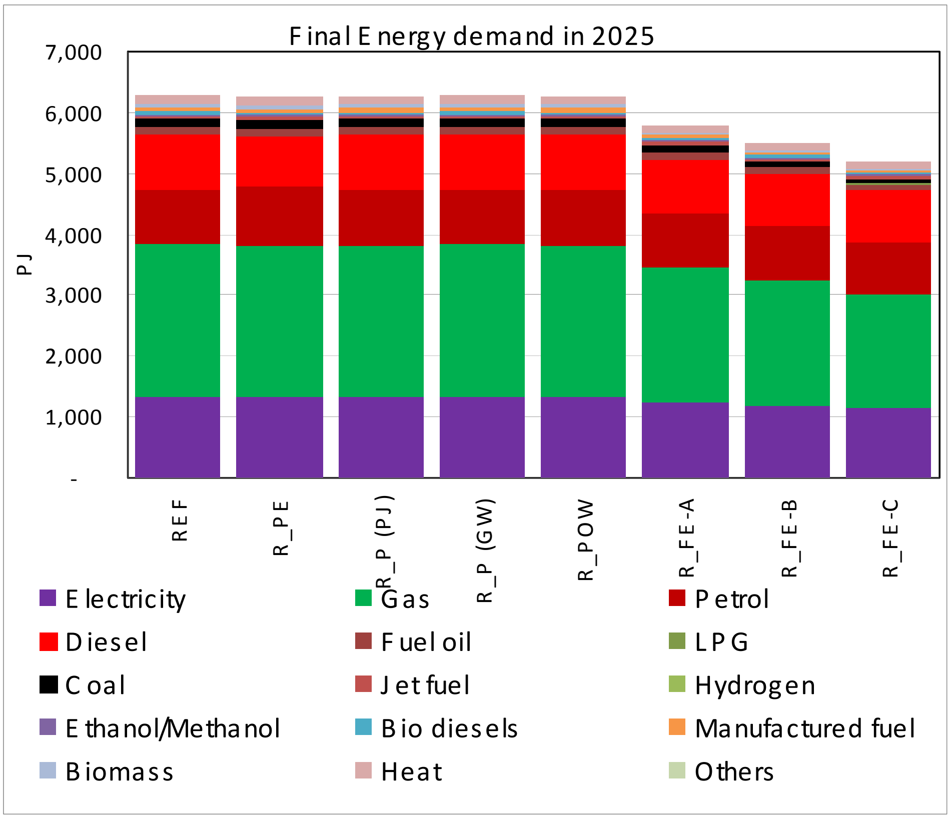
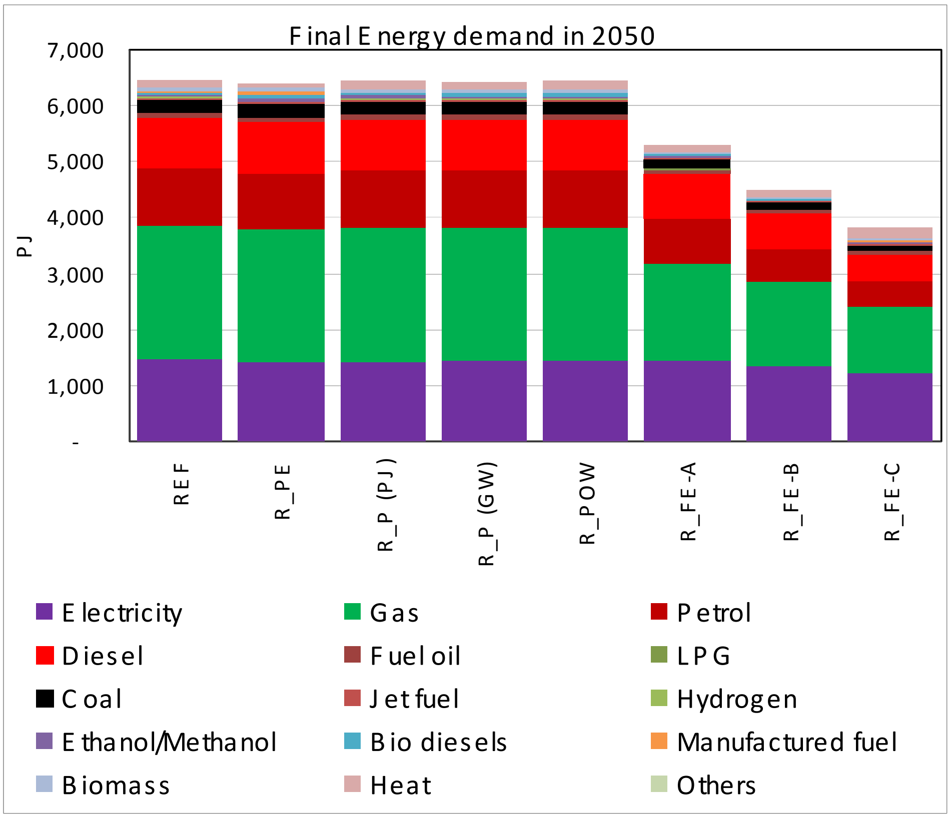


Figure A-6: Final energy demand in parametric runs





Reduction of final energy

Figure A-6 shows final energy demand from the parametric runs. The final energy reduction constraints bite harder than the diversity constraints. An annual energy intensity reduction of 3.6% (*R_FE-D*) gives an infeasible solution. All end use sectors respond to the final energy constraint through energy efficiency improvements and fuel switching. In general, this constraint shifts the final energy mix from gas towards electricity. For example, gas based heating in the residential sector is replaced by heat pumps. By itself, this would lead to increased electricity demand. However, this is more than compensated by reductions in electricity demand for other purposes. Reducing final energy demand also reduces primary energy demand, which now coal dominates. Although coal dominates electricity generation, CO_2 emissions fall by 40% from the 1990 level.

There is a substantial demand side response in the residential sector. This declines by 25% in 2025 and 47% in 2050 (Figure A-7). The high level of demand reduction results in very high welfare losses of £6-18bn in 2025 and £10-45bn in 2050 (Table A-4).

Figure A-7: Demand reduction in residential sector (in parametric runs)

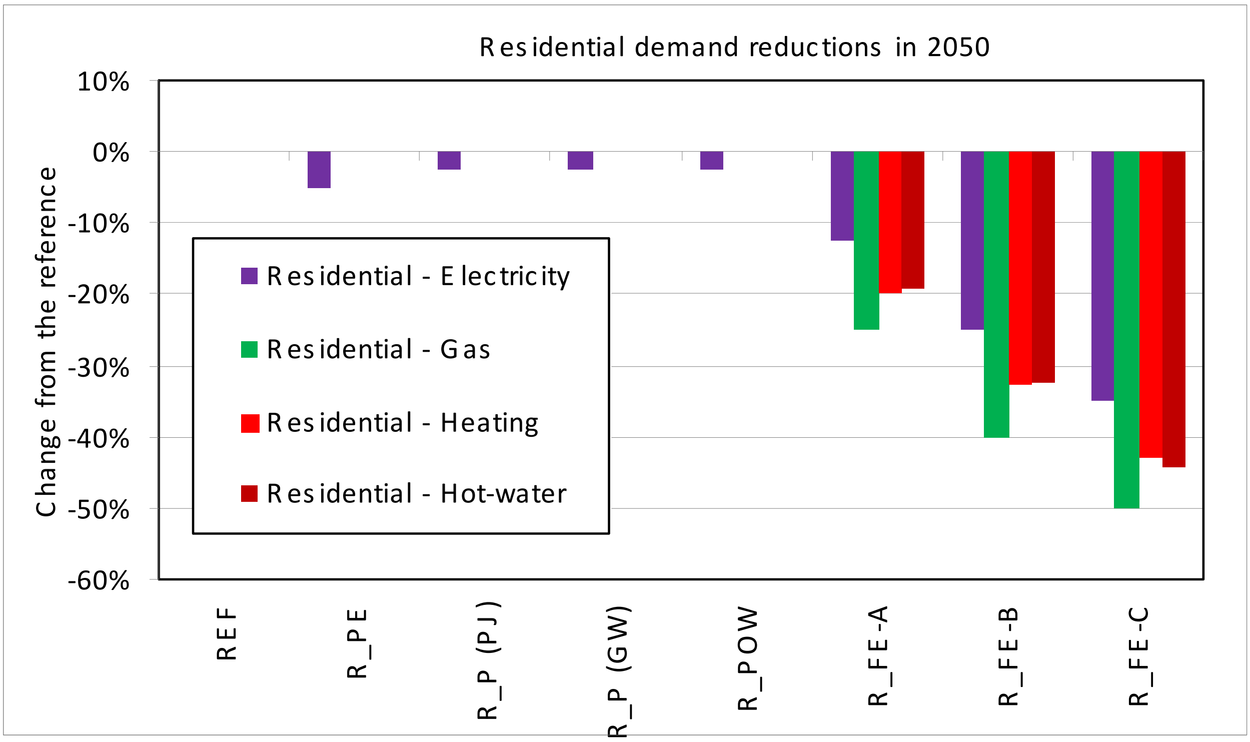


Table A-4: Welfare costs in 2050 with respect to the *Reference* scenario

MED indicators	R_PE	R_P (PJ)	R_P (GW)	R_POW	R_FE-A	R_FE-B	R_FE-C
	(in £ billion)						
Change in energy system cost	+2.52	+3.68	+2.18	3.77	-4.84	-7.74	-13.70
Welfare cost	-3.56	-3.99	-2.54	-4.04	-9.96	-24.38	-45.55

Characterising the resilient core scenario

From the above parametric analyses, it is clear that none of the individual constraints fulfils all the criteria for the resilient energy system set out in Table A-3. Under the power supply diversity constraint *R_P(PJ)*, the share of gas in primary energy supply in 2025 is 43%, exceeding the 40% limit on market share. In the primary energy diversity constraint run *R_PE*, the share of coal based electricity generation (>57%) exceeds the threshold level of 40%. In neither of these runs, does final energy demand fall at more than 3.2% per annum. Conversely, in *R_FE-C* run, neither power supply nor primary energy supply diversify. Therefore all three constraints, diversity in primary energy supply (*R_PE*), diversity in power generation mix (*R_P (PJ)*) and a reduction in final energy intensity of 3.2% per annum (*R_FE-C*) have been combined for the core resilient scenario.

In the *Low Carbon* scenario, residential heating switches entirely to heat pumps. This also happens in the *R_FE-C* run. To ensure diversity, an additional constraint is imposed in the *Resilient* scenario so that only a maximum of 30% of residential heating demand can be met by heat pumps.

A.3 Electricity System Reliability[14]

This section addresses the treatment of reliability in the WASP model described in Section 3.

The main objective of electric system planning is to adequately meet demand for electric power at the minimum cost within the broader energy and its related policy targets. The amount of generation capacity in a power system is considered to be “adequate” if it meets electricity demand with an “economically efficient” level of reliability. Conceptually this “optimal” level of capacity to be installed would be determined by balancing generation investment costs against benefits associated with the improvements in reliability of supply, i.e. the reduction in loss of supply to consumers. Instead of conducting such a cost benefit analysis, generation system planners traditionally aim to maintain a certain level of reserve (capacity) margin that would deliver a minimum reliability performance as measured by various reliability indices.

Factors that affect the long-term reliability of the generation system include:

- Random breakdown of generating equipment (forced outages)
- Variation in demand to be met by generating system (including random variations)
- Variation in available energy from energy limited generation sources (e.g., wind and hydro power) which also affects the available capacity to the system
- Scheduled maintenance of generating units which increases with plant aging
- Decommissioning or de-rating of plants
- Changes in new capacity scheduled to come online, e.g., delays or cancellations because of financial and other constraints.

[14] This discussion applies to the WASP model. A similar approach was used in CGEN.

A number of system reliability evaluation measures are being used or have been proposed. Such indices may apply to the entire power system, from generation through transmission to distribution. The reliability indices discussed in this Annex are with reference to generation system reliability only and exclude transmission and distribution. The most common indices include reserve margin, Loss of load probability, loss of load expectation and expected energy not served. Others include loss of energy probability, frequency and duration of failures, effective load carrying capability and firm equivalent capacity. It should be noted that the popularity of an index is not necessarily due to it providing an accurate assessment of system reliability. Rather it could be due to the ease of its use and required magnitude of input/data for its assessment. Some indices are mutually convertible or one can be approximated from the other.

In a centrally planned system dominated by thermal generation technologies, the most frequently used index has been the “Loss of Load Probability” (LOLP) which specifies the probability that the system peak demand will not be met. The last security standard applied in the UK, by the Central Electricity Generation Board ahead of privatisation in 1990, required that the risk of peak demand exceeding available supply (LOLP) was not to exceed 0.09 (i.e., interruptions in supply should not occur in more than nine winters in a century). Based on the probabilities of plant failure, including uncertainty in the timely development of generation that corresponded to an equivalent generation availability of 85%, this standard would require a capacity margin of approximately 20%.

The North American Electricity Reliability Council (NERC) reports a use of LOLP, LOLE and reserve margin measures to evaluate the adequacy of their regional generation capacity portfolios. Many of the regional reliability councils (regions) in NERC’s jurisdiction apply either LOLP (1 in ten years) or LOLE (0.1 day/year or 2.4 hour/year).[15] In Australia, the reliability standard for generation and bulk supply is expressed in terms of the maximum permissible unserved energy or the maximum allowable level of electricity at risk of not being supplied to consumers. This is set at 0.002% of the annual energy consumption for the associated region or regions per financial year.[16]

It is important to recognise that each index has certain strengths and weaknesses and does not provide a complete description of generating system reliability. A strategic study of system development should quantify system reliability using more than one measure. The WASP model was used in this study to assess the electricity generation system's reliability and security of supply level in terms of the following three indicators:

- Loss-of-Load Probability (LOLE): the percentage of time during which the system load exceeds the available generating capacity in the system

- Energy not Served (ENS): the amount of energy required by the system and which cannot be supplied by the generating capacity existing in the system

[15] Resource and Transmission Adequacy Recommendations, North American Electric Reliability Council (NERC), 2004
[16] Comprehensive Reliability Review, AEMC Reliability Panel. Australian Energy Market Commission, 2007

- Capacity (Reserve) Margin (CM): is the amount of generation capacity in the system in excess of the annual peak load.

The three reliability indices encompass technical constraints referring to the minimum acceptable level of generating system performance and an economic criterion (ENS coupled with a value assigned to energy not served) to include the generating system reliability considerations directly in the determination of minimum overall costs. System reliability indices, LOLE and ENS, are computed for each system expansion configuration that has an overall generating capacity within user-specified reserve margin constraints. These are calculated in the model during the probabilistic simulation of system operation for each configuration. The simulation model applies a stochastic model for treating individual unit's availability to model their forced outages. Maintenance schedules and any limitations in the availability of wind and hydro energy are also accounted for.

We have applied the LOLE reliability standard as 0.05% of the year to determine adequate capacity level in the system. This is equivalent to LOLE = 4 hours/year (0.05x8760/100 = 4.38 hours/year).[17] Similar standards are exercised in other power systems such as France (LOLE: 3 hours/year)[18] and Republic of Ireland (LOLE: 8 hours/year).[19] No direct constraint is applied on the amount of energy not served. This is reflected in the trade-off between reliability costs and other system costs. If an expansion plan contains system configurations for which the annual energy demand is greater than the expected annual generation from all units for the corresponding year, the total costs of the plan is penalized by the resulting cost of the energy-not-served (£5/kWh of energy not served).

Considering the variation in characteristics of the diverse technologies modelled in this study, a wide range of reserve margin constraints - 15% to 50% - were initially applied for each scenario. The purpose of restricting the range of reserve margins is to limit the number of possible configurations (combinations) of various technologies over the study period. This approach results in saving some processing time with the computationally intensive WASP model. However, the model flags up cases where the optimal solution is likely to exist outside the set reserve margin range, or if the target LOLE level may not achievable. In such cases the range was further expanded to allow further capacity augmentation in order to obtain a (least) cost optimal generation plan meeting the required reliability levels.

A system with low reliability is likely to be a long term concern. This may be the symptom of a fundamental problem – a lack of sufficient supply capacity – which will take time to rectify due to long lead times involved in building new capacity. All electricity generation systems are designed to be reliable in terms of one or more of the criteria specified above. However, these criteria exclude events (including exogenous incidents) such as industrial action, terrorism and large scale interruptions of primary energy for geopolitical reasons. These events, although less frequent to date, are getting increasing attention due to the serious potential impacts on supply security. From the consumer's perspective, however, there usually appears to be little if any difference between an interruption caused by an inadequate capacity condition (reliability issue)

[17] Modern Power System Planning, X. Wang, J.R. McDonald, McGraw Hill, 1994
[18] Generation Adequacy Report on the electricity supply-demand balance in France, RTE 2007
[19] Generation Adequacy Report, Republic of Ireland, EirGrid 2007

and one caused by an event outside the traditional reliability domain. However, from a system development perspective, the two causes have very different ramifications.

Reliable generation systems such as those described in Section 5 identified by running the WASP model, will be inherently less vulnerable to *any* cause of supply interruption. However they may not be able to manage exceptional high impact events. A resilient energy system as defined in Section 4 may be able to tolerate both, with minimal impact on consumers and system costs.

ANNEX B: THE RESILIENT SCENARIOS IN DETAIL

This section describes in detail the results of the *Resilient* and *Low Carbon Resilient* scenarios. The *Reference* and *Low Carbon* scenarios are described in detail in Anandarajah et al. (2009). The two resilient scenarios are compared systematically with the other core scenarios. The discussion is grouped round themes: primary energy demand; final energy demand; electricity supply; CO_2 emissions; marginal CO_2 abatement costs; and demand reduction and welfare costs. However, the discussion also flags important cross-sectoral linkages reflected in overall system change.

B.1 Primary energy demand

Figure B-1 compares primary energy demand in the core scenarios. In the *Resilient* scenario, there is a steep reduction in primary energy demand driven by the constraint on final energy demand. Compared to the *Reference* scenario, primary energy demand is 14% lower in 2025 and 42% lower in 2050. This reduction is achieved by a combination of fuel-switching and energy efficiency improvements both on the supply and demand sides.

In 2025, coal demand is 23% lower, gas 13% lower and oil 10% lower (Figure B-2). The reduced coal demand is because of a switch from coal to gas in the power sector. However, overall gas demand is down because the residential sector uses 33% less gas. The reduction in residential gas demand is driven by a switch from gas-fired central heating to heat pumps, and price induced demand reduction - the latter is very substantial. Since both coal and gas demand fall, oil demand has to decline to meet the supply diversity constraint. It thereby induces changes in the transport sector.

In 2050, coal dominates primary energy supply in the *Reference* scenario with a market share of 38%. In the *Resilient* scenario coal's share declines to 28% and gas has the largest share with 31%. The change in the primary fuel mix is driven mainly by a switch from coal to nuclear in the power sector in order to meet the diversity constraint. Biomass supply is 8% higher in the *Resilient* scenario and meets 6% of primary energy demand, compared to 3% in the *Reference* scenario. However, renewable electricity is 8% lower, which only just meets the renewable obligation in the power sector. Instead, imported electricity is almost three times the level in the *Reference* scenario.

The pattern of the primary energy demand in the *Low Carbon Resilient* scenario is similar to that in the *Resilient* scenario (Figure B-2). In 2025, demand is 14% lower than in the *Low Carbon* scenario. In terms of its fuel mix, gas demand is 16% lower but coal demand is 35% higher. The decline in gas demand is required to meet the supply diversity constraint as the market share of gas in the *Low Carbon* scenario is over 44%.

Primary energy demand in 2050 is down on the *Low Carbon* scenario. Coal demand falls by 65%. Its market share declines to 14% in the *Low Carbon Resilient* scenario from 32% in the *Low Carbon* scenario. The reduction is coal demand is primarily in the industrial and power sectors. In the power sector, generation from coal CCS shrinks by 65%. The share of oil (mainly for transport fuel) in primary energy demand doubles, although in absolute terms it declines by 23%. This is because the transport sector deploys hybrid vehicles rather than ethanol and plug-in hybrid vehicles in the *Low Carbon* scenario. This results in a relatively low use of bioenergy. The combination of supply diversity, demand reduction and the shift in technology pathways significantly alters the decarbonisation pathway.

Figure B-1: Trend in primary energy supply in the core scenarios

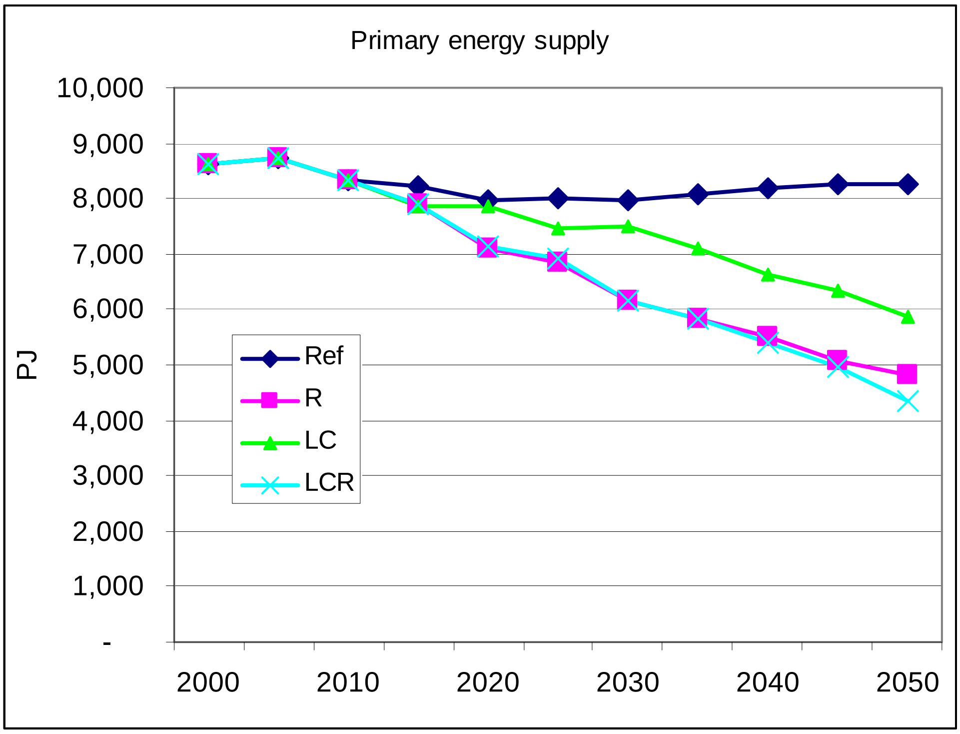
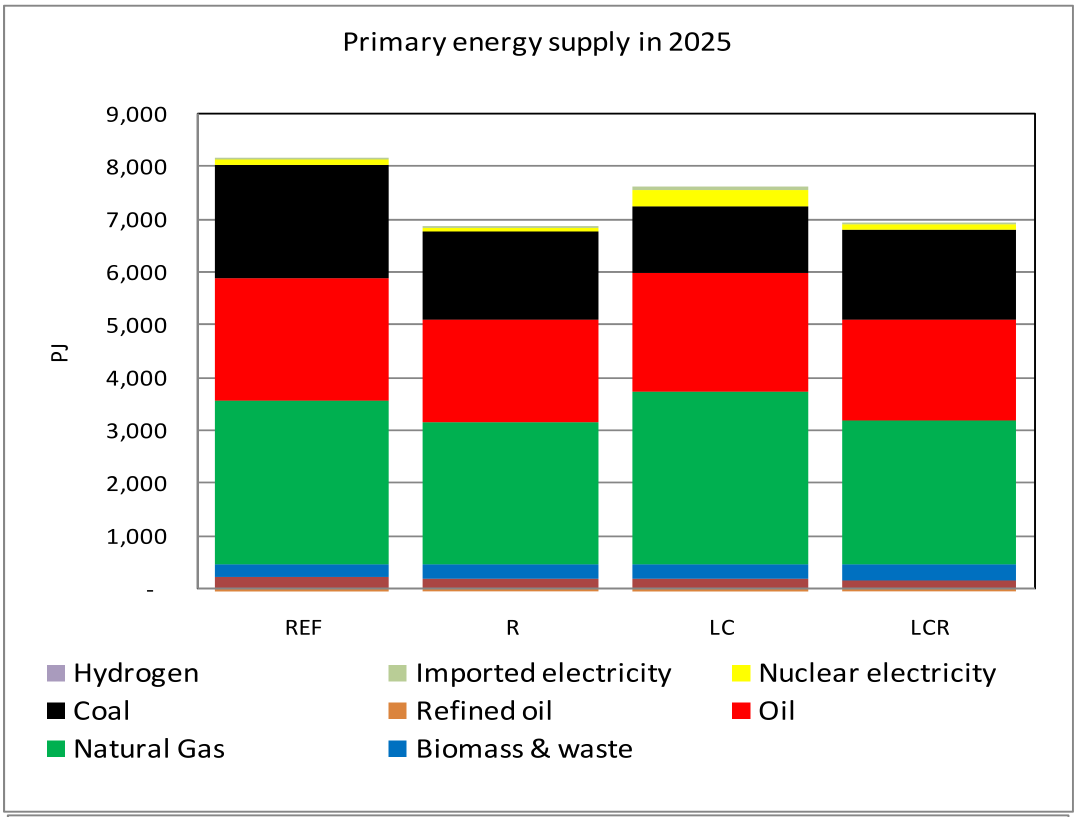
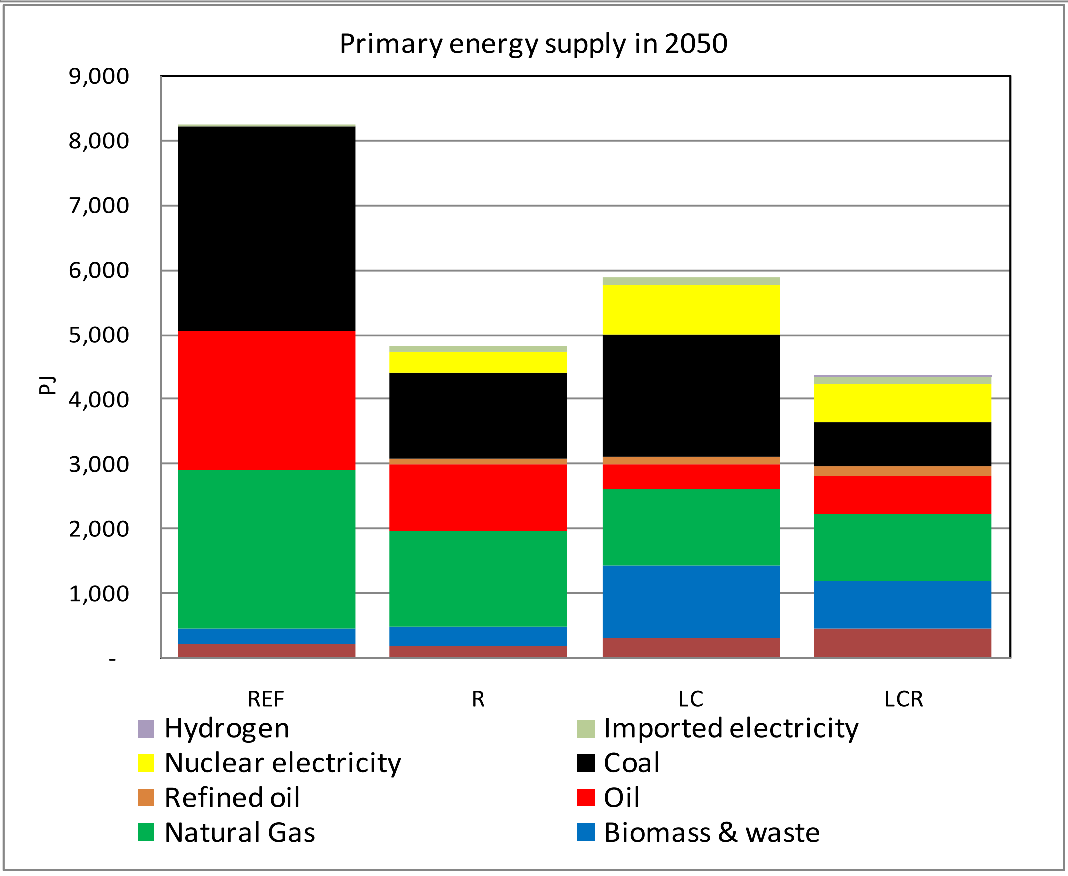


Figure B-2: Primary energy supply in core scenarios





B.2 Final energy demand

General Picture

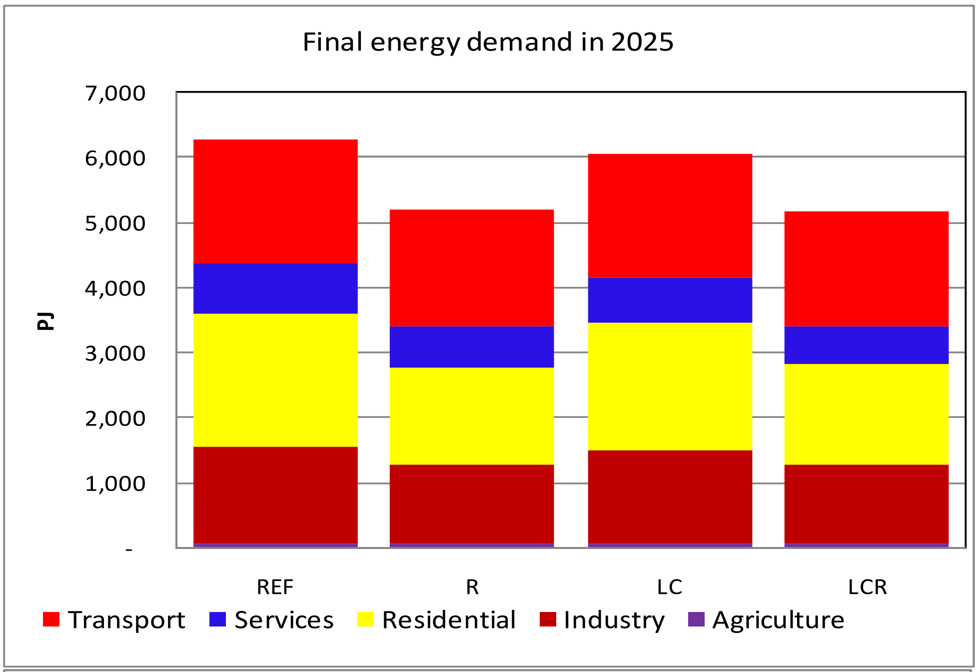
Final energy demand in the *Resilient* scenario is 17% lower than in the *Reference* scenario in 2025 (Figure B-3). Demand falls across all end use sectors, but the decline is most significant in the residential and industrial sectors. The reduction in gas demand for residential heating enables the power sector to switch from coal to gas. The demand response from the industrial sector reduces coal demand by 26% from the *Reference* scenario. In 2050, final energy demand is 41% lower than in the *Reference* scenario.

Figure B-4 shows final energy demand by sector. Final energy demand in 2025 is lower in the *Resilient* scenario in all end use sectors (residential is 27%, industry and service sectors 17%, and transport 7% lower than the *Reference* scenario in 2025). The lower reduction (7%) in the transport sector is because of the availability of a wide range of alternative fuel and vehicle technologies (e.g. hydrogen, ethanol, hybrid and plug-in hybrid). There are more limited opportunities for fuel switching in other end sectors.

In the *Low Carbon Resilient* scenario, final energy demand in 2025 is 14% lower than in the *Low Carbon* scenario, and 16% below the 2000 level. The reduction in residential energy demand is substantial (23%), and is partly delivered by fuel switching (from gas-fired central heating to heat pumps). This enables a large reduction of gas use in the energy system (25%) and thereby lower CO_2 emission. These low CO_2 emissions allow other sectors to use more carbon intensive fuels. For example, electricity generation from coal (without CCS) contributes 23% of total electricity generation in the *Low Carbon Resilient* scenario whereas the *Low Carbon* scenario has coal only with CCS.

In 2050, final energy demand in the *Low Carbon Resilient* scenario is 15% lower than in the *Low Carbon* scenario, and 40% below the 2000 level. Unlike in the *Low Carbon* scenario, the residential sector continues to use gas because heat pumps are constrained from taking 100% market share. Therefore, gas demand in the residential sector accounts for about 10% of final energy demand whereas there is no residential gas in the *Low Carbon* scenario. Since residential energy demand is higher than in the *Low Carbon* scenario (due to the restriction on heat pumps), the model struggle to meet the final energy constraint. In response, the power sector decarbonises to a greater extent than in the *Low Carbon* scenario.

Figure B-3: Final energy demand in core scenarios by fuel type



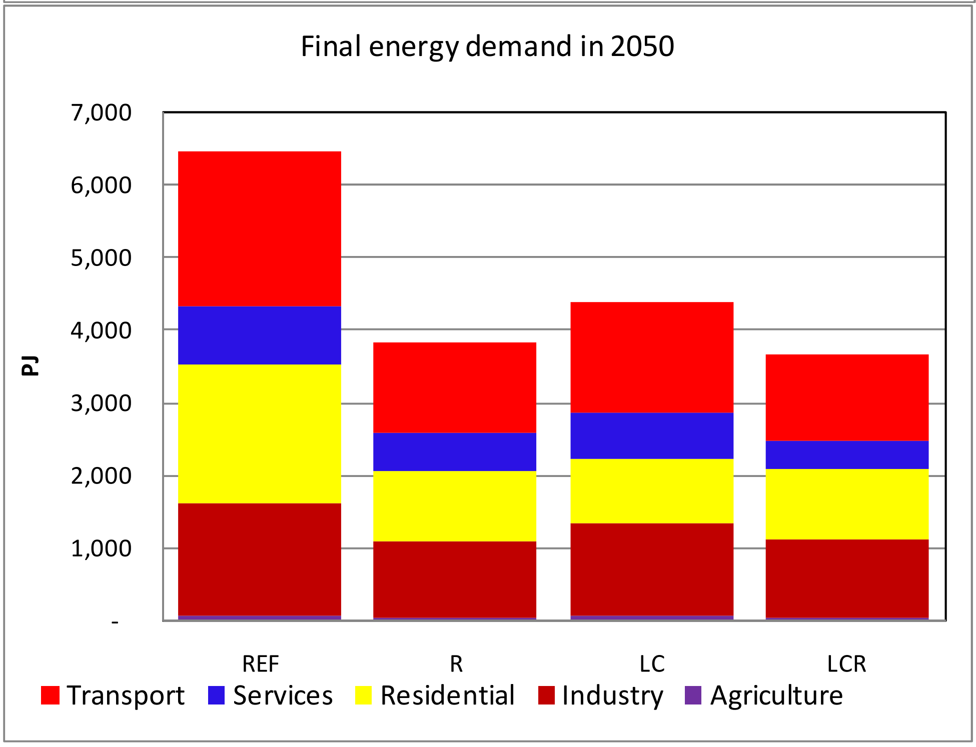
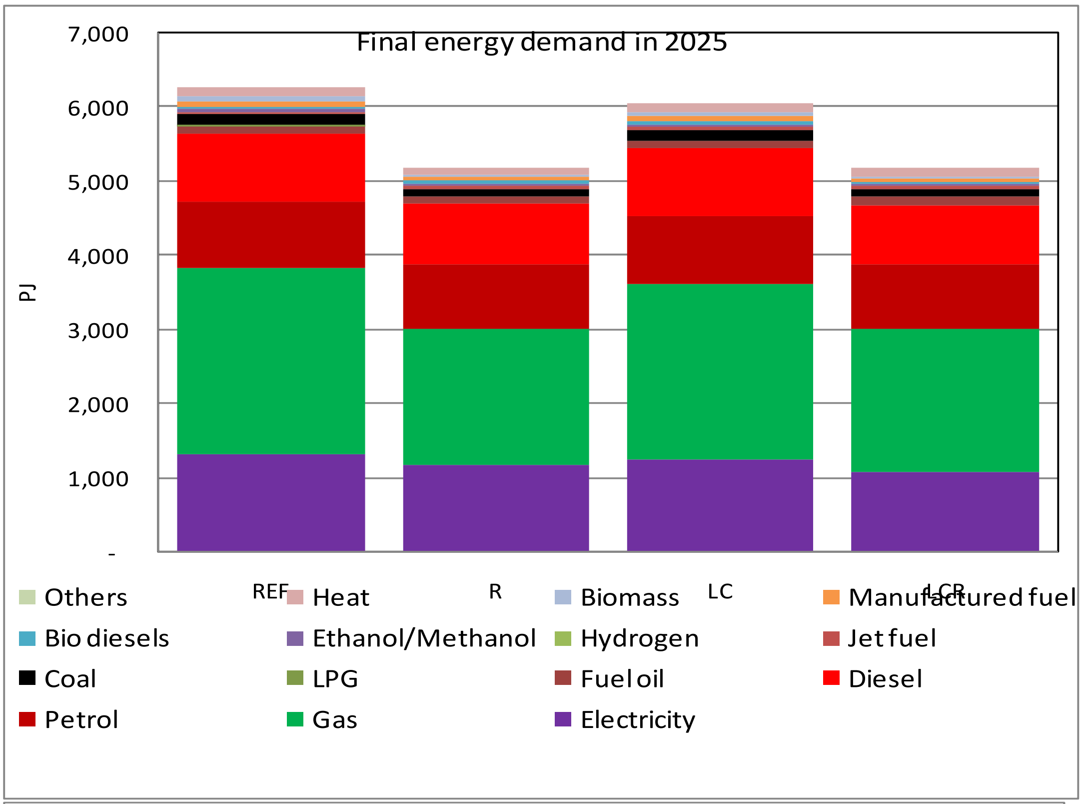
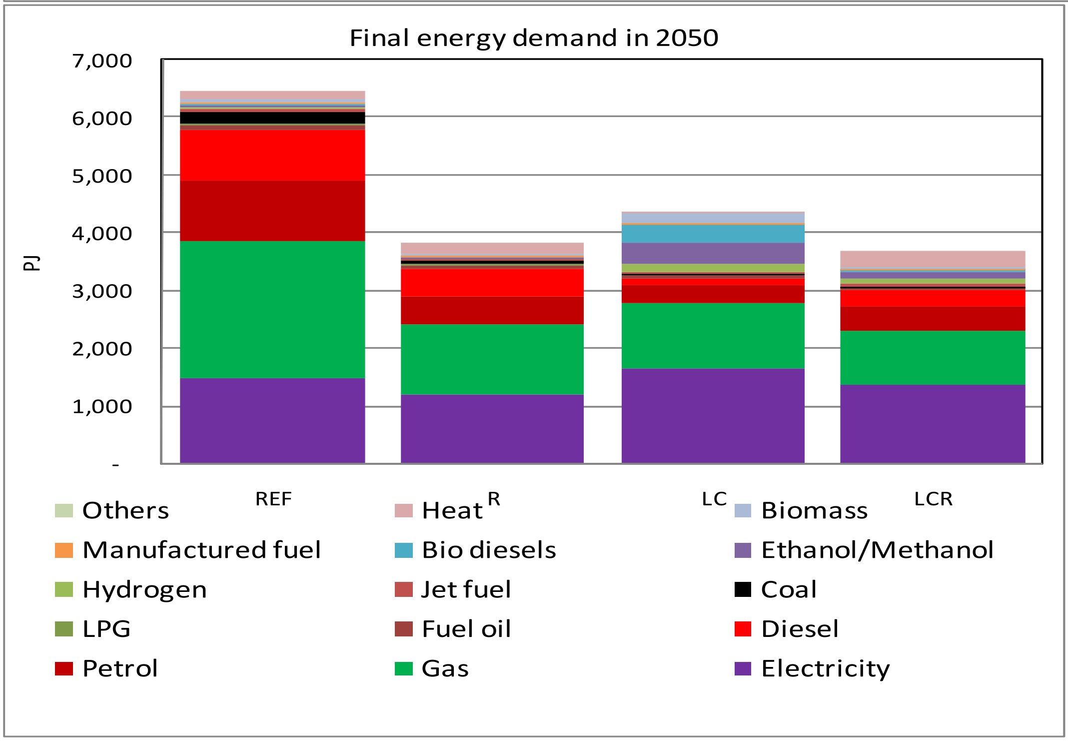


Figure B-4: Final energy demands in core scenarios by sectors





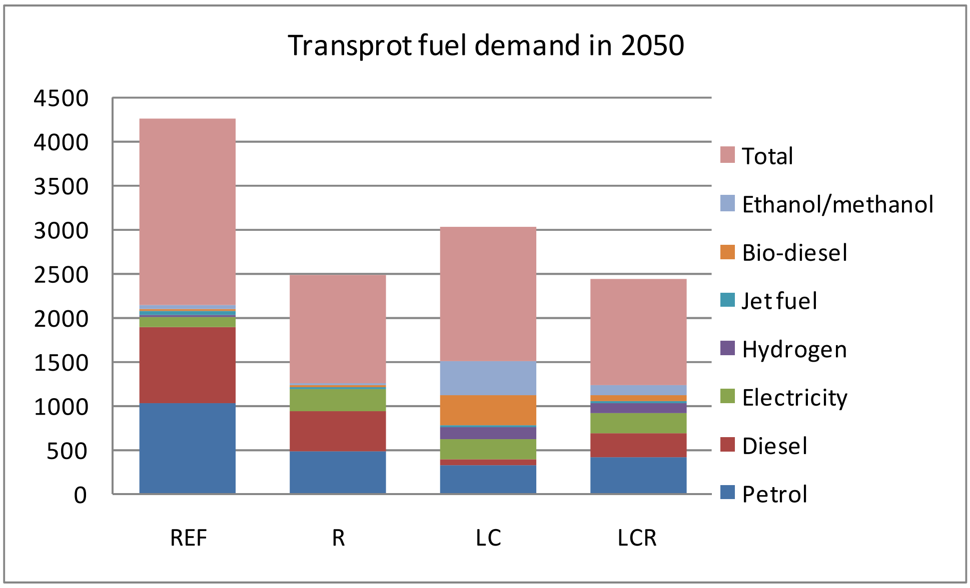
The Transport Sector

By 2025, there have been no significant changes in the transport sector. *A*lthough total final energy demand declines by 14% in the *Resilience* scenario compared to the

Reference scenario, transport demand declines by less than 6%. There are no significant changes in vehicle technology or in the fuel mix.

By 2050, transport fuel demand almost halves in the *Resilient* scenario with respect to the *Reference* scenario (Figure B-5). This is largely induced by higher prices (Figure B-6). However, electricity demand more than doubles because car fleets moves from the conventional ICE to plug-in hybrid vehicles (Figure B-7). This change in car fleet also reduces the demand for biofuels, which remains constrained however by the renewable transport fuel obligation (RTFO). The reduction in electricity demand in other end use sectors exceeds the incremental electricity demand from the transport sector, and therefore total electricity demand declines by 20%.

Figure B-5: Transport fuel demand in core scenarios (2050)



Comparing the *Low Carbon Resilient* and *Low Carbon* scenarios in 2050, total transport fuel demand declines by 22%, which is larger than the 15% reduction in total final energy. Transport demand is again lower because of price effects. Unlike other end use sectors, the transport sector enjoys a wide range of technology and fuel choice. Therefore the price-induced level of demand reduction is lower relative to other end use sectors (Figure B-6). At the same time the transport sector uses efficient hybrid vehicles in the *Low Carbon Resilient* scenario compared to ethanol ICE vehicles in *Low Carbon* scenario (Figure B-7).

In the *Low Carbon* scenario, the car fleet uses ICE ethanol and plug-in hybrid engines while buses and goods vehicles use biodiesel. Biofuel ICE vehicles are inefficient and are therefore not deployed in the *Low Carbon Resilient* scenario. Hence the model chooses efficient petrol/diesel hybrid cars. Although this enables a lower level of transport fuel demand, petrol and diesel demand increase by 32% and 172% in 2050 with respect to the *Low Carbon* scenario. Biofuel demand (ethanol and biodiesel) declines by three quarters.

Changes in technology choice result in lower transport fuel demand but higher CO_2 emissions indicating a trade off between final energy and CO_2 constraints. The model tries to reduce final energy demand in transport using efficient vehicle but there is insufficient decarbonisation to meet the 80% target. This drives the power sector to decarbonise drastically.

Figure B-6: Demand price response in transport sector (2050)

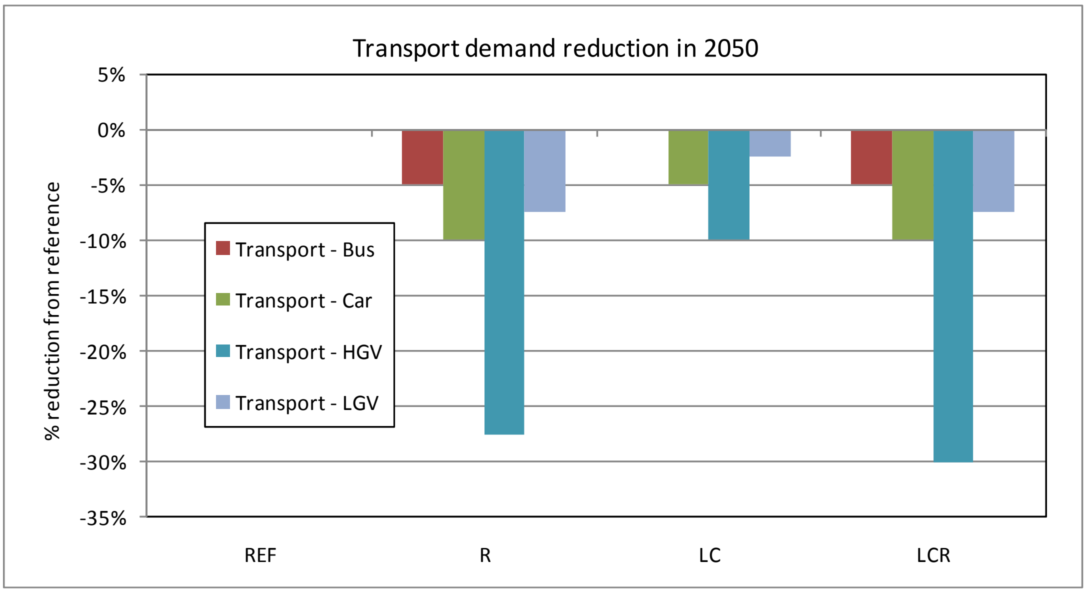
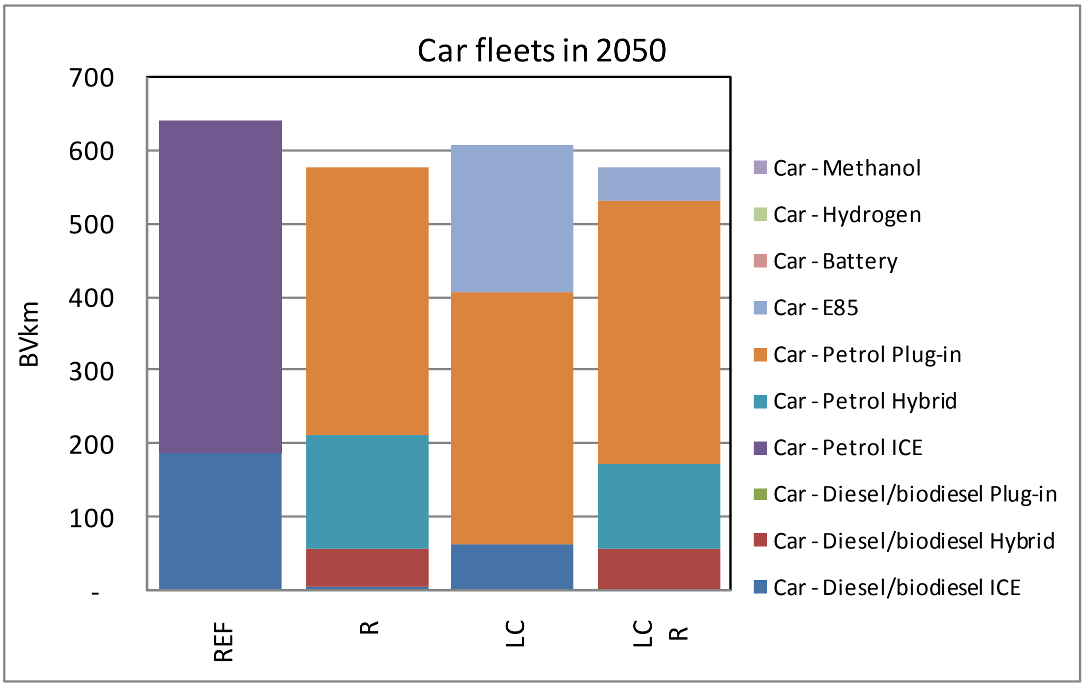


Figure B-7 Car fleets in core scenarios (2050)



The Residential Sector

Up to 2025, imposing the resilience constraints does not lead to significant changes in the residential sector because of the existing stock of heating technologies. However, the residential sector plays a key in the longer term (Figure B-8). In the *Low Carbon* scenario, the residential sector contributes to CO_2 emission reduction through the deployment of heat pumps using decarbonised electricity (Figure B-9). However, in the resilient scenarios, heat pumps are prevented from achieving 100% market share. In this case, the sector continues to use gas. Consequently, the level of demand reduction in the residential sector is far higher in the resilience scenarios than in the *Low Carbon* scenario.

Figure B-8: Residential energy system in core scenarios (2050)

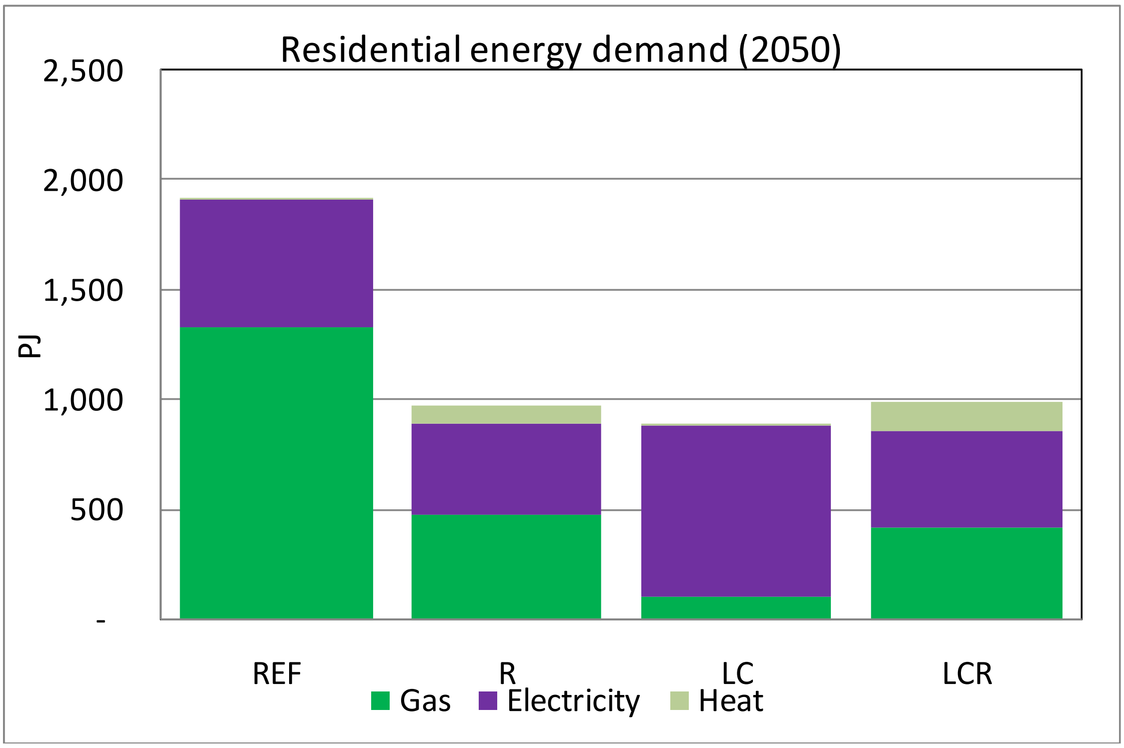
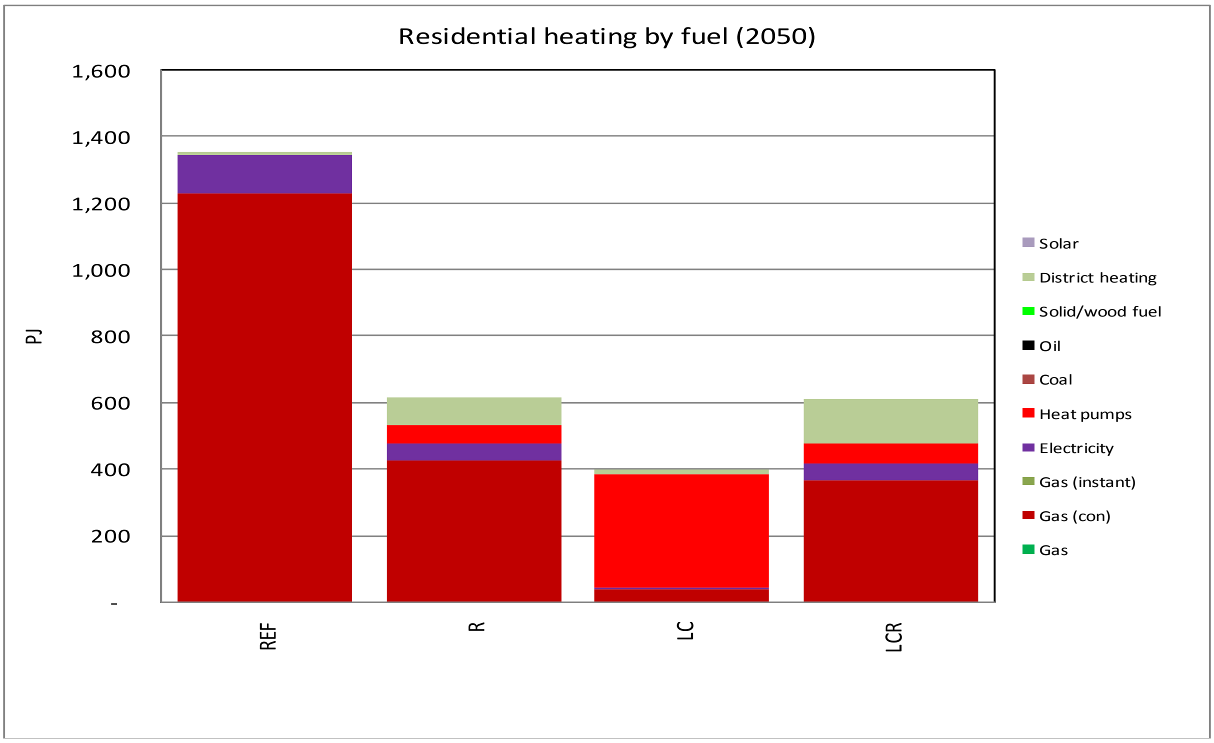


Figure B-9: Residential heating in core scenarios by fuel (2050)



B.3 Electricity supply

Electricity demand in the *Resilient* scenario is 11% lower in 2025 and 19% lower in 2050 than in the *Reference* scenario (Figure B-10). In 2025, the biggest reduction in electricity demand is from the industrial sector (17%) followed by the service (12%) and residential (8%) sectors. The reduction in electricity demand is primarily driven by a price-induced demand response. In 2050, electricity demand declines across most end use sectors but doubles in the transport sector due to the high penetration of plug-in hybrid cars. Electricity demand in the *Low Carbon Resilient* scenario in 2025 is 14% lower than in the *Low Carbon* scenario.

Figure B-11 shows the electricity generation mix in the core scenarios. In 2025, the coal dominated power sector in the *Reference* scenario moves towards gas in the *Resilient* scenario. Coal generation declines by 34% and gas generation almost doubles. However, the reduction of gas demand in the end use sectors exceeds the higher demand from the power sector and the net result is lower gas use.

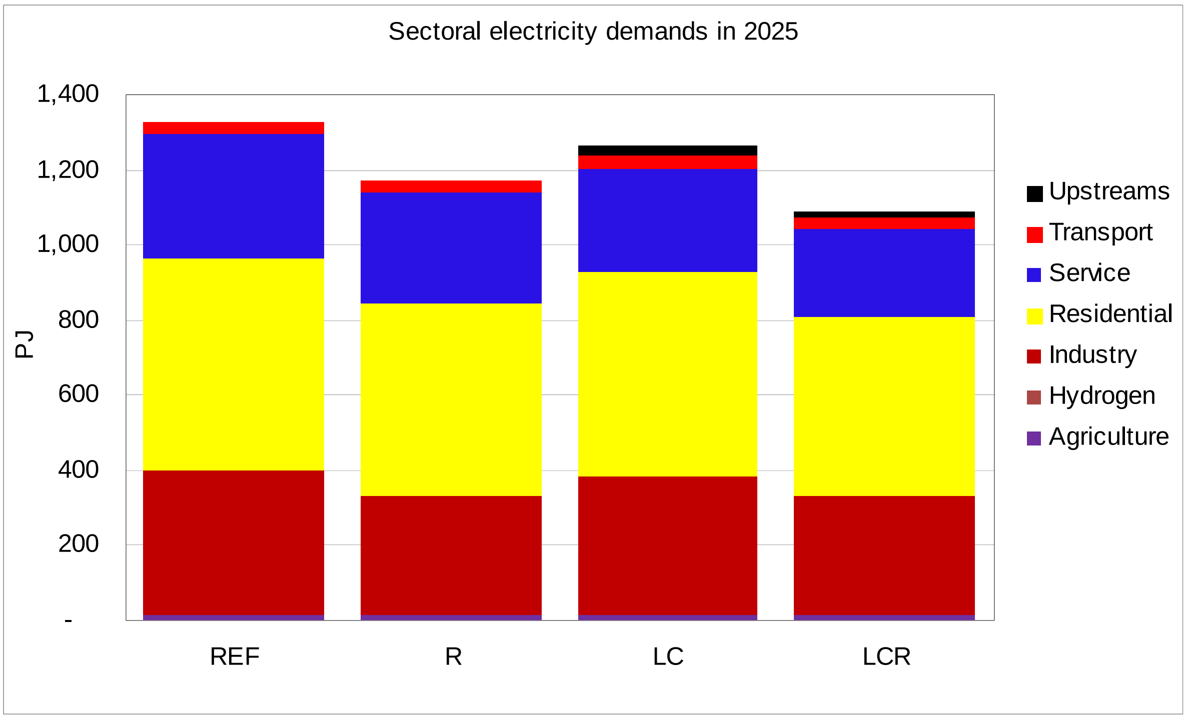
In the *Low Carbon Resilient* scenario, lower demand reduces electricity generation from gas, nuclear, renewable, and imported electricity. Nuclear generation declines by almost one-third, while coal's share increases to 23% from zero in the *Low Carbon* scenario (Figure B-11). The uptake of coal generation is driven by the power supply diversity constraint. At the same time, the additional CO_2 emissions from coal based generation are offset by lower CO_2 emission from end use sectors due to demand reduction.
In 2050, the power sector diversifies from coal to nuclear as we move from the *Reference* to the *Resilient* scenario. Coal's market share declines to 40% from 81%, while nuclear generation contributes 23% compared to zero in the *Reference* scenario. This diversification of the power sector substantially contributes to the diversification of overall primary energy supply. Although total electricity generation declines by 19%, renewable electricity declines by only 8%. Wind generation stays at the same level as in the *Reference* scenario but hydro generation declines to one-third. Imported electricity increases and contributes 8% to total electricity supply compared to 2% in the *Reference* case.

Moving from the *Low Carbon* to the *Low Carbon Resilience* scenario in 2050, the power sector decarbonises radically. This is achieved partly via low electricity demand (down 26%) and through the deployment of a combination of nuclear, renewable (wind in particular), and coal with CCS. The market share of nuclear increases to about 40%. Compared to the *Low Carbon* scenario, wind generation almost doubles and accounts for 23% of the generation mix. Total renewable electricity generation increases by 117% from the *Low Carbon* scenario. However, coal CCS generation falls by two thirds and its market share is only 20% compared to 40% in the *Low Carbon* scenario. This shift from coal CCS to renewables is mainly because the system cannot accommodate residual emissions from the CCS.

Figure B-12 shows installed capacity in the core scenarios. In 2025, coal capacity in the *Resilient* scenario is 19GW compared to 29GW in the *Reference* scenario. Gas capacity increases to 23 GW compared to 18 GW in the *Reference* scenario. In 2050, 50 GW coal capacity in the *Reference* scenario falls to 21 GW in the *Resilient* scenario while nuclear capacity reaches 12 GW. There is no significant change in renewables capacity, but interconnector capacity increases to 6 GW from 3 GW in the *Reference* scenario.

In the *Low Carbon Resilient* scenario, nuclear capacity is 3 GW in 2025 and increases to 23 GW in 2050 compared to 29 GW in the *Low Carbon* scenario. There is 10 GW coal plant in 2025 in the *Low Carbon Resilient* scenario compared to 3GW in the *Low Carbon* scenario. 7 GW of coal plant continues to operate in 2050 whereas there is no coal plant in the *Low Carbon* scenario at that time. In 2025, coal CCS capacity is 8 GW in the *Low Carbon Resilient* scenario compared to 12 GW in the *Low Carbon* scenario. By 2050, the capacities of coal CCS and gas plants in the *Low Carbon Resilient* scenario fall to 16 GW and 9 GW respectively compared to 31 GW and 26 GW in the *Low Carbon* scenario. In 2025, investment in wind capacity is 2 GW lower than in the Low Carbon scenario. In 2050 wind capacity in the *Low Carbon Resilient* scenario is 31 GW compares to 18 GW in the *Low Carbon* scenario. Interconnector capacity in 2050 increases to 10 GW.

Figure B-10: Electricity demand in core scenarios by sectors



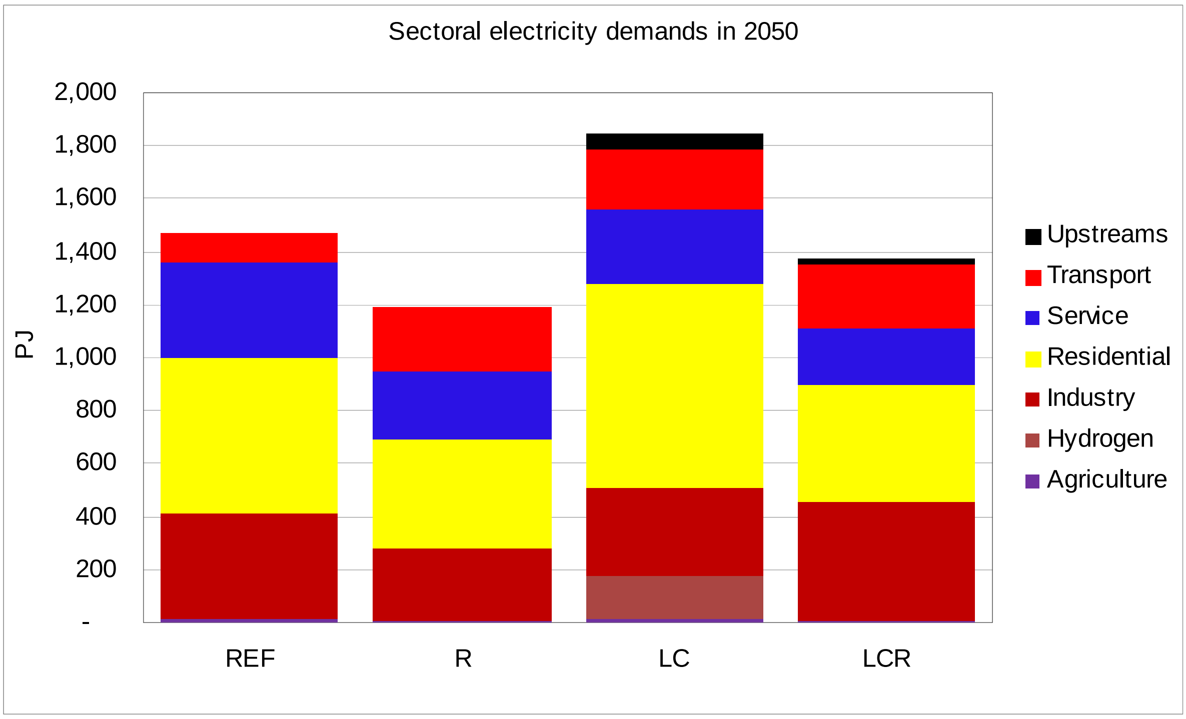


Figure B-11: Electricity generation mix in core scenarios

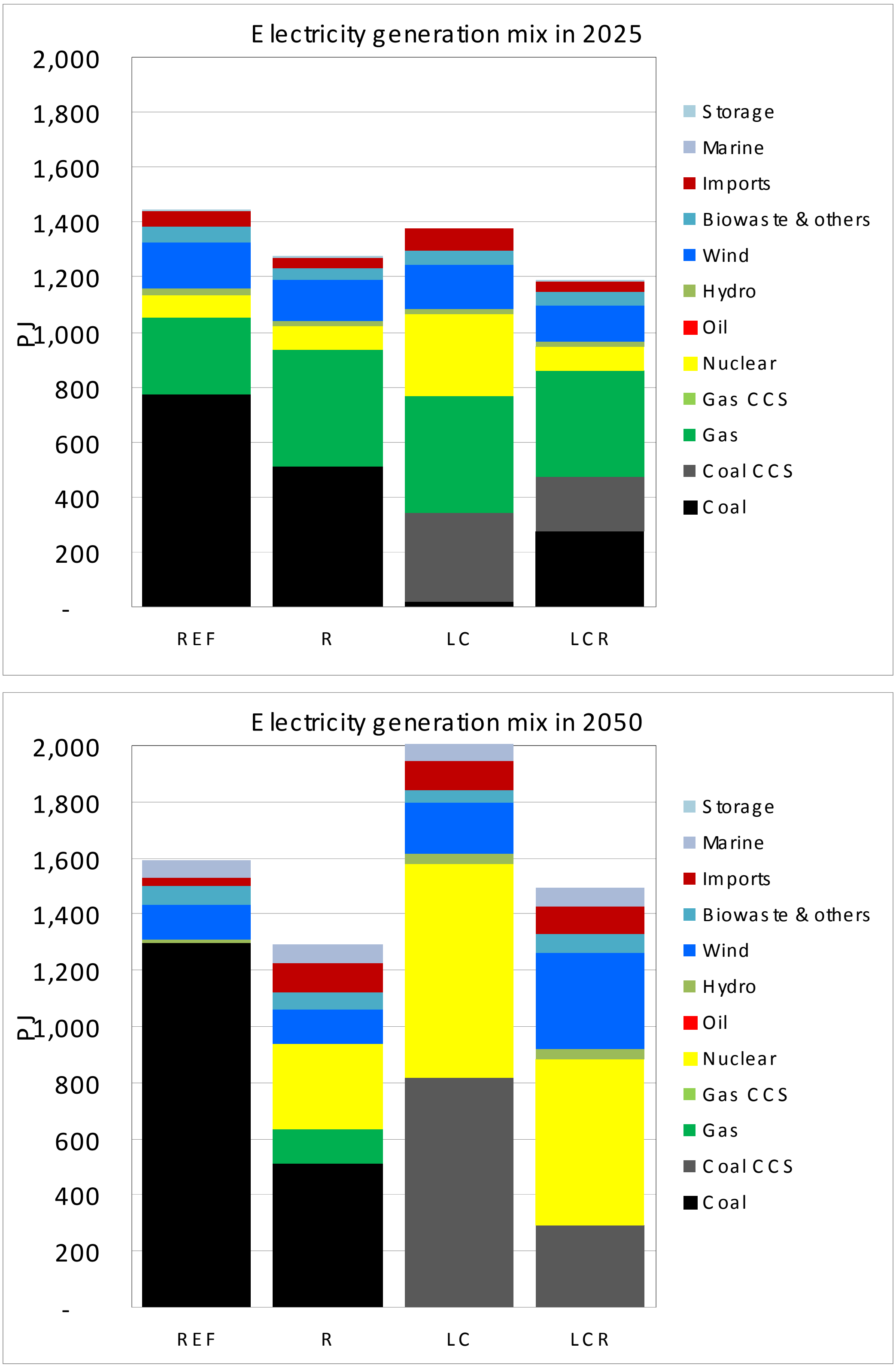
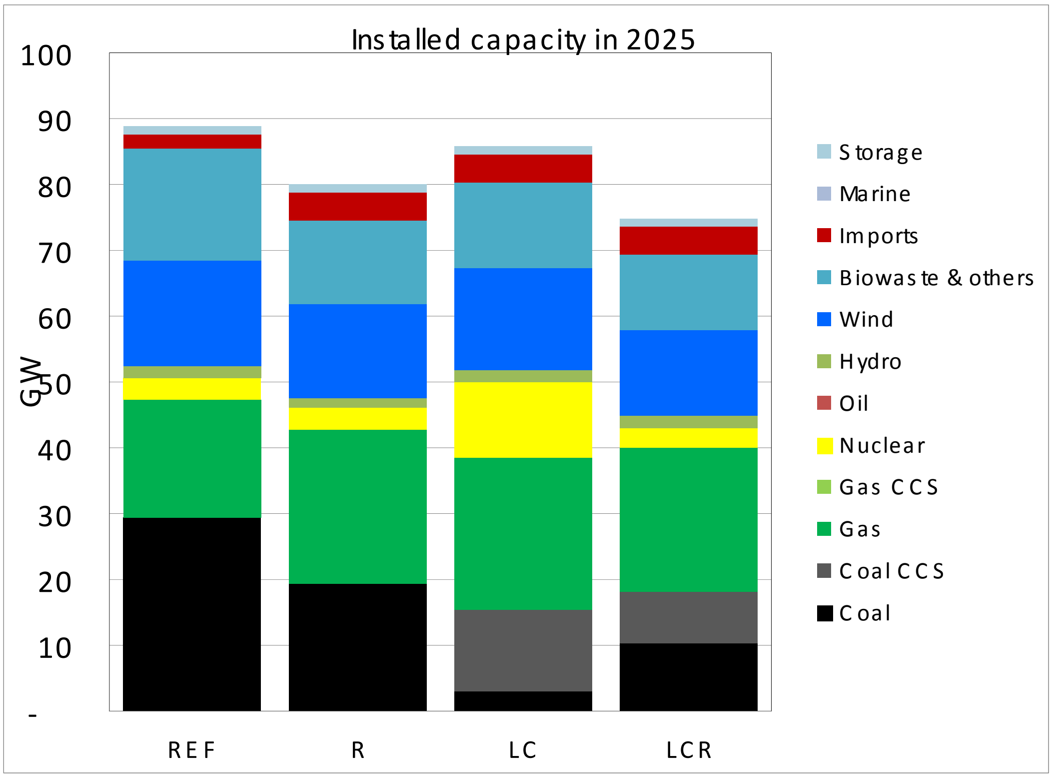
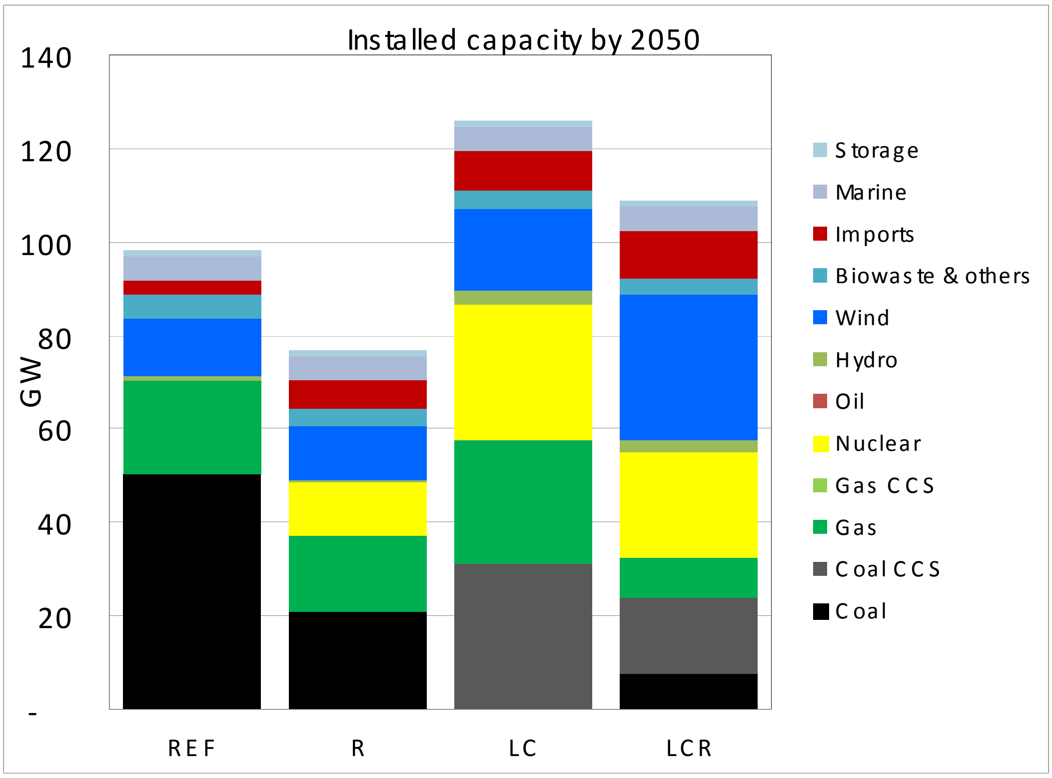


Figure B-12: Installed capacity in core scenarios





B.4 CO_2 emissions

Due to large reductions in final energy demand, CO_2 emissions also reduce across all end use sectors (Figure B-13). In the *Resilient* scenario, CO_2 emissions in 2025 are 422mt compared to 523mt in the *Reference* scenario, or 18% below the 2005 level. About 35% of this CO_2 reduction is achieved in the residential sector (by demand reduction) while a 20% is from the power sector (switching from coal to gas).

In the *Resilient* scenario, CO_2 emissions in 2050 are 285mt compared to 583mt in the *Reference* scenario. All end use sectors and the power sector contribute to this emissions reduction. However, the contribution from the residential sector is substantial, more than 65%. The *Resilient* energy system reduces CO_2 emission by 48% below the 1990 level, insufficient to reach the UK's 80% carbon reduction target.

In 2025, CO_2 emissions from all end use sectors in the *Low Carbon Resilient* scenario fall by between 7-25% from the levels in the *Low Carbon* scenario due to demand reduction and fuel switching. This enables the power sector to switch to coal based generation from nuclear and gas in the *Low Carbon* scenario. Therefore CO_2 emissions from the power sector increase by 65% in 2025. In 2050, CO_2 emissions are higher in the transport (60%) and residential (300%) sectors in the *Low Carbon Resilient* scenario while the power sector decarbonises to a greater extent than in the *Low Carbon* scenario. For example, the CO_2 intensity of electricity generation in the *Low Carbon Resilient* is 18 g/kWh versus 21 g/kWh in the *Low Carbon* scenario (Figure B-14).

Higher CO_2 emissions from the residential sector are because a complete shift to heat pumps has been prevented. Also, the transport sector deploys petrol/diesel hybrid cars, rather than plug-in hybrids and ethanol ICE in the *Low Carbon* scenario, and therefore emissions are higher.

B.5 Marginal cost of CO_2 abatement

Figure B-15 shows the marginal cost of CO_2 abatement in 2025 and 2050. In 2025, the marginal cost of CO_2 abatement is £5/t in the *Low Carbon Resilient* scenario, half of that in the *Low Carbon* scenario. Since the resilient energy constraints themselves reduce CO_2 emissions, the marginal cost of CO_2 abatement declines. However, in 2050 the marginal abatement cost of £322/t is double that in the *Low Carbon* scenario. This high marginal cost is because the residential sector hardly decarbonises at all and the power sector must decarbonise through the deployment of more expensive renewables.

Figure B-13: CO2 emission in core scenarios by sector

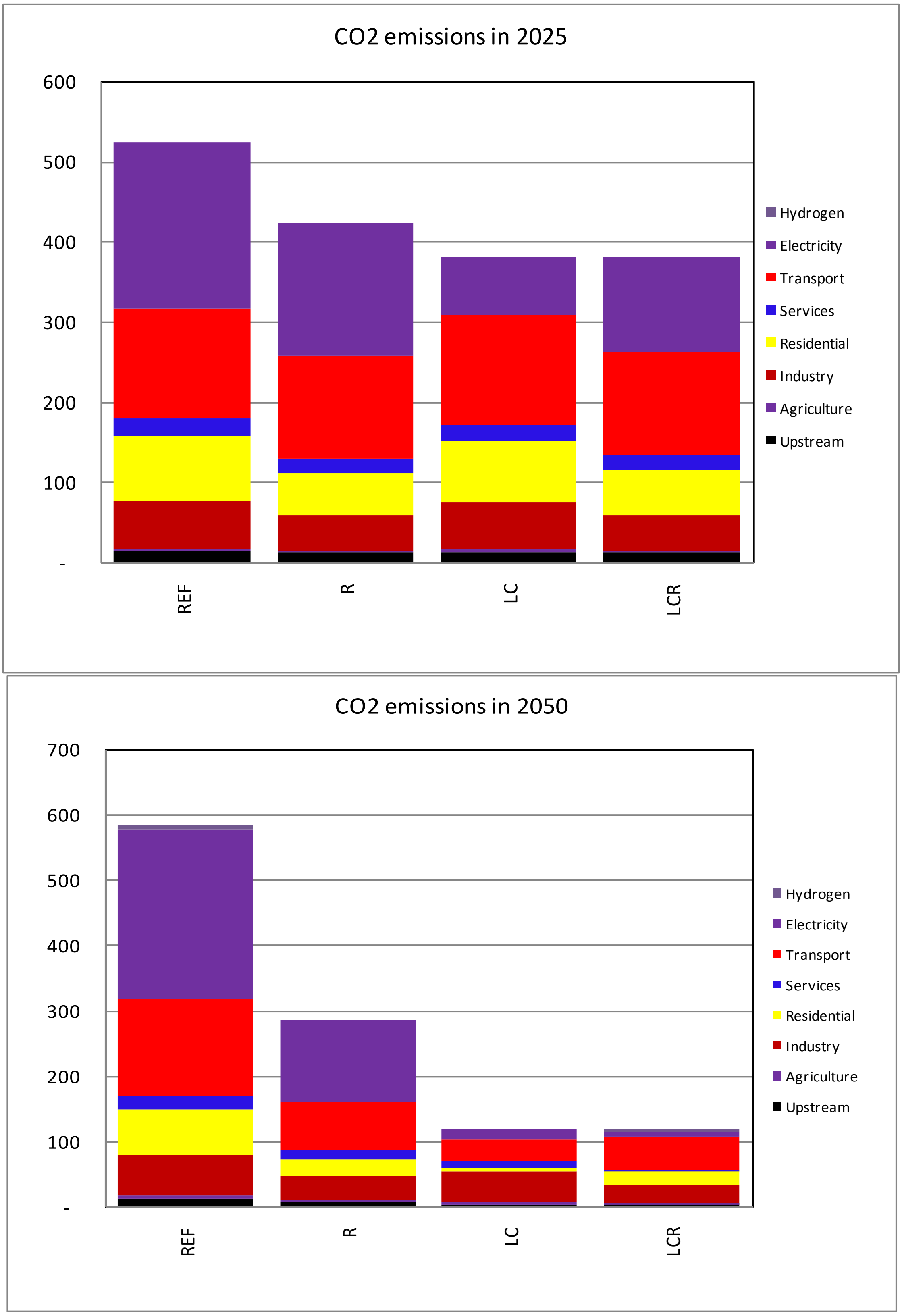


Figure B-14: CO2 intensity of electricity generation in core scenarios

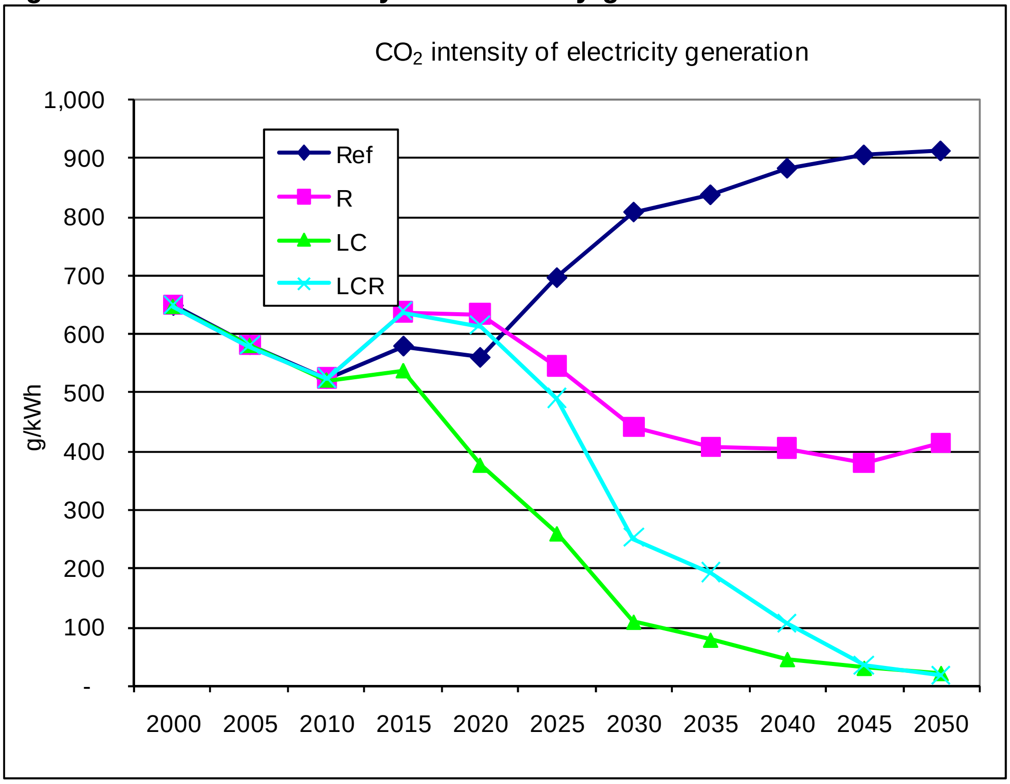
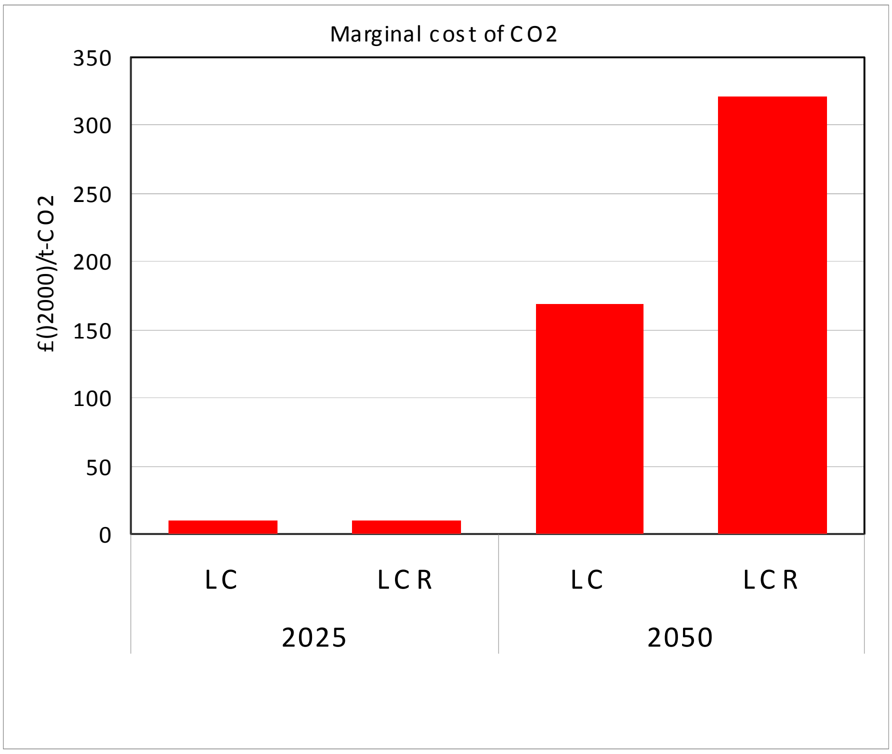


Figure B-15: Marginal cost of CO_2 abatement



B.6 Demand response (demand reduction) and welfare costs

It is clear that the resilient energy systems are much smaller than those in the *Reference* scenario and therefore incur a lower energy system cost (Figure B-16). Undiscounted energy system costs in 2025 are about £2.5 billion lower than in the *Reference* case compared to a £2.3bn increase in the *Low Carbon* scenario. However, price-induced demand reduction in the end use sectors results in a loss of consumer surplus. The combination of changes in producer and consumer surpluses are taken to be a valid metric for welfare cost. In the *Resilient* scenario, the welfare costs are about £19bn in 2025 and increase to £48bn in 2050. Figure B-16 shows these changes in the core scenarios with respect to the *Reference* scenario.

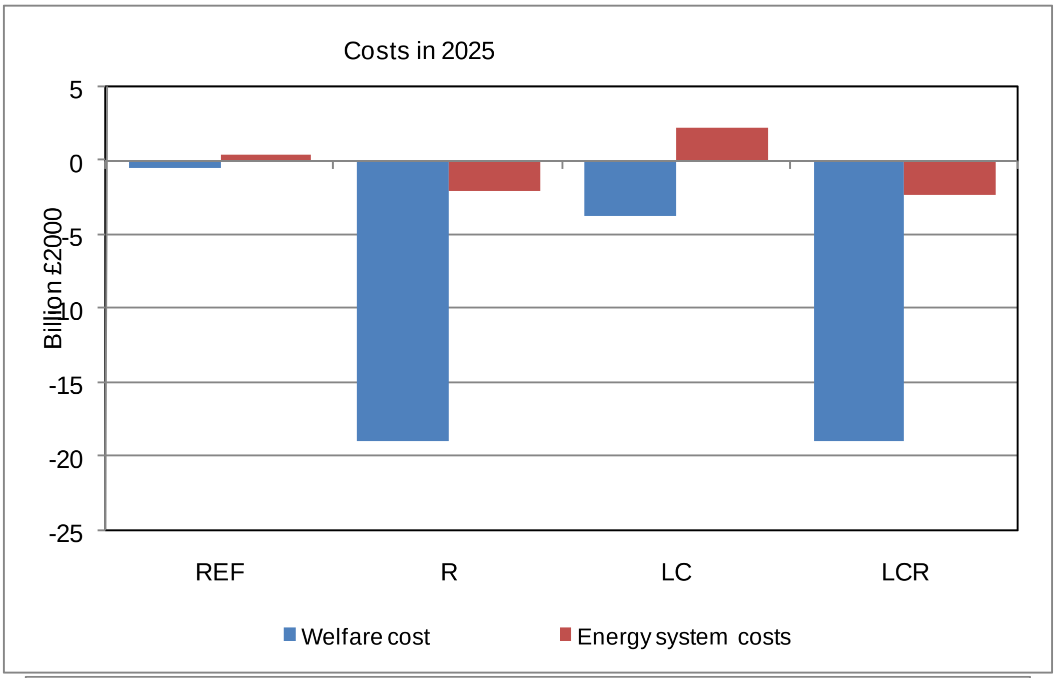
The *Low Carbon Resilient* scenario requires a substantial demand response to meet the low carbon as well as the resilience constraints, particularly for final energy demand. By 2050, demand reductions in the resilience scenarios are far higher than in the *Low Carbon* scenario. The welfare cost in 2025 at £19bn is similar to that in the *Resilient* scenario, but far higher than in the *Low Carbon* scenario. The welfare cost in 2050 increases to £60bn (£37bn in *Low Carbon*).

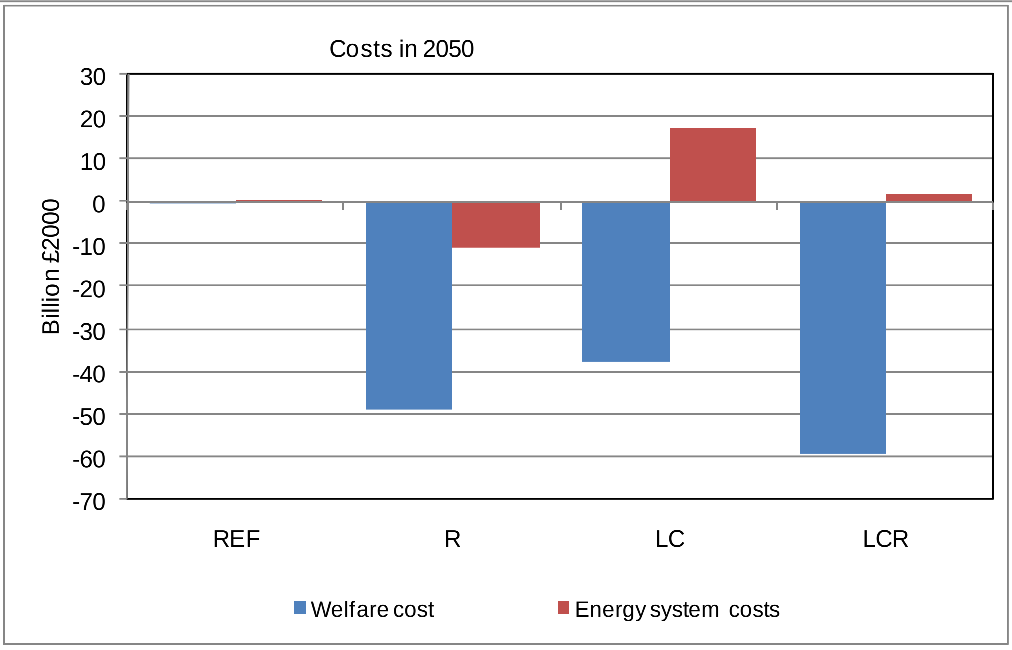
Table B-1 compares the range of price-induced demand reduction levels in the core scenarios with respect to the *Reference* scenario. Because of the final energy demand constraint, the reduction in demand for energy services is far higher in the resilient scenarios than it is in the *Low Carbon* scenario in all end use sectors. For example, residential demand in 2025 is less than 5% lower in the *Low Carbon* scenario whereas it is up to 27% lower in the resilient scenario. The lower demand response from the transport sector is because of availability of a wide range of alternative vehicle technologies.

Table B-1: Demand reduction in core scenarios with respect to reference scenario

End-use sectors	R	LC	LCR	R	LC	LCR
	2025			*2050*		
Industry	10% - 30%	2% - 7%	10% - 30%	22% - 50%	10% - 32%	21% - 50%
Residential	13% - 27%	2% - 5%	15% - 27%	35% - 50%	10% - 30%	30% - 50%
Services	2% - 20%	2% - 3%	5% - 18%	13% - 36%	+3% - 18%	8% - 35%
Transport	2% - 13%	0% - 2%	2% - 13%	5% - 28%	0% - 10%	5% - 30%

Figure B-16: Welfare costs in core scenarios





B.7 Uncertainties in welfare costs

The high level of welfare costs imputed in the *Resilient* and *Low Carbon Resilient* scenarios need to be treated with caution. This is because of some of the detailed modelling assumptions.

One of the inputs to the MARKAL model is energy service demand (ESD). ESD for the residential sector has been estimated from the UK Domestic Carbon Model (UKDCM). The UKDCM has its own methodology/assumption on the uptake of residential conservation measures based on historical uptake, behavioural change, and affordability.

The uptake of residential conservation measures has been kept constant across the core scenarios by "turning off" MARKAL-MED's endogenous selection of conservation measures, as they are assumed to have been covered in the UKDCM runs. This means that reductions in demand, which is elastic to price, are induced by prices only. This implies a fall in consumer surplus particularly if demand is relatively inelastic.

In practice however, additional high cost conservation measures could be cost effective under a resilient energy system. Therefore additional sensitivity analyses have been carried out by allowing high cost conservation measures to be taken up endogenously in the residential and service sectors. This sensitivity analysis is aimed at investigating the impact on welfare costs. The results show that the welfare loss in the *Resilient* scenario compared to the *Reference* scenario in 2025 falls to £16bn (compared to £19bn without endogenous conservation measures and in 2050 falls to £36bn compared to £48bn. In fact, the additional conservation measures do not increase the consumer surplus in the residential and service sector. Instead demand adjusts in other end use sectors. Energy savings are effectively passed on to substitute for more expensive measures in other sectors. For example, industrial demand reduction falls to 18-47%, compared to 23-50% in the *Resilient* scenario without endogenous conservation. The additional conservation measure reduce the welfare loss in the *Low Carbon Resilient* scenario from £60 billion to £ 50 billion in 2050. However, there is no significant change in energy pathways.

ANNEX C: DETAILED GAS ASSUMPTIONS

Table C-1 shows the assumed cost of natural gas in the core scenarios in 16 separate tranches. A limited volume of gas is available in each tranche before the MARKAL and CGEN models move on to the next most expensive tranche.

Table C-1: Assumed Cost of Natural Gas (2000 £/GJ)

	2000	2005	2010	2015	2020	2025	2030
Norway	2.934	2.934	2.655	2.655	2.753	2.878	3.003
Russia	3.117	3.117	2.821	2.821	2.925	3.058	3.191
Russia	3.301	3.301	2.987	2.987	3.097	3.238	3.379
Russia	3.484	3.484	3.153	3.153	3.269	3.418	3.567
LNG	2.567	2.567	2.323	2.323	2.409	2.519	2.628
LNG	3.668	3.668	3.319	3.319	3.441	3.598	3.754
LNG	4.034	4.034	3.65	3.65	3.786	3.958	4.13
Domestic gas 1	1.853	1.853	1.853	1.853	1.853	1.853	1.853
Domestic gas 2	2.327	2.327	2.327	2.327	2.327	2.327	2.327
Domestic gas 3	2.516	2.516	2.516	2.516	2.516	2.516	2.516
Domestic gas 4	3.275	3.275	3.275	3.275	3.275	3.275	3.275
Domestic gas 5	3.465	3.465	3.465	3.465	3.465	3.465	3.465
Domestic gas 6	3.844	3.844	3.844	3.844	3.844	3.844	3.844
Domestic gas 7	4.318	4.318	4.318	4.318	4.318	4.318	4.318
Domestic gas 8	4.792	4.792	4.792	4.792	4.792	4.792	4.792
Domestic gas 9	5.266	5.266	5.266	5.266	5.266	5.266	5.266

Domestic gas supply is limited by UKCS recoverable gas reserves shown in Table C-2.

Table C-2: UKCS gas reserves in 2008 (bcm)

Domestic gas region	Proven	Probable	Possible	Potential Additional Resources
Northern & Shetlands	104	62	85	43
Central	186	98	90	28
Southern	128	70	86	47
Irish	62	18	18	7
Domestic gas cost tranches[1]	1,2	3,4,5	6,7,8	9

Note: 1) volume is split evenly between tranches

Import supply availability is shown in Table C-3. All imports are subject to further constraints on the capacity of pipelines connected to the UK national gas transmission system.

Table C-3: Annual Import Availability (bcm)

	2005	2010	2015	2020	2025	2030
Norway	27	33	40	40	40	40
Russia	160	240	270	270	270	270
LNG	27	107	134	156	186	210

Note: LNG and Russian gas supplies are split evenly between tranches

Table C-4 shows the entry costs of gas at six terminals receiving pipeline gas.

Table C-4: Assumed Entry Costs for Pipeline Gas

Terminal	Cost (2000 £/GJ)
St Fergus	0.061
Bacton	0.017
Teesside	0.006
Easington	0.005
Theddlethorpe	0.006
Barrow	0.000