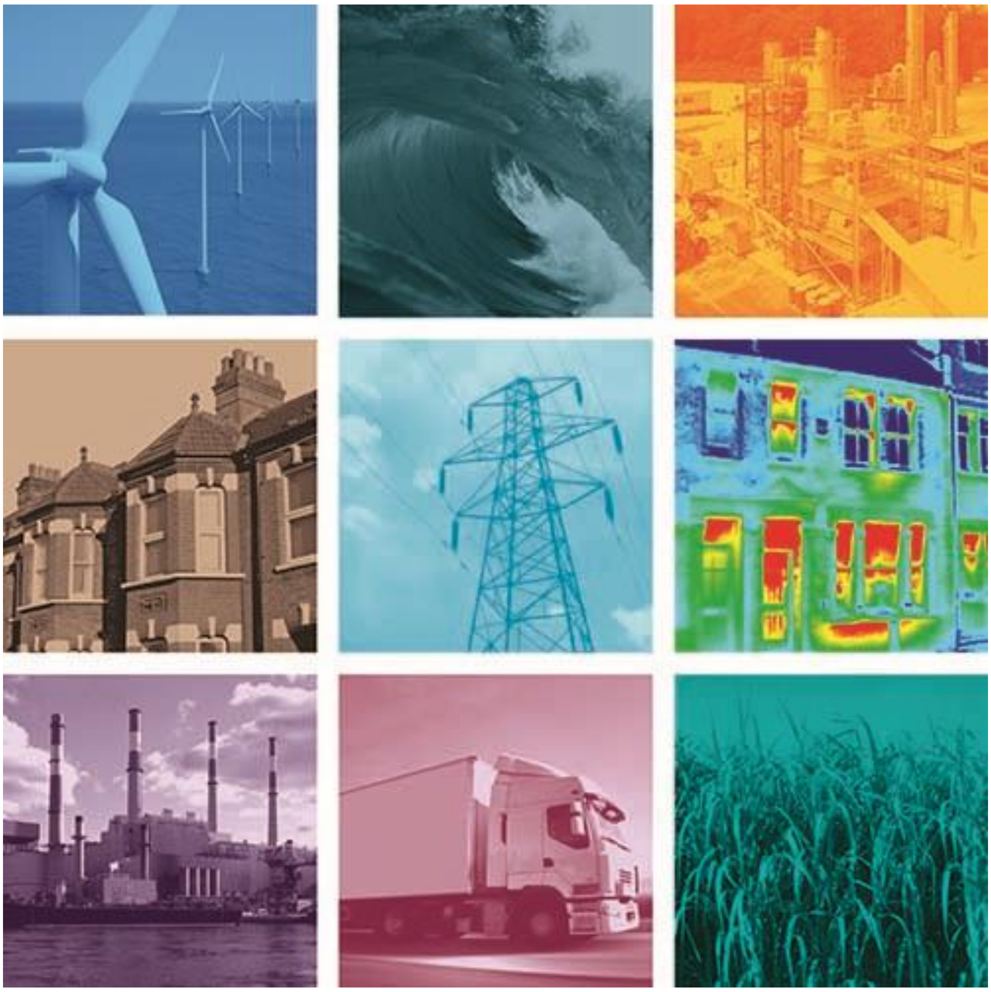
# DECC Small Modular Reactor Techno-Economic Assessment – Project 2 Technical Report

Strategic tools and assessment for SMR technologies in a UK low carbon energy system

Technical Report – 20th May 2016



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## Revision Description

| Version | Description |
|---|---|
| A | First issue to DECC as reporting Deliverable 3.1 incorporating contract Deliverables D2.1, D2.2, D2.3 and D2.4. Provided for information and comment as ETI's Mid Term report. This report is structured as for the full report with placeholders for the scope to be completed later. Comment and feedback is sought on the structure, layout and content to support subsequent preparation of the final report. |
| B | Updates to content and structure where appropriate from DECC economist comments on mid-term report, addition of D.2.5 and D2.6 analysis. |
| C | Revised based on feedback on version B received from DECC. |
| D | Minor revisions based on further feedback received from DECC. |

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## Executive Summary

### Key Findings:

**The role and value of SMRs is critically dependent on the wider energy system configuration.**

In an energy landscape where large nuclear, carbon capture and storage (CCS) and a basket of renewables can be developed and rolled out successfully to offer a balanced generation portfolio, SMRs for baseload electricity constitute a low value, easily substitutable technology option. However, the availability of other technologies in a cost effective and timely manner cannot be taken for granted.

**The risks associated with other low carbon technologies suggest a role for SMR development as a 'hedge' option.**

If the deployment of a new fleet of large nuclear reactors is not fully realised, an opportunity would open up for SMRs to provide baseload energy. Similarly, if a CCS programme fails to materialise or is deemed unattractive due to the risk of sustained high gas prices – SMRs can play a role in providing additional, affordable energy and power sector flexibility.

**SMRs with combined heat and power capability would provide wider system value while tapping into other revenue streams emerging as part of a whole system low carbon transition.**

CHP capability would raise the value of SMRs through the delivery of low carbon heat to new district heating networks in major cities. Under high deployment scenarios, as much as half of all energy for heat networks could be provided by SMRs.

**While baseload generation offers a conventional revenue stream for SMRs, load following and wider system services can form a critical part of the technology and commercial offering.**

The ability for SMRs to operate on a load following basis as part of a daily cycle would increase their value further by offering a wider set of system services beyond baseload energy. This need is driven in part by variation in demand, but may increasingly be driven by intermittent supply in high renewables scenarios.

**In addition to these wider system needs, the role of SMRs out to 2050 will be impacted by technology-specific factors including: capital cost, date of first deployment and build rates.**

As a capital intensive technology, a more optimistic capital cost profile clearly improves the prospects for SMRs to contribute as part of a least-cost low carbon energy system.

As more optimistic SMR assumptions are explored (alongside system assumptions favourable to their deployment), 2050 SMR capacity comes up against two limiting factors: annual build rates and date of first commercial operation. Even under favourable conditions, it must be assumed that build rates will initially be constrained by the need to develop supply chains and production facilities. Earlier ETI analysis suggested an maximum build rate of 400MW/yr for the first ten years, followed by a step up to 1200MW/yr thereafter. Clearly, to make a substantial impact by 2050, the date of first operation must happen early enough to allow a meaningful period of deployment at the higher rate.

## Project 2 Overview

Within the DECC Small Modular Reactor (SMR) Techno-Economic Appraisal, Project 2 delivers tools and assessment of the use and deployment of SMRs in a UK low carbon energy system. The analysis is undertaken using the ETI's established and peer reviewed ESME modelling system, which enables a cost optimised analysis of scenarios for the transition to a low carbon energy system. The extensive results from the ESME analysis are collated in the SMR Energy System Opportunity (SESO) Model which accompanies this report.

The scope of the project and this report is in six parts:

1. A description of the ETI, the ESME model and ETI's current analysis on SMRs
2. A description of this project and the interface with TEA Project 1
3. The definition of DECC's preferred baseline scenario for this project
    - This is based on ETI's "Clockwork" scenario but with modifications agreed with DECC at the start of the project.
4. Results of a range of deterministic sensitivity scenarios specified by DECC
    - These scenarios made use of generic SMR cost and performance characteristics provided by the ETI.
5. Results of a number of deterministic scenarios testing individual SMR technologies
    - For these scenarios, ETI used anonymised data (provided by Project 1) from prospective SMR vendors, for "near term" technologies with potential for first UK operations around 2030. There was useful learning from this analysis with indications of the probable differing levels of design maturity between reactor vendors as well as general vendor optimism bias.
6. Results of three probabilistic 'Monte Carlo' runs selected by DECC
    - For these probabilistic runs, ETI again used an anonymised dataset from Project 1, this time representing a single consolidated SMR technology (corrected for vendor bias[1] by Project 1). A series of three Monte Carlo runs were conducted, each involving many simulations where different cost outcomes occur across the full set of technologies. This dataset also included ranges for SMR cost parameters which enabled a probabilistic assessment of the impact of key uncertainties on SMR deployment.

The key contribution of Project 2 is to test a range of SMR assumptions within the context of a low carbon transition across ***the whole energy system***. A rapid decarbonisation of the power sector is now a robust feature of most UK low carbon scenarios, including those explored in this report. Decarbonising electricity can help achieving near-term emissions reductions in the most cost-effective way, and is an important precondition for further reductions through electrification of heat, transport and industry.

Although an extensive range of electricity generating technologies are available, each of these has its limitations, risks and uncertainties, meaning there is always the potential for a new technology such as SMRs - with the right costs and characteristics - to find a place in a least cost energy system design.

[1] Where data used in ESME has been corrected for vendor optimism, this correction was derived and applied by Project 1 prior to sharing with Project 2. No further adjustment has been made in Project 2.

While decarbonising the electricity grid may be a ‘no regrets’ option, a whole system analysis reveals the need for a range of low carbon energy vectors, rather than a blanket ‘all electric’ approach across the board. Although the electrification of heat is likely to play an important role in decarbonising energy use in our buildings, ETI assesses district heat networks as offering a more cost-effective approach for many homes, particularly in dense urban areas. As such, there is a significant opportunity for any technology, such as CHP-capable SMRs, that can energise heat networks in a cost effective way.

### The role and value of SMRs is critically dependent on the wider energy system configuration.

Across the many scenarios explored within this project, SMRs have been tested alongside over 250 other technologies. In some cases, the assumptions adopted for those other technologies create favourable conditions for the deployment of SMRs, in other cases not. It is therefore critically important to consider the wider system context before concluding the role that SMRs might play.

As part of its energy system analysis activities, ETI examines the opportunity cost associated with different technologies. This is the difference in cost between a system with all technology options available, and one with the given technology removed from the dataset. The high opportunity costs of CCS and bioenergy have been a consistent feature of this analysis for a number of years, indeed these are an order of magnitude above that of other technologies. Still, a number of other technologies have significant opportunity costs, including district heating, large nuclear, offshore wind etc.

In a policy-neutral pathway, assuming perfect foresight, and with all the technology options available, the opportunity space for electricity-only SMRs tends to be crowded out by large nuclear reactors, carbon capture and storage (CCS) and a basket of renewables (dominated by offshore wind). Even where some capacity of SMRs is deployed in this context, comparison against a baseline scenario reveals that the reduction in total system cost through deployment of SMRs is modest. That is, SMRs are substitutable for other technologies at relatively low cost. This is especially true of electricity-only SMRs, but even CHP SMRs have been shown to be substitutable by other electricity and heat generating technologies in a manageable way.

Where there are barriers to the successful rollout of the various higher value technologies though, we have seen that SMRs can play a role in a reconfigured least cost solution.

### The risks associated with other low carbon technologies suggest a role for SMR development as a ‘hedge’ option.

While a techno-economic optimisation model will always deploy the most cost effective combination of technologies to satisfy demand (and other constraints), in reality technology deployment is not policy neutral, perfect foresight of technology and resource costs does not exist, and there are a variety of other risks associated with the key technologies that typically form part of a cost-optimal low carbon pathway.

This points towards the need to develop and prove a variety of technology options to ensure there is some combination capable of delivering an energy system that meets our needs in the event of technology failure, or as other factors emerge.

Across the scenarios explored here, there are sufficient grounds to consider SMRs as one of a number of important ‘hedge’ technologies that can make a valuable contribution under certain conditions. For example, if further cost reductions in offshore wind fail to materialise, the deployment of a new fleet of large nuclear reactors is stalled, or a CCS programme fails to materialise (or is deemed unattractive due to the risk of sustained high gas prices), SMRs could play a significant role in making up the shortfall in low carbon electricity.

From the many scenarios examined throughout this project, some of the key sensitivities around the role of SMRs are listed below.

### SMR sensitivity to large nuclear deployment

In the context of the electricity sector, SMRs offer similar benefits to large nuclear but at higher costs. If more sites are available for large reactors, these could be deployed on a sufficient scale as to undermine the case for SMRs. On the other hand when tighter limits are placed on large reactors, SMRs could be one of the key technologies to provide replacement capacity.

Importantly, there are limits to how much combined nuclear capacity can be deployed before the average capacity factors of some reactors begin to decline due to periods of low demand. For a combined total nuclear capacity in the region of 40GW, both large reactors and SMRs would be able to deliver electricity unconstrained at their design capacity factor. In most of the runs in this project with a higher level of combined nuclear capacity, it is the SMRs which operate on a daily cycle.

It is important to note that high levels of deployment of large nuclear reactors remains dependent on site availability and eventual cost competitiveness. ETI have assumed (2010 GBP) capex levels of £3800/kWe in the near term falling to £3000/kWe by 2050 due to learning, consistent with government publications. This compares with the approximately £5000/kWe associated with the CfD arrangement for a ‘first of a kind’ plant at Hinkley Point C.

### SMR sensitivity to gas price and CCS deployment

When constraints are placed on deployment of Gas CCGT with CCS, we see increased SMR capacity as one part of a reconfigured cost optimal solution (other notable changes include a role for Coal CCS). The optimal capacity of CCGT with CCS is itself highly sensitive to the price of gas. The optimal capacity of SMRs is therefore highly sensitive to the cost of gas via the impact on CCGT with CCS.

### SMR sensitivity to biomass availability

ESME places a high value on biomass, typically developing the UK resource supply to the maximum available, as well as importing considerable quantities from overseas in later years. This is in large part due to the potential for negative emissions when combined with CCS. However, the biomass resource availability is uncertain, and is therefore modelled probabilistically in ESME. In those cases where we see less biomass in the system, and therefore less negative emissions, more comprehensive efforts must be made to fully decarbonise the energy system, including reducing residual emissions from Gas CCGT with CCS. In the ‘low biomass’ runs then, the lower capacity of CCGT with CCS presents an opportunity for deployment of SMRs.

## SMRs with combined heat and power capability would provide wider system value while tapping into other revenue streams emerging as part of a whole system low carbon transition.

CHP capability would raise the value of SMRs through the delivery of low carbon heat to new district heating networks in major cities. Under high deployment scenarios, as much as half of all energy for heat networks could be provided by SMRs.

### Without district heating, (electricity-only) SMRs can support higher electrification

Although district heating has been identified as an important component of a low-cost, low carbon transition for heat, there may be barriers to deployment that limit its role in the UK. It is therefore important to consider the least-cost energy system configuration where district heating has been prohibited.

In cases where district heating is unavailable in ESME, space heating across the entire building stock is comprehensively electrified, resulting in: more household retrofits to reduce space heat demand, more heat pump installations supported by electric resistive heaters and within-building heat storage, higher electricity capacity and generation and local distribution grid reinforcement.

In such ‘high electricity demand’ scenarios, large scale nuclear reactors remain the most cost effective option for baseload electricity in ESME (given cost and performance assumptions), but the upper capacity limit of 35GWe of new large scale reactors by 2050 (due to siting constraints), means that additional capacity must be provided by other technologies. This presents an opportunity for any cost-effective SMR design.

### With district heating, CHP-capable SMRs are a robust feature of the cost-optimal pathway

Where ESME has been configured to allow the deployment of large scale district heat networks, there is considerable value to be gained from deploying SMRs with combined heat and power capability. These SMRs can provide a significant volume of baseload electricity generation whilst simultaneously helping to energise heat networks with low carbon heat.

Other options for energising these networks include: heat recovery from large scale thermal power stations (excluding large nuclear plants), large scale marine-sourced heat pumps (e.g. from rivers, lakes, seawater); geothermal energy (where available). In the absence of CHP SMRs, these alternative technologies are sufficiently cost effective to ensure that ESME still chooses to deploy heat networks extensively. When CHP SMRs are available though, they tend to take a sizeable share of network hot water provision across the country.

### With district heating, electricity-only SMRs play a more limited role

There is a clear narrative around the role of electricity-only SMRs in a high electrification scenario. Similarly, the narrative is clear for CHP SMRs in a district heating scenario. A third case to consider is where electricity-only SMRs are the only variant available, but in a district heating scenario. Other things being equal, electricity-only SMRs would be deployed to a lesser extent in a district heating scenario, as the substantial increase in demand that accompanied the high electrification scenario does not materialise. However, the results of the runs in this project suggest that if the cost and performance assumptions are sufficiently favourable, electricity-only SMRs can still play a limited role in a scenario with district heating.

## While baseload generation offers a conventional revenue stream for SMRs, load following and wider system services can form a critical part of the technology and commercial offering.

The ability for SMRs to operate on a load following basis as part of a daily cycle would increase their value further by offering a wider set of system services beyond baseload energy. This need is driven in part by variation in demand, but may increasingly be driven by intermittent supply in high renewables scenarios.

There are many examples throughout this report of runs in which SMRs are required to operate below maximum capacity at certain times of the year, suggesting that in practice the flexible operation of SMRs is an important consideration in assessing their competitiveness versus large nuclear and renewables. This is especially apparent in those runs where favourable cost assumptions result in higher deployment of SMRs, on top of the 30GW+ capacity of large nuclear plants. Since there are periods of the year where electricity demand drops below this combined nuclear capacity, it is necessary to ramp down some of that capacity as part of a daily cycle.

In this context, the value of SMRs depends critically on system service provision, where the ability to load follow contributes to their competitiveness vs large nuclear and renewables.

### High temperature process heat

The claim from some proponents that emerging SMR technologies could play a role in hydrogen production is discussed in section 1. It is the view of the ETI that a range of alternatives are available for hydrogen production (including electrolysis, methane reforming, coal and/or biomass gasification) that are better understood, available in the nearer term and therefore capable of being scaled up to the levels required as part of a cost-effective low carbon pathway to 2050. By comparison, insufficient evidence is available to judge whether and when nuclear hydrogen production might compete with more established technologies. As new evidence emerges though, ETI can test this in the context of a whole systems analysis.

**In addition to these wider system needs, the role of SMRs out to 2050 will be impacted by technology-specific factors including: capital cost, date of first deployment and build rates.**

As a capital intensive technology, a more optimistic capital cost profile clearly improves the prospects for SMRs to contribute as part of a least-cost low carbon energy system. As more optimistic SMR assumptions are explored (alongside system assumptions favourable to their deployment), 2050 SMR capacity comes up against two limiting factors: date of first commercial operation and annual build rates.

### SMR date of first operations and build rate limits

From the runs conducted using ETI's generic SMR cost data, the date of first (possible) operations does not appear to be a major sensitivity. This is because most of these runs show SMRs being initially deployed much later than they could be. Similarly, the maximum build rate tends not to constrain the majority of those runs. By contrast (and unsurprisingly), the more favourable cost assumptions adopted in some of the vendor runs and in the Monte Carlo runs result in a much high level of SMR deployment, often at the bounds of the build rate limit.

Even under favourable conditions, it must be assumed that build rates will initially be constrained by the need to develop supply chains and production facilities. Earlier ETI analysis suggested a maximum build rate of 400MW/yr for the first ten years, followed by a step up to 1200MW/yr thereafter. Clearly, to make the greatest impact by 2050, the date of first operations must happen early enough to allow a meaningful period of deployment at the higher rate. In those cases, modelling a higher build rate or earlier deployment date would enable higher total capacity to be achieved by 2050.

### Capital Cost

SMRs, like large nuclear reactors, have a through-life cost profile that is dominated by front-end capital cost. Across the range of model runs conducted for this study, a large variation in SMR capex has been explored, and unsurprisingly this has been shown to greatly impact on the cost-optimal deployment[2]. Although capital costs dominate, operating & maintenance costs cannot be ignored, as

[2] While more or less optimistic assumptions have been tested for SMR technologies in these runs, ETI has not validated these alternative assumptions.

shown by SMR deployment levels in the two vendor runs (D2.5.2 & D2.5.6) sharing the same level of capex but with very different operating cost assumptions.

## Probabilistic assessment of SMR Deployment (using TEA derived generic SMR data)

The various batches of scenarios conducted in this project culminated in a series of three probabilistic ESME runs (described in section 10), using a generic SMR dataset collated and synthesised by Project 1 from the provisional findings of the different projects in the wider TEA. This 'TEA generic SMR' data included: input from Project 3 on emerging technologies; first UK operations dates adjusted for vendor bias by Project 1; capex and opex costs adjusted for vendor bias by Project 1; and a learner rate derived by projects 5, 6 & 7.

For near term electricity-only SMRs, Project 1 provided a (central) capex of £3505/kWe (in 2010 GBP) for the first deployment from 2031, falling to £3329/kWe by 2050 (this represented a substantial reduction from the comparable 'ETI generic SMR' assumptions used in the earlier batch of scenarios i.e. £4750/kWe with no learner effect). In the probabilistic run where these electricity-only SMRs were available from 2031 (and where heat networks could be deployed), an average deployment of 10GWe of SMRs was observed in 2050 across the 150 simulations.

In a second probabilistic run, SMRs were made available from 2031 on a combined heat and power (CHP) basis, with cost and performance adjusted accordingly. In this case, where SMRs could support district heat networks, average deployment by 2050 was 14GWe (with most of the runs reaching the capacity limit of 15GWe).

In the third probabilistic run, the electricity-only SMR design represented an emerging technology, with a later first deployment date of 2035 and a capex markup applied. As a result, an average of only 3GWe was observed across the 150 simulations.

## Recommendation to update the DECC TEA agreed baseline scenario and test SMR deployment

Section 4 outlines the approach taken to agree a baseline scenario for these runs. This built upon previous discussions between DECC and ETI in August 2015. Since that time, the Comprehensive Spending Review and related announcements have amounted to an energy policy 'reset', with profound implications for the least-cost pathway previously set out. The most significant change is the withdrawal of capital support for a CCS demonstration competition in the UK, meaning the demonstration projects assumed to occur in the baseline run are highly unlikely to go ahead. As a result, the commercial-scale deployment of CCS technologies from 2020 as represented in the baseline seems highly unlikely.

In addition to these policy changes, DECC has been working on a revised set of cost assumptions for electricity generation technologies, which are yet to be published. Since SMRs have been shown to be highly sensitive to the deployment of other technologies, it is important to check the findings of this report against these new costs. There is therefore a need to bring the baseline up to date with latest DECC assumptions and in the context of a delay to CCS deployment, to assess the impact on the potential role of SMRs. Given the attractiveness of CHP SMRs in the ETI baseline for example, these would be expected to become more attractive if other technologies are delayed or face higher costs. Electricity-only SMRs are less attractive than CHP SMRs but might become significantly more attractive with less competition from other generating technologies.

## Contents

# 1. Energy Technologies Institute (ETI)

The Energy Technologies Institute (ETI) is a public-private partnership between the UK government and several global companies: BP, Caterpillar, EDF, Rolls-Royce and Shell. ETI makes targeted investments in R&D projects to accelerate the development of affordable, clean, secure technologies needed to help the UK meet its emissions targets.

## 1.1. ETI's Energy System Modelling Environment (ESME)

In 2008 ETI began development of the internationally peer-reviewed Energy System Modelling Environment (ESME), initially to support the identification of priority areas for investment. Since then ESME has become an important tool in its own right, sitting at the heart of ETI's modelling and analysis capability. ESME is also used by member organisations to support strategic thinking and decision making. Notable citations of ESME include: The Renewable Energy Review[3], The Carbon Plan[4], UK Bioenergy Strategy[5], The Future of Heating[6,7].

ESME has also been licensed to support a number of academic research projects, for example: exploring the role of demand reduction[8] and energy strategy under uncertainty[9],[10].

## 1.2. Model overview

ESME is a least-cost optimisation model designed to explore technology options for a carbon constrained UK energy system, subject to additional constraints around energy security, peak energy demand, build rates etc. ESME covers the power, transport, buildings and industry sectors, and the infrastructure that supports and connects them, in five-year time steps from 2010-2050.

A system-wide carbon budget is provided for each time step, in line with existing government carbon budgets in the near term, then linearly out to 2050 in line with the Climate Change Act greenhouse gas reduction target of 80% against a 1990 baseline.[11]

Energy demand across the year is sub-divided into five diurnal time slices (morning, mid-day, early evening, late evening, overnight) in each of two seasons (summer, winter). A further five time slices

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[3] CCC (2011) "The Renewable Energy Review", http://www.theccc.org.uk/publication/the-renewable-energy-review/
[4] HMG (2011) "The Carbon Plan: Delivering our low carbon future", https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47613/3702-the-carbon-plan-delivering-our-low-carbon-future.pdf
[5] DfT, DECC, DEFRA (2012) "UK Bioenergy Strategy", https://www.gov.uk/government/publications/uk-bioenergy-strategy
[6] DECC (2012) "The Future of Heating: A strategic framework for low carbon heat in the UK", https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48574/4805-future-heating-strategic-framework.pdf
[7] DECC (2013) "The Future of Heating: Meeting the challenge", https://www.gov.uk/government/publications/the-future-of-heating-meeting-the-challenge
[8] Pye, S., Usher, W., & Strachan, N. (2014a). The uncertain but critical role of demand reduction in meeting long-term energy decarbonisation targets. Energy Policy, 73, 575-586.
[9] Pye, S., Sabio, N., & Strachan, N. (2014b). An integrated systematic analysis of uncertainties in UK energy transition pathways [forthcoming].
[10] Pye S., Sabio, N., Strachan, N. (2014c). Energy Strategies Under Uncertainty: An Integrated Systematic Analysis of Uncertainties in UK Energy Transition Pathways. UKERC Report UKERC/WP/FG/2014/002.
[11] The Carbon budget is therefore an exogenous constraint, while an implied carbon price can be derived endogenously.

are used to represent an exceptional peak day and ensure that ESME designs a system capable of responding to a 1-in-20-year multi-day cold weather event.

Spatially, the UK is divided into 12 onshore regions (Scotland, Wales, Northern Ireland, with England sub-divided into East, East Midlands, London, North East, North West, South East, South West, West Midlands, Yorkshire & Humber). Energy demand in each region can be met by exploiting energy resources within that region, through transmission of energy from an adjacent region or, in some cases, by importing energy resources such as biomass.

There are also 12 offshore regions, nine of which contain energy resources (wind, wave and/or tidal energy) that can be harvested with the appropriate technologies and transmitted to an adjacent onshore region. The remaining three offshore regions represent areas that can be used for the storage of captured $CO_2$.

Interconnectors with Europe are also represented. These make a limited contribution to the peak capacity margin calculation. As a default it is assumed that net importing (or exporting) of electricity does not take place over the course of a year.

ESME incorporates a probabilistic approach to the treatment of uncertainty, allowing a large number of simulations to be carried out to explore the impact of different cost trajectories etc. This is described in more detail below.

ESME includes a placeholder for $CO_2$ emissions outside the scope of the energy system, ensuring it covers all $CO_2$ emissions in UK territory. However, the government's 2050 emissions target refers to *all* greenhouse gases, not just $CO_2$. ETI assumes a trajectory to 2050 for non-$CO_2$ emissions proposed by the Committee on Climate Change[12] (CCC). Subtracting this from the UK target for all greenhouse gases gives a 2050 target for $CO_2$ of 105Mt which is used in the ESME model. Note that the reduction in $CO_2$ emissions relative to 1990 levels is greater than 80% because the assumed reduction in non-$CO_2$ greenhouse gases is less than 80%.

## Energy demand

Energy demands in ESME are specified out to 2050 for each region and, where appropriate, for each period of the day and year. However, these demands are not specified in terms of energy *per se*, but as a range of energy services. These energy services are the actual useful services that energy provides to households, business and industry, such as 'passenger km' for private vehicles, 'freight km' for haulage, 'lumens' of light in the home etc. Different technologies are available for ESME to use to deliver these services, e.g. electric cars or hydrogen fuel cell cars for 'passenger km'. Since competing technologies may have different input fuels and efficiencies, the actual volume of energy required is not established until runtime, when ESME builds the cost-optimal supply side solution to satisfy the demands. In doing so, ESME must balance energy supply and demand in each time step, region and time slice.

Establishing appropriate assumptions for energy service demands out to 2050 is clearly an area of considerable uncertainty. To ensure the robustness of our insights against a range of possible futures, ETI has devised a series of demand cases, each depicting a self-consistent view of the world. One of these, the reference case, draws on government projections of population, GDP, and demand for energy services where these are available.

[12] see table 3.4 of http://archive.theccc.org.uk/aws2/4th%20Budget/CCC-4th-Budget-Book_plain_singles.pdf

Note: in the runs conducted as part of this project, only the reference demand case has been used. By way of context though, the ETI internally carries out sensitivity studies using an additional two demand cases, one with a higher population and economic growth (more weighted towards services) and another characterised by slower growth.

## Technology dataset

In the v4.0 release of ESME, over 250 technologies are represented. The ESME technology dataset is primarily populated with data based on outputs and insights from ETI's portfolio of technology research, development and demonstration projects. In the earliest versions of ESME the technology data was populated by consolidating inputs from ETI's public and private sector members. Over time, ETI's portfolio of research projects has delivered a more robust evidence base for the costs and characteristics of technologies and the initial ESME dataset has been gradually superseded. Where the ETI has no projects in a technology area, such as for solar, ETI has conducted a critical appraisal of the available evidence in the published literature.

A high level of effort has been applied in ETI towards building datasets for ESME, and effort continues to be spent on updating the assumptions and increasing the level of segmentation in industry, the power sector, transport and buildings (always having regard for the need to capture a range of uncertainty as part of this).

For each technology the capital, fixed and variable costs are defined for 2010 and 2050 on an 'n$^{th}$ of a kind' basis, similarly for performance characteristics such as efficiency, load factors etc. Unless otherwise specified, ESME interpolates the values for the intermediate time steps in a linear fashion.

## Dataset variations

The standard ESME dataset is updated and released to ETI members and ESME software licensees on a six monthly basis. Internally, the ETI maintains a dataset for ESME which represents the best current view, unbiased by lobbying and other factors. As ever, where a wide range of outcomes are possible these are represented by wide probability distributions on those inputs. To this end, ETI produce an annual 'Director's Cut' version of ESME, in which the standard dataset is modified to incorporate the latest views submitted from across the strategy team – these can include developing insights from ETI's in-progress technology projects.

Modification for the Director's Cut can involve reducing the costs or improving the performance of technologies in the model, or adding new technology variants with distinct characteristics. Clearly, improving the technologies and adding new options in this way makes it more cost effective for ESME to deliver a low carbon transition. At the same time it makes it harder for any unmodified technologies to compete. The choice of dataset is crucial in assessing the role of a given technology and will be discussed further in later sections of this report.

## Treatment of uncertainty

ESME is designed to incorporate uncertainty regarding outcomes for different technologies. This is mostly applied in the context of capital costs and fuel prices where, in addition to a mean value, a triangular distribution can be defined around the 2050 cost.

ESME can be operated in deterministic mode, where it produces a single energy system design, with all probabilistic variables assigned to their 2050 deterministic values (usually the mean of the 2050 distribution, sometimes the mode), with values in intermediate years interpolated accordingly. When ESME is operated in probabilistic mode, it produces a user-defined number of energy system designs or 'simulations'. For each simulation the probabilistic variables are assigned a randomly selected value from their 2050 range[13]. Once the 2050 value is assigned, the intermediate values are once again interpolated linearly from 2010. The ability to automate the analysis of uncertainty is a particular strength of ESME. It should be noted that some of the inputs used in this study were provided by others and uncertainty is represented by scenario alternatives rather than probability distributions. The conclusions should be interpreted accordingly.

### Constraints

In addition to the overarching constraint of a decreasing carbon budget over time, ESME can be populated with a series of other constraints intended to improve the realism of the energy system transition. These include limits on the availability of certain resources, maximum build rates and quantities for different technologies, as well as constraints governing their operation.

### Existing assets

ESME is programmed to start out in 2010 with a range of existing assets across the energy system based on historical data, including power stations, road vehicles, the building stock (and associated heating systems) and so on. When new technologies are deployed in ESME, they have a finite 'technical life' before they must be retired and replaced. Since the existing assets are part-way through their technical lives, a custom retirement profile is often imposed upon them (for example to reflect the anticipated retirements of coal and nuclear power plants).

To improve the near term realism of the energy system transition, ESME is also programmed with *minimum* build requirements of different technologies, consistent with known developments since the baseline year of 2010 e.g. for onshore and offshore wind farms. The current project pipeline and system 'momentum' can be represented, even if it is not the nominally most cost-effective one.

## 1.3. ESME Treatment of Industrial Heat

*Context: Some of the technologies considered in the TEA are lightwater reactors which offer the capability of steam supply at modest temperatures or hot water for district heating system energisation. There are other designs of high temperature reactors for which the proponents claim that the supply of high temperature process heat is a major economic advantage. One of the challenges for Project 2 was to consider this proposition from amongst the emerging reactor technologies.*

Energy use by industry is represented in ESME via 9 subsectors, and for each sector energy use is further subdivided into generic categories e.g. high temperature process heat, low temperature process heat, drying & separation. A set of 91 'technologies' are available in ESME v4.0 to represent different forms of energy use in the different subsectors. Overall levels of UK industrial activity are set

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[13] In some cases, correlations are defined between technologies with similar characteristics to ensure they are assigned values from a similar point in their respective ranges.

in ESME's energy service demands by subsector, by region and by year. Each industry technology consumes a mixture of energy vectors and produces industry activity which contributes to the overall requirement. Costed abatement options are available in the form of switching from fossil fuels to lower carbon fuels (e.g. electricity, biomass[14], hydrogen[15]), CCS technologies, and a small number of other alternative processes.

Typically the carbon targets and cost-minimisation in ESME lead to results in 2030 & 2040 which have a mixture of fuel switching to natural gas, biomass and hydrogen, and a small amount of industrial CCS. In 2050 the tighter carbon targets lead to more deployment of lower carbon and more expensive options: fuel switching to hydrogen, fuel switching to biomass in combination with CCS and fuel switching to natural gas in combination with CCS.

The whole industry sector was revised in Q2 of 2015 for the development of ESME v4.0. This project included a broad literature review of how industry has been represented in other energy models in the UK, EU and USA, as well as a review of the available data sources which could be used to populate ESME. This review concluded that the best approach was to increase the number of sectors and subsectors in the ESME model considerably, and to populate these with abatement options primarily from *Industrial Energy Use (UK)*, UKERC 2013 (link). This dataset was the result of a major academic project giving baseline energy use and emissions for key process industries and costed opportunities for reducing them.

There is no representation in ESME of the ability for nuclear power to provide process heat to industries. Although it is a possible future development, provision of nuclear heat was not included in the UKERC industry review, nor has it been included in other comparable datasets or energy models. The development and licensing of nuclear technologies for industrial heat is at an early stage. In contrast there are many proven abatement options in the form of switching to low-carbon fuels, and a body of literature on the potential for industry CCS, which constitute a broad and proven set of options.

SMRs for industrial process heat are currently unproven, with little time to develop, prove and deploy them in sufficient quantities to make a significant contribution to process heat by 2050. The ETI currently judges that there are likely to be lower risk and more cost effective solutions based on more proven technologies for the supply of industrial process heat.

For these reasons the provision of nuclear process heat to industry is not considered a practical abatement strategy. While there might be niche applications and demonstrators by 2050, it is not included in the ESME model at present[16]. If a concrete development and application path for nuclear industrial heat emerges, its impact on the UK can be examined. Given that the nuclear asset and the industrial plant are both likely to be new, this would be in the context of a narrative about UK industrial strategy.

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[14] Biomass in ESME is assumed to be low-carbon and sustainable. Uncertainty over how much low-carbon and sustainable biomass will be available to the UK in future is explored by ETI via scenario analysis and/or Monte Carlo analysis.

[15] Hydrogen can be generated by a variety of technologies in ESME, including electrolysis, methane reforming, gasification of coal and gasification of biomass.

[16] It is worth noting that ESME does include the ability for nuclear SMRs to supply heat to district heat networks. Although this is a different technical proposition, it is an analogous route for SMRs to provide extra value to the energy system through the supply of low-carbon heat.

### Typical ESME pathway for industry heat

Figure 1 shows the fuel consumption for high temperature process heat across industry, taken from the baseline run (D2.3.2) described in more detail later. While fossil fuels dominate the energy mix at present, the longer term pathway sees the introduction of hydrogen and biomass as the key low carbon alternatives. It should be noted that the majority of hydrogen in this and most other scenarios is itself generated from biomass, via gasification. The use of biomass, both directly and indirectly via hydrogen, affords the opportunity for negative emissions when coupled with CCS, adding significant system-wide value.

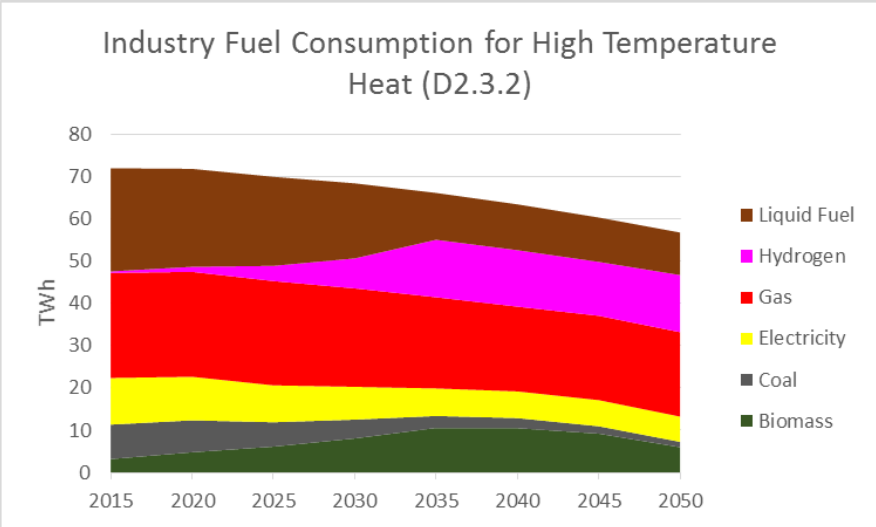


*Figure 1: Fuel Consumption for high temperature process heat across all Industry sectors in the baseline scenario (D2.3.2) described later in this report.*

Where CCS is not available to the model, electrolysis is another low carbon route for hydrogen production. For a given cost of electricity generation, electrolysis can convert to hydrogen for an additional 3p/kWh (assuming a high capacity factor for the conversion plant).

It is typical to see hydrogen production in ESME breaching 100TWh/yr by 2040 where bio-CCS is available (by 2050 if relying on electrolysis). This sort of scale implies hydrogen production capacity of around 10GW (assuming a very high capacity factor). Any consideration of emerging nuclear technology for hydrogen production must be considered in this context.

## 1.4. Economic analysis using ESME

The objective function in ESME is to minimise the net present value (NPV) of total energy system cost. To understand how this is calculated, we give below the definitions for the different types of cost assumptions used in the model:

- Capital cost: Cost of deploying a technology (per capacity unit), based on cost estimates for $n^{th}$ of a kind. Costs include, where relevant: engineering, procurement and construction (EPC) cost, infrastructure connection costs, pre-licensing costs, technical and design costs, licensing costs and public enquiry costs. Land purchase costs are excluded and interest during construction (IDC) is calculated separately in ESME.
- Fixed O&M costs: Technology costs, e.g. operation and maintenance, which are incurred per year, regardless of level of usage (per capacity unit).

- Variable O&M costs: Technology costs, e.g. operation and maintenance costs, which are in proportion to the level of usage (per capacity unit). NB this does not include fuel costs, or balancing costs.
- Resource/Fuel Costs: defined on a per unit basis for fuels such as gas, coal, oil, biomass etc.

The annual system cost for each time step (typically every 5th year) is made up of all the fixed, variable and resource costs in that year plus *annualised* capital costs:

- Whenever ESME deploys a technology, the capital expenditure (capex) is assumed to be financed at an investment rate of 8%, and paid in identical annual payments over the economic life of the technology. Hence, the annual system cost for 2040 will include annual costs for technologies deployed in 2030, 2035 etc.

The net present value (NPV) of total energy system cost is calculated by constructing an annual system cost for each time step and applying a social discount rate of 3.5%, before summing these to give a 2010 NPV cost.

## Base year for cost calculations

All costs in ESME, and in this report, are normalised to 2010 GBP. This is true for any input costs such as technology capex, as well as for outputs such as total system costs. In this report there is an exception (labelled clearly in each instance): levelised cost of energy (LCOE) is reported in 2015 GBP as this was required for data sharing across other Projects in the TEA.

## Opportunity cost

ESME is often used to estimate the opportunity cost of a given technology. This is calculated as the difference in expected cost (across the probability space defined by the inputs) between a system with all technology options available, and one with the given technology removed from the dataset. The opportunity cost of a technology is a measure of both the scale of deployment and the degree to which the technology can be ‘substituted’ in the energy system design. For example, if a technology is found to be widely deployed in the ESME energy system but has a low opportunity cost, this implies that it can be readily substituted at little additional cost. In some cases this is true, but in many cases a significant reconfiguration is seen as the whole energy system adjusts to the removal of a technology – this is usually associated with a larger opportunity cost.

## Abatement cost

The ‘absolute’ total system costs in ESME can seem very high, however many costs will be incurred by the energy system *even in the absence of a carbon target*, in order to keep the lights on, replace cars, boilers etc.

It is therefore helpful to think of the cost of a low carbon transition as the *additional* cost of meeting our needs through a low-carbon rather than a high-carbon energy system, i.e. the abatement cost. For this reason, a ‘no $CO_2$ target’ counterfactual has been included in the SESO model spreadsheet for comparison. Against this run, the abatement cost of each SESO sensitivity run can be calculated.

This abatement cost can be expressed in £bn/year, and therefore as a percentage of GDP. To support in this calculation, a projection for UK GDP over the period to 2050 is required. In the reference case (used in the SESO runs) this is informed by HM Government’s central forecast.

### Learning rates

Capital costs for most technologies in ESME are projected to decline over time, as a result of technology innovation and learning. While learning through deployment is an important factor in achieving cost reduction in the real world, in ESME cost curves for each technology must be set out in advance (as demanded by the linear programming approach adopted). That is, the cost of deploying a technology in period *x* is unaffected by the level of deployment observed in earlier periods.

In most cases this is reasonable, on the basis that learning through deployment is not limited to UK deployment specifically, but can occur anywhere in the world, and building up a scenario of global deployment of each technology is clearly beyond the scope of a model like ESME.

All technology capital costs are defined on an 'n$^{th}$ of a kind' (NOAK) basis, disregarding the additional costs that would be incurred while transitioning from the 'first of a kind' (FOAK) to NOAK. Again this is a restriction of the linear programming approach, but does not prevent further off-model analysis of the likely FOAK markup that might be expected for different technologies.

If FOAK costs were included in the model, and were substantial and persistent, this may well impact on the attractiveness of a technology and its selection as part of a least cost pathway. This can be tested in ESME through assuming a substantial and persistent markup on NOAK costs throughout (this is the approach adopted in this study under the 'high capex' runs).

While the FOAK/NOAK issue relates to a temporary period of initial learning, the more general uncertainty over long term future costs is something ESME is able to address through the probabilistic feature explained elsewhere.

### Market, Policy & Regulatory measures

Aside from the obvious policy of reducing carbon emissions over time, ESME is otherwise a policy neutral model. ESME identifies current technology portfolio options that are most likely to deliver secure, affordable and sustainable UK energy systems.  Creating the policy and market environment to deliver real energy systems over time is not within its scope.

Used properly ESME is about making sensible strategic choices, not about prediction. Studying the full range of results from a probabilistic run shows how divergent the outcomes can be, as technologies compete over time to deliver viable energy systems.

Within the ETI, technologies with significant option values have been targets for investment, in some combination of greater understanding and engineering development.  The detail with which practical deployment is studied goes far beyond most published scenarios.

## 1.5. Wider ETI modelling capability

ESME occupies a central position in ETI's modelling capability and is supported by a comprehensive suite of modelling and analysis tools across a portfolio of nine technology programme areas (see Figure 2). These models have more granularity than ESME within their specific sector. The models are usually soft-linked with ESME, whereby the outputs from one model inform the inputs of the other.

The majority of the models in Figure 2 have been commissioned by the ETI, where a gap in the knowledge base has been identified for which no model previously existed. Others are existing third party tools licensed by ETI to support its own analysis.

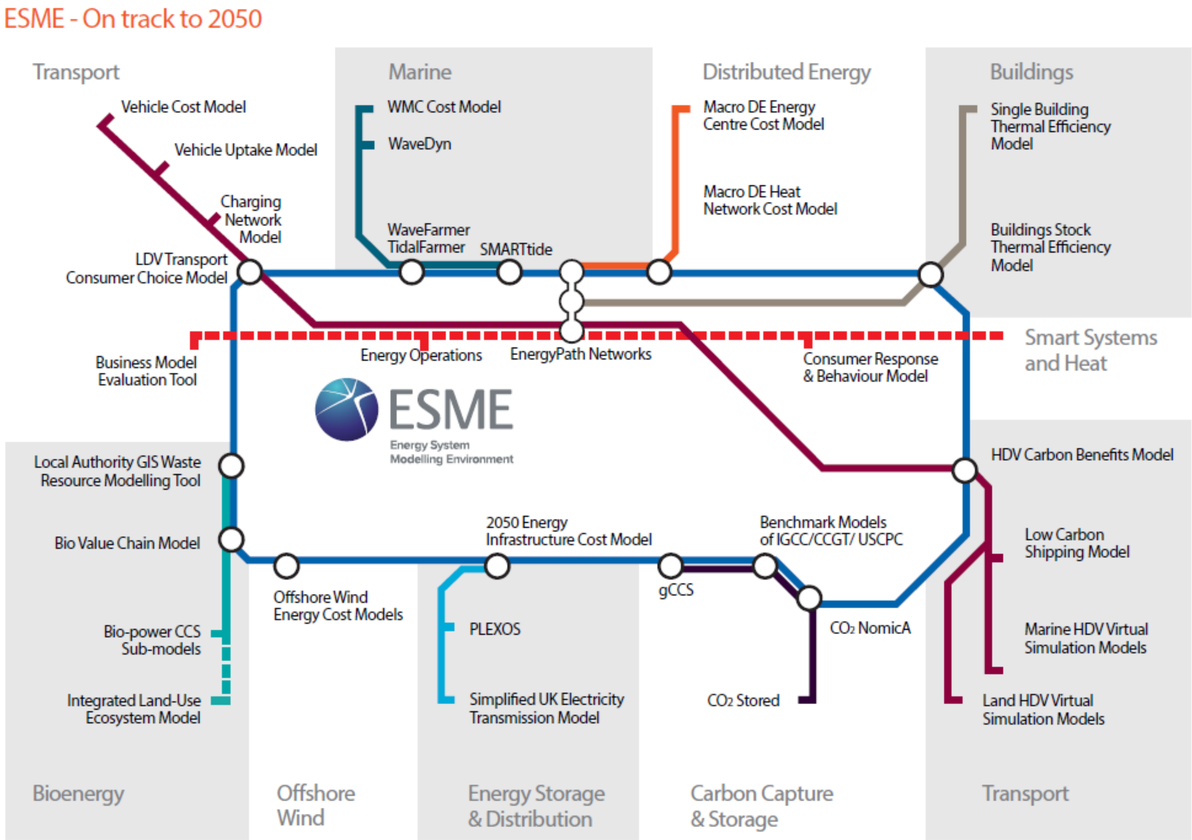


*Figure 2 Schematic map of models used by ETI, arranged by programme area. Each 'station' represents a model, each circle represents a model with a direct interaction with the ESME optimisation model.*

## 1.6. Energy System Scenarios: Clockwork And Patchwork

In 2015 ETI released two scenarios, Clockwork and Patchwork[17]. These are stylised ESME runs supplemented by a narrative storyline depicting potential social and political developments consistent with each energy system design. The two scenarios were constructed in such a way as to represent a good portion of the cost-effective design space identified in the many thousands of simulation runs conducted through ESME's normal probabilistic mode.

### Scenario development process

Throughout 2014, the ETI scenario team worked with members and other stakeholders to develop ESME runs and qualitative narratives for the two scenarios. As part of an iterative process, the team began with a set of model runs developed in previous years to inform internal strategic thinking about the role of different technologies under different conditions.

[17] "Options, Choices, Actions: UK scenarios for a low carbon energy system transition", ETI, March 2015.

The model runs that would eventually form the basis of the two scenarios were based on different demand cases. Clockwork was built upon the reference case projections (described earlier), while Patchwork assumed higher population growth and an economic composition weighted more towards services. This initial distinction ensured that the optimal energy system design would be different for the two scenarios. However, with the same costs, performance and constraints on the supply side technologies available in the model, the difference would largely be one of degree (with a similar basket of technologies being deployed in both cases but at different scales to meet higher or lower demands in each sector).

By engaging with stakeholders in a series of workshops and one-to-one sessions, the scenario team gradually crafted a more distinct set of assumptions governing the cost and availability of technologies in each run, consistent with the 'world view' implicit in the emerging scenario narratives. These were crafted to ensure that many of the key lessons and insights from years of strategic thinking at ETI could be expressed.

## Scenario outlines

A key distinction between the Clockwork and Patchwork narratives is the extent of national coordination of the energy system transition. In Clockwork, a stronger role for a strategic, central decision making body leads to the regular build of new nuclear and gas CCS in the power sector from the early 2020s. National-level strategy also supports the deployment of large-scale district heating networks, leading to the retirement of parts of the local gas distribution network in the 2040s. The comprehensive use of sustainable biomass in combination with CCS to produce 'negative emissions' creates significant headroom in the emissions budget. This headroom buys time for the road transport fleet to decarbonise more slowly, which is achieved through hybrid electric/liquid fuel vehicles along with substantial improvements in fuel efficiency.

In Patchwork, a less coherent national energy strategy means that local and regional authorities follow divergent pathways. This results in an array of distinct energy strategies, with new nuclear playing less of a role, and CCS being somewhat delayed. In place of these, a basket of renewables are deployed to decarbonise the power sector, led by offshore wind. Although district heat networks make an important contribution in some localities, there is more of an emphasis on energy conservation and efficiency measures in the building stock to reduce demand in the first place, partly in response to higher energy prices. A more conservative attitude to the use of negative emissions means there is a need to decarbonise the road transport fleet more comprehensively. Partly, this is mitigated through a slowdown in new vehicle sales, but eventually there is a need to shift from fossil fuel to hydrogen based vehicles.

Some of the thinking behind the Clockwork scenario informed the baseline assumptions described in this report. Further detail of this scenario is therefore provided later.

## 2. ETI internal SMR analysis

Prior to and separate from the analysis conducted in this TEA, ETI conducted its own internal assessment of the potential role of SMRs in the UK in early 2015. Given that the ETI has subsequently published an insights paper based on this work, it is worth noting that any differences between the model results in these two studies are the result of using distinct sets of assumptions and input sensitivities.

To assess the possible role for SMRs in the UK energy system, ETI performed a series of sensitivity runs in ESME, using a range of possible costs and constraints informed by two recently completed ETI projects: System Requirements for Alternative Nuclear Technologies (ANT) and the Power Plant Siting Study (PPSS).

The ESME model runs were aimed at identifying the preferred SMR technologies under different conditions, in order to arrive at a generic set of assumptions for an SMR technology to be used in other ESME modelling. These runs were built upon the latest ESME dataset at the time (v3.5), which has since been superseded.

By contrast, the ESME runs conducted for the TEA project were built upon ESME v4.0 and modified according to the 'Director's Cut' approach explained earlier, along with further modifications consistent with the DECC view on a range of technologies. The rationale for this is given in Section 4, but a key impact is to create a more competitive environment in which to explore the potential role of SMRs. This difference should be understood if comparing results from ETI's internal analysis with that performed for DECC within the current Project.

### Power Plant Siting Study

The Power Plant Siting Study investigated the theoretical UK site capacity for the deployment of large nuclear power stations at locations that meet the established UK criteria for the siting of nuclear power stations, and then through a range of sensitivity studies explored:

- The theoretical site capacity for the deployment of small reactors at locations not suitable for large reactors
- The potential for competition for development sites between developers of nuclear power stations and developers of thermal power stations with CCS

The PPSS summary report is available from the ETI website[18].

ETI's conclusions and data carried forward into ESME are reported in ETI's Nuclear Insights[19]. The capacity of sites in England and Wales suitable for large reactors is strongly influenced by the application of the siting criteria for new nuclear power stations as detailed in National Policy Statement EN-6. The PPSS found no good reason to amend these criteria and their application showed that capacity adjacent to existing sites as well as capacity at greenfield and brownfield sites is heavily constrained.

The ETI's Nuclear Insights booklet describes an upper bounding limit of 35 GWe of new large reactors by 2050, based on the availability of sites. The PPSS also explored the site availability for the deployment of SMRs at sites not suitable for large reactors and found this capacity less constrained. The ETI's Nuclear Insights booklet describes a lower bounding limit of 21 GWe, based on the availability of sites for SMRs. It is a lower bounding limit because the PPSS did not

[18] http://www.eti.co.uk/wp-content/uploads/2015/10/PPSS-Summary-Report-with-Peer-Review.pdf
[19] http://www.eti.co.uk/the-role-for-nuclear-within-a-low-carbon-energy-system/

exhaustively explore the limit of capacity and it is likely that further work will reveal more potential sites which meet the siting criteria, particularly in the application for combined heat and power.

### System Requirements For Alternative Nuclear Technologies

The Alternative Nuclear Technologies (ANT) project examined what SMRs would be required to do in terms of outputs, performance, availability and cost envelope to be of interest for potential deployment in the UK Energy System. The project involved the derivation of a set of credible technical performance characteristics for use in ESME, and also derived an indicative cost model independent of cost assumptions created by current SMR reactor vendors. The ANT summary report is available from the ETI website[20].

ETI's conclusions and data carried forward into ESME are reported in ETI's Nuclear Insights[21]. The ANT project enabled the characterisation of a Generic ETI SMR for scenario assessment within ESME with the following characteristics:

- Nominal plant unit size of 300 MWe
- Most likely UK FOAK first operations date of 2030
- Build out rate using low, medium and high scenarios, with the medium scenario being consistently applied of subsequent connections after UK FOAK of 400 MWe/yr for 10 years, and 1200 MWe/yr thereafter
- Plant construction period for NOAK of 3 years
    - Given the starting point of a concrete foundation base mat, the large ABWR reactor was built and commissioned at one site in 36 months. The design concept in the ANT is highly modularised construction, including civil engineering.
- Plant availability factor of 0.85
    - Selected as a conservative estimate for modelling purposes. Some SMR vendors claim higher availability factors but these are not demonstrated. Some nuclear utilities outside the UK have consistently demonstrated nuclear plant capacity factors above 90% but these have not been demonstrated in the UK.
- NOAK costs: CAPEX £4750/kWe (with an uncertainty range +40%/-20%), OPEX £130/kWe/yr falling to £100/kWe/yr
- As well as electricity generation only, the generic SMR could be configured for Combined Heat and Power with CAPEX and OPEX additions of £200/kWe and £5/kWe/yr respectively. The CHP configuration would supply heat to district heating system, but with a 20% reduction in electrical power generation whilst delivering heat.

### ETI's ESME Analysis Using ANT and PPSS Project Data

The conclusions were that there is a role for nuclear in an affordable UK low carbon energy system alongside both renewables and plants fitted with CCS. Large reactors may be best suited for baseload electricity generation, and SMRs may be best suited for CHP deployment for the generation of electricity and the energisation of city scale district heating systems. Sensitivity analyses indicated that the levels of SMR deployment within ESME scenarios were influenced by CAPEX cost, first operations date for an SMR in the UK, build out rate assumptions, and whether deployment was as CHP or for electricity only.

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[20] http://www.eti.co.uk/wp-content/uploads/2015/10/ANT-Summary-Report-with-Peer-Review.pdf
[21] http://www.eti.co.uk/the-role-for-nuclear-within-a-low-carbon-energy-system/

# 3. Methodology and Objectives Of TEA Project 2

## 3.1. Interfaces With Project 1

For the completion of the vendor technology runs described in Section 9, Project 2 requested the following anonymised data from the participating vendors (gathered and anonymised by Project 1):

- Construction period
- Capital cost – for 2010 and 2050
- Fixed O&M cost – for 2010 and 2050
- Variable O&M cost – for 2010 and 2050
- Economic life
- Technical life
- Ramp rate
- Annual build rate constraints (and how this can scale over time. The ETI can specify maximum total capacity and max capacity per region)
- Availability factor
- Plant efficiency (input of nuclear fuel per kWh electric, and output of recoverable heat/network hot water per kWh electric where relevant)
- Heat supply as part combined heat and power operations
- High temperature heat supply for process heat applications

No vendors provided a complete set of data according to the above specification, however minor gaps in the data were filled by ETI generic SMR assumptions to give a complete technology profile. In some cases though, the gaps in the data were significant enough that the technology could not meaningfully be tested.

For those technology runs that were conducted by Project 2, the following data was provided back to Project 1:

- Level of deployed capacity by 2050
- Rate of deployment from first UK operations through to 2050 deployment level
- Annual Capacity Factor (less than or equal to the vendor specified availability factor; the capacity factor is influenced by the extent to which the energy system uses the SMRs as baseload electricity providers or whether power is cut back at times of low demand)
- LCOE derived from the ESME results (explained in section 5)
- Potential reduction in system abatement cost as % of GDP, compared with energy system where SMRs are unavailable

Project 1 then collated interim findings from Projects 2 to 7 before contributing to the shaping and definition of the inputs for the final scenarios described in Section 10 of this report.

## 3.2. Summary Of Project 2 Methodology

The workflow followed by ETI is shown in Figure 3 and described in more detail below.

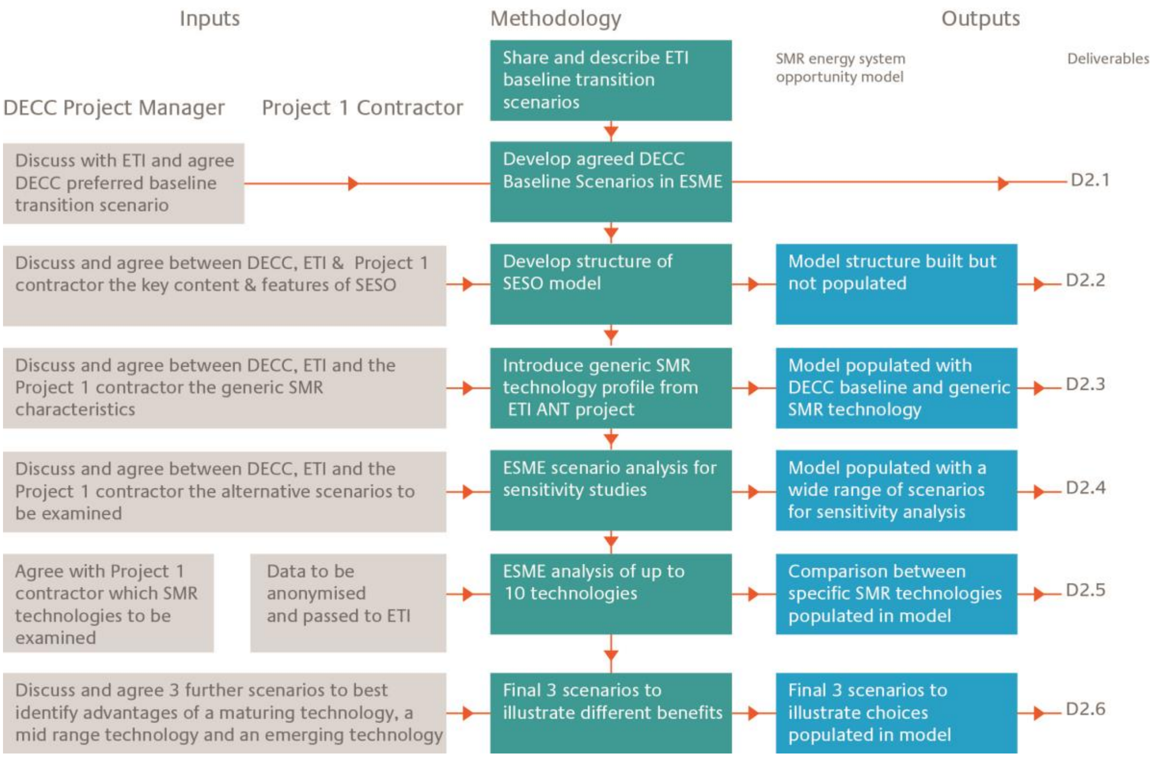


*Figure 3: Workflow diagram for TEA Project 2*

## Agreement on a Baseline Scenario

Deliverable 2.1, described in Section 4 of this report. In summary: ETI previously launched two scenarios Clockwork and Patchwork in March 2015. Subsequently ETI engaged closely with DECC (Science and Innovation) to modify the Clockwork scenario according to the Department's thinking on a range of issues. The 'DECC Clockwork' scenario therefore represents a scenario under a set of conditions agreed upon by DECC and ETI, albeit built upon an old ESME dataset (v3.4).

As part of this Project, ETI recommended and DECC agreed on a baseline that would be built upon the newer ESME v4.0, but also incorporate aspects of the DECC Clockwork run deemed suitable for the project.

## Development of SMR Energy System Opportunity (SESO) model framework

Deliverable D2.2, Section 5 of this report. The analysis conducted by ETI in project 2 is delivered through the framework of the SMR Energy System Opportunity (SESO) model. SESO is not an operational model in its own right, rather it is a collection of discrete ESME runs. Given the pedigree of the ESME model and dataset, there is a significant amount of insight to be gained from such a comparison of runs. However, the volume of output data in a standard ESME run can be overwhelming. Judgement is therefore required in deciding what level of detail should be represented. ETI recommended and DECC agreed a subset of the typical ESME outputs, including:

- **Pathway Charts** showing the broad transition from 2010-2050 in 5 year time steps for each of the sectors and energy vectors represented in ESME.
- **Cashflow Charts** representing the investment of capital across the range of technologies/sectors over the period 2010-2050. Charts also depict resource costs, and fixed/variable operating costs.

- **2050 Electricity Supply Chart** focusing on the energy system solution in 2050 and showing how electricity is being supplied at different times of the day and year, including during the notional peak day.
- **2050 Space Heat Supply Chart** which again focuses on the 2050 solution, this time showing how buildings are heated across the day and year, including for the peak day (which represents an extreme cold weather event).
- **2050 Electricity Generating Capacity by Region** showing how the 2050 electricity capacity of each technology is broken down by (onshore and offshore) region in ESME.
- **LCOE calculations** based on the (input) cost assumptions and the (output) capacity factors, these calculations show the levelised cost per unit of energy for the range of electricity (and hydrogen) generating technologies seen in the scenario. However, if used inappropriately LCOE can be a limited, even misleading, metric for assessing the system-wide value of a technology. These limitations are discussed later in this report.

### Energy System Transition Scenarios (Deterministic)

Deliverables D2.3 and D2.4, and Sections 6-8 of this report. The outputs from ETI's ESME modelling were used to populate the SESO model in accordance with the parameters agreed with DECC. This comprised the baseline run described above, and a run with the same base assumptions but also the introduction of generic SMRs. Further population of SESO included results from a set of scenarios agreed with DECC, exploring: a range of delays on SMR deployment, a range of SMR capex costs, scenarios with and without district heating networks (where SMR recoverable heat might be used). A number of additional scenarios looked at impacts from delays on other technologies, including bioenergy, Large (Gen III) nuclear reactors and CCGT with Carbon Capture and Storage (CCS). These runs are discussed in detail later.

### SMR Technology and Technology Genre Comparisons (Deterministic)

Deliverable D2.5 and Section 9 of this report. A series of scenarios were conducted using a common baseline and a series of SMR technology vendor datasets (anonymised by the Project 1 Contractor before delivery to Project 2). Where there were gaps in the vendor datasets, e.g. for fixed operating costs, generic SMR data was used from ETI's ANT project. Five of the vendor datasets were sufficiently complete to enable these specific technology runs. Five others were identified as representing less developed and less well-defined technologies, and were therefore treated as representative of a 'technology genre'. Project 3 assisted in defining appropriate 'technology genre' parameters for these runs.

### Final Runs to test consolidated TEA assumptions (Probabilistic)

Deliverable D2.6 and Section 10 of this report. In this section three Monte Carlo runs of ESME were devised in agreement with DECC, enabling the probabilistic assessment of uncertainties for key inputs. For the first run, the SMR data was taken from a consolidated dataset provided by Project 1 for an electricity only SMR design. For the second run, CHP capability was added to this, using data from ETI's own analysis, such as capex markup, and power downgrade when operating in CHP mode. In the final run, an electricity only SMR 'emerging technology' was tested, with a delay in earliest deployment and markup on capex.

# 4. Baseline Energy System Transition

This section describes the stages of development towards the baseline scenario for the SESO runs.

## 4.1 Agreement on ESME dataset and adjustments

### ETI Clockwork

In March 2015, ETI published two energy system scenarios, Clockwork and Patchwork (but since the Patchwork scenario was not used in this TEA, the summary will focus on Clockwork).

The Clockwork scenario was built upon the ESME v3.4 dataset, but incorporated a number of modifications, as per the 'Director's Cut' dataset described earlier (see 'Dataset variations' in section 1.2). The next step was to incorporate a series of changes resulting from stakeholder workshops held by ETI. This included a series of near term 'Momentum Effects' for Clockwork, i.e.

- early retirements (for coal and oil power plants as part of the large combustion plant directive);
- minimum build quantities for offshore wind, onshore wind and solar PV out to 2020 (to reflect known developments and anticipated completion of a proportion of the existing project pipeline).

In addition, a series of constraints were imposed upon the longer term pathway, driven by policy assumptions drawn from the Clockwork narrative. These policy refinements included:

- a constraint on car fleet emissions (gCO2/km) tightening over time;
- the maintenance of a minimum level of wind and solar capacity out to 2050 to reflect a narrative whereby future governments choose to maintain a steady supply chain for those technologies.

A range of other refinements were made to achieve a more 'polished' plausible deployment pathway in other sectors.

### DECC Clockwork

Subsequent to publication of the ETI Scenarios *and separate from the current Project*, DECC (Science & Innovation) approached ETI to request some variations of the Clockwork scenario, to support their own technology strategy work. The principal adjustments made for the DECC Clockwork run were:

- 2030 carbon target adjusted (down to 316.8Mt from 325Mt) to more precisely match the Carbon Budget 5 pathway. The 2050 target remains the same, intermediate years were recalibrated accordingly.
- 10GW of Solar by 2020. This was an increase from the original 5GW anticipated in ETI's own Clockwork run, and reflects more recent data from DECC on uptake rates.
- Cost adjustment for solar farms. Again, using latest data from DECC, capex was revised down to reflect observed costs, while fixed cost were similarly reduced.
- Refineries – options for abatement by 2030 were restricted, ensuring emissions are no more than 36% below 2012 baseline of 16.28Mt.
- Biomass imports resource constraints were revised down to max 23TWh in 2050 (from 100TWh in original scenario).
- The constraint on car fleet emissions ($gCO_2$/km) was removed from Clockwork to allow free technology selection in the cost optimisation.

### ESME v4.0 Release

Subsequent to the development of the scenarios (and variations), a new version of ESME was released in August 2015. ESME v4.0 incorporated new evidence from a number of ETI projects. Of particular interest to this work are the two studies commissioned by ETI to inform the analysis of the potential for SMRs in the UK energy system. The Power Plant Siting Study (PPSS) and System Requirements for Alternative Nuclear Technologies (ANT) were summarised in section 2.

The body of evidence from the PPSS and ANT studies (and from other non-nuclear ETI projects) was used to update the dataset for ESME v4.0, including the disaggregation of a previously generic 'Nuclear' technology into four parts: Legacy, Gen III, Gen IV and a generic SMR technology. The ETI generic SMR technology is assumed to be capable of having an offtake for district heating to be added at additional cost and with some loss of efficiency.

The generic SMR technology in ESME v4.0 was removed for this project, to create a baseline without SMRs, and to make space for a baseline with four distinct SMR variants described in section 6.

### Synthesis

ETI recommended (and DECC agreed) that the runs conducted for this Project should be built upon the latest evidence, hence it was agreed that ESME v4.0 would be used.

It was also agreed that this Project should capitalise on the extensive efforts already made to ensure alignment with DECC assumptions as part of the Clockwork variations. To ensure consistency then, the ETI's Director's Cut modifications, near term momentum effects, and DECC Clockwork adjustments were applied to the v4.0 dataset.

It was recognised that the constraints on car fleet emissions and minimum solar and wind capacities were inappropriate in the context of this Project, where the model should be able to deliver a cost-optimal outcome. For that reason, those refinements were not adopted here.

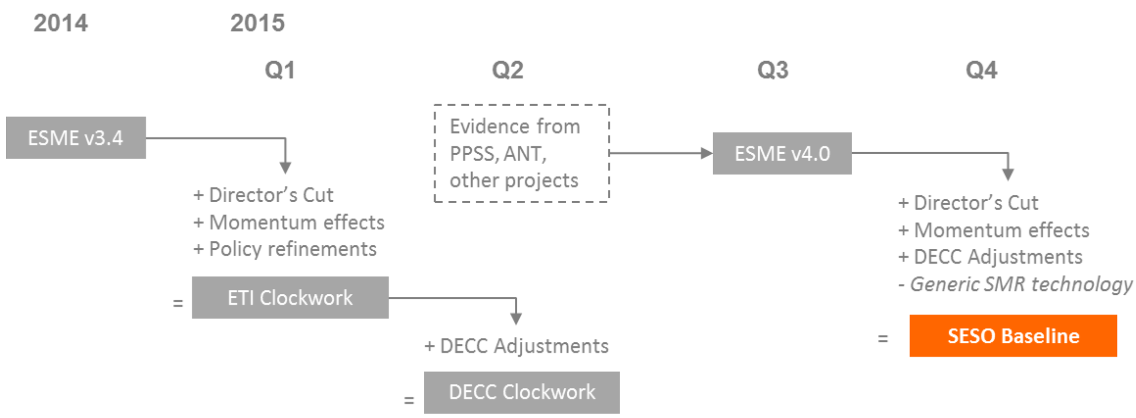


*Figure 4: Diagram showing sequence of modifications/dataset variations leading to SESO Baseline D2.3.1*

## 4.2 Summary of key assumptions

The full ESME dataset includes assumptions on the cost, performance, operational and deployment constraints of more than 250 technologies (across the power, conversion, heat, transport and industry sectors). In addition to technology data, there are assumptions covering resource availability and commodity prices. The full dataset is shared with the DECC modelling team as part of each ESME release.

Assumptions for some of the key technologies are summarised here, namely those power sector technologies observed to play a significant role in the SESO runs.

## Technology Assumptions

The table below summarises capital, fixed, variable and fuel costs for a selection of power sector technologies (in real 2010 £GBP). Across all technologies, an 8% cost of capital is assumed (see section 1.4 for more information).

| Cost category | Capital | Fixed O&M | Variable O&M | Fuel | Capital | Fixed O&M | Variable O&M | Fuel |
|---|---|---|---|---|---|---|---|---|
| Year | **2010** | **2010** | **2010** | **2010** | **2050** | **2050** | **2050** | **2050** |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) |
| **CCGT** | 589 | 27.2 | 0 | 28.1 | 496 | 27.2 | 0 | 45.1 |
| **CCGT with CCS** | 997 | 52.3 | 0.4 | 30.5 | 745 | 52.3 | 0.4 | 46.2 |
| **H2 Turbine** | 590 | 30 | 0 | 0 | 500 | 30 | 0 | 0 |
| **Large Scale Solar PV** | 1400* | 50 | 0 | 0 | 400 | 15 | 0 | 0 |
| **Nuclear (Gen III)** | 3800 | 67.8 | 5.0 | 4.1 | 3040 | 67.8 | 5.0 | 8.4 |
| **Offshore Wind (fixed)** | 3000 | 86 | 0 | 0 | 1500 | 50 | 0 | 0 |
| **Offshore Wind (floating)** | 3000 | 86 | 0 | 0 | 1261 | 48.5 | 0 | 0 |
| **Onshore Wind** | 1490 | 17.6 | 0 | 0 | 1251 | 17.6 | 0 | 0 |

*Table 1: SESO Baseline cost assumptions for selected technologies (in real 2010 £GBP). Fuel costs are defined per unit of output electricity and are therefore a function of conversion efficiency. Hydrogen turbines have a fuel cost of zero as hydrogen is an endogenous product of the model, thus a cost cannot be derived until runtime when the particular hydrogen production technologies are chosen. Finally, Solar PV capital cost declines non-linearly (925 by 2015, 800 by 2020 then linearly to 400 in 2050).*

For the same subset of technologies, the following table provides some of the key build/performance characteristics. The indicative scale is provided as this has informed the cost assessment for each type of technology. For availability factor, dispatchable technologies have a maximum value (though utilisation may be lower than this in ESME depending on wider system needs), while non-dispatchable technologies have a fixed average utilisation in each time slice (subject to seasonal and diurnal variation), so the annual average is shown (in some cases this is also subject to variation by region, e.g. onshore wind and solar, so these figures shown the maximum of any region).

| | Indicative Scale | Technical Life | Construction Period | Availability Factor | Max Annual Build Rate: | | | |
|---|---|---|---|---|---|---|---|---|
| Year | | | | **2050** | **2020** | **2030** | **2040** | **2050** |
| Unit | MW | years | years | % max (avg) | MW/yr | | | |
| **CCGT** | 1000 | 30 | 2.5 | 90 | 2000 | 2000 | 2000 | 2000 |
| **CCGT with CCS** | 1000 | 30 | 3.5 | 85 | 1000 | 2000 | 2000 | 2000 |
| **H2 Turbine** | 500 | 20 | 2 | 90 | 2000 | 2000 | 2000 | 2000 |
| **Large Scale Solar PV** | 50 | 30 | 1 | (10)** | 1000 | 1000 | 1000 | 1000 |
| **Nuclear (Gen III)** | 1600 | 50 | 5 | 90 | - | 1500 | 1500 | 1500* |
| **Offshore Wind (fixed)** | 500 | 20 | 2 | (40) | 2000 | 3000 | 3000 | 3000 |
| **Offshore Wind (floating)** | 500 | 20 | 2 | (45) | - | 1000 | 3000 | 3000 |
| **Onshore Wind** | 500 | 20 | 2 | (31)** | 1000 | 1000 | 1000 | 1000 |

*Table 2: SESO Baseline additional assumptions for selected technologies. *Available sites limited to 35GW, build limit to 2025 allows for Hinkley Point C. **variation by region, values shown are the max.*

## 5. Structure and Purpose of SESO

The SMR Energy System Opportunity (SESO) model is a repository of results from a series of discrete ESME runs. The volume of possible outputs from an ESME run can be overwhelming to a non-user, so ETI have agreed with DECC a selection of the key results charts and datasets to support DECC analysis.

A naming convention has been adopted to assist in locating the relevant charts in the SESO model. Worksheets are named e.g. D2.3.2.A, where D2.3.2 is the code number of the ESME run or scenario. The letter A refers to the particular chart collection or dataset. The various chart collections and datasets include:

- A: Pathway Charts
- B: Cashflow Charts
- C: 2050 Electricity Supply Chart
- D: 2050 Space Heat Supply Chart
- E: 2050 Electricity Generating Capacity by Region
- F: LCOE calculations

If a number is appended onto the letter, e.g. D2.3.2.A.4, this indicates that the fourth chart on worksheet D2.3.2.A is being referred to.

### A: Pathway Charts

This is a collection of 20 charts for each run detailing the change in the UK energy system in 5 year time steps from 2010 to 2050, covering each of the main sectors and energy vectors represented in ESME. The full list of charts includes: net $CO_2$ emissions, primary resource consumption; capacity and generation charts for electricity, space heat and hot water; road transport fleet and energy consumption; energy storage capacity and power rating; retrofit of power plants and of dwellings; electricity consumption; hydrogen production and consumption; gas consumption; biomass consumption; network hot water production.

### B: Cashflow Charts

This collection of charts shows expenditure across the energy system out to 2050, including capital expenditure, fixed and variable operating costs, and resource costs. Capex costs are shown at various levels of aggregation. Also see abatement costs below.

### C: 2050 Electricity Supply Chart

This chart focuses on the energy system solution in 2050, and shows how electricity is being supplied during each of the time slices in a typical summer and winter day, and during the extreme peak day.

### D: 2050 Space Heat Supply Chart

This chart again focuses on the 2050 solution, this time showing how buildings - including homes, public and commercial buildings - are heated across the day and year, including for the peak day (which represents a prolonged cold weather event).

### E: 2050 Electricity Generating Capacity by Region

This dataset shows the breakdown of technologies contributing to the 2050 electricity capacity within each region (both onshore and offshore) in ESME.

## F: LCOE calculations

Based on the cost assumptions and the outturn capacity factors, these calculations show the levelised cost of energy for the range of electricity generation and hydrogen production technologies seen in the scenario.

Note that all LCOE calculations in this report are calculated against actual generation, rather than maximum potential generation (as might be used to compare technologies prospectively). As a result, technologies that are able to contribute to meeting wider system needs by running at a lower capacity factor (e.g. to provide flexible reserve) will show a correspondingly higher LCOE than their design potential. This reflects the shortcomings of LCOE in that not all system value can be captured in terms of a levelised cost of energy over the year.

Our calculation method is detailed below:

- The annual total of all costs associated with technology *k* in year *t* is defined as:

$$\begin{aligned} &Total\ Annual\ Cost\ (k,t) \\ &\qquad = Annual\ Fuel\ Cost\ (k,t) + Technology\ Investment\ Cost\ (k,t) \\ &\qquad + Fixed\ Operating\ Cost(k,t) + Variable\ Operating\ Cost(k,t) \end{aligned}$$

- $Annual\ Fuel\ Cost\ (k,t)$ is determined from the fuel cost in year *t*, an ESME input, multiplied by the total fuel consumption by technology *k* in year *t*, an ESME output.
- $Technology\ Investment\ Cost\ (k,t)$ is the total annualised capital cost in year *t* of all capacity of technology *k* deployed by ESME. The capacity deployed is an ESME output. The capital cost (£/kW) is an ESME input. Note that it is common for the capital cost to vary over the decades to 2050 in the ESME inputs, and this calculation reflects the sum of annualised capital costs for multiple vintages installed in different decades. The annualisation is calculated using the ESME inputs for cost of capital (or hurdle rate), and the length of the construction period for technology *k*. Interest during construction is estimated on the basis of uniform rate of capital spend during the construction period, this is added to the capital cost and the total is amortised over the life of the technology.
- $Fixed\ Cost(k,t)$ is the total of all fixed costs for the capacity and vintages deployed. The capacity deployed is an ESME output. The fixed cost (£/kW/year) is an ESME input.
- $Variable\ Cost(k,t)$ is the total of all variable costs for the capacity and vintages deployed and the hours operated in year *t*. The capacity deployed and the hours operated are ESME outputs. The variable cost (£/kWh) is an ESME input.
- The LCOE of technology *k* in year *t* is finally calculated as:

$$Total\ Annual\ Cost\ (k,t)\ /Total\ Generation\ (k,t)$$

Different methodologies for calculating LCOE can be seen in the energy literature. Our choice of calculation method is influenced by the categories of input and output data available from the ESME model. In particular the ESME model gives load factor information throughout the lifetime of a technology. If the load factor changes significantly during the lifetime, as often happens given the changing patterns of electricity demand and the changing generation mix, then the above calculations may result in different LCOE values in different years during the lifetime of a plant.

## Abatement costs

Finally, a single worksheet is included with each version of SESO summarising the abatement cost of all runs completed thus far.

# 6. RESULTS: Baseline runs

## 6.1. Baseline run (no SMRs)

As the benchmark for future runs, the results of the 'Baseline run (no SMRs)' is described in particular detail here to give a good sense of the energy system landscape into which SMRs will be introduced as an option in future runs.

*Selected Charts on p94*

| D2.3.1 | Baseline run (no SMRs) |
|---|---|
| Key Amendments: | (baseline run as per Section 4 of this report, no amendments) |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | 43.3 £bn/yr | *NPV: 10.9 £bn/yr (1.2% of GDP)* |
| | | |
| Cumulative (2010-2050): | 550.8 £bn | *NPV: 204.2 £bn (0.4% of GDP)* |

*Abatement cost summary table includes (all in 2010 £) top-left: undiscounted annual abatement cost for 2050; top-right: discounted annual abatement cost for 2050 (and as a percentage of discounted 2050 GDP); bottom-left: undiscounted cumulative abatement cost over the 40 year modelled period; bottom-right: discounted cumulative abatement cost (and as a percentage of discounted cumulative GDP) .*

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 32 | 45% (85%) | 126 | 101 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Offshore Wind (fixed)** | 10 | 40% (40%) | 35 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 16 | 26% (26%) | 37 | 83 |
| **Other** | 26 | - | 93 | - |

In this baseline run overall electricity capacity remains at around 80-90GW for most of the transition, with significant deployment of additional capacity towards the end, reaching over 140GW by 2050. This is made up of a balanced generation mix, principally: 32GW of Gas CCS, 35GW of new large Nuclear, 40GW of onshore and offshore wind (with offshore making up the balance once available economic onshore sites are used), plus a range of supplementary renewable and interconnector capacity.

Due to the wide variation in load factors of these technologies, the total annual generation from each source shows a quite different balance, with large nuclear as the dominant source of electricity by 2050. The various renewables technologies make a smaller contribution relative to their share of nominal capacity. The average annual load factor of Gas CCS declines over time as this technology increasingly performs a seasonal load balancing role (running more throughout the winter to support the increasing electrification of heat).

For the provision of heat, our buildings gradually shift away from reliance on gas boilers, at least for day-to-day heating. Although biomass boilers may make a transitional contribution (as shown in this scenario), in the long term the system relies on two key solutions: district heating networks and electric heating (primarily heat pumps but supplemented by electric resistive heating). It is important to recognise that gas boilers continue to play a role in this 2050 energy system as a backup solution in the event of a prolonged cold weather event, but the day-to-day heat provision is supplied by electricity (see SESO Figure D2.3.1.D).

The optimal arrangement adopted by ESME is to install a modestly sized heat pump that will run as a 'baseload' heat source for the home, coupled with heat storage to handle daily peaking. In the case of heat storage, overnight output from the heat pump (and where necessary cheap electric resistive heating) is stored up and used during times of peak demand during the day. This 'baseload-with-storage' operation of heat pumps has two advantages, first it makes cost-optimal use of the capital intensive heat pump technology, and second it avoids exacerbating the peak profile of the electricity required to support it.

Meanwhile, the characteristics of a heat network solution are such that the network can manage its own demand profile (including for peak events) without requiring in-house backup from gas boilers or electric resistive heating. In this model run heat is provided to the district heat networks primarily through recovery of waste heat from large thermal power stations, although this is eventually supplemented by large scale marine heat pumps and geothermal sources, where these make economic sense in a region. As with individual homes in the heat pump example, heat networks have district heat storage facilities, enabling the networks to economically balance supply and demand.

Other sectors of the energy system merit discussion here. As in the Clockwork scenario described previously, the baseline run is able to take advantage of the significant potential for negative emissions through the combination of biomass and CCS. This negative emissions route is critical in keeping down the cost of transition in other sectors.

Because of the comprehensive decarbonisation of the day-to-day operation of the power and heat sectors by 2050 and the significant role for negative emissions, the transport sector is able to transition in a more modest fashion. For cars, this involves continued improvements in the efficiency of internal combustion engines (ICEs) and gradually the hybridisation of ICEs with batteries to enable an increasing share of each journey to be conducted in electric mode. Light duty vehicles experience a similar transition. For heavy duty vehicles, although the fleet is smaller in number the energy demand is disproportionately high. Additionally, electrification is a more difficult and costly route for large vehicles. In this scenario the preferred lower carbon option is the integration of natural gas as a fuel for heavy duty vehicles. The combination of improved fleet efficiency for light duty vehicles, and diversification of fuel supply for heavy duty vehicles, means demand for liquid fuel falls to below half of today's levels by 2050. In the case of aviation and shipping, ESME v4.0 includes no low carbon alternatives and must rely on on-going efficiency improvements in planes and ships. As a result, while other sectors decarbonise, aviation and shipping come to take up an ever larger proportion of the (shrinking) carbon budget over time.

## 6.2. Addition of Generic SMR Technologies

In ESME v4.0 nuclear technology has been disaggregated into four parts: Legacy, Gen III, Gen IV and a single generic SMR technology. However, the generic SMR was excluded from the baseline run D2.3.1, in order to provide a clear benchmark against which to measure the impact of SMR inclusion specifically. In this next comparison run, four SMR variants were added to the set of available technologies in the SESO baseline.

The ETI-commissioned ANT project identified 6 "service offerings" or ways in which SMRs could be deployed and operated as part of the energy system. These are summarised in the table below.

| | Baseload | Flexible | Extra-flex |
|---|---|---|---|
| Electricity only SMR power plant | Baseload power (runs continuously) | Operated in load-following mode | (Slightly) reduced baseload power with extra storage & surge capacity |
| Combined Heat & Power (CHP) plant | As above but with heat | As above but with heat | As above but with heat |

*Table 3. The six "service offerings" or ways in which SMRs could be deployed and operated as part of the energy system identified by the ANT project.*

The intent was to make each of these available as a technology choice within ESME with different cost, performance and service characteristics and allow the cost optimiser to identify the variant(s) offering greatest reduction in system cost. However, the distinction between the baseload and flexible offerings was too subtle given ESME's coarse representation of time, therefore this set of six technologies was reduced to the following four variants available as technology choices with ESME:

- a baseload electricity only variant (**SMR Elec**)
- a baseload CHP-capable variant (**SMR CHP**)
- a highly flexible electricity only variant (**SMR Elec Extraflex**), and
- a highly flexible CHP-capable variant (**SMR CHP Extraflex**)

Each variant represents a 'several hundred MW' scale reactor with a technical life of 50 years. The construction period is defined as 3 years (used in calculating financing costs, i.e. including interest during construction).

### SMR technology costs

Capex for the standard electricity only variant is £4750/kW. Adding Extraflex to this incurs a £665/kW mark up, while adding CHP capability incurs a separate £200/kW mark up. No capital cost reduction is assumed over time. The original analysis showed the impact of a learner rate to be small compared with the uncertainty in absolute CAPEX level, which is tested as part of the sensitivity analysis in this report.

Fixed costs for the standard electricity only variant fall from £130/kW/yr in 2010 to £100/kW/yr in 2050 (intermediate values are interpolated linearly, passing through £115/kW/yr in 2030). For *each* of the 'Extraflex' and CHP capabilities, a £5/kW/yr markup is applied throughout.

The variable cost of 0.5p/kWh for all variants includes a small payment into a decommissioning fund. Nuclear fuel costs rise from 0.16p/kWh in 2010 to 0.34p/kWh in 2050.

These costs are summarised below, alongside Nuclear (Gen III) for comparison.

| Cost category | Capital | Fixed O&M | Variable O&M | Fuel | Capital | Fixed O&M | Variable O&M | Fuel |
|---|---|---|---|---|---|---|---|---|
| Year | 2010 | | | | 2050 | | | |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) |
| **Nuclear (Gen III)** | 3800 | 67.8 | 5.0 | 4.1 | 3040 | 67.8 | 5.0 | 8.4 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Nuclear (SMR CHP Extraflex)** | 5615 | 140 | 5.0 | 5.8 | 5615 | 110 | 5.0 | 12.6 |
| **Nuclear (SMR CHP)** | 4950 | 135 | 5.0 | 5.8 | 4950 | 105 | 5.0 | 12.6 |
| **Nuclear (SMR Elec Extraflex)** | 5415 | 135 | 5.0 | 4.6 | 5415 | 105 | 5.0 | 10.1 |
| **Nuclear (SMR Elec)** | 4750 | 130 | 5.0 | 4.6 | 4750 | 100 | 5.0 | 10.1 |

*Table 4: The cost assumptions (2010£) used for the SMR technologies, and for comparison Nuclear (Gen III). Although SMRs cannot be deployed from 2010, placeholder costs are necessary for all years in ESME. Fuel costs reflect conversion efficiencies (unit costs of fuel are consistent across nuclear technology variants).*

## Performance characteristics

Like the large scale 'Gen III' reactors, SMRs are assumed to have a 95% availability factor during periods of peak demand, making them extremely reliable contributors during these times. The average availability factor over the whole year though is lower at 85% (see section 2) to account for maintenance and forced outage (this compares to 90% for Gen III[22] and 70% for legacy reactors).

Power technologies also have a 'flexibility factor' in ESME, which is derived from the ramp rate of the technology and defined as the percentage of plant capacity that can brought online within one hour. For the two standard SMR variants, the ramp rate is assumed to be 0.5% of plant capacity per minute (as per the findings of the ANT project), giving a flexibility factor of 30% (compared to 38% for large reactors). This flexibility was based on ramp rates similar to large reactors, noting that some small reactors are being developed using natural convection flow for the primary circuit. The achievement of rapid power transients in a plant using natural convection flow requires very careful design, and it is unreasonable to assume that all SMRs can be more flexible with a higher ramp rate than large reactors. Meanwhile the two Extraflex SMR variants enjoy a flexibility factor of 100%, implying ramp up to full plant capacity within one hour.

The two SMR variants capable of CHP can operate in either of two modes: electricity only mode or CHP mode. In electricity only mode, the thermal efficiency of electricity generation in these SMRs is assumed to be 34% as for the two electricity only variants. In CHP mode, where a significant volume of hot water is being diverted to heat networks, the thermal efficiency of electricity generation falls to 27% (because energy is being removed from the power generation cycle by the extraction of steam from the Intermediate Pressure Stage turbine. This reduces power developed in the IP and LP turbines, causing the electrical output to fall). However, since heat is being recovered during this operation mode, the total energy conversion efficiency is assumed to be 88%. This can be otherwise stated as: for every 2.94kWh of nuclear fuel, SMR can produce 1kWh of electricity (in electricity only mode) or 0.8kWh of electricity and 1.8kWh of heat (in CHP mode).

## Deployment constraints

The deployment of SMRs in ESME is constrained by an upper capacity limit as well as annual build rate limits. In both cases, these constraints apply to the total SMR capacity rather than to specific variants. Using assumptions from the PPSS project, a set of region specific capacity limits have been adopted, giving a total UK-wide limit of 21GWe for SMRs (this is in addition to the 35GWe for large reactors).

[22] "UK Electricity Generation Costs Update" Mott MacDonald for DECC, 2010, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65716/71-uk-electricity-generation-costs-update-.pdf

Despite this upper limit of 21GWe in principle, the *effective* 2050 deployment limit in ESME can be lower than this, depending on the rate of deployment. In the 'Baseline run (with SMRs)' for example, maximum annual build rates (400MW/yr from 2030-2040, 1200MW/yr thereafter) are such that no more than 16GWe can be deployed by 2050. In other runs described later in this report the date of first deployment is explored as a sensitivity, giving more or less time for SMR deployment by 2050.

## 6.3. Baseline run (with SMRs)

*Selected Charts on p96*

| **D2.3.2** | **Baseline run (with SMRs)** |
|---|---|
| **Key Amendments (from D2.3.1):** | **Four SMR variants added** as per specification laid out in section 6.2, i.e. Baseload Electricity only, Baseload CHP, Extraflex Electricity only, Extraflex CHP.<br>**Earliest Deployment 2030**, i.e. SMRs prohibited before 2030, then (collectively) constrained to max 400MW/yr for first 10 years, 1200MW/yr thereafter, meaning *effective 2050 max deployment of 16GW*. |

| **Abatement Cost Summary** | | |
|---|---|---|
| **Annual (2050):** | **42.7 £bn/yr** | *NPV: 10.8 £bn/yr, 1.1% of GDP* |
| | -0.59 £bn/yr | vs Baseline run (no SMRs) |
| **Cumulative (2010-2050):** | **546.9 £bn** | *NPV: 202.9 £bn, 0.4% of cu GDP* |
| | -3.86 £bn | vs Baseline run (no SMRs) |

| **2050 Power Sector Summary** | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 29 | 42% (85%) | 109 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR CHP)** | 9 | 70% (85%) | 54 | 130 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 6 | 45% (45%) | 24 | 61 |
| **Onshore Wind** | 14 | 27% (27%) | 32 | 82 |
| **Other** | 15 | - | 77 | - |

*Note: in this and all other runs with CHP SMRs, 'annual capacity factor' in the summary table is derived from electrical output, and since the CHP mode incurs a 20% power downrating, less electricity is generated than if the plant were to run in dedicated electricity only mode. That is, in electricity mode, a plant running 85% of the year would show a capacity factor of 85% (the maximum potential), while in CHP mode a plant running 85% of the year would show 68% (0.80*0.85). Values above 68% for CHP SMRs occur because of a mix of operation in electricity only and CHP modes at different times of the year according to system needs.*

This section describes the impact on the baseline energy system design when the four SMR variants described above are introduced to ESME in scenario D2.3.2. In this run, we assumed an earliest date of first deployment of 2030, with deployment then limited to 400MWe/yr up to 2040 and 1200MWe/yr thereafter. A maximum of 16GWe is therefore possible by 2050.

The electricity capacity pathway chart (see Appendix) shows a material role for SMRs in the energy system, with deployment beginning in the 2030s and the least-cost energy transition pathway reaching 9GWe of installed SMR capacity by 2050. As a result of the higher load factor associated with SMRs (compared with renewables), the total power sector capacity is significantly reduced, with the 9GW of SMRs displacing 25GW of capacity elsewhere, primarily solar and offshore wind.

The only SMR technology selected in this run is the standard CHP variant. The system value of heat clearly justifies the CHP capex markup and the lost electricity due to down-rating of electricity output in CHP mode. Over half of all heat supply to district heat networks comes from SMRs by 2050 in this run (see Appendix). The availability of CHP SMRs evidently improves the cost-effectiveness of district heating, leading to an increase in its share of total space heat supply, with correspondingly less input from heat pumps (and consequently less electricity demand).

This transition sees £44bn undiscounted capital investment in the generic SMR CHP technology, or equivalently £15bn when discounted back to the present value in 2010. In terms of the overall system though, this scenario sees an overall net saving of £1.3bn in the discounted cumulative energy system costs compared with the baseline without SMRs.

# 7. RESULTS: Sensitivity Scenarios (Runs D2.4.1-11)

Following the definition of the baseline energy transition scenario and the introduction of generic Nuclear SMR technologies, this section describes 11 alternative scenarios examined and reported in the SESO model (runs D2.4.1-11). These are listed in Table 5.

The purpose of the 11 alternative scenarios explored here is to understand in more detail the conditions which allow SMRs to play a role in least-cost energy systems. By testing a variety of scenarios it is possible to discover what alternative assumptions might enhance, or reduce, the value of SMRs in the energy pathway.

During this stage of the TEA project the principle reason for studying exploratory scenarios was to perform a sensitivity analysis: many of the assumptions taken on the costs and build rates of SMRs are uncertain, so it is important to understand the sensitivity of the results and conclusions to variations in these assumptions. Likewise there are very many uncertainties in the wider energy system which might affect the role for nuclear SMRs, and these too need to be explored. While this is done probabilistically in section 10, for the set of runs described in this section some indicative values were chosen and tested deterministically.

The particular value of an exploratory sensitivity analysis at this stage of the TEA project was to allow for better informed design of subsequent modelling work, including the analysis of specific SMR technologies explored later. It also allowed the stakeholders at DECC and in the other interacting TEA projects to begin to formulate draft conclusions about the type of role that SMRs could play, and therefore to understand the further analysis required in order to test and confirm those conclusions.

## 7.1 Definition Of Scenarios

The code for each scenario shown in Table 5 corresponds to the numbering of the charts and data tables in the SESO model. These scenarios were selected based on an initial proposed list of suggested scenarios, subsequently adjusted and confirmed in discussions between DECC and ETI.

Scenarios 2.4.1-5 all explore variations in the assumptions made for the generic electricity-only SMR technologies, focussing on the key uncertainties of earliest deployment date and capital cost. The selection of these two parameters as the key uncertainties amongst the SMR technology assumptions reflect both the early results seen in the baseline run as well as past experience of running the ESME model and investigating alternative scenarios:

- Cost is naturally the key parameter for any technology or fuel in a cost optimisation model, and particularly for nuclear it is the capital cost that dominates the overall contribution of nuclear SMRs to the total energy system cost in ESME. Levelised cost of electricity (LCOE) can be used as a cost metric for combining all of the various direct costs associated with nuclear SMRs: capital cost, fixed and operating costs, payments towards waste and decommissioning fund (captured as part of the variable operating costs in the ESME input data) and fuel costs. However, it must be stressed that LCOE on its own can be misleading as it does not fully capture all of the costs and benefits of every power technology in the ESME model: flexibility, intermittency, need for firm backup capacity, transmission costs associated with distance from demand centres, cogeneration of heat & electricity, and the cost of any emissions at the prevailing carbon price all affect the attractiveness of a power generation technology in the ESME model *in addition* to LCOE. Nevertheless, by the LCOE metric around 70% of the total through-life cost of SMRs stems from the capital cost, making capital cost the natural variable to use for cost sensitivities in scenarios 2.4.4-5. The impact of changes in the other cost categories of SMRs, in fuel costs, or in SMR fuel efficiency will each be slightly different, but they will all be secondary compared to the capital cost, and indeed for a first approximation can be estimated based on the results of the capital cost sensitivity runs.

- The choice of deployment date as the other key variable for study in scenarios 2.4.1-3 is based primarily on interpretation of the results of the baseline scenario. In this baseline the SMRs do not hit the maximum limits imposed on total capacity (i.e. site availability) or deployment rate (i.e. GW/year), but they *do* hit the constraint on earliest possible deployment (starting in 2030). This is seen in the appearance of active SMR plant by 2035. Clearly there is real uncertainty over the earliest deployment date, and the baseline cases suggest that it is likely to have an impact on the results. Delaying the first deployment could see a “competitor” low-carbon generating technology deployed in place of SMRs in the early 2030s. Similarly an earlier first deployment might see SMRs eating into the capacity of other low-carbon generation which was otherwise deployed in the baseline scenario.

Scenarios 2.4.7-11 explore the impact of key uncertainties in the energy system that are likely to affect the role of SMRs, beyond the development of SMR technologies themselves and their supply chains. The choice of these scenarios is based on inspection of the baseline scenario and also heavily influenced by past experience of running ESME scenarios.

- It is notable that in the baseline scenario the CHP variant of nuclear SMR is preferred, because this technology provides an additional benefit to the energy system of supplying heat as well as electricity. Testing the comparison between scenarios with/without CHP will give an understanding of how important the CHP role is in the overall value of SMRs to the energy system. Scenarios 2.4.1-5 all assume that district heating networks (and therefore SMR CHP) are not part of the energy system, whilst scenarios 2.4.6-7 explore the impact of allowing CHP/district heating, potentially opening up a larger market for SMRs as they can deliver energy into both electricity and heat markets.
- As mentioned above, direct competition with other low-carbon electricity generators is also a key issue for nuclear SMRs, and this is behind the design of scenarios 2.4.8-11. In particular, CCS and Bioenergy are priorities because they are technologies which are both (i) prevalent in the baseline scenario and (ii) technologies for which there is uncertainty over the rate of deployment which will be possible. Further, CCS and Bioenergy are particularly important to the approach ESME selects to meet the carbon targets in the baseline, with the Bio-CCS technologies accruing significant “negative emissions”. Therefore a slower (and ultimately lower) deployment of bio and CCS will force additional carbon abatement, which is likely to increase the demand for low-carbon electricity. On the other hand large nuclear is a more straightforward competitor with SMRs, and a delay in large nuclear will likely have the straightforward effect of increasing the opportunity for economical deployment of SMRs, and *vice versa*. In this respect offshore wind or any other low-carbon generator could be used in scenarios 2.4.10-11, but large nuclear is particularly interesting because many of the policy and regulatory issues are related or similar to those for SMRs. Scenarios 2.4.8-11 have been designed as no District Heating cases.

| Code | SMR assumptions | Other assumptions |
|---|---|---|
| **D2.4.1** | Central deployment date (2030); Central capex; | no District Heating |
| **D2.4.2** | Early deployment date (2025); Central capex; | no District Heating |
| **D2.4.3** | Late deployment date (2035); Central capex; | no District Heating |

| | | |
|---|---|---|
| **D2.4.4** | Central deployment date (2030); Low capex (-20%); | no District Heating |
| **D2.4.5** | Central deployment date (2030); High capex (+20%); | no District Heating |
| **D2.4.6** | Central deployment date (2030); Central capex; | (NB this scenario duplicates D2.3.2) |
| **D2.4.7** | Central deployment date (2030); High capex (+20%); | |
| **D2.4.8** | Central deployment and capex | CCS slow/low deployment; no District Heating |
| **D2.4.9** | Central deployment and capex | Bio-energy slow/low deployment; no District Heating |
| **D2.4.10** | Central deployment and capex | Large nuclear deployed to the limit of site availability; no District Heating |
| **D2.4.11** | Central deployment and capex; Doubled limits on max build rates of SMR | Large nuclear low and slow; no District Heating |

*Table 5. The codes and descriptions of the scenarios examined and reported in this section. Codes correspond to the results charts and tables delivered in the SESO model spreadsheet.*

## D2.4.1

*Selected Charts on p98*

| **D2.4.1** | **Central SMR assumptions; No District Heating** |
|---|---|
| **Key Amendments (from D2.3.2):** | **District heat networks ruled out** as an option for decarbonising heat provision in buildings. |

| **Abatement Cost Summary** | | |
|---|---|---|
| Annual (2050): | **47 £bn/yr** | *NPV: 11.9 £bn/yr, 1.3% of GDP* |
| | +4.37 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **578.5 £bn** | *NPV: 213 £bn, 0.4% of GDP* |
| | +31.53 £bn | vs Baseline run (with SMRs) |

**2050 Power Sector Summary**

| Generating Technology | GW | Annual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---|---|---|---|---|
| **CCGT with CCS** | 36 | 42% (85%) | 134 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec)** | 4 | 85% (85%) | 30 | 103 |
| **Offshore Wind (fixed)** | 15 | 40% (40%) | 52 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 29 | - | 102 | - |

Scenario D2.4.1 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant). In this scenario no district heating or CHP is permitted in the energy system.

The assumption that district heating and CHP are not deployed in this scenario has the consequence that the cost optimisation model instead decarbonises the heat sector via electrification (Fig D2.4.1.A.4). This contributes to the demand for electricity which increases from around 300TWh/year today to over 600TWh/year in 2050. Electricity use in transport is also a contributor to the increased electricity demand, but to a lesser extent. The other impact of proscribing CHP is that of course there is no value in the supply of heat, so SMRs must compete on an electricity-only basis with the other generators in the power sector.

The large increase in electricity demand leads to significantly higher generating capacity than today, almost all of which is zero-carbon by 2050. The landscape of the energy system is one in which the heat and electricity sectors have negligible emissions in 2050, while the industry and transport sectors both retain emissions of $CO_2$, albeit significantly reduced from today's levels. This pattern is of course a consequence of the cost minimisation performed by the ESME model, and results from the differing cost of abatement measures in the different sectors.

The additional electricity demand has an important seasonal characteristic: space heating is the largest component of the additional electricity demand and is of course skewed to the winter months. The other major components of the increase in electricity demand (transport and water heating) do not vary seasonally, and whilst the demand for air conditioning is skewed to summer, this remains a small part of the total. The net result is therefore that the total electricity demand exhibits stronger seasonal variation than today. The seasonal variation has a potentially significant impact on the choice of electricity generators: whilst there remains a certain level of baseload demand throughout the whole year, much of the additional winter demand will necessarily be met with some technologies that will be operated at low load factors during the summer months.

The high capital costs of SMRs, as a proportion of their total LCOE, may make this scenario seem challenging from an economic perspective. However it must be stressed that there are similar challenges for the other competing low carbon generation options: intermittency and firm backup requirements are challenges for renewables, while high capital costs and the costs of uncaptured $CO_2$ are challenges for CCS plants. Taken together, these factors reinforce the conclusion that *LCOE alone is not definitive* in determining the most economical energy system design. The best way to take all of the above into consideration is to perform a whole-system analysis as we are doing here.

From the electricity capacity and generation charts (see D2.4.1 figures in Appendix) the role for nuclear SMRs is limited in this scenario with deployment of SMRs not starting until the late 2040s. Capacity of 4GWe is built in the final time period and generates 30TWh in 2050. The carbon constraint is steadily tightening throughout the pathway which causes the ever increasing deployment of generating capacity. But whereas the costs of CCGT with CCS and renewables reduce over time to reflect learning from innovation, the cost of SMRs is assumed to remain flat. So why is it logical to deploy SMR capacity in 2045-50 and not earlier? A number of effects could be responsible:

- ESME only deploys technologies at the point in time when they become part of the economically optimal solution. We can conclude from the results of the optimisation that the generation technologies deployed in 2030-2045 are, from a whole-system perspective, cheaper than SMRs.
- Large nuclear hits its ultimate capacity limit (35GW) in 2050 but not before. We can conclude that large nuclear is preferred over SMRs for cost reasons, but once 35GW is reached any additional generation capacity must be found from other, more expensive, generators.
- Other low carbon generators including CCGT with CCS, Wind, Solar and Tidal all experience rapid deployment in the period 2045-50. If any of these technologies hits a constraint on maximum build rate then this presents a dilemma to the cost minimisation: either deploy earlier to ensure sufficient capacity is attained in 2050, or opt to deploy capacity of a different, more expensive generator (e.g. SMRs). Both courses of action introduce additional cost so it is a matter of determining the lesser of the two.

- The energy resources for renewable generators are dispersed regionally. The energy system will feel different costs from capacity in different regions, even though the technology capital cost is assumed the same in every region, because of transmission costs and losses to reach demand centres and differing load factors in different regions. These effects can mean that a particular renewable resource is fully exploited in one region, and for additional generation the next cheapest might be a choice between the same renewable in a different region, or a different technology altogether (e.g. SMRs).

It is also notable that the load factor of the 4GW of SMR deployed is 85% in 2050. This is attaining the maximum permitted in the model input assumptions, and therefore indicates that the SMRs are being run “flat out”. This indicates that SMRs, and indeed all the large nuclear power stations, are fulfilling a baseload role and are not accessing any of the substantial demand for electricity which is seasonally varying. In contrast CCGT with CCS plants are running at an annual load factor of 42% in 2050 in this scenario.

In summary this scenario is one in which SMRs play a limited role at the very end of the pathway to 2050. They are deployed after 2045, after the available sites for large nuclear have been fully developed, and they run as baseload generators. Considering this scenario alone, the role of SMRs in the energy system is marginal: the deployment of 4GW is relatively small and is restricted to one build period (2045-50). Therefore it is expected to be sensitive to changes in the assumptions and we can anticipate that variations will be seen in the following scenarios.

## D2.4.2

*Selected Charts on p99*

| D2.4.2 | No District Heating; SMR deployment possible from 2025 |
|---|---|
| **Key Amendments (from D2.3.2):** | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**SMRs can be deployed from 2025** (build rate as before: 400MW/yr for 10 years, 1200MW/yr thereafter; maximum possible build out would therefore hit total capacity limit of 21GW). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **47 £bn/yr** | *NPV: 11.9 £bn/yr, 1.3% of GDP* |
| | +4.37 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **578.5 £bn** | *NPV: 213 £bn, 0.4% of GDP* |
| | +31.53 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 36 | 42% (85%) | 134 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec)** | 4 | 85% (85%) | 30 | 103 |
| **Offshore Wind (fixed)** | 15 | 40% (40%) | 52 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 29 | - | 102 | - |

Scenario D2.4.2 takes the early deployment assumption for SMRs (deployment possible from 2025) and central capex (4750£/kW for basic electricity-only plant). In this scenario no district heating or CHP is permitted in the energy system.

This scenario tests the value of having the ability to deploy SMRs five years earlier than scenario D2.4.1. The particular feature of D2.4.1 to note is that it sees SMRs deployed from 2045-50 only, and therefore that scenario is not hitting its constraint of earliest deployment from 2030 onwards. The potential to deploy SMRs even earlier, from 2025, is therefore inconsequential and the results (see D2.4.2 figures in Appendix) show that no additional SMR capacity is deployed in this scenario compared to D2.4.1. The two scenarios are identical. This scenario is therefore another one in which SMRs play a limited role at the very end of the pathway to 2050. They are deployed after 2045, after the available sites for large nuclear have been fully developed, and they run as baseload generators.

## D2.4.3

*Selected Charts on p100*

| D2.4.3 | No District Heating; SMR deployment possible from 2035 |
|---|---|
| **Key Amendments (from D2.3.2):** | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**SMRs can be deployed from 2035** (build rate as before: 400MW/yr for 10 years, 1200MW/yr thereafter; meaning maximum possible capacity of 10GW by 2050). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **47 £bn/yr** | *NPV: 11.9 £bn/yr, 1.3% of GDP* |
| | +4.37 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **578.5 £bn** | *NPV: 213 £bn, 0.4% of GDP* |
| | +31.53 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 36 | 42% (85%) | 134 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec)** | 4 | 85% (85%) | 30 | 103 |
| **Offshore Wind (fixed)** | 15 | 40% (40%) | 52 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 29 | - | 102 | - |

Scenario D2.4.3 takes the late deployment assumption for SMRs (deployment possible from 2035) and central capex (4750£/kW for basic electricity-only plant). In this scenario no district heating or CHP is permitted in the energy system.

The design of this scenario differs from D2.4.1 in not allowing any deployment of SMRs in the period 2030-35. In any case, given that no such deployment is part of the cost-minimised pathway in D2.4.1, it is to be expected that this scenario produces exactly the same results as D2.4.1. This scenario is therefore another one in which SMRs play a limited role at the very end of the pathway to 2050. They are deployed after 2045, after the available sites for large nuclear have been fully developed, and they run as baseload generators.

## D2.4.4

*Selected Charts on p101*

| D2.4.4 | No District Heating; SMR low capex (-20%) |
|---|---|
| Key Amendments (from D2.3.2): | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**SMR capex reduced by 20%** (3800£/kW for baseload electricity-only). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **46.8 £bn/yr** | *NPV: 11.8 £bn/yr, 1.2% of GDP* |
| | +4.1 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **576.8 £bn** | *NPV: 212.4 £bn, 0.4% of GDP* |
| | +29.84 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 35 | 42% (85%) | 131 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec)** | 8 | 85% (85%) | 58 | 90 |
| **Offshore Wind (fixed)** | 15 | 40% (40%) | 51 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 20 | - | 82 | - |

Scenario D2.4.4 takes the central deployment assumption for SMRs (deployment possible from 2030) and capex 20% below central assumptions (3800£/kW for basic electricity-only plant). In this scenario no district heating or CHP is permitted in the energy system.

This scenario is a variant on D2.4.1 and tests the impact of lower SMR capital costs than were assumed in that case. As discussed above, the deployment of SMRs in D2.4.1 was limited by cost considerations: a limited deployment was seen in 2045-50, but in earlier years other technologies were selected by the cost optimisation algorithm of ESME for the expansion and decarbonisation of the power sector in 2030-45. We therefore anticipate that a reduction in the assumed SMR cost could have a material impact, depending on the relative costs for SMRs and other low-carbon generators.

The results for this scenario (see D2.4.4 figures in Appendix) show greater SMR deployment than D2.4.1 as expected, with 1.8GW deployed in 2030-35 and a further 6GW deployed in 2045-50, making a total of 7.8GW in 2050. The comparison to D2.4.1 exhibits two distinct differences:

- Firstly there is extra deployment of SMRs in the final years of the pathway (2045-50) compared with D2.4.1, this extra deployment replaces deployment in Solar, Tidal Stream and Wind. This reflects a more competitive cost of SMRs in the final years of the pathway compared with other low-carbon technology options when the energy system is rapidly deploying extra generation capacity as the carbon constraint tightens towards the ultimate 2050 target.

- Secondly there is now deployment of 1.8GW of SMRs in 2030-35 at the beginning of the allowed window. This replaces 2GW of CCGT with CCS deployment which otherwise took place in D2.4.1 in these years. It is perhaps surprising to see deployment of both SMR and CCGT with CCS in 2030-35, but preferential deployment of CCGT with CCS ahead of SMR in the period 2035-45 (repeating the pattern of D2.4.1) followed by deployment of SMR again in 2045-50. This is characteristic of closely matched costs between the two technologies. The closeness of the costs implies that the particular assumptions made about cost reductions will be having an impact in this case. Two effects to note are that:
    - We have assumed that the SMR capital cost is constant throughout 2030-50, whereas the CCGT with CCS capex is gradually decreasing. This should favour the latter in later decades.
    - The implicit cost of carbon increases through 2030-50 as the carbon limits tighten. This causes increased electrification of heat and transport leading to increased demand for electricity, and it also adds indirect costs onto CCGT with CCS, associated with the 5% of uncaptured $CO_2$ emissions at the prevailing carbon price.

Whilst the exact numerical results are dependent on the fine details of the capital cost and learning rate assumptions used in this scenario, we should try to look beyond this. The broader qualitative conclusion to draw from this scenario is that, at these costs and in a “no CHP” scenario, the SMR technology is finely balanced in competition with CCGT with CCS.

## D2.4.5

*Selected Charts on p102*

| D2.4.5 | No District Heating; SMR high capex (+20%) |
|---|---|
| Key Amendments (from D2.3.2): | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**SMR capex increased by 20%** (5700£/kW for baseload electricity-only). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **46.9 £bn/yr** | *NPV: 11.8 £bn/yr, 1.2% of GDP* |
| | +4.21 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **578.9 £bn** | *NPV: 213.2 £bn, 0.4% of GDP* |
| | +31.93 £bn | vs Baseline run (with SMRs) |

| Generating Technology | GW | Annual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---|---|---|---|---|
| **CCGT with CCS** | 37 | 44% (85%) | 141 | 102 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Offshore Wind (fixed)** | 16 | 40% (40%) | 56 | 78 |
| **Offshore Wind (floating)** | 16 | 45% (45%) | 63 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 34 | - | 119 | - |

Scenario D2.4.5 takes the central deployment assumption for SMRs (deployment possible from 2030) and capex 20% above central assumptions (5700£/kW for basic electricity-only plant). In this scenario no district heating or CHP is permitted in the energy system.

This scenario is another variant of D2.4.1 and tests the impact of higher SMR capital costs than were assumed in that case. Given the results of D2.4.1 and D2.4.4, we anticipate that the higher cost could see a reduced deployment of SMRs, with the change depending on the relative costs for SMRs and the alternative low-carbon generators. This is indeed the case, as **no SMRs are deployed**; instead this scenario deploys an additional 4.8GW of Tidal Stream, 1.7GW of Wind, 0.2GW of H2 Turbine, and 0.7GW of CCGT with CCS in preference to SMRs.

Noting that the capital cost and learning rate assumptions for the other low-carbon technologies are also uncertainties, it is inappropriate to conclude from this scenario that SMRs can never be an economical option at 5700£/kW. Nevertheless D2.4.5 scenario does suggest that at this cost SMRs will find it difficult to compete on an electricity-only basis. This further reinforces the conclusion that the SMR deployment seen in D2.4.1 is marginal, and sensitive to changes in the relative costs of SMRs versus a number of other low-carbon generating technologies.

## D2.4.6

Run D2.4.6 is listed as a placeholder in the summary table of scenarios, however this describes a run that was brought forward to act as the baseline D2.3.2 so no further analysis is required here.

## D2.4.7

*Selected Charts on p103*

| D2.4.7 | SMR high capex (+20%) |
|---|---|
| Key Amendments (from D2.3.2): | **SMR capex increased by 20%** (5700£/kW for baseload electricity-only). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **43.2 £bn/yr** | *NPV: 10.9 £bn/yr, 1.1% of GDP* |
| | +0.53 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **550 £bn** | *NPV: 203.8 £bn, 0.4% of GDP* |
| | +3.04 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 30 | 42% (85%) | 110 | 105 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR CHP)** | 4 | 68% (85%) | 25 | 151 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 14 | 45% (45%) | 53 | 61 |
| **Onshore Wind** | 15 | 26% (26%) | 35 | 83 |
| **Other** | 20 | - | 84 | - |

Scenario D2.4.7 takes the central deployment assumption for SMRs (deployment possible from 2030) and capex 20% above central assumptions (5700£/kW for basic electricity-only plant, plus markup for CHP and Extraflex). In this scenario district heating and CHP are permitted in the heat sector.

The results show that the increased costs lead to a smaller deployment of SMRs, with the deployment now restricted to 4.2GW during 2045-50. The SMR variant chosen is again the CHP variant which now supplies 38% of the heat for heat networks. When contrasted to D2.3.2 this scenario shows that at the higher capital costs SMRs still have a role in the least-cost energy system, but that role is smaller and more marginal. In the power sector SMRs are displaced by extra capacity of Wind and Solar PV, with the only deployment of SMRs left in the final time period 2045-50. In the supply of heat to heat networks SMRs are displaced by extra supply from thermal power stations and heat pumps. There is also a reduction of 15% in the total heat supplied to district heating, which indicates that there is a two way link between the value of SMRs and the value of district heating: to some extent they both rely on each other to maximise the benefit to the overall energy system. As Figure 6 shows, the most economical scenarios overall are those in which district heating is permitted, and in these scenarios cheaper SMR capital costs mean an increased role for SMRs and overall savings on the total system cost.

## D2.4.8

*Selected Charts on p105*

| **D2.4.8** | **CCS slow/low deployment; no District Heating** |
|---|---|
| **Key Amendments (from D2.3.2):** | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**CCS deployment constrained** to prevent rollout before 2025, then limited to 1GW/yr. (baseline assumption is 1GW/yr 2020-2025, 2GW/yr thereafter). |

| **Abatement Cost Summary** | | |
|---|---|---|
| Annual (2050): | **51.1 £bn/yr** | *NPV: 12.9 £bn/yr, 1.4% of GDP* |
| | +8.39 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **615.5 £bn** | *NPV: 227.2 £bn, 0.5% of GDP* |
| | +68.6 £bn | vs Baseline run (with SMRs) |

| **2050 Power Sector Summary** | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 14 | 42% (85%) | 52 | 94 |
| **Nuclear (Gen III)** | 35 | 79% (90%) | 241 | 84 |
| **Nuclear (SMR Elec)** | 10 | 60% (85%) | 54 | 139 |
| **Offshore Wind (fixed)** | 23 | 39% (40%) | 80 | 84 |
| **Offshore Wind (floating)** | 28 | 44% (45%) | 107 | 66 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 28 | - | 100 | - |

Scenario D2.4.8 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant), and no district heating or CHP is permitted in the energy system. In this scenario the deployment of any CCS application (power and non-power) is limited to a maximum of 1GW/year from 2025 onwards. By comparison, in other runs CCS begins to be rolled out at 1GW/yr from 2020-2025, followed by rates closer to 2GW/yr, before stabilising.

Scenario D2.4.8 is therefore a variant of D2.4.1 which tests the impact of later and slower deployment of CCS. This is of interest for 2 quite different reasons, firstly because Gas CCGT with CCS is a direct competitor of Nuclear SMRs in the low-carbon electricity sector of D2.4.1 around which there are numerous uncertainties. As well as uncertainties over capital cost and fuel cost, which CCGT with CCS shares with SMRs, there are also uncertainties about public acceptance, regulatory systems, and $CO_2$ storage site appraisal, all of which make it prudent to explore a low and slow CCS scenario. Secondly, we know from previous experience of analysing the energy system with the ESME model that CCS is consistently the single most valuable technology, and therefore we expect that low CCS deployment will have a significant impact on the wider energy system.

The results for the power sector (see D2.4.8 figures in Appendix) show steady deployment of SMRs from 2030 onwards reaching 10.3GW capacity in 2050. Greater deployment by 2050 than in D2.4.1, coupled with a more robust profile of steady deployment over 20 years indicates a much more pronounced role for SMRs in this scenario. Figure 5 shows how the role for CCGT with CCS is much reduced in the power sector, and additional capacity is instead deployed for SMRs, Wind and Tidal. As well as reflecting the direct substitution for constrained CCGT with CCS, this also reflects the wider value of CCS when used with biomass to generate “negative emissions”. The negative emissions are so valuable that ESME chooses to use most of the available CCS capacity for the production of hydrogen from biomass. Preserving the role for Bio-CCS comes at the cost of CCGT with CCS capacity in the power sector.

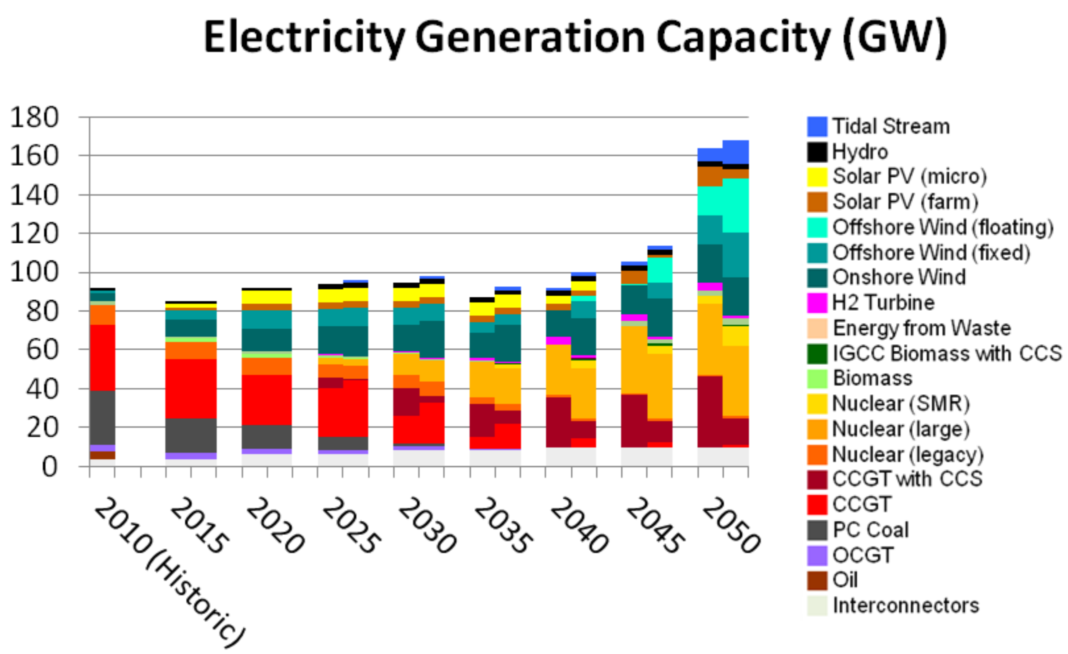


*Figure 5. Comparison of electricity generating capacity from in Scenarios D2.4.1 (left hand bars in each year) and D2.4.8 (right hand bars in each year).*

The lower capacity factor of SMRs in D2.4.8 vs D2.4.1 also demonstrates that in the absence of CCGT with CCS, SMRs are increasingly required to perform a load following role.

## D2.4.9

*Selected Charts on p106*

| D2.4.9 | Bio-energy slow/low deployment; no District Heating |
|---|---|
| Key Amendments (from D2.3.2): | **District heat networks ruled out** as an option for decarbonising heat provision in buildings. **Bio-energy resource constrained** to only half the availability of the baseline (73TWh vs 143TWh in 2050). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **70.9 £bn/yr** | *NPV: 17.9 £bn/yr, 1.9% of GDP* |
| | +28.22 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **827.5 £bn** | *NPV: 297.2 £bn, 0.6% of GDP* |
| | +280.61 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 35 | 42% (85%) | 128 | 106 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec)** | 6 | 85% (85%) | 45 | 103 |
| **Offshore Wind (fixed)** | 19 | 39% (40%) | 66 | 79 |
| **Offshore Wind (floating)** | 20 | 44% (45%) | 78 | 63 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 24 | - | 78 | - |

Scenario D2.4.9 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant), and no district heating or CHP is permitted in the energy system. In this scenario the available quantity of sustainable bioenergy is limited, climbing to 73TWh in 2050, versus the baseline assumption of 143TWh in 2050 in scenario D2.4.1 etc.

As discussed above, biomass plays a key role in combination with CCS in the cost optimised energy system design for scenario D2.4.1. By 2050 almost all the biomass is used in a CCS gasification process to produce hydrogen. This hydrogen is in turn used for industry, power generation and transport (Fig D2.4.1.A.16 in spreadsheet). Reducing the available biomass means that these sectors will need to be supplied with energy via different routes, and importantly it also means that the negative emissions accrued by the use of biomass with CCS will be reduced. This means that other sectors will have to abate $CO_2$ emissions even further than in D2.4.1 in order to continue to meet the system wide carbon target. Comparing scenarios D2.4.1 and D2.4.9, significantly reduced hydrogen production from biomass is the main direct impact of reduced biomass availability. This shortfall is made up through an increased production of hydrogen from coal (Fig D2.4.9.A.12 in spreadsheet). Comparison of the $CO_2$ emissions chart (Fig D2.4.9.A7 in spreadsheet) shows that increased abatement in the transport sector is implemented to meet the carbon target, with a shift towards greater electrification of the car fleet (Fig D2.4.9.A.5 in spreadsheet).

The cost of greater abatement in the transport sector is significant, making this scenario the most expensive to deliver, as can be seen in Figure 8. However, these costs are predominantly driven by the increased interventions needed in the transport sector. There is relatively little increase in total electricity demand (around 2%), and therefore little impact is seen in the power sector. Only an additional 4GW of capacity is deployed in the power sector by 2050 compared with D2.4.1, of which 2 GW is extra SMR capacity. In Scenario D2.4.9 the role for SMRs is therefore very similar to D2.4.1: 6GW capacity is deployed in the final years of the pathway 2045-50, but this still appears as a relatively marginal part of the transition to a low-carbon power sector.

## D2.4.10

*Selected Charts on p107*

| D2.4.10 | Large nuclear capacity limit raised; no District Heating |
|---|---|
| Key Amendments (from D2.3.2): | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**Large nuclear (Gen III) total capacity limit raised** to 50GW (from 35GW in baseline). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **46 £bn/yr** | *NPV: 11.6 £bn/yr, 1.2% of GDP* |
| | +3.36 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **574.7 £bn** | *NPV: 212 £bn, 0.4% of GDP* |
| | +27.81 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 36 | 42% (85%) | 134 | 104 |
| **Nuclear (Gen III)** | 41 | 90% (90%) | 322 | 75 |
| **Offshore Wind (fixed)** | 15 | 40% (40%) | 52 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 25 | - | 88 | - |

Scenario D2.4.10 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant), and no district heating or CHP is permitted in the energy system.

In this scenario large nuclear plants are allowed to deploy the limit of site availability. The ETI Nuclear Insights paper identified a maximum theoretical site capacity based on existing siting constraints of around 62 GWe when applied to England and Wales. The paper identifies that if the capacity of individual new nuclear power stations is limited to between 2.5 to 3.5 GWe per site, then the upper bounding limit for large reactor deployment is around 35 GWe. If this constraint is lifted and new nuclear power stations are developed to limit of each and every site, then the practical limit for deployed capacity rises to around 50 GWe. The consequence of deploying at this scale is that no suitable sites have been identified which would be available for a later generation of large nuclear power stations, such as those deploying Generation IV technology.

As discussed above, the deployment of SMRs in D2.4.1 is dependent on the cost competition against other low carbon generators and on the fact that Large Nuclear deployment hits the maximum limit of 35GW by 2050. We concluded from the results of D2.4.1 that ESME's cost optimisation was preferentially deploying large nuclear over SMRs, and so we expect this scenario to show additional large nuclear capacity which displaces the role of SMRs. This is indeed seen, with large nuclear now reaching 41GW capacity by 2050 and no SMRs deployed. This scenario therefore reinforces our earlier conclusions about the role played by SMRs and demonstrates how the marginal role in for them in D2.4.1 can be affected by uncertainties other than cost. Although we have not performed the equivalent model runs, we can similarly expect that conditions which lead to greater deployment of CCGT with CCS or of renewables, such as a scenario with lower offshore wind costs, will also reduce the capacity of SMRs in the cost-optimised energy system.

## D2.4.11

*Selected Charts on p108*

| **D2.4.11** | **Large nuclear low/slow; SMR build limits doubled; no District Heating** |
|---:|---|
| **Key Amendments (from D2.3.2):** | **District heat networks ruled out** as an option for decarbonising heat provision in buildings.<br>**Large nuclear (Gen III) limited to 9GW** only.<br>**SMR build rate and total capacity limits doubled** to 800MW/yr for ten years, then 2400MW/yr up to a max total of 42GW. |

| **Abatement Cost Summary** | | |
|---:|---|---|
| Annual (2050): | **45.6 £bn/yr** | *NPV: 11.5 £bn/yr, 1.2% of GDP* |
| | +2.93 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **578.7 £bn** | *NPV: 213.4 £bn, 0.4% of GDP* |
| | +31.76 £bn | vs Baseline run (with SMRs) |

**2050 Power Sector Summary**

| Generating Technology | GW | Annual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---:|:---:|:---:|:---:|:---:|
| **CCGT with CCS** | 34 | 50% (85%) | 149 | 99 |
| **Nuclear (Gen III)** | 9 | 90% (90%) | 74 | 79 |
| **Nuclear (SMR CHP)** | 18 | 72% (85%) | 113 | 127 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 14 | 45% (45%) | 56 | 61 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 25 | - | 91 | - |

Scenario D2.4.11 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant), and no district heating or CHP is permitted in the energy system. In this scenario the deployment of large nuclear plants is limited to 9GWe, i.e. only the lead projects from each of the three developers are brought online.

We anticipate that this scenario will complement D2.4.10 and show the opposite behaviour: when large nuclear is constrained more tightly then SMRs will be deployed sooner and to a greater extent than in D2.4.1. In order to get a better sense of the demand for SMR capacity in this scenario we have relaxed the limits on maximum deployment rate and maximum deployment capacity (both are doubled).

The expected behaviour is observed, with steady deployment of SMRs from 2030 onwards and reaching 18GWe by 2050. This is the greatest capacity of SMRs seen in any of the scenarios D2.3-4. It again reinforces the above discussion of D2.4.1, emphasising how the role for SMRs is strongly linked to the ultimate constraints on the deployment of large nuclear. The availability of SMRs to substitute for the lost capacity of large nuclear in this scenario helps to keep the cost impact to a minimum (Figure 8). If the future deployment profile on large nuclear is considered a significant uncertainty, either for cost or policy reasons, then SMRs can be seen as providing valuable optionality in the overall energy system transition.

## 7.2 Impact of District Heating assumption

Having described a number of scenarios with and without district heating, it is worth examining the impact of this assumption before continuing to the next set of scenarios.

Figure 6 shows a comparison of the cumulative discounted abatement costs (expressed as a percentage of cumulative discounted GDP) for scenarios D2.3.1-2 (the baseline cases with and without SMRs) and a subset of the scenarios examined so far D2.4.1-7.

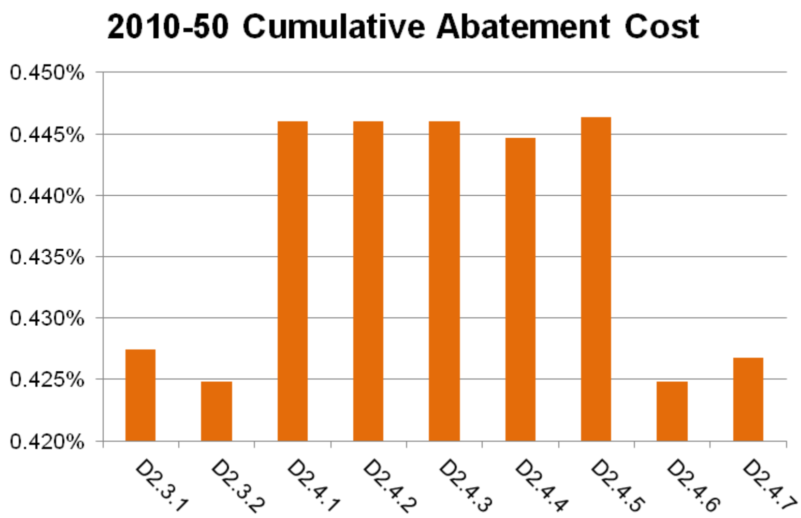


*Figure 6. Cumulative discounted abatement costs 2010-50 for scenarios D2.3 and D2.4.1-7. Cost is expressed as a percentage of cumulative discounted projected GDP.*

Taking run D2.4.1 as the central case among the 'no district heating' runs, the energy system has a distinctly different character from the D2.3.2 baseline. In D2.3.2 district heating provides just under 30% of the total space heat demand, corresponding to about 27% of dwellings. District heating displaces electric heating technologies reducing the total electricity use by about 7%. The resulting difference in the power sector can be seen in Figure 7, which shows how scenario D2.3.2 has a less dramatic push for additional capacity in the final years of the pathway, particularly in renewables.

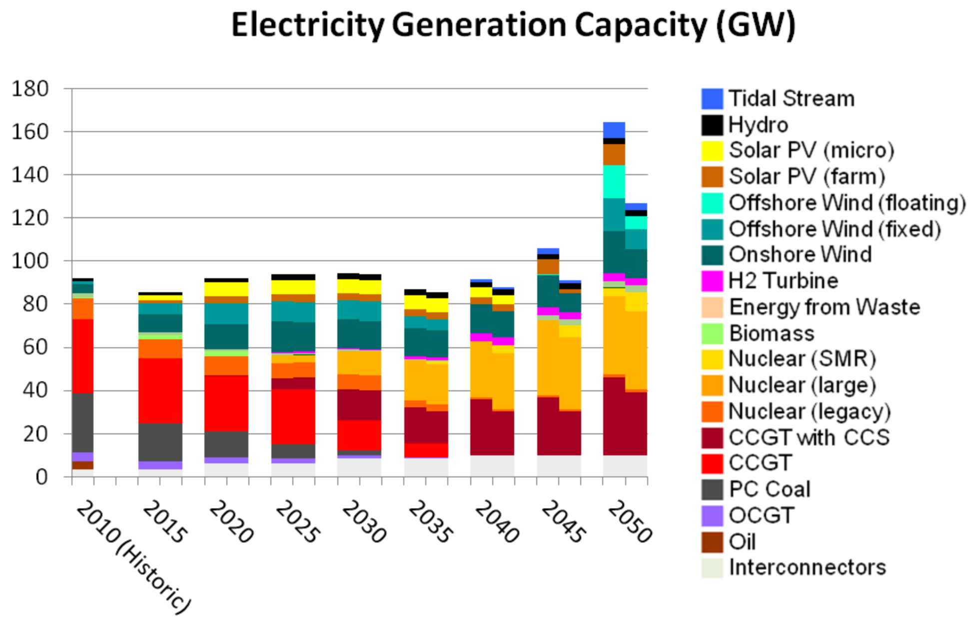


*Figure 7. Comparison of electricity generating capacity from in Scenarios D2.4.1 (left hand bars in each year) and D2.3.2 (right hand bars in each year).*

Figure 7 also shows the different role played by SMRs in this scenario. Instead of the deployment being restricted to the last minute push in 2045-50, D2.3.2 has a steady deployment of SMRs starting in 2030-35 and steadily building to 9GWe by 2050. The generic SMR technology selected in D2.3.2 is the CHP variant, which reveals that supplying heat as well as electricity delivers an improved commercial offer compared to the electricity-only mode. In terms of the overall heat supply to district heating in 2050, 58% comes from SMRs, 38% from other thermal power stations (CCGT with CCS and H2 Turbines), with the rest from commercial heat pumps. In 2050 the SMRs are delivering 54TWh of electricity to the grid and 101TWh of heat to heat networks. The supply of substantial quantities of heat is sufficient in this scenario to make SMRs economical and indeed a central part of the energy system.

The overall cost of the energy system is lower in D2.3.2 than the comparable scenario without district heating (D2.4.1) as shown in Figure 6. The majority of this difference must be categorised as the value to the energy system of district heating, but we have in D2.3.2 a scenario with significant district heating in which SMRs play a central role in the energy system, providing substantial quantities of both electricity and heat. It is therefore no surprise to find that the opportunity cost of SMRs is greater in scenarios with district heating than in scenarios without district heating:

- If there is **no district heating** the cost difference between scenarios with/without SMRs (e.g. D2.4.5 & D2.4.1) is small, 0.2£bn in the discounted cumulative energy system costs.
- **With district heating** the cost difference between scenarios with/without SMRs (i.e. D2.3.2 and D2.3.1) is much larger, 1.3£bn in the discounted cumulative energy system costs.

Run D2.4.5 demonstrates that in a ‘no district heating’ case, where the value of SMRs is marginal, a 20% increase in capex effectively rules out this technology in a deterministic world.

## 7.3 Impact of CCS assumption

The high value of CCS as a technology is shown by Figure 8 which compares the total system cost for all of the scenarios in D2.3 and D2.4. The additional cost to the energy system of the restricted deployment of CCS is clearly significant. Of course the precise level of restriction placed on CCS in D2.4.8, a maximum deployment rate of 1GW/yr, is only an illustrative number. It can be expected that further restricting CCS will lead to even greater impact.

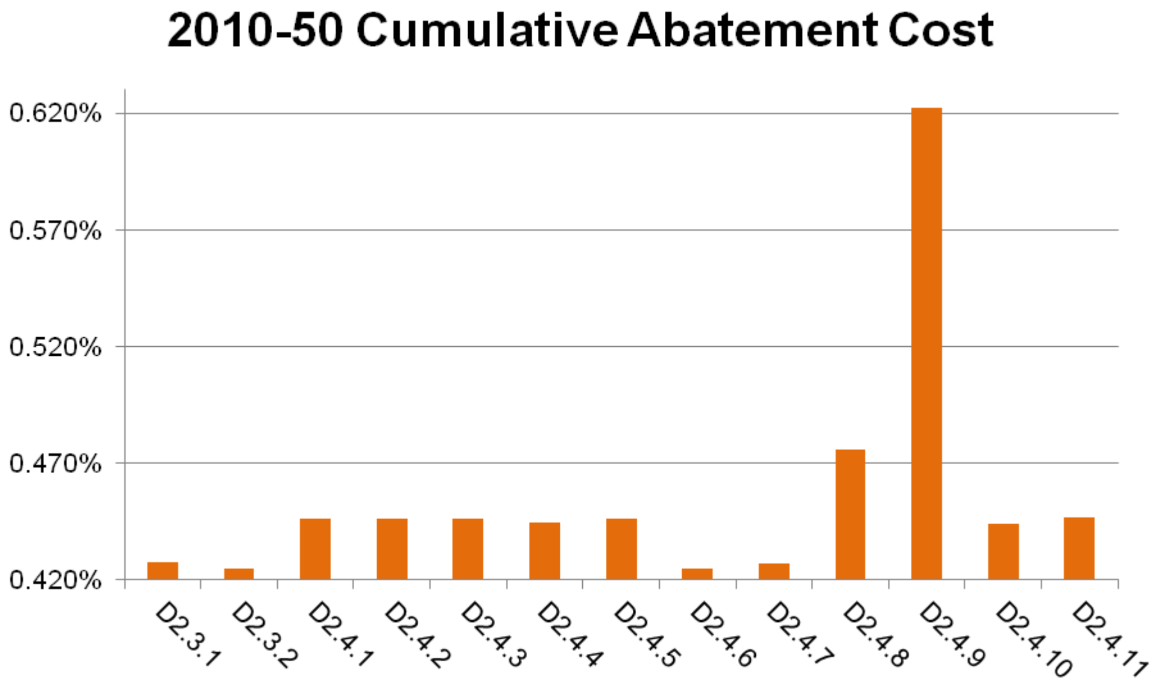


*Figure 8. Cumulative discounted abatement costs 2010-50 for scenarios D2.3 and D2.4. Cost is expressed as a percentage of cumulative discounted projected GDP.*

## 8. RESULTS: Additional scenarios (Runs D2.4.12-17)

Following receipt of Deliverable D2.4, DECC requested an additional six ESME scenarios to be run. From the vast design space that could be tested in principle, it was clear from the earlier runs that many such tests would be redundant since the relevant boundary conditions had already been identified.

The following cases therefore prioritised further variations in SMR capex (where sensible), as well as scenarios looking at high and low gas price and a scenario looking at the impact of slower decarbonisation in domestic heating. The additional runs are numbered D2.4.12-17. They are summarised in Table 6 and are described in detail in the following sections.

| Code | SMR assumptions | Other assumptions |
|---|---|---|
| **D2.4.1** | Central deployment date (2030);<br>Central capex; | no district heat |
| **D2.4.2** | Early deployment date (2025);<br>Central capex; | no district heat |
| **D2.4.3** | Late deployment date (2035);<br>Central capex; | no district heat |
| **D2.4.4** | Central deployment date (2030);<br>Low capex (-20%); | no district heat |
| **D2.4.5** | Central deployment date (2030);<br>High capex (+20%); | no district heat |
| **D2.4.6** | Central deployment date (2030);<br>Central capex; | (NB this scenario duplicates D2.3.2) |
| **D2.4.7** | Central deployment date (2030);<br>High capex (+20%); | - |
| **D2.4.8** | Central deployment and capex | CCGT and CCS slow/low deployment |
| **D2.4.9** | Central deployment and capex | Bio-energy slow/low deployment |
| **D2.4.10** | Central deployment and capex | Large nuclear deployed to the limit of site availability |
| **D2.4.11** | Central deployment and capex<br>Doubled limits on max build rates of SMR | Large nuclear low and slow |
| **D2.4.12** | Central deployment date (2030);<br>Very high capex (+35%); | - |
| **D2.4.13** | Central deployment date (2030);<br>Central capex, with learner rate from 2030-50 | - |
| **D2.4.14** | Central deployment date (2030);<br>Central capex; | Low gas price |
| **D2.4.15** | Central deployment date (2030);<br>Central capex; | High gas price |
| **D2.4.16** | Central deployment date (2030);<br>Central capex; | Low gas price |
| **D2.4.17** | Central deployment date (2030);<br>Central capex; | Slow progress on heat decarbonisation |

*Table 6. The codes and descriptions of the 11 original scenarios reported in [D2.4] and the six additional scenarios. Codes correspond to the results charts and tables delivered separately in the SESO model and the charts appendix.*

## D2.4.12

*Selected Charts on p110*

| D2.4.12 | SMR very high capex (+35%) |
|---|---|
| Key Amendments (from D2.3.2): | **SMR capex increased by 35%** (6413£/kW for baseload electricity-only). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **43.4 £bn/yr** | *NPV: 11 £bn/yr, 1.2% of GDP* |
| | +0.73 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **550.6 £bn** | *NPV: 204 £bn, 0.4% of GDP* |
| | +3.67 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 30 | 42% (85%) | 111 | 105 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR CHP)** | 2 | 68% (85%) | 13 | 164 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 15 | 26% (26%) | 35 | 83 |
| **Other** | 25 | - | 92 | - |

Scenario D2.4.12 takes the central deployment assumption for SMRs (deployment possible from 2030) and very high capex (6413£/kW for basic electricity-only plant). In this scenario district heating and CHP are permitted in the heat sector.

Taken together, scenarios D2.3.2, D2.4.7 and D2.4.12 form a sequence of three scenarios in which district heating and CHP are enabled and SMR capex is respectively baseline, baseline +20% and baseline +35%. The results (see D2.4.12 figures in Appendix) show that the increased costs lead to 2.2GW deployment of SMRs, with the deployment only occurring during 2045-50. The SMR variant chosen is again the CHP variant which now supplies 21% of the heat for heat networks. When considered alongside D2.3.2 and D2.4.7 this scenario shows the continuing trend that the role for SMRs in the least-cost energy system is diminished as their capital costs increase. At the capex level of baseline +35% the remaining role for SMRs is small and marginal, i.e. could easily be displaced by an alternative low carbon generator. As the capex of SMRs increases from baseline +20% to baseline +35% it is seen that SMRs are displaced in the power sector by extra capacity of Wind and Solar PV. In the supply of heat to heat networks SMRs are displaced by extra supply from heat pumps and geothermal.

## D2.4.13

*Selected Charts on p112*

| D2.4.13 | SMR capex with learner rate |
|---|---|
| Key Amendments (from D2.3.2): | **SMR capex follows a learner rate from 2030-2050** (4750£/kW declining to 4000£/kW for baseload electricity-only). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **42.3 £bn/yr** | *NPV: 10.7 £bn/yr, 1.1% of GDP* |
| | -0.38 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **544.6 £bn** | *NPV: 202.2 £bn, 0.4% of GDP* |
| | -2.38 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 28 | 42% (85%) | 105 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR CHP)** | 10 | 71% (85%) | 62 | 121 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 6 | 45% (45%) | 24 | 61 |
| **Onshore Wind** | 13 | 27% (27%) | 31 | 82 |
| **Other** | 14 | - | 67 | - |

Scenario D2.4.13 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex in 2030 (4750£/kW for basic electricity-only plant), but with capex reducing from 2030-50 due to learning effects. The capex in 2050 is taken to be 4000£/kW. In this scenario district heating and CHP are permitted in the heat sector.

To test the impact and value of the capex reductions in scenario D2.4.13 the appropriate comparison is to D2.3.2. The results show an increased deployment of Nuclear SMRs, 10 GW in 2050 (see D2.4.13 figures in Appendix) compared to 8.8GW (see D2.3.2 figures in Appendix). This additional capacity is all added during the final five years 2045-50. The impact of the capital cost learning effect is therefore a greater role for SMRs, as would be expected.

Note that the capex in 2050 in this scenario is approximately 16% below baseline due to the learning rate but, because the capex matches baseline in 2030, this scenario corresponds to a more subtle change in SMR total capex from 2030-2050 than other scenarios considered in this report which assert e.g. capex +/- 20% throughout the pathway. As a result the change in deployed capacity (1.2GW) as a result of the capex learning rate is relatively smaller than the changes seen in previous scenarios with capex +/- 20% throughout the pathway.

The total discounted cumulative energy system cost is reduced by 0.7£bn relative to scenario D2.3.2. This reflects direct savings in the cost of deploying SMRs thanks to the capex learning rate, as well as secondary savings from the 1.2GW of additional SMR capacity which are displacing some more expensive generation.

## D2.4.14

*Selected Charts on p114*

| **D2.4.14** | **Low gas price** |
|---|---|
| **Key Amendments (from D2.3.2):** | **Low gas price** (following profile in Figure 9). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **33.9 £bn/yr** | *NPV: 8.6 £bn/yr, 0.9% of GDP* |
| | -8.75 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **322.8 £bn** | *NPV: 106.5 £bn, 0.2% of GDP* |
| | -224.18 £bn | vs Baseline run (with SMRs) |

| | 2050 Power Sector Summary | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 55 | 58% (85%) | 280 | 63 |
| **Nuclear (Gen III)** | 28 | 90% (90%) | 219 | 75 |
| **Nuclear (SMR CHP)** | 1 | 68% (85%) | 8 | 134 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 30 | 77 |
| **Offshore Wind (floating)** | 4 | 45% (45%) | 16 | 61 |
| **Onshore Wind** | 6 | 28% (28%) | 15 | 77 |
| **Other** | 12 | - | 64 | - |

Scenario D2.4.14 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant). In this scenario district heating and CHP are permitted in the heat sector. A low gas price is assumed in this scenario, which has a profound impact on the total system cost, as summarised in the table above.

This scenario is another variant on D2.3.2, testing the impact of a lower gas price on the energy system and the role for SMRs. The central, low and high gas price assumptions in the ETI ESME dataset are shown in Figure 9. These gas prices are unchanged in ESME from v3.0 and are based on a past review by ETI of external projections (including the DECC gas price projections).

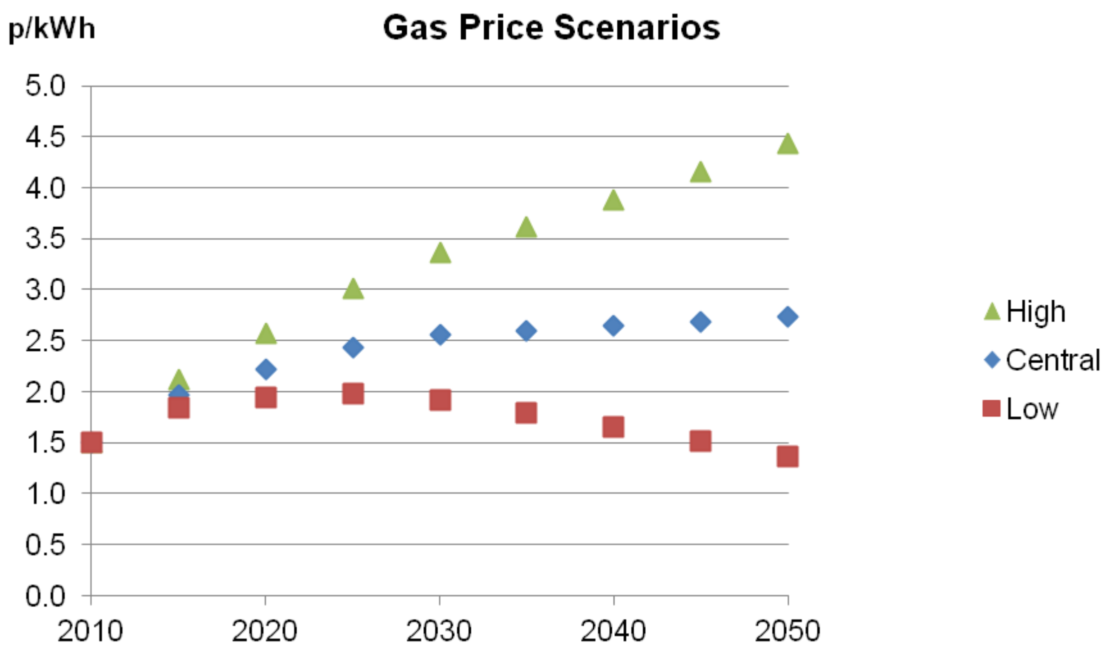


*Figure 9. Gas price scenarios used in ESME v4.0*

All of the ESME scenarios discussed in this report show a substantial amount of gas use remaining in 2050. Although very little gas use in domestic heating remains in 2050 in most scenarios, gas is persistently used in transport (heavy duty vehicles in particular), in industry and for power generation (CCGT with CCS). A significant change in the gas price therefore can have impacts across the energy system, but the most direct impact on SMRs is the cost competition with CCGT with CCS. The D2.4.14 figures in the Appendix show that the low gas price has a major impact on the power sector. SMRs are almost completely absent, with only 1.4GW deployed in 2045-50 whereas substantially more CCGT with CCS is deployed. Indeed the large nuclear technology also sees a reduction from 35GW to 28GW and there are smaller reductions in onshore and offshore wind as well.

In the other parts of the energy system the impact is much less dramatic (e.g. see gas consumption shown in Figure D2.4.14.A.15). Over 700 TWh of gas is consumed in the energy system of D2.4.14, compared to 390TWh in D2.3.2, a large increase which is almost exclusively due to additional generation by CCGT with CCS in the power sector, meaning additional emissions are kept to a minimum (an increased from 2Mt to 5Mt in 2050 due to uncaptured residual emissions).

## D2.4.15

*Selected Charts on p116*

| D2.4.15 | High gas price |
|---|---|
| Key Amendments (from D2.3.2): | **High gas price** (following profile in Figure 9). |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **48.2 £bn/yr** | *NPV: 12.2 £bn/yr, 1.3% of GDP* |
| | +5.59 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **737.4 £bn** | *NPV: 292 £bn, 0.6% of GDP* |
| | +190.5 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 0 | 42% (85%) | 1 | 118 |
| **Nuclear (Gen III)** | 35 | 85% (90%) | 262 | 79 |
| **Nuclear (SMR CHP)** | 11 | 59% (85%) | 57 | 150 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 15 | 26% (26%) | 35 | 83 |
| **Other** | 32 | - | 137 | - |

Scenario D2.4.15 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant). In this scenario district heating and CHP are permitted in the heat sector. A high gas price is assumed in this scenario.

D2.4.15 is a high gas price variant of D2.3.2, with the gas price as shown in Figure 9. In contrast to the low gas price scenario (D2.1.14), the results for D2.4.15 show a major shift away from CCGT with CCS in the power sector. SMRs are now deployed to 11GW in 2050 and there are also increases in the capacity of wind, hydrogen turbines and some 4.9GW of IGCC Coal with CCS which together displace CCGT with CCS from the power sector.

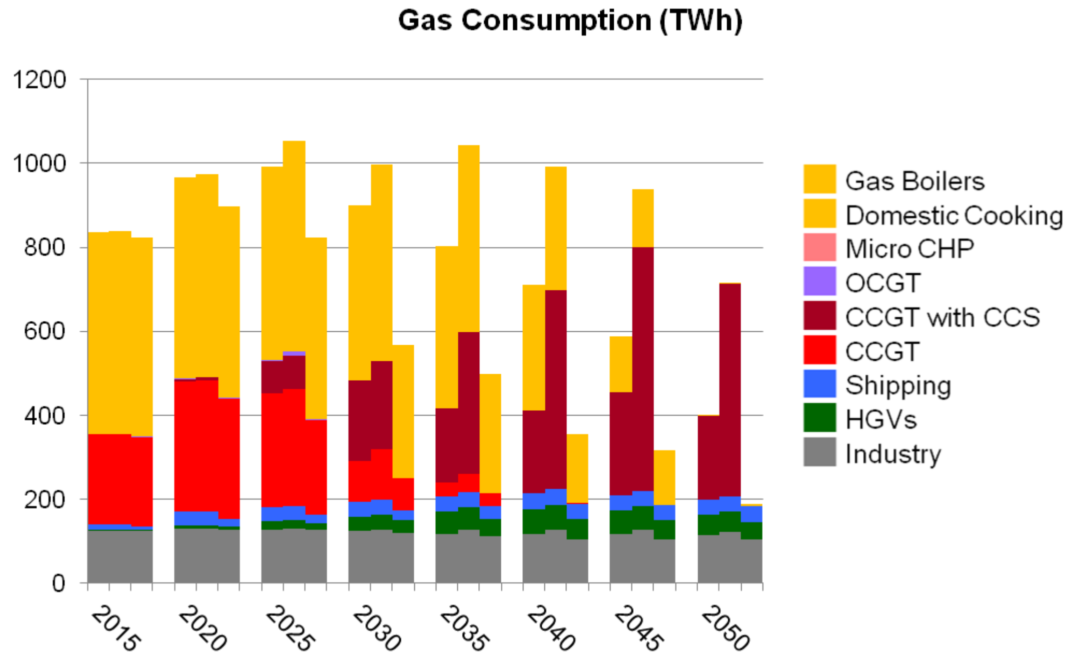


*Figure 10. Comparison of gas consumption in Scenarios D2.3.2 (left hand bars in each year), D2.4.14 (central bars in each year) and D2.4.15 (right hand bars in each year).*

Figure 10 shows a comparison of the gas consumption in the 3 scenarios D2.3.2, D2.4.14 and D2.4.15. This shows the sensitivity of gas use to the gas price, a reflection of the fact that there exist a number of alternative low-carbon generators in cost competition with CCGT with CCS. In contrast the use of gas in industry and as a fuel for shipping and HGVs is very resilient, which reflects the fact that abatement options in these sectors are not in close cost competition. In the high gas price scenario of D2.4.15 approximately half of the gas used in the energy system is in fact synthetic natural gas (SNG)[23], manufactured from biomass in a gasification process with CCS. The SNG manufactured in this way is effectively a low carbon fuel, and its appearance in the cost-optimised energy system reflects a delicate balance between the system cost of using natural gas, incorporating both the direct cost and the indirect cost of associated $CO_2$ emissions, and on the other hand the preferred use of biomass which is a scarce and valuable resource in the 2050 economics of ESME. The overall cost of the energy system is significantly higher in this scenario: 89£bn higher than scenario D2.3.2.

## D2.4.16

*Selected Charts on p118*

| D2.4.16 | Low gas price; no District Heating |
|---|---|
| Key Amendments (from D2.3.2): | **Low gas price** (following profile in Figure 9).<br>**District heat networks ruled out** as an option for decarbonising heat provision in buildings. |

[23] SNG is not a standard feedstock that ESME can purchase like natural gas, or biomass. Instead, it must be produced from those feedstocks through the appropriate (costed) conversion technologies.

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **37.8 £bn/yr** | *NPV: 9.5 £bn/yr, 1% of GDP* |
| | -4.87 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **348.9 £bn** | *NPV: 114.3 £bn, 0.2% of GDP* |
| | -198.02 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 55 | 53% (85%) | 255 | 66 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 75 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 14 | 45% (45%) | 55 | 61 |
| **Onshore Wind** | 7 | 27% (28%) | 18 | 78 |
| **Other** | 18 | - | 78 | - |

Scenario D2.4.16 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant). In this scenario district heating and CHP are not permitted and a low gas price is used.

Because district heating and CHP are ruled out, scenario D2.4.16 is a low gas price variant of D2.4.1. The low gas price has a similar effect here to that seen above: an increased capacity of CCGT with CCS is seen in the power sector at the expense of renewables and SMR capacity. There is no deployment at all of SMRs in scenario D2.4.16, compared to the 4 GW seen in D2.4.1.

In other sectors the low gas price has little effect on the technologies selected by ESME. Again the volume of gas being used in the energy system means that the cumulative NPV cost is significantly reduced in this scenario: £79bn lower than scenario D2.4.1.

## D2.4.17

*Selected Charts on p119*

| **D2.4.17** | **Slow progress on heat decarbonisation** |
|---|---|
| **Key Amendments (from D2.3.2):** | **District heating and heat pumps - build rate limits lowered** such that they make only half the contribution to 2050 heat provision as in the baseline. |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **70.4 £bn/yr** | *NPV: 17.8 £bn/yr, 1.9% of GDP* |
| | +27.69 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **833.3 £bn** | *NPV: 298.1 £bn, 0.6% of GDP* |
| | +286.41 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 24 | 31% (85%) | 65 | 122 |

| | | | | |
|---|---|---|---|---|
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR CHP)** | 7 | 71% (85%) | 46 | 128 |
| **Offshore Wind (fixed)** | 9 | 39% (39%) | 32 | 88 |
| **Offshore Wind (floating)** | 14 | 44% (45%) | 54 | 62 |
| **Onshore Wind** | 20 | 26% (26%) | 45 | 83 |
| **Other** | 29 | - | 78 | - |

Scenario D2.4.17 takes the central deployment assumption for SMRs (deployment possible from 2030) and central capex (4750£/kW for basic electricity-only plant). In this scenario district heating and CHP are permitted in the heat sector, but the heat sector is limited to slower decarbonisation.

In all the above scenarios ESME chooses to almost completely decarbonise the domestic and commercial heat sector by 2050 (although note that hybrid systems combine air source heat pumps with gas boilers to provide extra heat in extreme cold weather, see e.g. SESO Figures D2.3.1.A.19 and D2.3.1.D). There are significant barriers, both economic and policy related, to the adoption/deployment of heat pumps and district heating, and therefore a scenario to explore the effect of slow progress in the heat sector is very relevant. Scenario D2.4.17 was constructed by tightening the deployment rates of district heating and heat pumps, so that their contribution to the space heat supply chart in 2050 (SESO Figure D2.4.17.A.4) was approximately half that in scenario D2.3.2.

The principal impact is naturally in the heat sector, with SESO Figure D2.4.17.A.4 showing that a significant amount of gas boiler heating remains in 2050 in this scenario, and the contributions from ASHP and district heating are reduced. These additional emissions in the heat sector mean that 23Mt$CO_2$ of additional abatement must be found in other sectors. This is achieved primarily by abatement in the transport sector through greater electrification (see SESO Figure D2.4.17.A.7). With some reduction in CCGT with CCS in the power sector, there are correspondingly fewer residual emissions from that technology (a $CO_2$ capture rate of 95% is assumed). The impact on SMRs is a small reduction in capacity, from 8.8GW in 2050 to 7.4GW. This reflects a number of competing effects:

- Reduced capacity and generation by CCGT with CCS increases the opportunity for other low-carbon generators such as SMRs.
- The reduced electrification of heat however causes a small reduction in total electricity demand.
- The reduction in district heating deployment by 2050 reduces the value of CHP which, as noted above, is an important driver for SMR deployment.

The combined effect is a small reduction in SMR capacity, and instead it is wind and solar which show increases in capacity in this scenario, benefitting from the reduced capacity of CCGT with CCS. This scenario is a reminder of the numerous different factors which influence the role which SMRs could play, and again reinforces the conclusion that the ability to supply heat to district heating networks as well as to supply electricity to the grid is a very important factor.

# 9. RESULTS: Specific SMR technologies/genres (D2.5)

The scenarios reported in the preceding sections all explored the role of Nuclear SMRs in the energy system using “generic” technology data for the SMRs derived chiefly from the ETI’s ANT project. In this section we report on modelled scenarios using specific SMR technology data.

The specific technology data for SMRs used in this section was delivered by other projects in the TEA process. Project 1 performed a survey of SMR vendors and potential vendors. Anonymised vendor responses from that survey were passed to the ETI. Following a review of the data, five vendors were identified (numbers 2, 6, 7, 15 and 17) as having provided sufficient quantitative data to enable meaningful runs in the ESME model. These vendors relate to relatively near-term and relatively less uncertain technology types. Five other vendors (numbers 1, 5, 13, 14 and 16) were identified as relating to less developed technologies. Recognising the level of uncertainty in data for these technologies, and the gaps in the quantitative data which vendors have given, Project 3 provided further data to enable ETI to perform an ESME scenario to be run for each distinct technology genre.

The purpose of the scenarios in this section is to test the potential role which SMRs could play in the future energy system at the costs and performance envisaged by the technology vendors. The technology-specific data spans a broad range, from costs significantly lower than those used in our generic SMR scenarios to costs significantly higher. With such a wide range of costs to test, there could well be vendor optimism in some cases. In this section we analyse the data in its basic form, as provided by the vendors. The opportunity to adjust the data to address any perceived vendor optimism is provided in the final phase of analysis D2.6, based on further information provided by Project 1.

In each case we perform an ESME scenario by taking the same baseline conditions as above, removing all the generic SMR technologies, and adding in a single SMR technology corresponding to a specific vendor response. None of the vendors’ responses indicated that a significant study had been made of provision of heat to energise district heating networks, therefore we model each of the vendor SMR technologies as providing electricity only. District heating, energised by other sources, is nevertheless still available in these scenarios.

## 9.1. Near-term technology vendor scenarios

Scenarios are presented for vendors 2, 6, 7, 15 and 17 corresponding to relatively near-term SMR technologies. Table 7 gives a summary of the key data for these vendors, and for comparison the generic electricity-only SMR technology used in previous scenarios.

Note that the survey completed by all the vendors specified that costs be given in 2015 USD. The ETI ESME model uses 2010 GBP for all cost data, so conversion of cost data into 2010 GBP was performed using conversion factors: 0.65 to convert USD to GBP (provided by Project 1) and 0.85 to convert 2015 GBP to 2010 GBP, a conversion factor derived from UK RPI data published by ONS.

| Vendor | CAPEX (£/kW) | | Fixed O&M (£/kW/yr) | | Variable O&M (£/kWh/yr) | |
|---|---|---|---|---|---|---|
| | 2010 | 2050 | 2010 | 2050 | 2010 | 2050 |
| 2 | 3037 | 3037 | 130* | 100* | 0.0050* | 0.0050* |
| 6 | 3037 | 3037 | 76 | 76 | 0.0043 | 0.0043 |
| 7 | 5640 | 5640 | 196 | 196 | 0.0066 | 0.0066 |
| 15 | 1530 | 1530 | 130* | 100* | 0.0050* | 0.0050* |
| 17 | 2804 | 2804 | 86 | 86 | 0.0050* | 0.0050* |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Generic** | 4750 | 4750 | 130 | 100 | 0.0050 | 0.0050 |

*Table 7. Summary of the cost data (2010 GBP) used for the scenarios of near-term SMR technology vendor data and, for comparison, the cost data of the generic electricity-only SMR used in D2.4. Asterisks denote costs where the generic data was used because of lacking data in a vendor's response to the survey.*

## D2.5.2

*Selected Charts on p121*

| D2.5.2 | Vendor 2 SMR technology |
|---|---|
| **Key Amendments (from D2.3.2):** | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect vendor 2 costs as per Table 7. |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **42.7 £bn/yr** | *NPV: 10.8 £bn/yr, 1.1% of GDP* |
| | +0.05 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **540.6 £bn** | *NPV: 200.6 £bn, 0.4% of GDP* |
| | -6.34 £bn | vs Baseline run (with SMRs) |

| | 2050 Power Sector Summary | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 27 | 42% (85%) | 99 | 103 |
| **Nuclear (Gen III)** | 35 | 89% (90%) | 272 | 77 |
| **Nuclear (SMR Elec Vendor 2)** | 16 | 82% (90%) | 116 | 82 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 6 | 45% (45%) | 24 | 61 |
| **Onshore Wind** | 12 | 27% (27%) | 28 | 81 |
| **Other** | 14 | - | 67 | - |

Scenario D2.5.2 adjusts the baseline run (D2.3.2) by removing the four generic SMRs and adding in an electricity-only nuclear SMR technology based on vendor 2's response to the survey undertaken by Project 1. Vendor 2 did not supply estimates of fixed operation and maintenance costs or variable operation and maintenance costs, so values for these were taken from the ETI generic SMR data instead. This vendor did not give estimates for maximum build rates, so these were taken from the ETI generic SMR data, nor did it give a forecast date for a first of a kind (FOAK) commercial plant in the UK. A FOAK date of 2027 was assumed based on the responses from other vendors.

The results for Scenario D2.5.2 show 16GW of nuclear SMR deployed by 2050. This significantly exceeds the 8.8GW of SMR deployed in Scenario D2.3.2, and therefore the lower capital cost given by vendor 2 more than outweighs the restriction to supplying only electricity, rather than electricity and heat as was possible in D2.3.2. Compared to D2.3.2 there is a slight reduction in capacity of wind, CCGT CCS and Gen IV nuclear accompanying the increased SMR capacity. The total generating capacity is slightly higher in D2.5.2, with a higher annual total of electricity generation accompanying a slight reduction of district heating in favour of heat pumps in the heating sector. This change in the heat sector is relatively modest, and when looking at all of the sectors the energy systems of the 2 scenarios are very similar overall. The shift toward greater capacity of SMRs in the power sector is the single greatest difference.

The summary of 2050 power sector capacity shows that the SMRs are a significant part of the total, and that the capacity factor (a model output) is less than the assumed availability factor (a model input). This reflects that the SMRs are not being run baseload by the ESME model, but are load following to some extent.

## D2.5.6

*Selected Charts on p122*

| D2.5.6 | Vendor 6 SMR technology with higher build rate |
|---|---|
| **Key Amendments (from D2.3.2):** | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect vendor 6 costs as per Table 7.<br>**SMR build rate limit increased** to 800MW/yr for ten years, then 1600MW/yr, up to a max total of 31.5GW. |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **41.4 £bn/yr** | *NPV: 10.5 £bn/yr, 1.1% of GDP* |
| | -1.25 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **509.9 £bn** | *NPV: 189.9 £bn, 0.4% of GDP* |
| | -37.06 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 19 | 42% (85%) | 71 | 102 |
| **Nuclear (Gen III)** | 30 | 87% (90%) | 230 | 78 |
| **Nuclear (SMR Elec Vendor 6)** | 32 | 78% (95%) | 216 | 77 |
| **Offshore Wind (fixed)** | 8 | 40% (40%) | 29 | 77 |
| **Offshore Wind (floating)** | 4 | 45% (45%) | 17 | 61 |
| **Onshore Wind** | 6 | 27% (27%) | 14 | 78 |
| **Other** | 13 | - | 66 | - |

Scenario D2.5.6 takes the central baseline, adding in an electricity-only nuclear SMR technology based on vendor 6's response to the survey undertaken by Project 1. This vendor did not give estimates for maximum build rates, so these were initially (see below) taken from the ETI generic SMR data.

Vendor 6 gave the same capex estimate as vendor 2, and in addition gave estimates for fixed and variable costs which were lower than the generic data, see Table 7. The result is therefore overall reduced costs for this SMR technology compared to D2.5.2, and correspondingly the results show increased deployment in D2.5.6. In fact the costs are sufficiently low that the deployment in 2050 would hit the maximum deployment permitted by our standard constraints on build rate and site availability. In order to understand the full extent of SMR capacity which would be economic at these costs we have lifted the site availability for SMRs to 31.5GW, consistent with the conclusions from the PPSS project, and increased the maximum build out rate to 800 MWe for the first 10 years and

1600 MWe per year thereafter, consistent with the high scenario in the ANT project. We consider this to be at the limit of credible deployment of SMRs in the UK by 2050.

With the relaxed build limits, we see in scenario D2.5.6 deployment of 31.5 GW of nuclear SMRs. This additional capacity displaces capacity of all the other major generators: CCGT with CCS, large nuclear and wind. The total generating capacity is reduced from 129GW to 123GW, but the total annual generation marginally increases from 638TWh to 644TWh, reflecting displacement of intermittent renewables. It is also notable that, when displacing capacity of CCGT with CCS which is playing a seasonal load-following role, the SMR fleet in this scenario performs more load following and is run at a capacity factor of 78%, compared to 82% in D2.5.2.

Away from the power sector, the transport, heat and other sectors of D2.5.6 are very similar to D2.5.2.

## D2.5.7

Scenario D2.5.7 follows the same approach as above, adding in an electricity-only nuclear SMR technology based on vendor 7's response to the survey undertaken by Project 1. This vendor did not give estimates for maximum build rates, so these were taken from the ETI generic SMR data.

Table 7 shows that all the cost data for vendor 7 were significantly higher than the other vendors and the generic SMR technology. As a result, no SMR deployment is selected in D2.5.7, meaning this run replicates the results of D2.3.1 Baseline (no SMRs).

## D2.5.15

*Selected Charts on p124*

| D2.5.15 | Vendor 15 SMR technology with higher build rate |
|---|---|
| Key Amendments (from D2.3.2): | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect vendor 15 costs as per Table 7.<br>**SMR build rate limit increased** to 800MW/yr for ten years, then 1600MW/yr, up to a max total of 31.5GW. |

| **Abatement Cost Summary** | | |
|---|---|---|
| Annual (2050): | **38.5 £bn/yr** | *NPV: 9.7 £bn/yr, 1% of GDP* |
| | -4.17 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **479 £bn** | *NPV: 179.8 £bn, 0.4% of GDP* |
| | -67.96 £bn | vs Baseline run (with SMRs) |

**2050 Power Sector Summary**

| Generating Technology | GW | Annual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---|---|---|---|---|
| **CCGT with CCS** | 19 | 42% (85%) | 72 | 102 |
| **Nuclear (Gen III)** | 31 | 78% (90%) | 210 | 85 |
| **Nuclear (SMR Elec Vendor 15)** | 32 | 85% (91%) | 234 | 56 |
| **Offshore Wind (fixed)** | 8 | 40% (40%) | 29 | 77 |
| **Offshore Wind (floating)** | 4 | 45% (45%) | 16 | 61 |
| **Onshore Wind** | 7 | 27% (27%) | 17 | 79 |

| | | | | |
|---|---|---|---|---|
| **Other** | 14 | - | 64 | - |

Scenario D2.5.15 takes the central baseline, adding in an electricity-only nuclear SMR technology based on vendor 15's response to the survey undertaken by Project 1. Vendor 15 did not supply estimates of fixed operation and maintenance costs or variable operation and maintenance costs, so values for these were taken from the ETI generic SMR data instead. This vendor did not give estimates for maximum build rates, so these were initially taken from the ETI generic SMR data.

Vendor 15 has the lowest capital cost of all the scenarios in this section although, because no fixed or variable costs were given, the generic SMR fixed and variable costs were used and these are slightly higher than those of vendors 6 and 17. Nevertheless the overall LCOE associated with the SMRs of this vendor are the lowest of all in this section and it is unsurprising that the results are very similar to D2.5.6: SMR capacity is deployed up to our standard build limit of 16GW, and on relaxing these in the same way as was done for D2.5.6, we find SMRs are deployed up to the higher limit of 31.5GW. The only minor difference to note between D2.5.15 and D2.5.6 is that SMRs are run at a slightly higher capacity factor (85% versus 78%) and Gen III is run at a correspondingly slightly lower capacity factor. This is caused by the greater thermal efficiency claimed by vendor 15, which significantly reduces the fuel consumption and hence the short-run marginal cost of generation for the SMRs.

## D2.5.17

*Selected Charts on p125*

| D2.5.17 | Vendor 17 SMR technology with higher build rate |
|---|---|
| Key Amendments (from D2.3.2): | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect vendor 17 costs as per Table 7.<br>**SMR build rate limit increased** to 800MW/yr for ten years, then 1600MW/yr, up to a max total of 31.5GW. |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **40.6 £bn/yr** | *NPV: 10.3 £bn/yr, 1.1% of GDP* |
| | -2.03 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **501.2 £bn** | *NPV: 187 £bn, 0.4% of GDP* |
| | -45.75 £bn | vs Baseline run (with SMRs) |

**2050 Power Sector Summary**

| Generating Technology | GW | Annual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---|---|---|---|---|
| **CCGT with CCS** | 19 | 42% (85%) | 71 | 102 |
| **Nuclear (Gen III)** | 30 | 89% (90%) | 231 | 77 |
| **Nuclear (SMR Elec Vendor 17)** | 32 | 77% (96%) | 212 | 75 |
| **Offshore Wind (fixed)** | 8 | 40% (40%) | 29 | 77 |
| **Offshore Wind (floating)** | 5 | 45% (45%) | 20 | 61 |
| **Onshore Wind** | 6 | 27% (27%) | 14 | 78 |
| **Other** | 13 | - | 67 | - |

Scenario D2.5.17 takes the central baseline, adding in an electricity-only nuclear SMR technology based on vendor 17's response to the survey undertaken by Project 1. Vendor 17 did not supply estimates of variable operation and maintenance costs, so values for these were taken from the ETI generic SMR data instead. This vendor did not give estimates for maximum build rates, so these were taken from the ETI generic SMR data.

The costs used for vendor 17 are similar to those of vendor 6, see Table 7, and the results are essentially the same. SMRs are deployed up to our usual build limit of 16GW, and on relaxing the build limits in the same way as was done for D2.5.6 and D2.5.15 we get the same result: deployment up to the new limit of 31.5GW, which we consider to be at the limit of credible deployment of SMRs in the UK by 2050. The LCOE from the vendor 17 SMR technology is close to that of vendor 6 and higher than that of vendor 15, and the capacity factor also closely matches that of D2.5.6.

## 9.2. Emerging technology genre scenarios

In this section we present scenarios for clusters of emerging SMR technologies. The input provided by Project 3 is summarised in Table 8, and is based on Generic Feasibility Assessment (GFA) level professional judgements of the characteristics of each technology cluster. The capital factor in Table 8 represents a judgement of the capital costs relative to a baseline which is a small modular pressurised water reactor.

It is important to note that the analysis undertaken by TEA project 3 is a qualitative analysis using the GFA tool, whereas ESME is a quantitative modelling tool. The numerical results discussed here in section 9.2 and later in section 10 for run D2.6.3 should therefore be considered as indicative only, to reflect the qualitative way in which the inputs are derived.

In order to construct a fair comparison with the vendor technology scenarios for SM-PWRs described above, we adopt for the scenarios in this section a profile for a generic SM-PWR based on the median data supplied by vendors 2, 6, 7, 15 and 17. Specifically, this means: first operations date 2030, capital cost US$5,500/kWe, operating costs as defined by the ETI generic SMR, technical life of 60 years, availability factor of 90% and maximum build-out rates as per the ANT standard mid-range scenario (400 MWe/year for 10 years followed by 1200 MWe/year thereafter).

| Reactor Type | On-line date | Capital Factor | Comments |
|---|---|---|---|
| ***Generic SM-PWR*** | *2030* | *1.00* | *Reference* |
| **SM-HTR** | 2035 | 1.25 | Relies on fewer barriers than SM-PWRs but much lower power density and more complex fuel design. |
| **SM-SFR** | 2040 | 1.25 | Necessitates secondary circuit and extra barriers to limit sodium containment. |
| **SM-LFR (Pb coolant)** | 2050 | 1.25 | Reduced complexity related to coolant escape relative to sodium. However, necessitates more complex instrumentation and chemistry control systems, in addition to systems to ensure Pb coolant does not freeze. |
| **LFR (LBE coolant)** | 2050 | 1.50 | Similar to LFR (Pb coolant). However, coolant freezing is less of an issue with LBE. Main economic drawback is scarcity of bismuth. |

| | | | |
|---|---|---|---|
| **SM-MSThR Thermal spectrum MSR (limited on-line reprocessing)** | 2060 | 1.25 | No complex reprocessing plant but robust barriers to ensure coolant/fuel does not escape. |
| **SM-MSFR Fast spectrum MSR (extensive on-line reprocessing)** | 2070 | 1.50 | Requires a complex reprocessing plant and robust barriers to ensure coolant/fuel does not escape. |

*Table 8. The inputs on emerging technology clusters provided by Project 3.*

## SM-HTR (D2.5.HTR)

*Selected Charts on p126*

| **D2.5.HTR** | **SM-HTR technology** |
|---|---|
| **Key Amendments (from D2.3.2):** | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect Project 3 assumptions for an electricity only Small Modular High Temperature Reactor.<br>**Earliest SM-HTR deployment of 2035** |

| **Abatement Cost Summary** | | |
|---|---|---|
| Annual (2050): | **43 £bn/yr** | *NPV: 10.9 £bn/yr, 1.1% of GDP* |
| | +0.34 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **549.5 £bn** | *NPV: 203.8 £bn, 0.4% of GDP* |
| | +2.59 £bn | vs Baseline run (with SMRs) |

| **2050 Power Sector Summary** | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 31 | 42% (85%) | 116 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec HTR)** | 8 | 90% (90%) | 66 | 85 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 6 | 45% (45%) | 25 | 61 |
| **Onshore Wind** | 15 | 27% (27%) | 34 | 82 |
| **Other** | 20 | - | 83 | - |

The judgement from Project 3 was that a small modular high temperature reactor could first become online after 2035, and that an appropriate capital cost estimate is 125% of the capital cost for small modular PWR. Scenario D2.5.HTR takes the central baseline, adding in an electricity-only nuclear SMR technology based on this judgement of the SM-HTR.

Although these cost assumptions for the SM-HTR position it as more expensive than a SM-PWR, they are still sufficiently competitive that ESME chooses to deploy the technology. However, the later date for earliest deployment than in all the scenarios for the near-term technology vendor runs has a material impact. Deployment can only start later and only reaches 8.4GW by 2050. This is lower than the deployment of SMRs seen in the runs for vendors 2, 6, 15 &17 in the scenarios described above, and as a consequence higher deployment of CCGT CCS, wind and solar are seen.

## SM-SFR (D2.5.SFR)

*Selected Charts on p127*

| D2.5.SFR | SM-SFR technology |
|---|---|
| Key Amendments (from D2.3.2): | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** to reflect Project 3 assumptions for an electricity only Small Modular Sodium-cooled Fast Reactor.<br>**Earliest SM-SFR deployment of 2040** |

| Abatement Cost Summary | | |
|---|---|---|
| Annual (2050): | **43.2 £bn/yr** | *NPV: 10.9 £bn/yr, 1.1% of GDP* |
| | +0.5 £bn/yr | vs Baseline run (with SMRs) |
| Cumulative (2010-2050): | **550.1 £bn** | *NPV: 203.9 £bn, 0.4% of GDP* |
| | +3.15 £bn | vs Baseline run (with SMRs) |

| 2050 Power Sector Summary | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Annual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| **CCGT with CCS** | 30 | 42% (85%) | 110 | 104 |
| **Nuclear (Gen III)** | 35 | 90% (90%) | 275 | 76 |
| **Nuclear (SMR Elec SFR)** | 4 | 90% (90%) | 31 | 85 |
| **Offshore Wind (fixed)** | 9 | 40% (40%) | 32 | 77 |
| **Offshore Wind (floating)** | 15 | 45% (45%) | 60 | 61 |
| **Onshore Wind** | 14 | 26% (26%) | 33 | 83 |
| **Other** | 20 | - | 86 | - |

The judgement from Project 3 was that a small modular sodium-cooled fast reactor could first become online after 2040, and that an appropriate capital cost estimate is 125% of the generic small modular PWR. Scenario D2.5.SFR takes the central baseline, adding in an electricity-only nuclear SMR technology based on this judgement of the SM-SFR.

This cost assumption for the SM-SFR is sufficiently competitive that ESME does choose to deploy the technology. However, the later date for earliest deployment again has a material impact. Deployment can only start from 2040 and therefore the deployment is even more limited than in the D2.5.HTR scenario and only reaches 4GW by 2050. This is lower than the deployment of SMRs seen in the runs for vendors 2, 6, 15 &17 and in D2.5.HTR. Again, greater deployment of CCGT CCS, wind and solar is seen to compensate for the reduced SMR deployment, compared to those other scenarios.

## SM-LFR (Pb coolant)

The judgement from Project 3 was that a small modular lead-cooled fast reactor could first come online after 2050. Consequently this technology would not be able to contribute to decarbonisation of the energy system before 2050 and an ESME scenario was not run for this emerging technology cluster.

### LFR (LBE coolant)

The judgement from Project 3 was that a small modular lead-cooled fast reactor with a eutectic alloy coolant could first come online after 2050. Consequently this technology would not be able to contribute to decarbonisation of the energy system before 2050 and an ESME scenario was not run for this emerging technology cluster.

### SM-MSThR

The judgement from Project 3 was that a small modular molten salt thermal reactor could first come online after 2060. Consequently this technology would not be able to contribute to decarbonisation of the energy system before 2050 and an ESME scenario was not run for this emerging technology cluster.

### SM-MSFR

The judgement from Project 3 was that a small modular molten salt fast reactor could first come online after 2070. Consequently this technology would not be able to contribute to decarbonisation of the energy system before 2050 and an ESME scenario was not run for this emerging technology cluster.

## 10. RESULTS: Probabilistic Monte Carlo runs (D2.6)

The various scenarios in the preceding sections were all conducted as single deterministic runs. In this section we report on a series of three 'Monte Carlo' runs. In Monte Carlo mode, ESME can incorporate uncertainty for key variables such as capex for technologies, or the cost and availability of resources. For each of these probabilistic variables, in addition to a mean value, a range is defined for 2050 to reflect optimistic/pessimistic extremes.

When ESME is operated in Monte Carlo mode, it conducts a given number of simulation runs where probabilistic variables are assigned a randomly selected value from their 2050 range (in contrast to a single deterministic run using only mean values). Once the 2050 value is assigned, the intermediate values are interpolated linearly from 2010.

### 10.1 Definition Of Monte Carlo runs

In the baseline runs and sensitivity scenarios (Sections 6-8), a generic SMR dataset developed by ETI was adjusted according to the particular issue being analysed (capex/first deployment etc). In the specific SMR technology/genre runs (Section 9), a bespoke SMR dataset was built up for each run using data provided by vendors (with any gaps filled using generic ETI data).

In preparation for this set of Monte Carlo runs, the Project 1 contractor consolidated provisional learnings from across Projects 1-7 of this TEA, and developed an updated generic technology dataset for an *electricity only* SMR. This constituted the basis for the first Monte Carlo run (D2.6.1). For the second run (D2.6.2), ETI made adjustments to represent a CHP-capable SMR, by applying a capex markup, and providing data on how the SMR performs in CHP mode. For the third run (D2.6.3), electricity only SMRs were represented as a longer term 'emerging technology' akin to the high temperature reactor analysed in section 9.2, with adjustments made to capex and first deployment date accordingly. The capex adjustment reflects the expectation from project 3 that emerging technologies are unlikely to be as cost competitive as near term light water reactor technologies.

#### Cost and performance assumptions

The dataset provided by Project 1 included capex, fixed and variable costs for 'nth of a kind' Nuclear SMR technology. Consistent with all other technologies in ESME, these NOAK costs were applied from the date of first deployment (i.e. no provision was made for first of a kind costs). For the near term SMR runs (D2.6.1&2) a capex reduction rate was assumed (lowering capex by 5% by 2050). For the emerging technology SMR run (D2.6.3), the later deployment schedule implied less opportunity for learning, thus no learner rate was assumed. To facilitate probabilistic modelling in ESME's Monte Carlo mode, a high/low range was also provided for 2050 capex, fixed and variable costs, taken from Project 1 data. Table 9 provides a summary of SMR cost data assumed in these runs.

| Cost category | **Capital** | **Fixed O&M** | **Variable O&M** | **Capital (Mean)** | **Capital (Range)** | **Fixed O&M (Range)** | **Variable O&M (Range)** |
|---|---|---|---|---|---|---|---|
| Year | **2010** | **2010** | **2010** | **2050** | **2050** | **2050** | **2050** |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/kW(e) | +/- % | +/- % | +/- % |
| **ETI Generic SMR (Elec only)** | 4750 | 130 | 100 | 4750 | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **ETI Generic SMR (CHP)** | 4950 | 135 | 105 | 4950 | - | - | - |
| **D2.6.1 Near term SMR (Elec only)** | 3505 | 84 | 5 | 3329 | +35/-31 | +20/-23 | +4/-4 |
| **D2.6.2 Near term SMR (CHP)** | 3705 | 89 | 5 | 3529 | +35/-31 | +20/-23 | +4/-4 |
| **D2.6.3 Emerging SMR (Elec only)** | 4381 | 84 | 5 | 4381 | +35/-31 | +20/-23 | +4/-4 |

*Table 9: Revised SMR costs for use in Monte Carlo runs (with ETI Generic SMR costs for reference). For mean values, the cost curve is flat from 2010 to first deployment, then sloping according to any learner rate out to 2050 (no learner rate assumed for emerging tech). For probabilistic values, a 2050 cost is selected from the range and the cost curve over the pathway interpolated accordingly. Ranges for Variable O&M costs provided to Project 2 were limited, but were carried through into the modelling for completeness.*

The availability factor of SMRs was taken as 92% for all three runs, and a construction period of 4.5 years was used to inform cost calculations. For other performance characteristics and build constraints, ETI's baseline assumptions were used (see section 6.2).

Other things being equal, the probabilistic values assigned to SMR costs would clearly influence their attractiveness. However, the various sensitivity runs explored earlier also highlighted the impact of wider system uncertainties on the deployment of SMRs. In the Monte Carlo process these impacts are captured by the fact that around 100 other variables are subject to probabilistic value assignments, not just SMR costs. Table 10 shows the uncertainty ranges for a selection of these.

| Year | **2010** | **2050 (mean)** | **2050 (range)** |
|---|---|---|---|
| Unit | £/kW(e) | £/kW(e) | +/- % |
| **CAPEX CCGT with CCS** | 997 | 745 | +60 / -40 |
| **CAPEX H2 Turbine** | 590 | 500 | +30 / -30 |
| **CAPEX Large Scale Solar PV** | 1400 | 400 | +39 / -44 |
| **CAPEX Nuclear (Gen III)** | 3800 | 3040 | +40 / -30 |
| **CAPEX Offshore Wind (fixed)** | 3000 | 1500 | +50 / -30 |
| **CAPEX Offshore Wind (floating)** | 3000 | 1261 | +50 / -30 |
| **CAPEX Onshore Wind** | 1490 | 1251 | +30 / -30 |
| | | | |
| **Gas Price (p/kWh)** | 1.5 p/kWh | 2.73 p/kWh | +63 / -50 |
| **UK Biomass Availability (TWh)** | 28 TWh | 140 TWh | +50 / -50 |

*Table 10 - Mean values (in 2010£) and uncertainty ranges for selected probabilistic variables.*

## Interpreting Monte Carlo results

The previous ESME run summaries in this report have each described an individual energy system resulting from a deterministic run. In each of these Monte Carlo runs, the model was configured to deliver 150 distinct energy system designs. Interpreting the results therefore requires a combination of averages and distributions. The summary tables for the following three runs describe average values over the 150 simulations, as do the core charts in the SESO spreadsheet (and in the Appendix). For distributions, additional charts and tables have been added to the SESO spreadsheet (and reproduced below) to provide insight into the variation in power sector design across the simulations.

A multiple linear regression was performed for each Monte Carlo run to understand how the probabilistic input variables have impacted on the output level of deployment of SMRs by 2050. A standardised regression coefficient (SRC) was calculated for each probabilistic input variable as a measure of importance. A p-value or significance level of 0.05 was applied as a threshold.

There are approximately 100 ESME inputs which are characterised as probabilistic distributions for Monte Carlo analysis. Many of them are specified to be correlated, for example variations in the costs of onshore and offshore wind (correlation of 70%) and variations in cost of small versus large cars with the same powertrain (correlation of 100%). Correlated variables with a variance inflation factor (VIF) greater than 10 were removed from the regression analysis, in order to show the importance of different drivers as distinguished from simple correlation effects. A similar multivariate linear regression analysis of an ESME Monte Carlo run was conducted by Pye et al, who provide further detail on their methodology[24].

It should be noted that when interpreting the full list of SRCs calculated by a regression analysis, less confidence can be placed in some of the results with lower impact scores, in particular for variables with p-values or VIF values close to the chosen thresholds for acceptability. We have filtered some of these from the results presented for clarity. This aspect of the regression analysis can be improved by larger Monte Carlo sample sizes, but care is always needed in interpreting the results.

## D2.6.1

*Selected Charts on p128*

| D2.6.1 | Near term SMR (Electricity only) |
|---|---|
| Key Amendments (from D2.3.2): | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** based on near term electricity only SMR data in Table 9.<br>**Date of first deployment 2031**.<br>**Mont Carlo mode with 150 simulations**. |

| Abatement Cost Summary (average of 150 simulations) | | |
|---|---|---|
| Annual (2050): | **42.6 £bn/yr** | *NPV: 10.8 £bn/yr, 1.1% of GDP* |
| | | |
| Cumulative (2010-2050): | **517.5 £bn** | *NPV: 194.4 £bn, 0.4% of GDP* |
| | | |

| 2050 Power Sector Summary (average of 150 simulations) | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Actual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| CCGT with CCS | 28 | 45% (85%) | 112 | 93 |
| Nuclear (Gen III) | 32 | 89% (90%) | 251 | 76 |
| Nuclear (SMR Elec) | 10 | 88% (92%) | 80 | 79 |
| Offshore Wind (fixed) | 8 | 40% (40%) | 29 | 73 |
| Offshore Wind (floating) | 9 | 45% (45%) | 36 | 58 |
| Onshore Wind | 11 | 27% (27%) | 26 | 78 |

[24] Pye, S., et al., An integrated systematic analysis of uncertainties in UK energy system transition pathways. Energy Policy (2015) http://dx.doi.org/10.1016/j.enpol.2014.12.031

| | | | | |
|---|---|---|---|---|
| Other | 21 | - | 101 | - |

From the summary table above, it is clear that the average of 150 simulations is broadly similar to many of the deterministic runs explored in previous sections. Large Gen III Nuclear and CCGT with CCS form the bulk of power capacity at around 30GW each, with the various forms of wind energy providing about another 30GW.

Nuclear SMRs (electricity only) are deployed to an average of 10GW. This average is higher than in many of the deterministic runs and is best explained by the fact that the mean capex level assumed in these Monte Carlo runs is even lower than the 'low capex' case D2.4.4, making SMRs a more favourable technology option in these runs. Also, it was shown previously that SMR capacity was inversely correlated with Large Gen III Nuclear deployment, and while Gen III capacity will vary across the simulations according to the probabilistic, the upper bound of 35GW always remains in place. As a result, although there are various simulations where large nuclear is deployed to a lower level, offering SMRs the opportunity to step in, by definition there are no cases where large nuclear is deployed above 35GW (which would be expected undermine the case for SMRs).

The average SMR capacity factor of 88% compares with an availability factor of 92%. This does not necessarily mean longer shut down periods, but periods when the SMRs are operating at part load.

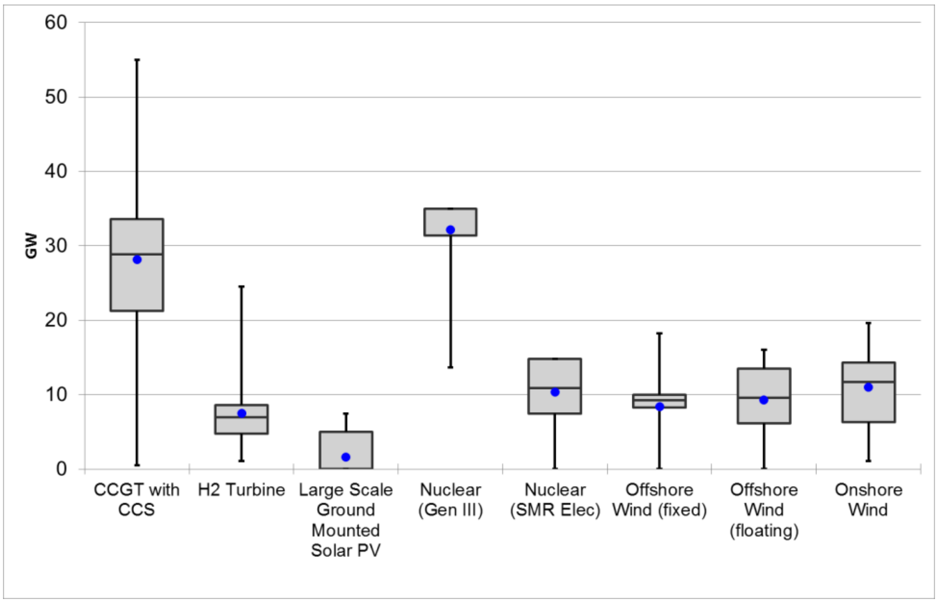


*Figure 11 - Boxes and Whiskers chart showing distribution of 2050 capacity for selected technologies in D2.6.1. Grey boxes indicated second and third quartiles, extending lines represent first and fourth quartiles. Blue dot represents mean capacity.*

Figure 11 shows a boxes and whiskers plot of power sector capacity across the 150 simulations. Consistent with the point made above, we can see that nuclear (Gen III) is concentrated around the 35GW mark, so much so that the top two quartiles have collapsed to that point and are not visible. The next quartile is visible showing the range 32-35, while the lowest quartile is showing a distribution down to a low of 13GW.

We can also see from this chart that Nuclear SMRs are also deploying against an upper limit, 15GW in this case (due to build rate limits). The top quartile are all deploying to this level, while the next two quartiles range from 8-15GW, and the lowest quartile ranges from 8GW down to cases with no deployment.

The most obvious feature of the boxes and whiskers plot is the large variation in the level of gas CCGT with CCS deployment. This technology has a capex range of +60/-40%, but compounding this is the variation in gas price (+63/-50%), and since fuel costs are a significant part of the total costs of CCGT with CCS, this can therefore produce a wide range of outcomes.

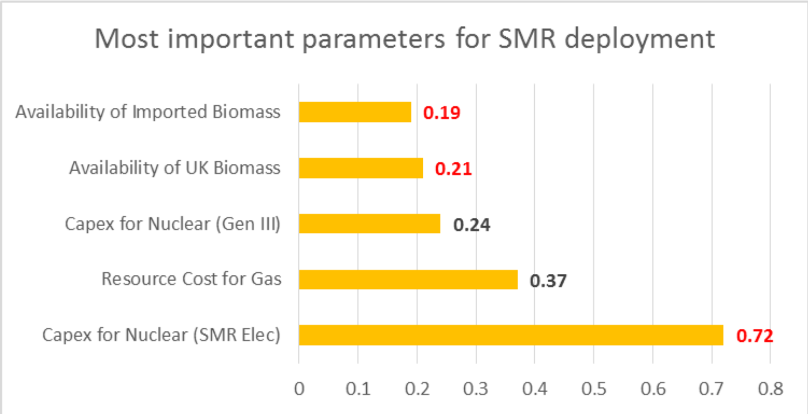


*Figure 12 - Multiple linear regression results for D2.6.1. Standardised regression coefficient (SRC) values are shown for the impact of various input variables on SMR deployment. SRCs are scored between ±1, with a larger absolute value implying a stronger impact. A negative score implies a negative correlation (bars indicate the absolute values, with red font indicating a negative correlation).*

Figure 12 shows the results of the regression analysis for this run, showing the five variables coming through as the most important factors in the deployment of SMRs. As expected, the capex of SMRs is a strong driver of the observed deployment levels, with the correlation being negative. This is the stand-out parameter from the chart, twice as important as the next factor, the cost of gas.

As shown in runs D2.4.14-16, the gas price can have a strong impact on SMR deployment via the impact this has on the attractiveness of CCGT with CCS. Since the range of deployment for this technology is so large (0-55GW as shown in Figure 11) it is clear why this would have a significant impact on SMR deployment (or any other marginal electricity generating technology).

The correlation with Capex Nuclear (Gen III) reinforces the findings of runs D2.4.10-11 which showed that higher or lower deployment of large nuclear has a bearing on the size of the gap that can be filled by SMRs.

The final two parameters relate to the ability of biomass to contribute to the energy system (whether sourced domestically or imported). Since biomass is valued so highly in ESME, due to its versatility and the opportunity to produce negative emissions in combination with CCS, the less biomass is available the more alternative low carbon technologies will have to be brought online, including SMRs.

## D2.6.2

*Selected Charts on p129*

| D2.6.2 | Near term SMR (CHP) |
|---|---|

| | |
|---|---|
| **Key Amendments (from D2.3.2):** | **Four generic SMR technology variants removed.**<br>**New single SMR technology added** based on near term CHP SMR technology data in Table 9.<br>**Date of first deployment 2031**.<br>**Mont Carlo mode with 150 simulations**. |

| **Abatement Cost Summary (average of 150 simulations)** | | |
|---|---|---|
| Annual (2050): | **40.7 £bn/yr** | *NPV: 10.3 £bn/yr, 1.1% of GDP* |
| | -1.95 £bn/yr | vs D2.6.1 |
| Cumulative (2010-2050): | **505.3 £bn** | *NPV: 190.7 £bn, 0.4% of GDP* |
| | -12.2 £bn | vs D2.6.1 |

**2050 Power Sector Summary (average of 150 simulations)**

| Generating Technology | GW | Actual Capacity Factor (of potential) | TWh | £(2015)/MWh |
|---|---|---|---|---|
| CCGT with CCS | 22 | 44% (85%) | 86 | 94 |
| Nuclear (Gen III) | 31 | 88% (90%) | 241 | 76 |
| Nuclear (SMR CHP) | 14 | 70% (92%) | 86 | 104 |
| Offshore Wind (fixed) | 7 | 40% (40%) | 22 | 72 |
| Offshore Wind (floating) | 6 | 45% (45%) | 24 | 57 |
| Onshore Wind | 10 | 27% (27%) | 24 | 78 |
| Other | 18 | - | 87 | - |

In this Monte Carlo run, CHP-capable SMRs prove highly attractive, with an average of 14GW being deployed across 150 simulations. Two thirds of those simulations deployed SMRs to the maximum 15GW (given build rate constraints), while the remainder deployed within the range 6-15GW.

It is important to note that the lower capacity factor for CHP SMRs does not imply that these plants are running only 70% of the year[25]. However the high levels of SMR and large Gen III nuclear capacity in these simulations does result in capacity factors below the design levels for each.

The ability of CHP SMRs to energise heat networks makes these networks more attractive, with an average of 50% more heat network capacity in this Monte Carlo run compared to D2.6.1 (with electricity only SMRs). The knock on impact of more heat network deployment is correspondingly lower electrification of heat. In turn, this means less capacity in the power sector, as shown in the summary tables. With less capacity overall, and CHP SMRs making a larger contribution, other technologies have a smaller role to play on average in this run. The (approximate) 30/30/30GW split between CCGT with CCS, Gen III Nuclear and Wind in D2.6.1 now becomes roughly 20/30/25GW.

These averages still cover a wide range of capacities across the simulations though, with Figure 13 providing a visualisation. An important insight from this run is that with a CHP-capability, SMR deployment is more robust against a wide range of variation across other technologies.

[25] . The metric used to calculate the capacity factor relates to the *electrical* output of the plant only, and when operating in CHP mode the SMRs suffer a 20% down rating in electrical output. In principle, if SMRs were only ever run in CHP mode (for the maximum 92% of the hours across the year) this would translate to a maximum electrical capacity factor of 74%. Since it must be left for ESME to determine the optimal mode of operation at different times of the year, the *effective* maximum electrical capacity factor cannot be known before runtime, and so we show the maximum potential if running in electric only mode.

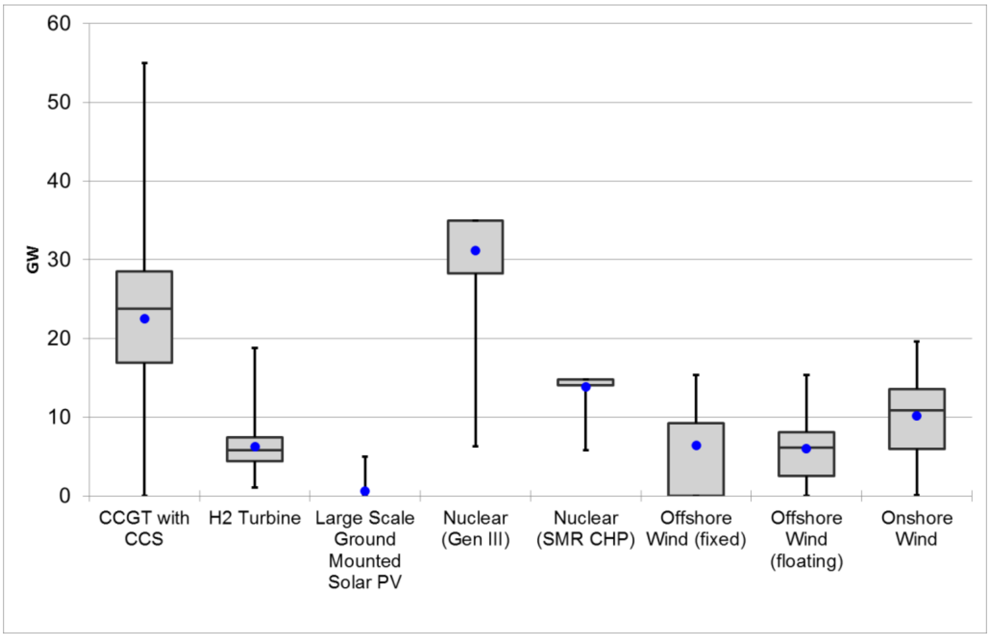


*Figure 13 - Boxes and Whiskers chart for D2.6.2.*

Figure 14 shows the results of the multiple regression analysis for this run. Once again the capex of SMRs comes out as the most important factor, although this time with a lower SRC value. This follows from the observation made above - that two-thirds of these simulations see CHP SMRs deployed to the maximum capacity of 15GW, meaning the potential of any probabilistic variables to drive *even more* deployment above this point cannot be explored. As a consequence, these variables will inevitably be assessed as having less importance in determining SMR capacity (we can imagine a more extreme case where all 150 simulations show the maximum capacity deployed, meaning there is simply no variation to assess).

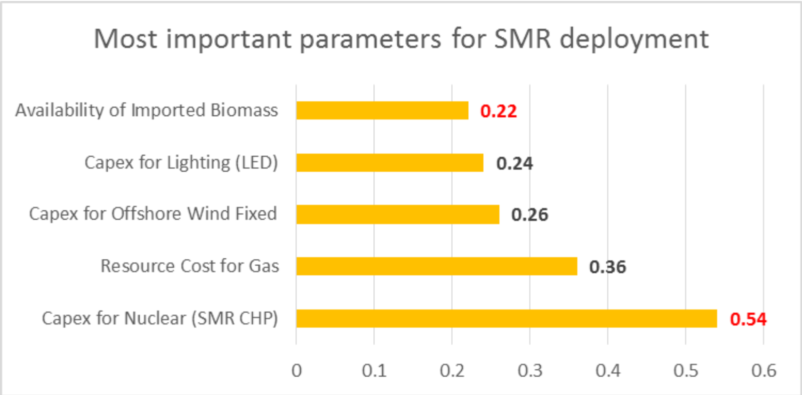


*Figure 14 - Multiple regression results for D2.6.2. SRC values are shown, red indicating negative correlation.*

The second most important factor is once again the cost of gas, via the impact on the attractiveness of CCGT with CCS. Interestingly capex for offshore wind appears in the list and, while the effect is smaller than others, this shows the intuitive ability to substitute these two power sector technologies. A higher cost for LED lighting will tend to prevent take up of this technology in favour of cheaper, less efficient CFL lighting (meaning higher electricity demand). This factor can therefore be taken as a proxy for higher electricity demand leading to higher SMR deployment. Finally the availability of biomass is once again among the list of important factors.

### D2.6.3

*Selected Charts on p131*

| D2.6.3 | Emerging tech SMR (Elec only) |
|---|---|
| Key Amendments (from D2.3.2): | **Four generic SMR technology variants removed.**<br>**New single electricity only SMR technology added** based on emerging electricity only SMR technology data in Table 9.<br>**Date of first deployment 2035**.<br>**Mont Carlo mode with 150 simulations**. |

| Abatement Cost Summary (average of 150 simulations) | | |
|---|---|---|
| Annual (2050): | **43.1 £bn/yr** | *NPV: 10.9 £bn/yr, 1.1% of GDP* |
| | +0.45 £bn/yr | vs D2.6.1 |
| Cumulative (2010-2050): | **521.6 £bn** | *NPV: 195.7 £bn, 0.4% of GDP* |
| | +4.06 £bn | vs D2.6.1 |

| 2050 Power Sector Summary (average of 150 simulations) | | | | |
|---|---|---|---|---|
| **Generating Technology** | **GW** | **Actual Capacity Factor (of potential)** | **TWh** | **£(2015)/MWh** |
| CCGT with CCS | 30 | 46% (85%) | 120 | 92 |
| Nuclear (Gen III) | 33 | 90% (90%) | 261 | 76 |
| Nuclear (SMR Elec) | 3 | 91% (92%) | 23 | 87 |
| Offshore Wind (fixed) | 11 | 40% (40%) | 37 | 75 |
| Offshore Wind (floating) | 11 | 45% (45%) | 44 | 59 |
| Onshore Wind | 13 | 27% (27%) | 29 | 79 |
| Other | 35 | - | 114 | - |

In this Monte Carlo run, the electricity only SMRs represented an ‘emerging technology’ with a higher capex, no learner rate, and delayed first deployment (and correspondingly lower maximum capacity). The lower average SMR deployment of 3GW is therefore to be expected. Almost half of the simulations had less than 1GW SMR capacity, and only 6 simulations reached the maximum deployment of 10GW.

Average capacities for CCGT with CCS and Nuclear Gen III are broadly similar to D2.6.1, but now the combined capacity of wind has crept up to an average of 35GW (from 30GW), while the remaining basket of technologies makes an average contribution of 35GW (up from 21GW).

Figure 15 shows a similar set of capacity distributions as for D2.6.1 albeit with a slightly higher centre of gravity for all technologies except SMRs.

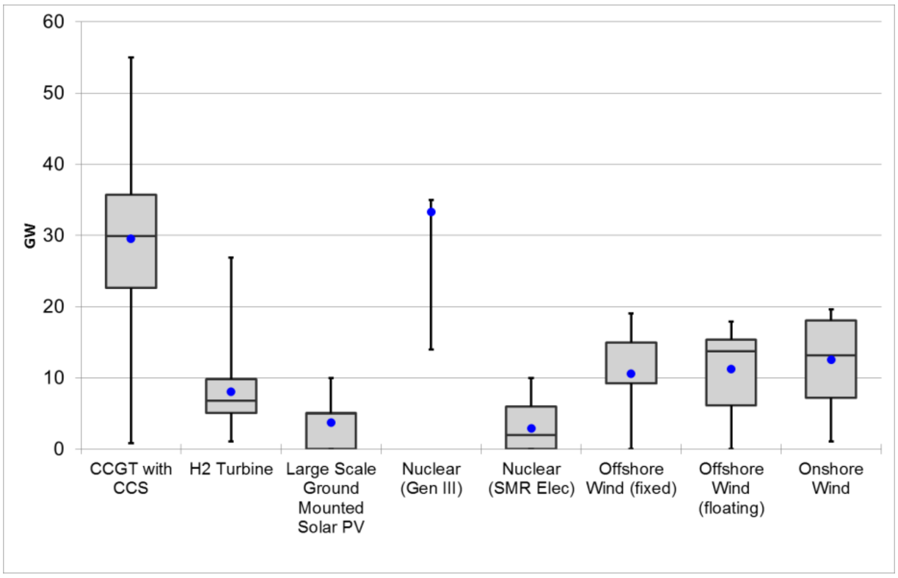


*Figure 15 - Boxes and whiskers chart for D2.6.3.*

Figure 16 shows the results of the multiple regression analysis. In the previous run D2.6.2, we saw that SMR capacity reached the upper bound of 15GW in two-thirds of cases. With only one third of cases showing any variation, the multiple regression analysis assigned less importance to the probabilistic variables. In the case of this run D2.6.3, the same is true in reverse – since around half of the simulations show little or no SMR deployment, the importance assigned to the predictor variables is reduced.

Only three variables stood out as credible in the context of this run. Once again, the capex of the SMR technology itself is seen as the key driver, while the gas price and biomass availability play a similar role as before in driving the wider system context within which SMRs are being selected (or not).

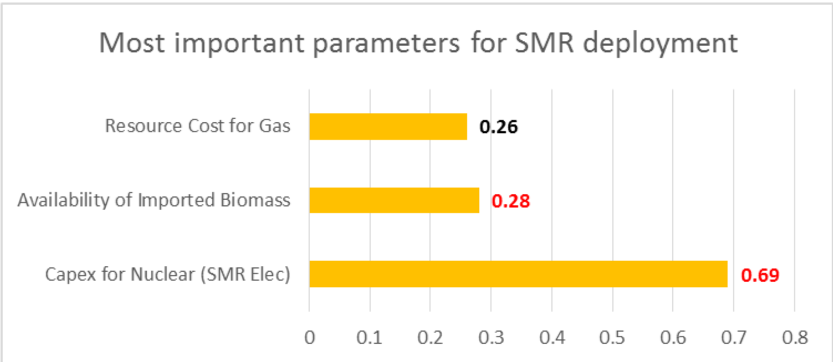


*Figure 16 - Multiple Regression results for D2.6.3. SRC values are shown, red indicating negative correlation.*

## 11. Conclusions

When assessing the contribution of SMRs to a low carbon UK energy system out to 2050, a whole-system perspective can add value in a number of ways. ETI's Energy System Modelling Environment (ESME) is a peer-reviewed tool with a proven track record in providing strategic analysis and insights to support government decision-making. The ESME dataset has been built up over a number of years with inputs from the ETI's portfolio of engineering projects.

By taking a 'policy-neutral' approach, ESME can identify those sectors better able to decarbonise at least-cost, so that other sectors which are more difficult to decarbonise, e.g. heavy industry, can do so more slowly. Also, while each technology deployed will have an associated cost, a whole-system approach can at the same time assess the wider benefits of this deployment.

A rapid decarbonisation of the power sector is a consistently robust feature of ESME and other UK energy system models. Not only does this achieve midterm emissions reduction in the most cost-effective way, it is also an important precondition for further reductions through electrification of heat, transport and industry.

Although an extensive range of electricity generating technologies are already represented in ESME, each of these has its own limitations, risks and uncertainties, meaning there is always the potential for a new technology - with the right costs and characteristics - to find a place in ESME's least cost energy system design. It is in this context that SMRs have been tested in this Project when deployed for electricity generation only, but also when configured for the supply of combined heat and power.

The various runs described in this report help to build an overall picture of the potential role for SMRs as part of a low carbon energy system in the UK. Some of the key messages have been drawn out within the individual summaries, and these are collected together here:

- The role and value of SMRs is critically dependent on the wider energy system configuration.
- The risks associated with other low carbon technologies suggest a role for SMR development as a 'hedge' option.
- SMRs with combined heat and power capability would provide wider system value while tapping into other revenue streams emerging as part of a whole system low carbon transition.
- While baseload generation offers a conventional revenue stream for SMRs, load following and wider system services can form a critical part of the SMR technology and commercial offering.
- In addition to these wider system needs, the role of SMRs out to 2050 will be impacted by technology-specific factors including: capital cost, date of first deployment and build rates.

### The role and value of SMRs is critically dependent on the wider energy system configuration.

Across the many scenarios explored within this project, SMRs have been tested alongside over 250 other technologies. In some cases, the assumptions adopted for those other technologies create favourable conditions for the deployment of SMRs, in other cases not. It is therefore critically important to consider the wider system context before concluding the role that SMRs might play.

As part of its energy system analysis activities, ETI examines the opportunity cost associated with different technologies. This is the difference in cost between a system with all technology options available, and one with the given technology removed from the dataset. The high opportunity costs of CCS and bioenergy have been a consistent feature of this analysis for a number of years, indeed these are an order of magnitude above that of other technologies. Still, a number of other technologies have significant opportunity costs, including district heating, large nuclear, offshore wind etc.

In a policy-neutral pathway, assuming perfect foresight, and with all the technology options available, the opportunity space for electricity-only SMRs tends to be crowded out by large nuclear reactors, carbon capture and storage (CCS) and a basket of renewables (dominated by offshore wind). Even where some capacity of SMRs is deployed in this context, comparison against a baseline scenario reveals that the reduction in total system cost through deployment of SMRs is modest. That is, SMRs are substitutable for other technologies at relatively low cost. This is especially true of electricity-only SMRs, but even CHP SMRs have been shown to be substitutable by other electricity and heat generating technologies in a manageable way.

Where there are barriers to the successful rollout of the various higher value technologies though, we have seen that SMRs can play a role in a reconfigured least cost solution.

## The risks associated with other low carbon technologies suggest a role for SMR development as a ‘hedge’ option.

While a techno-economic optimisation model will always deploy the most cost effective combination of technologies to satisfy demand (and other constraints), in reality technology deployment is not policy neutral, perfect foresight of technology and resource costs does not exist, and there are a variety of other risks associated with the key technologies that typically form part of a cost-optimal low carbon pathway.

This points towards the need to develop and prove a variety of technology options to ensure there is some combination capable of delivering an energy system that meets our needs in the event of technology failure, or as other factors emerge.

Across the scenarios explored here, there are sufficient grounds to consider SMRs as one of a number of important ‘hedge’ technologies that can make a valuable contribution under certain conditions. For example, if further cost reductions in offshore wind fail to materialise, the deployment of a new fleet of large nuclear reactors is stalled, or a CCS programme fails to materialise (or is deemed unattractive due to the risk of sustained high gas prices), SMRs could play a significant role in making up the shortfall in low carbon electricity.

From the many scenarios examined throughout this project, some of the key sensitivities around the role of SMRs are listed below.

### SMR sensitivity to large nuclear deployment

In the context of the electricity sector, SMRs offer similar benefits to large nuclear but at higher costs. If more sites are available for large reactors, these can be deployed on a sufficient scale as to undermine the case for SMRs. On the other hand when tighter limits are placed on large reactors, SMRs are one of the key technologies to provide replacement capacity. Importantly, there are limits to how much combined nuclear capacity can be deployed before the capacity factors of these technologies begin to decline. This is because electricity demand drops away at certain times of the year. In most of the runs in this Project with a high combined nuclear capacity, it is the SMRs which operate on a daily cycle. The one exception is the vendor 15 technology run, where the suggested fuel efficiencies of the SMRs were such that in modelling terms it was deemed more economical to keep those running, and to cycle the large nuclear instead.

It is important to note that high levels of deployment of large nuclear reactors remains dependent on site availability and cost competitiveness. ETI have assumed capex levels of £3800/kWe in the near term falling to £3000/kWe by 2050 due to learning, consistent with government publications. This compares with the approximately £5000/kWe implied by the CfD arrangement for a ‘first of a kind’ plant at Hinkley Point C.

### SMR sensitivity to gas price

When constraints are placed on deployment of Gas CCGT with CCS, we see increased SMR capacity as part of a reconfigured cost optimal solution. The optimal capacity of CCGT with CCS is itself highly sensitive to the price of gas. The optimal capacity of SMRs is therefore highly sensitive to the cost of gas through the impact on the attractiveness of CCGT with CCS.

### SMR sensitivity to biomass availability

ESME places a high value on biomass, typically developing the UK resource supply to the maximum available, as well as importing considerable quantities from overseas in later years. This is in large part due to the potential for negative emissions when combined with CCS. However, the biomass resource availability is uncertain, and is therefore modelled probabilistically in ESME. In those cases where we see less biomass in the system, and therefore less negative emissions, more comprehensive efforts must be made to fully decarbonise the energy system, including reducing residual emissions from Gas CCGT with CCS. In the ‘low biomass’ runs then, the lower capacity of CCGT with CCS presents an opportunity for deployment of SMRs.

**SMRs with combined heat and power capability would provide wider system value while tapping into other revenue streams emerging as part of a whole system low carbon transition.**

The whole system perspective followed by ESME identifies the clear opportunity for minimising cost through the interaction of a number of energy vectors, rather than a blanket ‘all electric’ approach across the energy system. As part of this, although the electrification of heat is likely to play an important role in decarbonising energy use in our buildings, ESME assesses district heat networks as offering a more cost-effective approach for many homes, particularly in dense urban areas. As such, there is a potentially significant opportunity for any technology that can energise heat networks in a cost effective way. The CHP-capable SMRs tested in this project are potentially a very cost effective low carbon heat source, whose investment case is strengthened by the revenues from the electricity co-product.

In D2.3.2, the Baseline run with SMRs, it was left to ESME to select the optimal SMRs from a selection of four designs, and the only design chosen was the ‘Baseload CHP’ SMR variant, implying that under the conditions assumed - where district heat networks are able to be built - the markup on capex is a price worth paying to ensure the SMRs can energise heat networks. However, it cannot be taken for granted that all SMR technologies will be designed for CHP, thus we tested cases where district heating is available but SMRs are deployed on an electricity-only basis. Finally, in the case where district heat networks are not deployed (perhaps due to lack of investor confidence or consumer acceptance), a more comprehensive electrification of heat would be required. While this may be a suboptimal solution from a whole systems perspective, if those are the conditions into which SMRs are able to be introduced, then it is important to understand how this changes the economic case for this technology. Our summary of these three cases starts with the latter case.

### Without district heating, 'electricity only SMRs' may contribute to higher electrical generation needs

In cases where district heating is unavailable in ESME, space heating across the entire building stock is comprehensively electrified, resulting in: more household retrofits to reduce space heat demand, more heat pump installations supported by electric resistive heaters and within-building heat storage, higher electricity capacity and generation and local distribution grid reinforcement.

Large scale (Gen III) nuclear reactors remain the most cost effective option for baseload electricity in ESME, but the upper capacity of 35GWe of new large scale reactors by 2050 (due to siting constraints), means that additional capacity must be provided by other technologies. This presents an opportunity for SMRs, explored in the runs D2.4.1-5, which represent five cases in which no district heat networks were allowed.

With a central 'first operations date of a UK SMR' (2030) and a central capex, ESME deployed 4GW of SMRs by 2050. In the two cases exploring alternative earliest deployment dates, the same level of capacity was observed, suggesting ESME is not particularly sensitive to this assumption (when a central capex value is applied).

When lower capex was assumed, SMR capacity in 2050 was doubled to 8GW, while a higher capex resulted in SMRs dropping out of the system altogether, implying SMR deployment in an electricity only scenario is highly sensitive to capital cost assumptions.

All in all, compared to the opportunity cost for CHP SMRs in a district heating scenario (see below), the opportunity cost for electricity only SMRs in an 'all electric' heating scenario is more marginal, reflecting the low deployment and the fact that the power sector technologies are generally more easily substitutable.

However, since electricity is so critical to energy systems with no district heating, it is worth reflecting that in run D2.4.11 (although this is an energy system *with* district heating) the lower deployment of large nuclear opened up a significant opportunity for SMRs. Thus, assuming capital costs were sufficiently competitive, the role for SMRs in an 'electrified heat' scenario would likely be greater if the deployment of large nuclear reactors were to run into difficulty.

### With district heating, 'CHP-capable SMRs' are a robust feature of the cost-optimal pathway

Where ESME has been configured to allow the deployment of large scale district heat networks, there is considerable value to be gained from deploying CHP-capable SMRs. These SMRs can provide a significant volume of baseload electricity generation whilst simultaneously helping to energise heat networks with low carbon heat. In the baseline run D2.3.2, following central SMR assumptions, almost 9GW of SMRs were deployed by 2050.

Whereas in the 'no district heating' cases, a higher capex resulted in electricity only SMRs being left out of the system altogether, when the same 20% markup was applied in the district heating case (see D2.4.7), 4GW of CHP SMRs were still deployed by 2050. Indeed, even a markup of 35% on the capex failed to knock out CHP SMRs, with 2GW still contributing (see D2.4.12).

To be clear, other options for energising heat networks exist, including: heat recovery from large scale thermal power stations (excluding large nuclear plants), large scale marine-sourced heat pumps (e.g. from rivers, lakes, seawater); geothermal energy (where available). In the absence of CHP SMRs, these alternative technologies are sufficiently cost effective to ensure that ESME still chooses to deploy heat networks extensively. When CHP SMRs are available though, they tend to take a sizeable share of network hot water provision across the country. The competition for cost effective low carbon heat supply is much less intense than for low carbon generation and SMRs in the UK may therefore be seen strategically as a heat play and not an electricity one.

The 'system-wide' value of CHP SMRs is therefore seen as an attractive proposition in ESME, as evidenced by the level of deployment and costs savings versus a district heating scenario with electricity only SMRs. This is despite the apparently high LCOE values calculated for CHP SMRs. LCOE is a calculation of the levelised cost of *electricity only* and so, as a consequence of the 20% electricity down-rating suffered by SMRs when operating in CHP mode, the full cost of the technology (including CHP capex markup) is spread over fewer units of electricity. A more accurate measure of the system wide value of SMRs would take into account the real value of heat.

It is important to bear in mind though that the cost differential between district heating scenarios with or without CHP SMRs is modest compared to the additional cost of meeting our heating demand with no district heating whatsoever.

### With district heating, 'electricity only SMRs' play a smaller role

There is a clear narrative to be told about the role of electricity-only SMRs in a high electrification scenario. Similarly, the narrative is clear for CHP SMRs in a district heating scenario. A third case to consider is where electricity-only SMRs are the only variant available, but in a district heating scenario. Intuitively, electricity-only SMRs would be expected to suffer in a 'district heating' scenario, as the substantial increase in demand that accompanied the 'high electrification' scenario does not materialise. This was the condition adopted for the vendor technologies explored in the D2.5 runs.

The results of those runs suggest that if the cost and performance assumptions are as optimistic as stated by those vendors, electricity-only SMRs can still play a substantial role in a scenario with district heating. However, these runs do not constitute a like-for-like comparison with the baseline case using ETI's generic SMR data. As discussed above, even in a high electrification world, electricity-only SMRs were not deployed at all when capex was raised by 20%. A key lesson here is therefore to reiterate the sensitivity of electricity-only SMRs to capital cost assumptions.

The Monte Carlo runs described in section 10 of this report were all set up on the basis that district heating was part of the system. D2.6.1 explored electricity only SMRs, while D2.6.2 explored the role of CHP SMRs in the same context. The comparison between these two runs emphasises once again how much more robust the CHP SMRs are to cost variation and to variability elsewhere in the system.

### **While baseload generation offers a conventional revenue stream for SMRs, load following and wider system services can form a critical part of the SMR technology and commercial offering.**

The ability for SMRs to operate on a load following basis as part of a daily cycle would increase their value further by offering a wider set of system services beyond baseload energy. This need is driven in part by variation in demand, but may increasingly be driven by intermittent supply in high renewables scenarios.

There are many examples throughout this report of runs in which SMRs are required to operate below maximum capacity at certain times of the year, suggesting that in practice the flexible operation of SMRs is an important consideration in assessing their competitiveness versus large nuclear and renewables. This is especially apparent in those runs where favourable cost assumptions result in higher deployment of SMRs, on top of the 30GW+ capacity of large nuclear plants. Since there are periods of the year where electricity demand drops below this combined nuclear capacity, it is necessary to ramp down some of that capacity as part of a daily cycle.

In this context, the value of SMRs depends critically on system service provision, where the ability to load follow contributes to their competitiveness vs large nuclear and renewables.

One implication is that even where proponents claim SMRs can be designed with a higher capacity factor of 90% or even 95%, in any pathway with a high level of SMR deployment (in addition to large nuclear baseload capacity) it is likely that those higher capacity factors will not be realised.

As ever, ESME is interested in the system wide value of SMRs, as part of which it sees the benefit of having SMRs despite not being able to run them to their maximum capacity factor. However, operating SMRs with a reduced capacity factor will clearly have an impact on the levelised cost of electricity (LCOE) calculations and perhaps the attractiveness of SMRs to any potential investor (if the market is not designed to reward wider system value).

Moreover, in the case of CHP SMRs, it is important to understand that even when the installed capacity is operating at its maximum capacity factor, any hours spent operating in CHP mode will necessarily incur a down-rating in electrical output. So long as the value of heat is excluded from the LCOE calculation, this will tend to penalise the SMRs for operating in CHP mode.

In an earlier set of scenarios conducted internally by ETI, the SMR electricity annual capacity factor was shown to be dependent upon the combined capacity (GW) of large reactors and SMRs. That range of scenarios taken together suggest that:

- For a combined total nuclear capacity of up to 40 GW, both large reactors and SMRs are able to deliver electricity unconstrained at their design capacity factor
- With large reactors deployed at their limit of 35 GW and in addition ~15 GW of CHP SMRs in an energy system where district heating was deployed, the SMR electricity annual capacity factor for SMRs was around 85%
- With large reactors deployed at their limit of 35 GW and in addition more than 15 GW of CHP SMRs in an energy system where district heating was deployed, the electricity annual capacity factor for SMRs reduced below 85%

When deployed alongside significant capacity of large nuclear baseload, the value of SMRs would depend critically on system service provision, with the abilities to deliver a daily shaped power profile and operate within a band contributing to their competitiveness.

### High temperature process heat

The proposition from some proponents that emerging SMR technologies could play a role in hydrogen production was raised in section 1. It is the view of the ETI that a range of alternatives are available for hydrogen production that are better understood, available in the nearer term and therefore capable of being scaled up to the levels required as part of a cost-effective low carbon pathway to 2050.

**In addition to these wider system needs, the role of SMRs out to 2050 will be impacted by technology-specific factors including: capital cost, date of first deployment and build rates.**

As a capital intensive technology, a more optimistic capital cost profile clearly improves the prospects for SMRs to contribute as part of a least-cost low carbon energy system. As more optimistic SMR assumptions are explored (alongside system assumptions favourable to their deployment), 2050 SMR capacity comes up against two limiting factors: date of first commercial operation and annual build rates.

### SMR Date of First Deployment and Build out rate

From the range of scenarios in this Project using ETI's generic SMR cost data, the date of first (possible) operations does not appear to be a major sensitivity. This is because most of these runs show SMRs being deployed much later than they could be anyway. Similarly, the build rate tends not to constrain the majority of those runs.

By contrast, the more favourable cost assumptions adopted in some of the vendor runs and in the Monte Carlo runs result in a much higher level of SMR deployment, often at the bounds of the build rate limit. Clearly, in those cases, applying a higher build rate or earlier deployment date would enable higher total capacity to be achieved by 2050. In the vendor runs where this occurred, we chose to model a higher build rate out of curiosity, and higher capacity is indeed what we observe. It is important to note that the vendors themselves did not provide a view on possible build rates, hence ETI used the approach described in the ANT report of a first tranche of deployment at a lower build rate (to represent getting to NOAK costs), followed by faster deployment.

The first operations date for SMRs will have important implications for the interaction with other parts of the energy system. For example, if the roll out of district heat networks progresses well ahead of SMR deployment, developers of those networks will have to opt for other sources of heat in the meantime, potentially locking out CHP SMRs from those markets.

### CAPEX

SMRs, like large nuclear reactors, have a through-life cost profile that is dominated by front-end capital cost. Across the range of model runs conducted for this study, a large variation in SMR capex has been explored, and this has been shown to greatly impact on the cost-optimal deployment. Operating costs cannot be ignored however, as shown by the two vendor runs (D2.5.2 & D2.5.6) sharing the same level of capex but with very different operating cost assumptions.

## Probabilistic assessment of SMR Deployment (using TEA derived generic SMR data)

The various batches of scenarios conducted in this project culminated in a series of three probabilistic ESME runs (described in section 10), using a generic SMR dataset collated and synthesised by Project 1 from the provisional findings of the different projects in the wider TEA. This 'TEA generic SMR' data included: input from Project 3 on emerging technologies; first UK operations dates adjusted for vendor bias by Project 1; capex and opex costs adjusted for vendor bias by Project 1; and a learner rate derived by projects 5, 6 & 7.

For near term electricity-only SMRs, Project 1 provided a (central) capex of £3505/kWe (in 2010 GBP) for the first deployment from 2031, falling to £3329/kWe by 2050 (this represented a substantial reduction from the comparable 'ETI generic SMR' assumptions used in the earlier batch of scenarios i.e. £4750/kWe with no learner effect). In the probabilistic run where these electricity-only SMRs were available from 2031 (and where heat networks could be deployed), an average deployment of 10GWe of SMRs was observed in 2050 across the 150 simulations.

In a second probabilistic run, SMRs were made available from 2031 on a combined heat and power (CHP) basis, with cost and performance adjusted accordingly. In this case, where SMRs could support district heat networks, average deployment by 2050 was 14GWe (with most of the runs reaching the capacity limit of 15GWe).

In the third probabilistic run, the electricity-only SMR design represented an emerging technology, with a later first deployment date of 2035 and a capex markup applied. As a result, an average of only 3GWe was observed across the 150 simulations.

### Further analysis recommended to update baseline scenario and test SMR deployment

Section 4 outlined the approach taken to agree a baseline scenario for these runs. This built upon previous discussions between DECC and ETI in August 2015. Since that time, the Comprehensive Spending Review and related announcements have amounted to an energy policy ‘reset’, with profound implications for the least-cost pathway previously set out. The most significant change is the withdrawal of capital support for a CCS demonstration competition in the UK, meaning the demonstration projects assumed to occur in the baseline run are highly unlikely to go ahead. As a result, the commercial-scale deployment of CCS technologies from 2020 as represented in the baseline seems highly unlikely.

In addition to these policy changes, DECC has been working on a revised set of cost assumptions for electricity generation technologies, which are yet to be published. Since SMRs have been shown to be highly sensitive to the deployment of other technologies, it is important to check the findings of this report against these new costs. There is therefore a need to bring the baseline up to date with latest DECC assumptions and in the context of a delay to CCS deployment, to assess the impact on the potential role of SMRs. Given the attractiveness of CHP SMRs in the ETI baseline for example, these would be expected to become more attractive if other technologies are delayed or face higher costs. Electricity-only SMRs are less attractive than CHP SMRs but might become significantly more attractive with less competition from other generating technologies.

## 13. Glossary

| | |
|---|---|
| ANT | System Requirements for Alternative Nuclear Technologies (ANT) was an project funded by ETI to examine what SMRs would be required to do in terms of outputs, performance, availability and cost envelope to be of interest for potential deployment in the UK Energy System. |
| Availability Factor | For dispatchable technologies, the *maximum* percentage of the year that a technology is capable of operating at. For non-dispatchable technologies, the *average* percentage of the year that a technology is assumed to operate at. |
| Capacity Factor | The percentage of the year that a technology is observed to operate at in a given ESME run. For dispatchable technologies this must be less than or equal to the availability factor. For non-dispatchable technologies this must be equal to the availability factor. |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage |
| CHP | Combined Heat and Power |
| Director's Cut | Variant of the ESME release dataset, adopting the ETI's latest view on the potential of different technologies, this can include developing insights from ETI's in-progress technology projects. |
| ESME | Energy Systems Modelling Environment, ETI's internationally peer-reviewed whole energy systems model. |
| FOAK/ NOAK | First of a kind / Nth of a kind. FOAK costs represent the real-world expense of deploying a new technology for the first time. NOAK cost represents the cost that can be achieved after a period of learning through deployment. In ESME only NOAK costs are used. The additional 'wedge' of costs incurred in moving from FOAK to NOAK remain an important consideration for off-model analysis and reflection. |
| LCOE | Levelised Cost of Electricity. See Section 5 for further details of how LCOE has been calculated in this report. |
| PPSS | Power Plant Siting Study was an ETI funded project to explore the potential for deployment of Nuclear Small Modular Reactors at sites across the UK. |
| SESO | SMR Energy System Opportunity (SESO) model. Used to refer to the collection of discrete ESME runs conducted in this project. |
| SMR | Nuclear Small Modular Reactor. |

## 14. Appendix I: Key Assumptions

The various tables in this Appendix are collected from throughout the report and provide an indication of the key assumptions and adjustments made in each set of runs. For more context on the rationale behind these changes, see the relevant section in the body of the report.

### All deterministic runs (D2.3.x-2.5.x): Cost data for selected technologies

ETI's core ESME dataset contains over 250 technologies. A full description of the costs, characteristics and constraints relating to each of these would be prohibitive. For the purpose of exploring the role of Nuclear SMRs, the obvious technologies to understand more fully are those that typically appear in a least cost low carbon power sector pathway. i.e. the technologies that SMRs are seeking to displace.

The following table is reproduced from section 4 and provides a summary of key cost assumptions for selected electricity generation technologies underpinning the baseline run without SMRs, D2.3.1:

| Cost category | Capital | Fixed O&M | Variable O&M | Fuel | Capital | Fixed O&M | Variable O&M | Fuel |
|---|---|---|---|---|---|---|---|---|
| Year | **2010** | **2010** | **2010** | **2010** | **2050** | **2050** | **2050** | **2050** |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) |
| **CCGT** | 589 | 27.2 | 0 | 28.1 | 496 | 27.2 | 0 | 45.1 |
| **CCGT with CCS** | 997 | 52.3 | 0.4 | 30.5 | 745 | 52.3 | 0.4 | 46.2 |
| **H2 Turbine** | 590 | 30 | 0 | 0 | 500 | 30 | 0 | 0 |
| **Large Scale Solar PV** | 1400* | 50 | 0 | 0 | 400 | 15 | 0 | 0 |
| **Nuclear (Gen III)** | 3800 | 67.8 | 5.0 | 4.1 | 3040 | 67.8 | 5.0 | 8.4 |
| **Offshore Wind (fixed)** | 3000 | 86 | 0 | 0 | 1500 | 50 | 0 | 0 |
| **Offshore Wind (floating)** | 3000 | 86 | 0 | 0 | 1261 | 48.5 | 0 | 0 |
| **Onshore Wind** | 1490 | 17.6 | 0 | 0 | 1251 | 17.6 | 0 | 0 |

*SESO Baseline cost assumptions for selected technologies (in real 2010 £GBP). Fuel costs are defined per unit of output electricity and are therefore a function of conversion efficiency. Hydrogen turbines have a fuel cost of zero as hydrogen is an endogenous product of the model, thus a cost cannot be derived until runtime when the particular hydrogen production technologies are chosen. Finally, Solar PV capital cost declines non-linearly (925 by 2015, 800 by 2020 then linearly to 400 in 2050).*

The following table summarises key assumptions on fuel costs. Ranges in 2050 are only used in the probabilistic runs (D2.6):

| Resource | *Native Unit* | *Base Line 2010* | *Ref Case 2050* | ESME Unit | Base Line 2010 | Ref Case 2050 | range 2050 Min | range 2050 Max |
|---|---|---|---|---|---|---|---|---|
| **Gas** | *$/mmbtu* | *6.6* | *12.0* | p/kWh | 1.50 | 2.73 | 1.36 | 4.44 |
| **Coal** | *£/tonne* | *70* | *80* | p/kWh | 0.94 | 1.07 | 0.54 | 1.34 |
| **Liquid Fuel** | *p/L* | *38.4* | *52.5* | p/kWh | 4.11 | 5.62 | 3.99 | 7.22 |

## D2.3.2 Baseline with SMRs: Cost data for ETI's Generic SMR technology

The following table summarised the key cost assumptions used as part of ETI's Generic SMR representation and introduced into ESME as part of the baseline run with SMRs, D2.3.2:

| Cost category | Capital | Fixed O&M | Variable O&M | Fuel | Capital | Fixed O&M | Variable O&M | Fuel |
|---|---|---|---|---|---|---|---|---|
| Year | 2010 | | | | 2050 | | | |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/MWh(e) |
| **Nuclear (Gen III)** | 3800 | 67.8 | 5.0 | 4.1 | 3040 | 67.8 | 5.0 | 8.4 |
| **Nuclear (SMR CHP Extraflex)** | 5615 | 140 | 5.0 | 5.8 | 5615 | 110 | 5.0 | 12.6 |
| **Nuclear (SMR CHP)** | 4950 | 135 | 5.0 | 5.8 | 4950 | 105 | 5.0 | 12.6 |
| **Nuclear (SMR Elec Extraflex)** | 5415 | 135 | 5.0 | 4.6 | 5415 | 105 | 5.0 | 10.1 |
| **Nuclear (SMR Elec)** | 4750 | 130 | 5.0 | 4.6 | 4750 | 100 | 5.0 | 10.1 |

*Table 11: The cost assumptions (2010£) used for the SMR technologies, and for comparison Nuclear (Gen III). Although SMRs cannot be deployed from 2010, placeholder costs are necessary for all years in ESME.*

## D2.4.x Sensitivity scenarios: key adjustments

In the sensitivity runs described in sections 7&8, a range of adjustments were made either to the SMR data or to the wider system, as follows:

| Code | SMR assumptions | Other assumptions |
|---|---|---|
| **D2.4.1** | Central deployment date (2030);<br>Central capex; | no district heat |
| **D2.4.2** | Early deployment date (2025);<br>Central capex; | no district heat |
| **D2.4.3** | Late deployment date (2035);<br>Central capex; | no district heat |
| **D2.4.4** | Central deployment date (2030);<br>Low capex (-20%); | no district heat |
| **D2.4.5** | Central deployment date (2030);<br>High capex (+20%); | no district heat |
| **D2.4.6** | Central deployment date (2030);<br>Central capex; | (NB this scenario duplicates D2.3.2) |
| **D2.4.7** | Central deployment date (2030);<br>High capex (+20%); | - |
| **D2.4.8** | Central deployment and capex | CCGT and CCS slow/low deployment |
| **D2.4.9** | Central deployment and capex | Bio-energy slow/low deployment |
| **D2.4.10** | Central deployment and capex | Large nuclear deployed to the limit of site availability |
| **D2.4.11** | Central deployment and capex<br>Doubled limits on max build rates of SMR | Large nuclear low and slow |
| **D2.4.12** | Central deployment date (2030);<br>Very high capex (+35%); | - |
| **D2.4.13** | Central deployment date (2030);<br>Central capex, with learner rate from 2030-50 | - |

| | | |
|---|---|---|
| **D2.4.14** | Central deployment date (2030);<br>Central capex; | Low gas price |
| **D2.4.15** | Central deployment date (2030);<br>Central capex; | High gas price |
| **D2.4.16** | Central deployment date (2030);<br>Central capex; | Low gas price |
| **D2.4.17** | Central deployment date (2030);<br>Central capex; | Slow progress on heat decarbonisation |

*Codes correspond to the results charts and tables delivered separately in the SESO model and the charts appendix.*

### D2.5.x Vendor data runs

In section 9 a set of runs were conducted using SMR data provided by prospective vendors (anonymised via Project 1).

| Vendor | CAPEX (£/kW) | | Fixed O&M (£/kW/yr) | | Variable O&M (£/kWh/yr) | |
|---|---|---|---|---|---|---|
| | **2010** | **2050** | **2010** | **2050** | **2010** | **2050** |
| **2** | 3037 | 3037 | 130* | 100* | 0.0050* | 0.0050* |
| **6** | 3037 | 3037 | 76 | 76 | 0.0043 | 0.0043 |
| **7** | 5640 | 5640 | 196 | 196 | 0.0066 | 0.0066 |
| **15** | 1530 | 1530 | 130* | 100* | 0.0050* | 0.0050* |
| **17** | 2804 | 2804 | 86 | 86 | 0.0050* | 0.0050* |
| **Generic** | 4750 | 4750 | 130 | 100 | 0.0050 | 0.0050 |

*Summary of the cost data (2010 GBP) used for the scenarios of near-term SMR technology vendor data and, for comparison, the cost data of the generic electricity-only SMR used in D2.4. Asterisks denote costs where the generic data was used because of lacking data in a vendor's response to the survey.*

Amongst the vendor datasets were some identified by TEA Project 3 as representing longer term emerging technologies. These were modelled with later first deployment dates and higher capex accordingly (see section 9 for more detail).

| Reactor Type | On-line date | Capital Factor | Comments |
|---|---|---|---|
| ***Generic SM-PWR*** | *2030* | *1.00* | *Reference* |
| **SM-HTR** | 2035 | 1.25 | Relies on fewer barriers than SM-PWRs but much lower power density and more complex fuel design. |
| **SM-SFR** | 2040 | 1.25 | Necessitates secondary circuit and extra barriers to limit sodium containment. |
| **SM-LFR (Pb coolant)** | 2050 | 1.25 | Reduced complexity related to coolant escape relative to sodium. However, necessitates more complex instrumentation and chemistry control systems, in addition to systems to ensure Pb coolant does not freeze. |
| **LFR (LBE coolant)** | 2050 | 1.50 | Similar to LFR (Pb coolant). However, coolant freezing is less of an issue with LBE. Main economic drawback is scarcity of bismuth. |

| | | | |
|---|---|---|---|
| **SM-MSThR Thermal spectrum MSR (limited on-line reprocessing)** | 2060 | 1.25 | No complex reprocessing plant but robust barriers to ensure coolant/fuel does not escape. |
| **SM-MSFR Fast spectrum MSR (extensive on-line reprocessing)** | 2070 | 1.50 | Requires a complex reprocessing plant and robust barriers to ensure coolant/fuel does not escape. |

*Table 12. The inputs on emerging technology clusters provided by Project 3.*

## D2.6.x Probabilistic runs using TEA Generic SMR data

In section 10 a series of runs are described which were conducted using ESME's probabilistic mode. The table below summarises the SMR assumptions delivered by Project 1 for use in Project 2.

| Cost category | **Capital** | **Fixed O&M** | **Variable O&M** | **Capital (Mean)** | **Capital (Range)** | **Fixed O&M (Range)** | **Variable O&M (Range)** |
|---|---|---|---|---|---|---|---|
| Year | **2010** | **2010** | **2010** | **2050** | **2050** | **2050** | **2050** |
| Unit | £/kW(e) | £/kW(e)/yr | £/MWh(e) | £/kW(e) | +/- % | +/- % | +/- % |
| **ETI Generic SMR (Elec only)** | 4750 | 130 | 100 | 4750 | - | - | - |
| **ETI Generic SMR (CHP)** | 4950 | 135 | 105 | 4950 | - | - | - |
| **D2.6.1 Near term SMR (Elec only)** | 3505 | 84 | 5 | 3329 | +35/-31 | +20/-23 | +4/-4 |
| **D2.6.2 Near term SMR (CHP)** | 3705 | 89 | 5 | 3529 | +35/-31 | +20/-23 | +4/-4 |
| **D2.6.3 Emerging SMR (Elec only)** | 4381 | 84 | 5 | 4381 | +35/-31 | +20/-23 | +4/-4 |

*Revised SMR costs for use in Monte Carlo runs (with ETI Generic SMR costs for reference). For mean values, the cost curve is flat from 2010 to first deployment, then sloping according to any learner rate out to 2050 (no learner rate assumed for emerging tech). For probabilistic values, a 2050 cost is selected from the range and the cost curve over the pathway interpolated accordingly*

In addition to these new SMR assumptions, around 100 other variables in ESME are subject to probabilistic value assignments. The table below shows the uncertainty ranges for a selection of these.

| Year | **2010** | **2050 (mean)** | **2050 (range)** |
|---|---|---|---|
| Unit | £/kW(e) | £/kW(e) | +/- % |
| **CAPEX CCGT with CCS** | 997 | 745 | +60 / -40 |
| **CAPEX H2 Turbine** | 590 | 500 | +30 / -30 |
| **CAPEX Large Scale Solar PV** | 1400 | 400 | +39 / -44 |
| **CAPEX Nuclear (Gen III)** | 3800 | 3040 | +40 / -30 |
| **CAPEX Offshore Wind (fixed)** | 3000 | 1500 | +50 / -30 |
| **CAPEX Offshore Wind (floating)** | 3000 | 1261 | +50 / -30 |
| **CAPEX Onshore Wind** | 1490 | 1251 | +30 / -30 |
| | | | |

| | | | |
|---|---|---|---|
| **Gas Price (p/kWh)** | 1.5 p/kWh | 2.73 p/kWh | +63 / -50 |
| **UK Biomass Availability (TWh)** | 28 TWh | 140 TWh | +50 / -50 |

*Mean values (in 2010£) and uncertainty ranges for selected probabilistic variables.*

# 15. Appendix II: Selected Charts

## D2.3.1 Baseline no SMRs

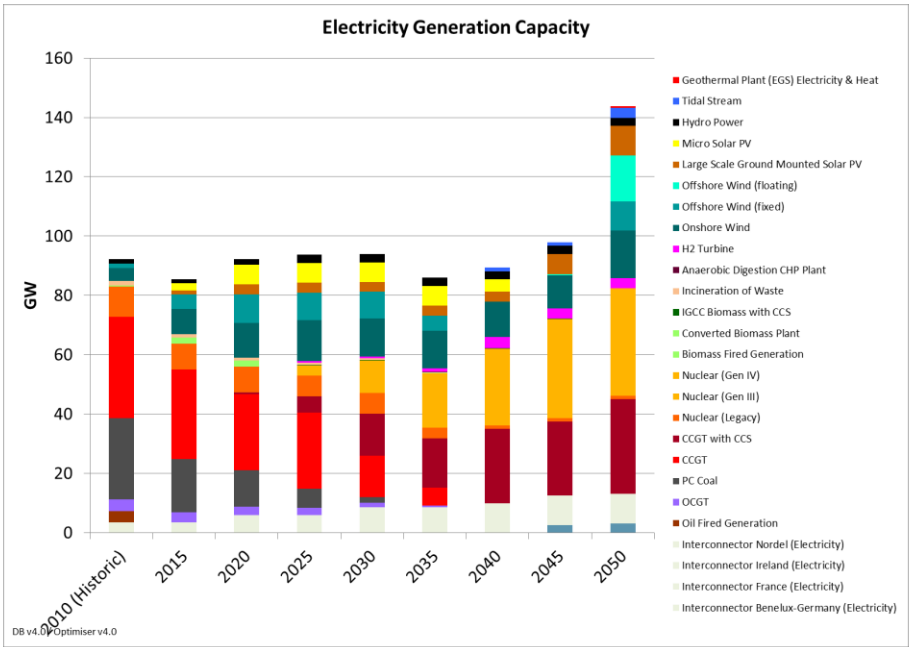


*Figure 17*

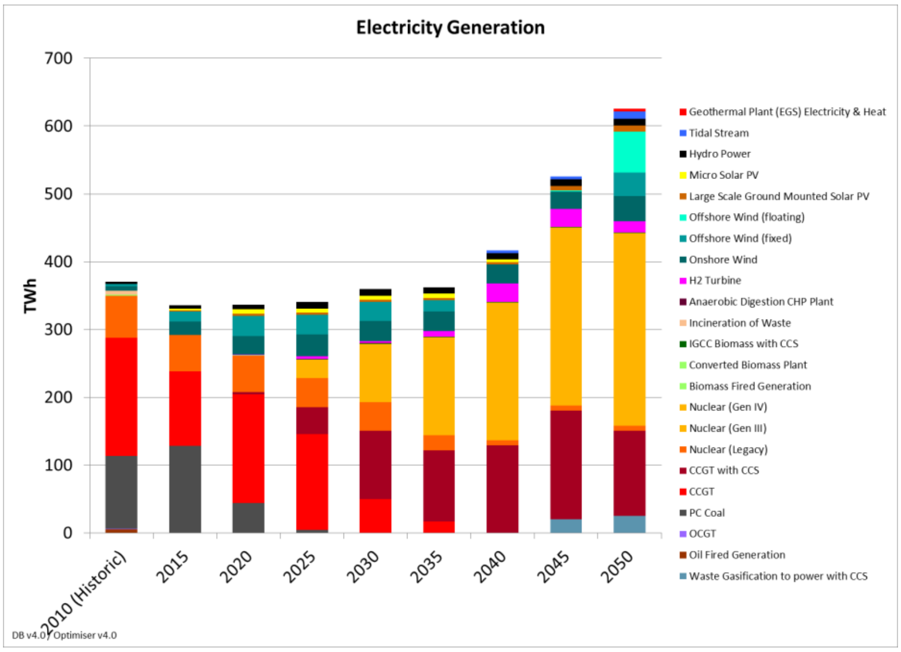


*Figure 18*

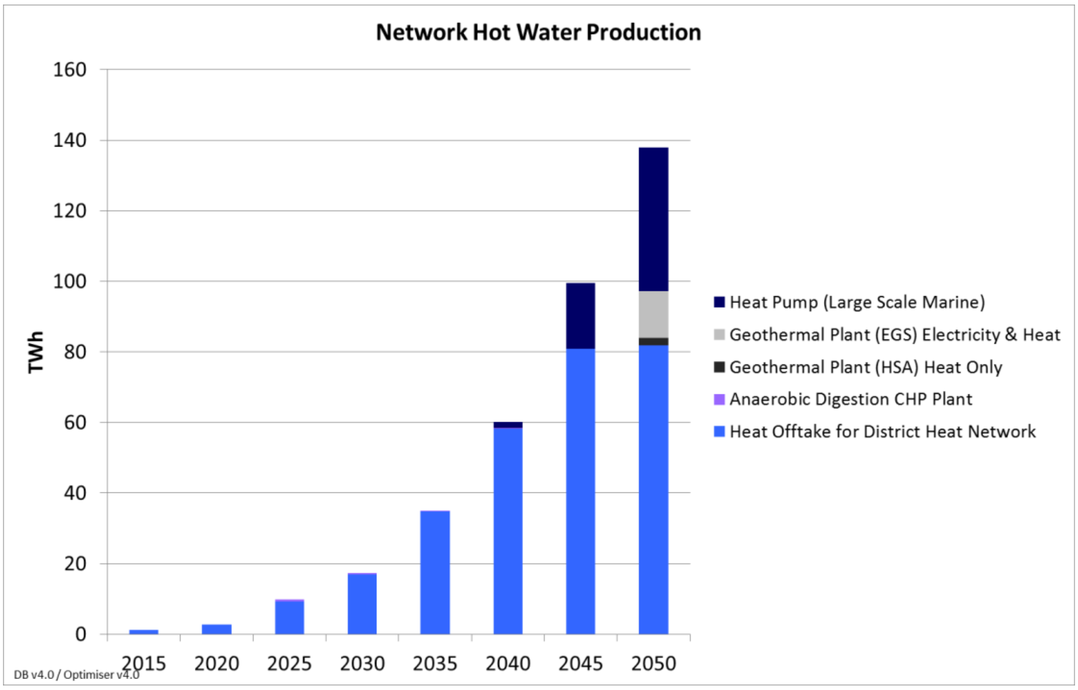
Network Hot Water Production
160
140
120
100
80
60
40
20
0
TWh
2015
2020
2025
2030
2035
2040
2045
2050
Heat Pump (Large Scale Marine)
Geothermal Plant (EGS) Electricity & Heat
Geothermal Plant (HSA) Heat Only
Anaerobic Digestion CHP Plant
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 19*

## D2.3.2 Baseline with SMRs

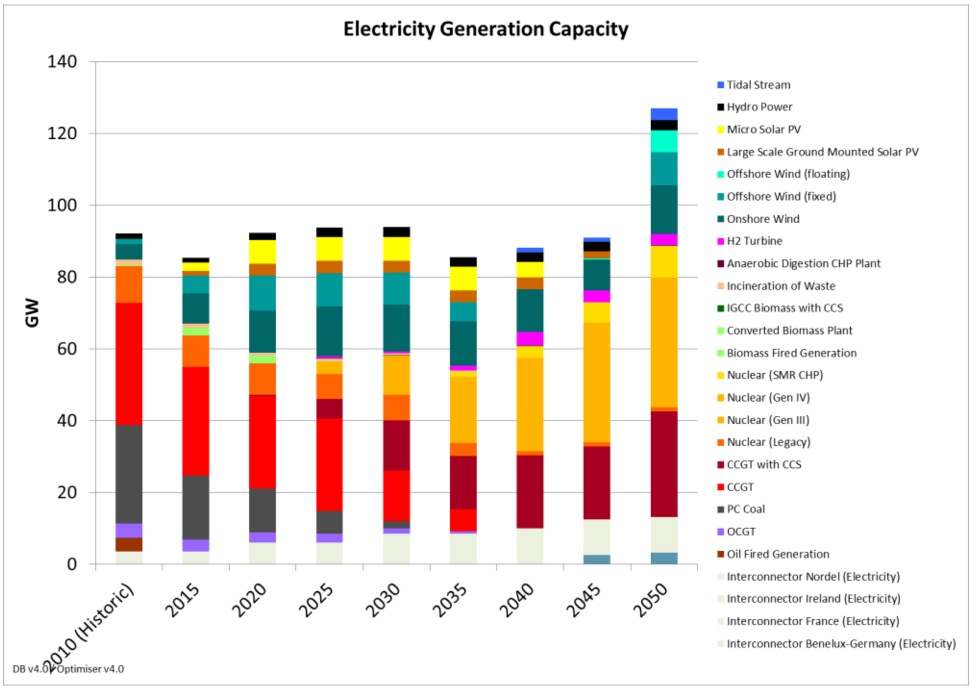


*Figure 20*

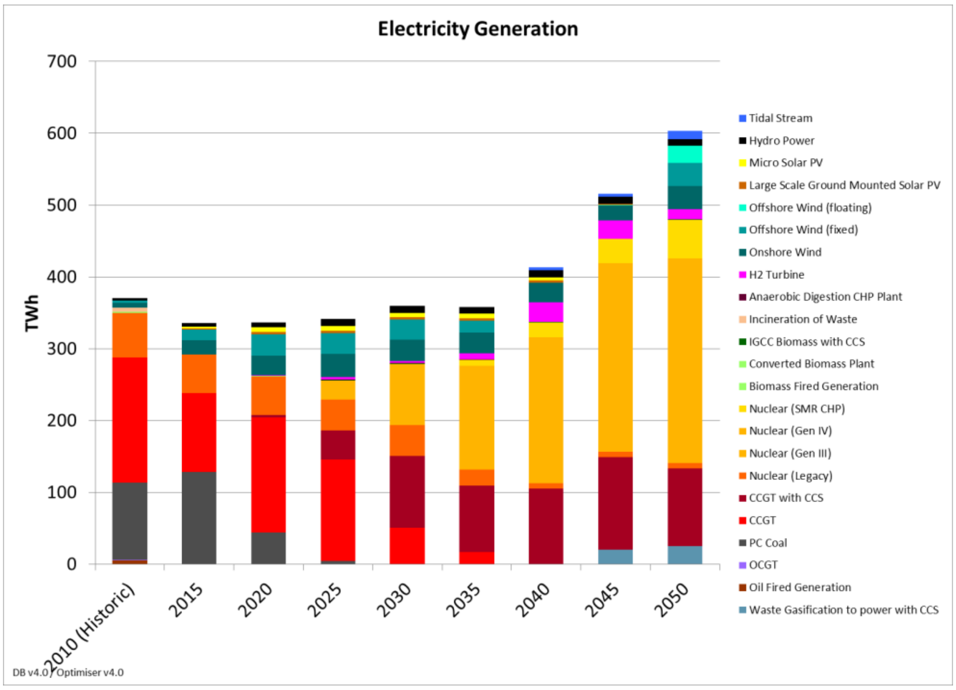


*Figure 21*

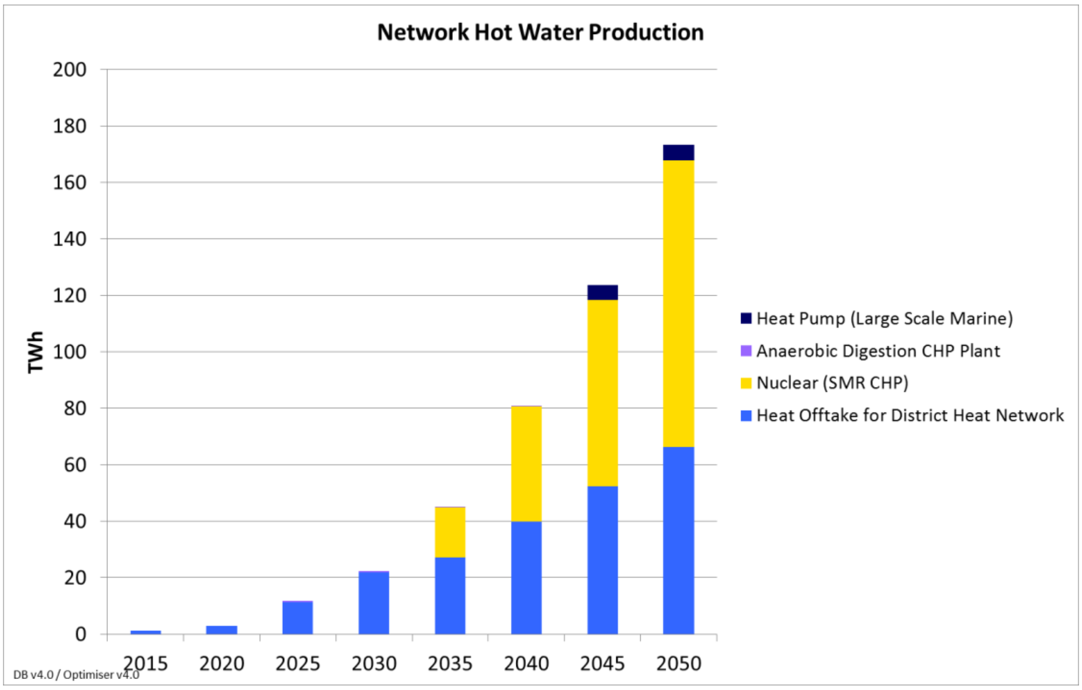
Network Hot Water Production
200
180
160
140
120
100
80
60
40
20
0
TWh
2015
2020
2025
2030
2035
2040
2045
2050
DB v4.0 / Optimiser v4.0
Heat Pump (Large Scale Marine)
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network

*Figure 22*

## D2.4.1 Central deployment date (2030); central Capex; no CHP

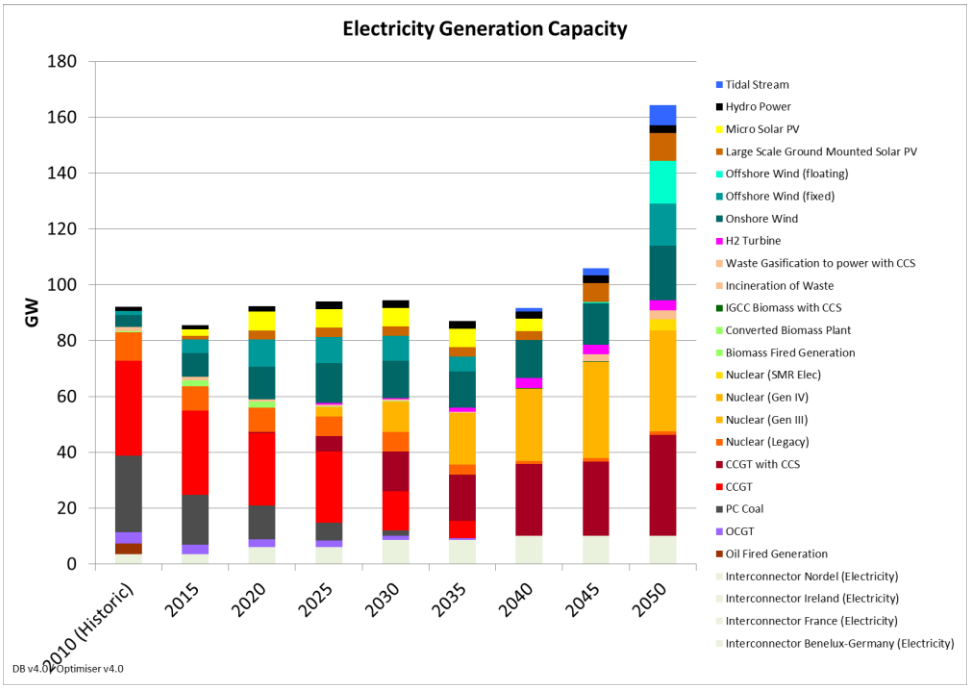


*Figure 23*

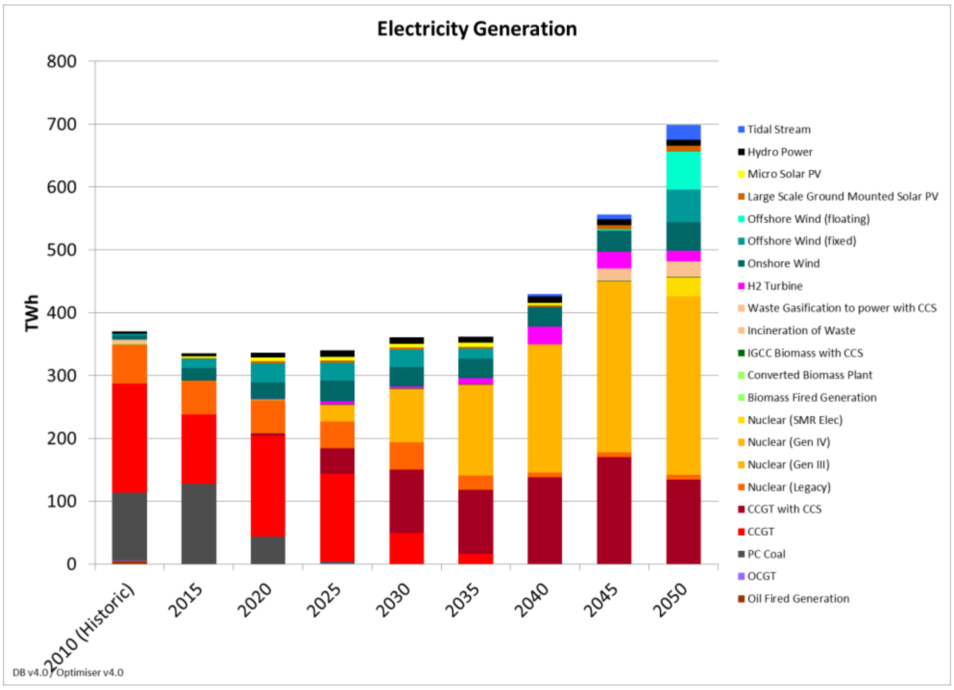


*Figure 24*

## D2.4.2 Early deployment date (2025); central capex; no CHP

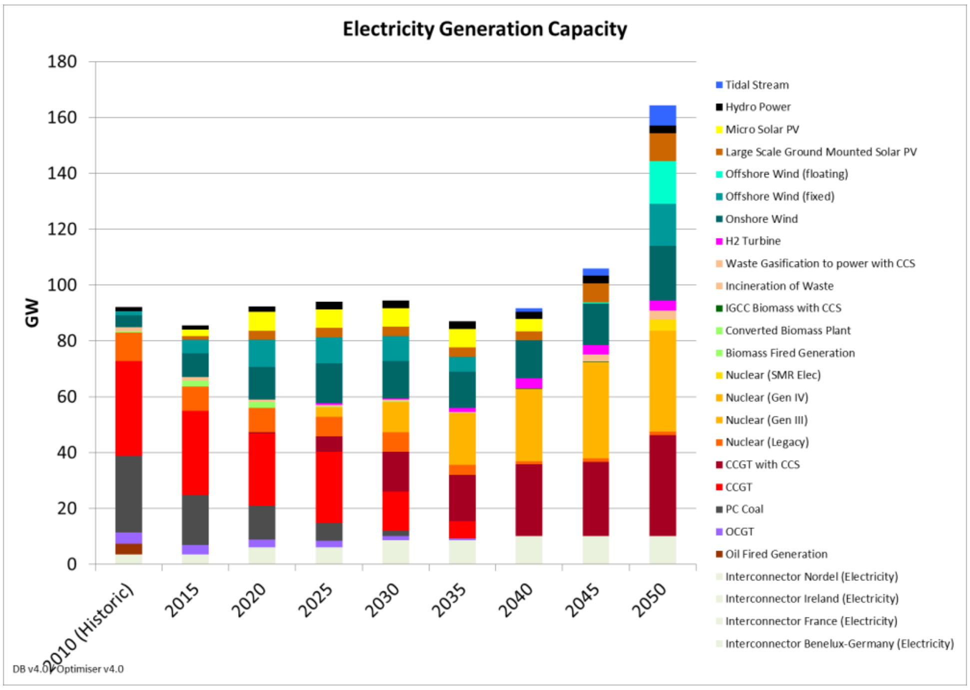


*Figure 25*

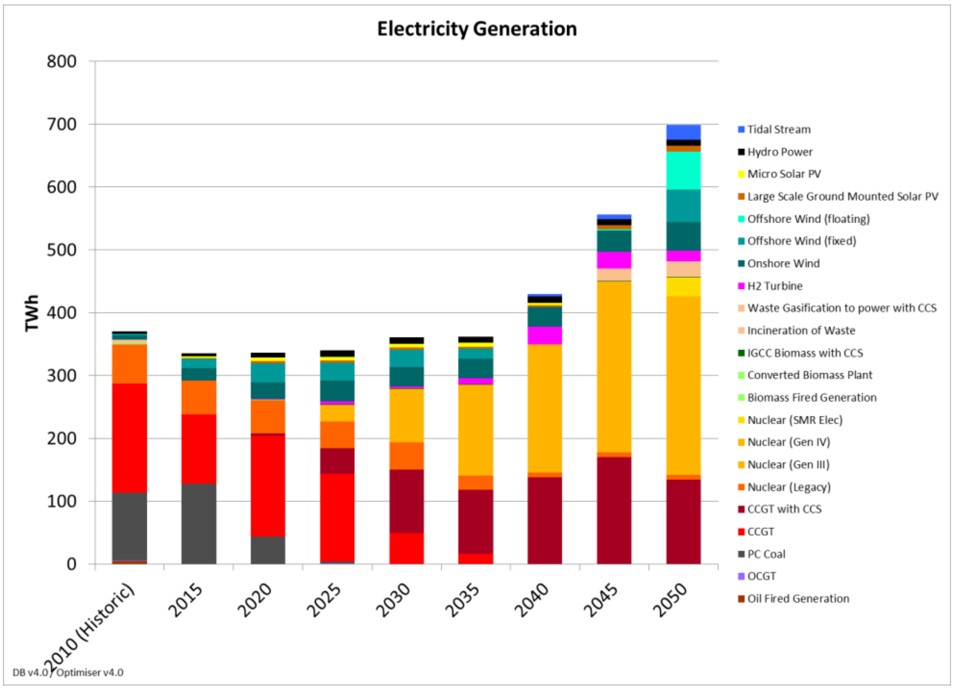


*Figure 26*

## D2.4.3 Late deployment date (2035); central capex; no CHP

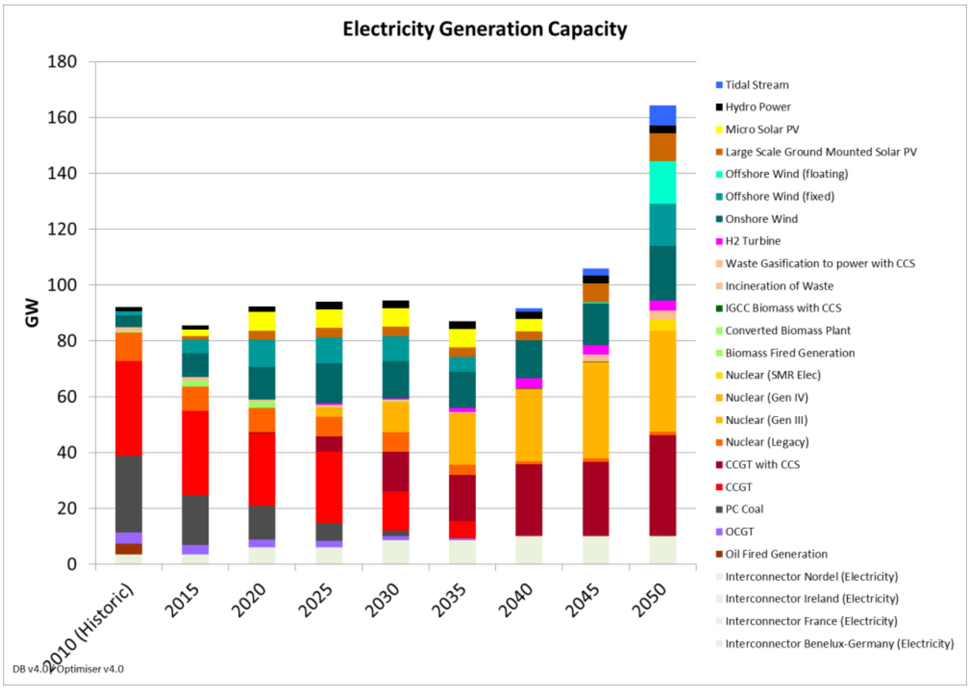


*Figure 27*

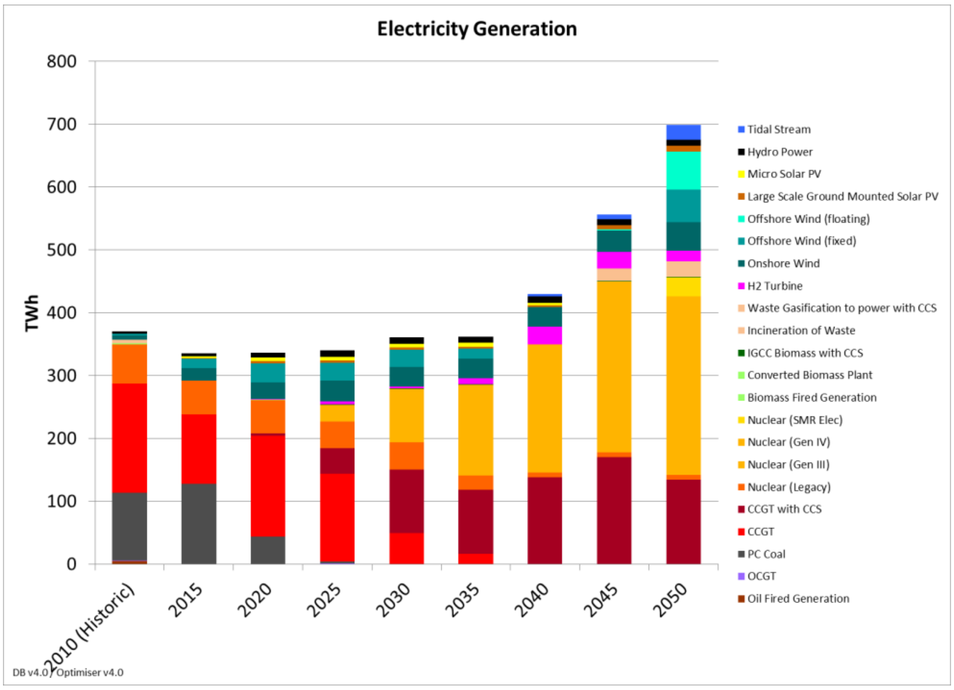


*Figure 28*

## D2.4.4 Central deployment date (2030); low capex; no CHP

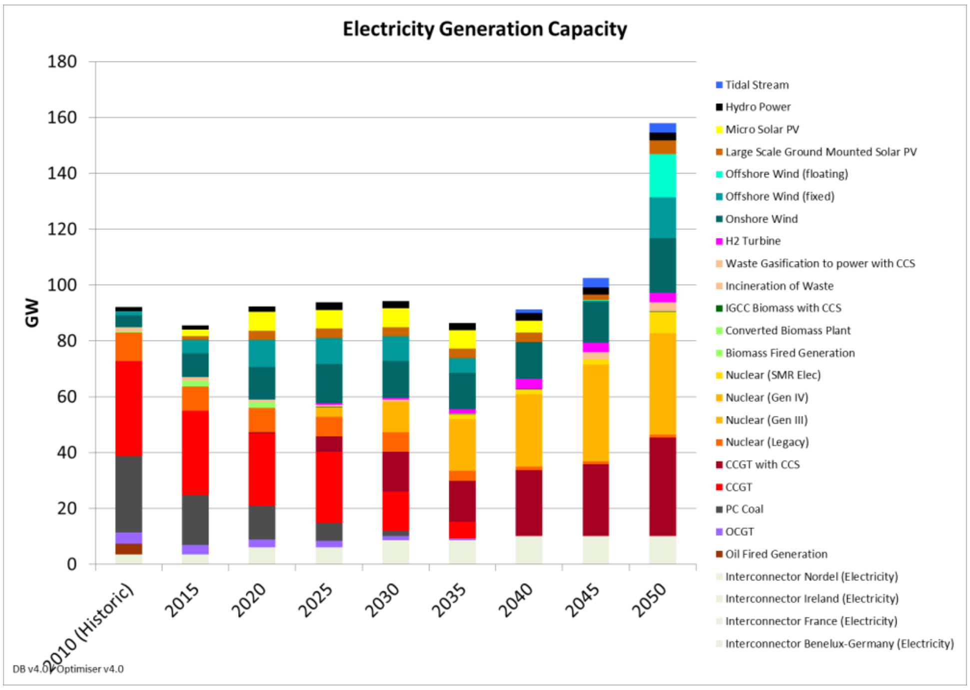


*Figure 29*

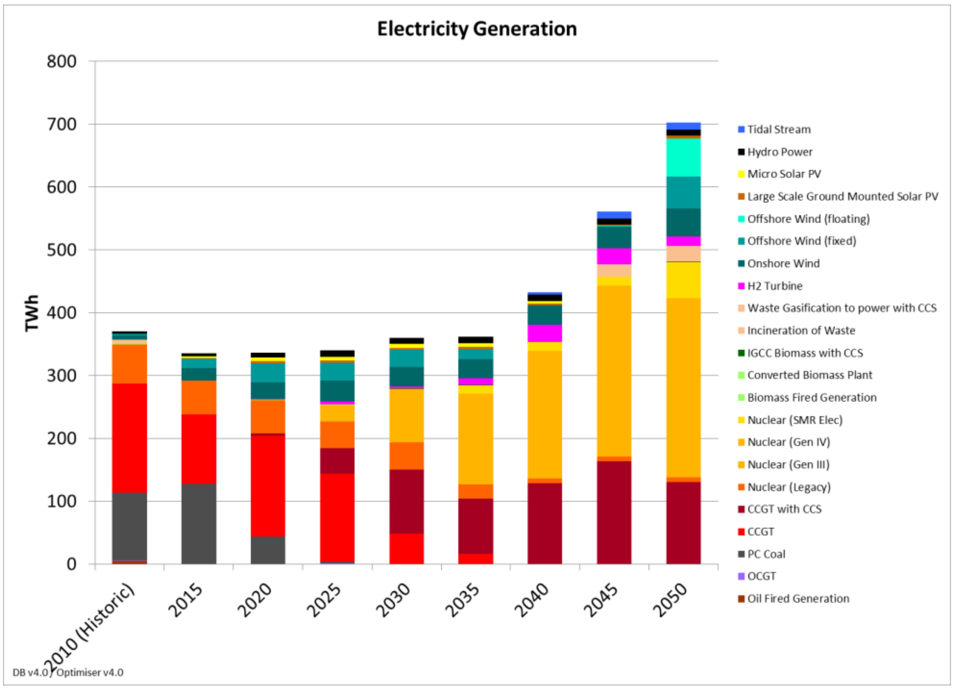


*Figure 30*

## D2.4.5 Central deployment date (2030); high capex; no CHP

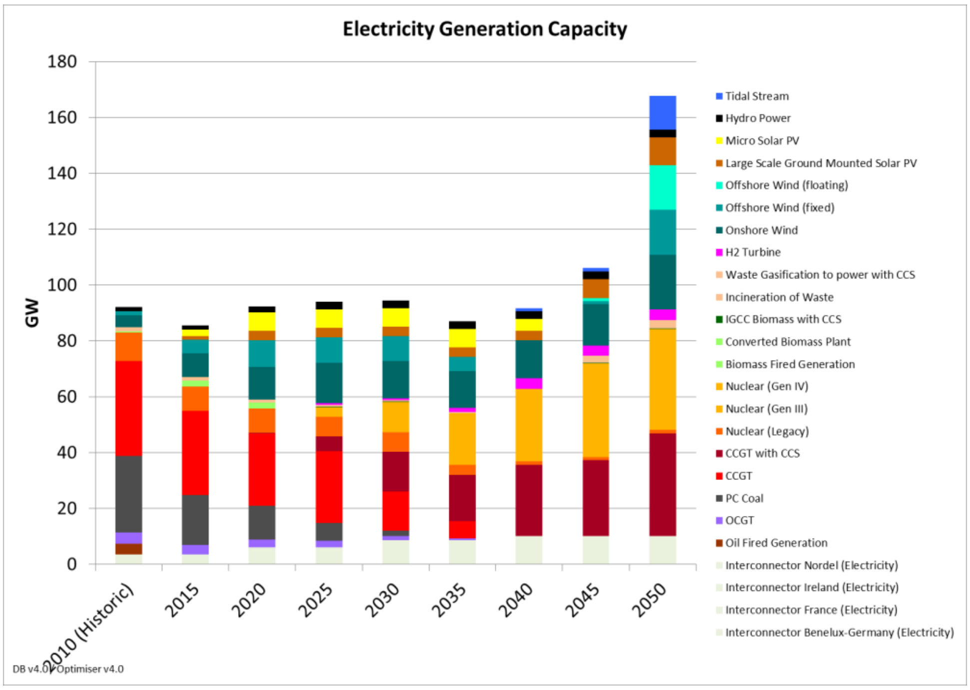


*Figure 31*

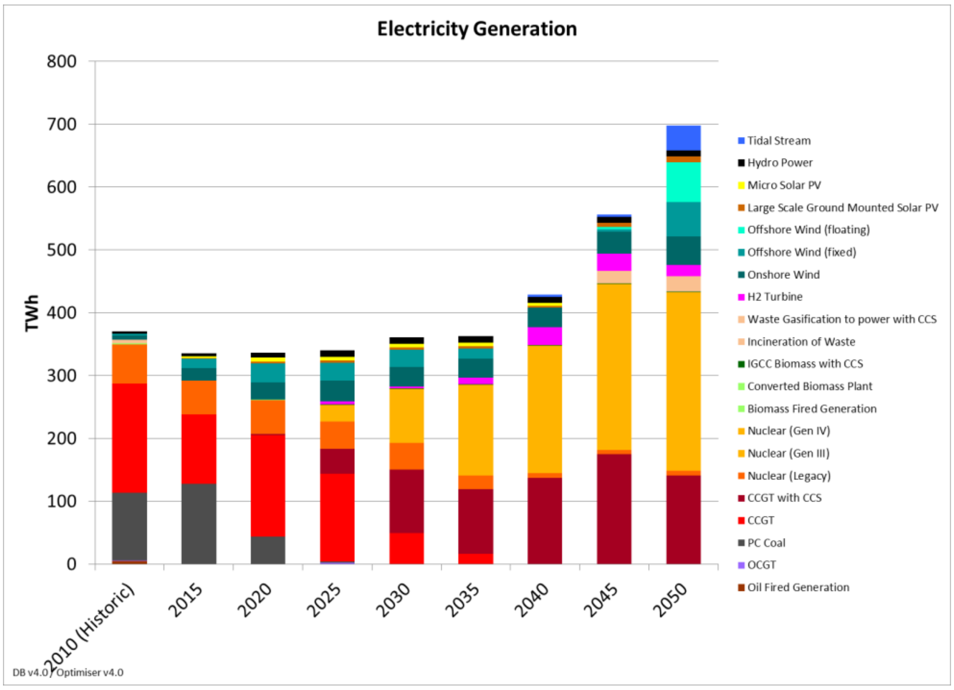


*Figure 32*

## D2.4.6 Central deployment date (2030); central capex; with CHP potential

(Identical results to D2.3.2, see earlier charts)

## D2.4.7 Central deployment date (2030); high capex; with CHP potential

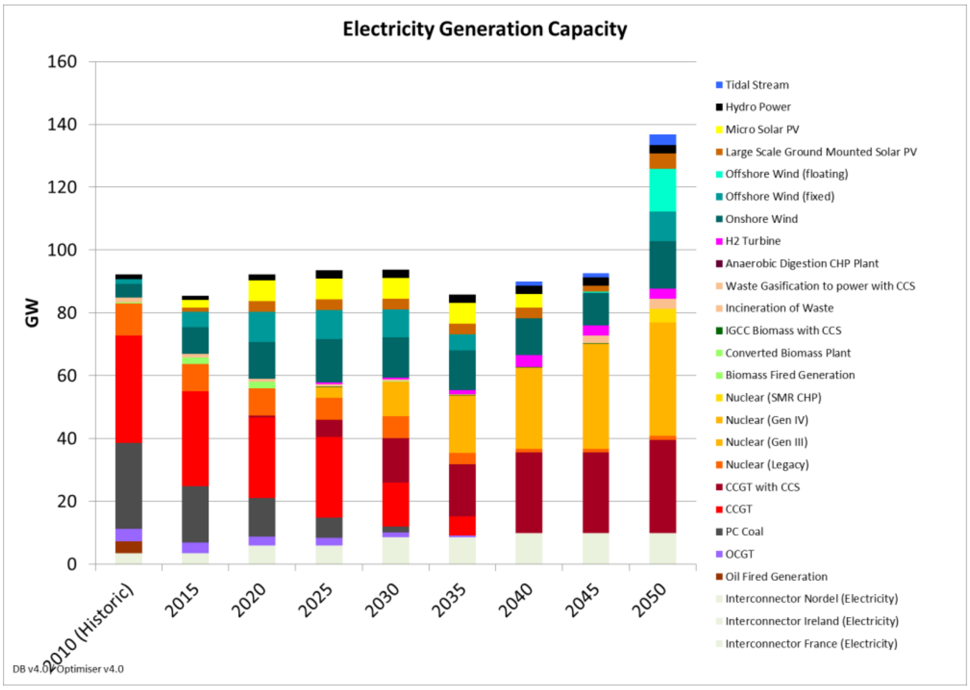


*Figure 33*

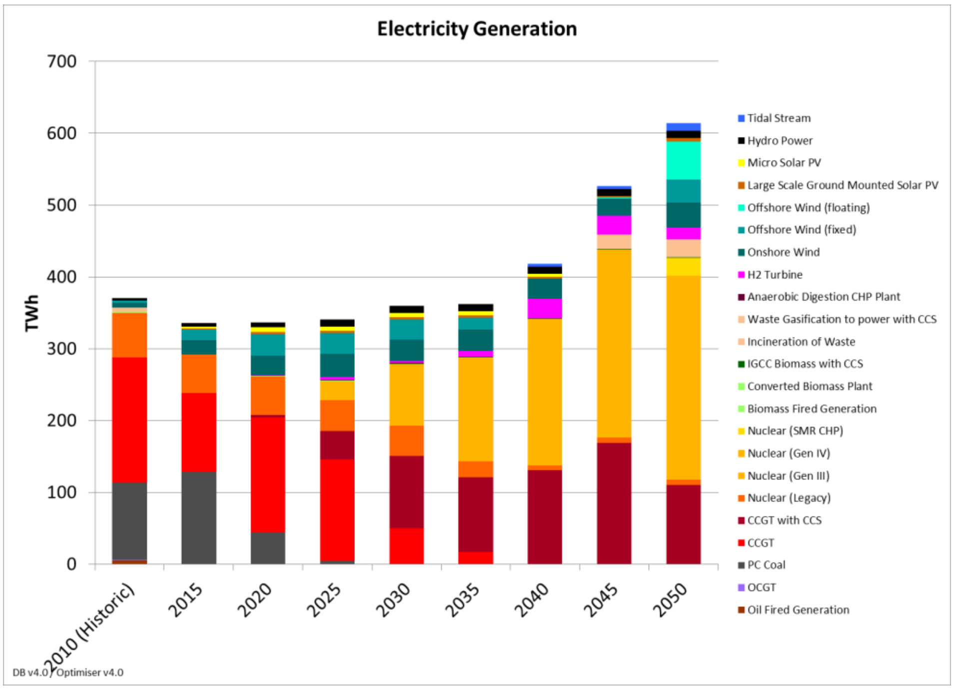


*Figure 34*

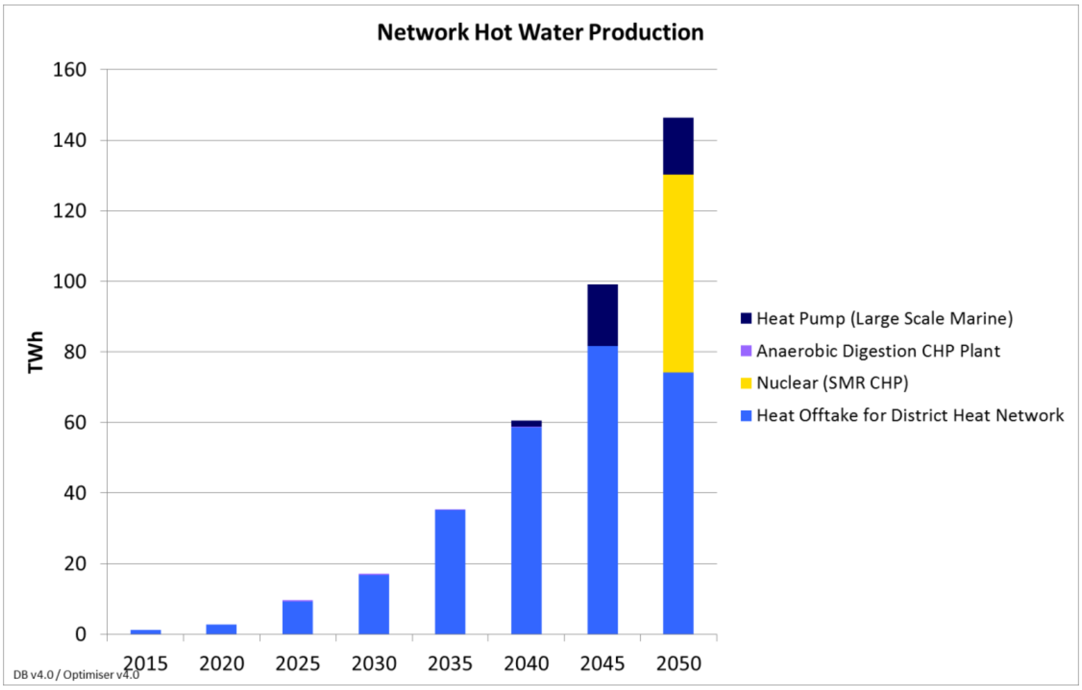
Network Hot Water Production
160
140
120
100
80
60
40
20
0
TWh
2015
2020
2025
2030
2035
2040
2045
2050
Heat Pump (Large Scale Marine)
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 35*

## D2.4.8 Gas CCGT and CCS slow/low deployment (SMR: central deployment and capex)

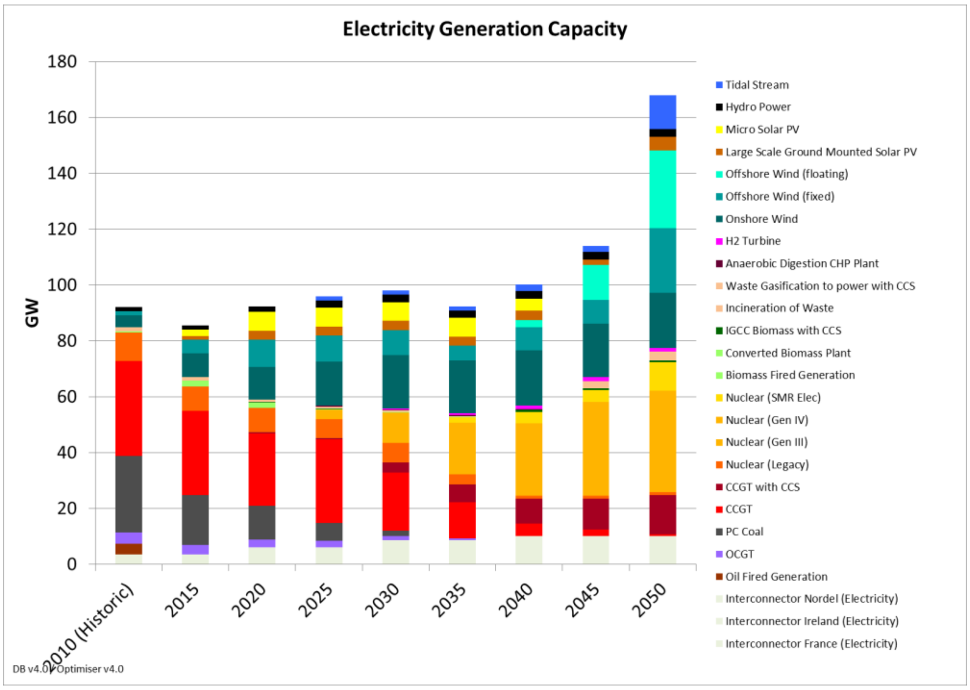


*Figure 36*

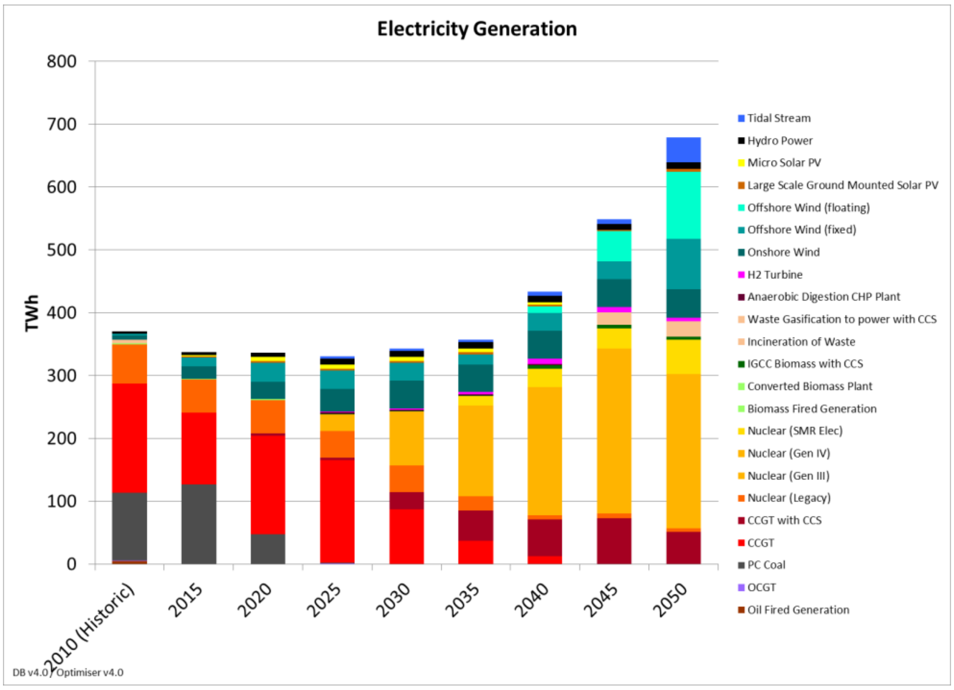


*Figure 37*

## D2.4.9 Bio-energy slow/low deployment (SMR: central deployment and capex)

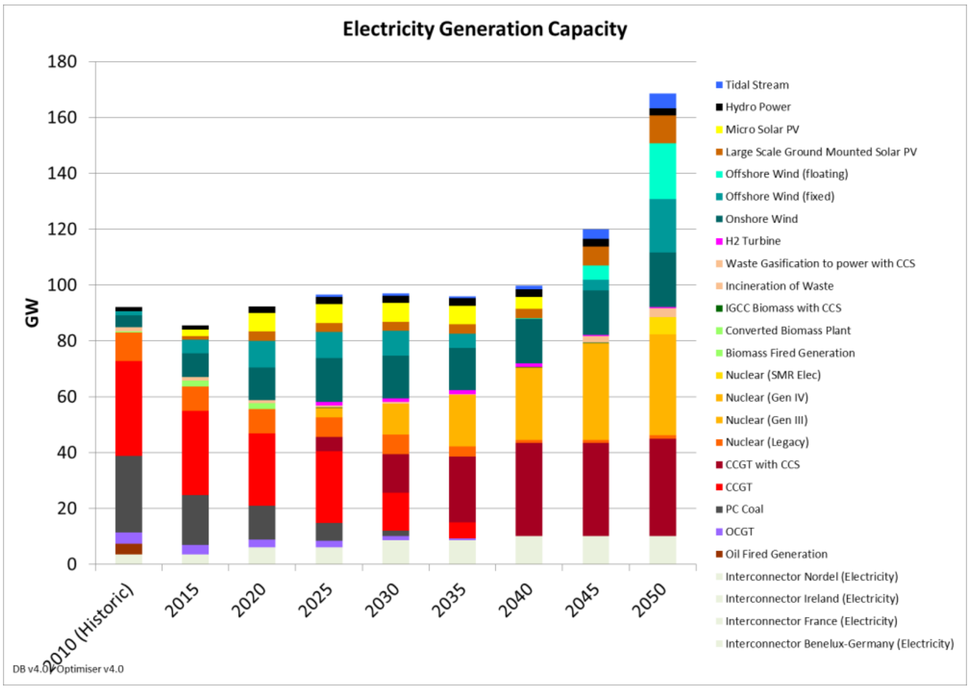


*Figure 38*

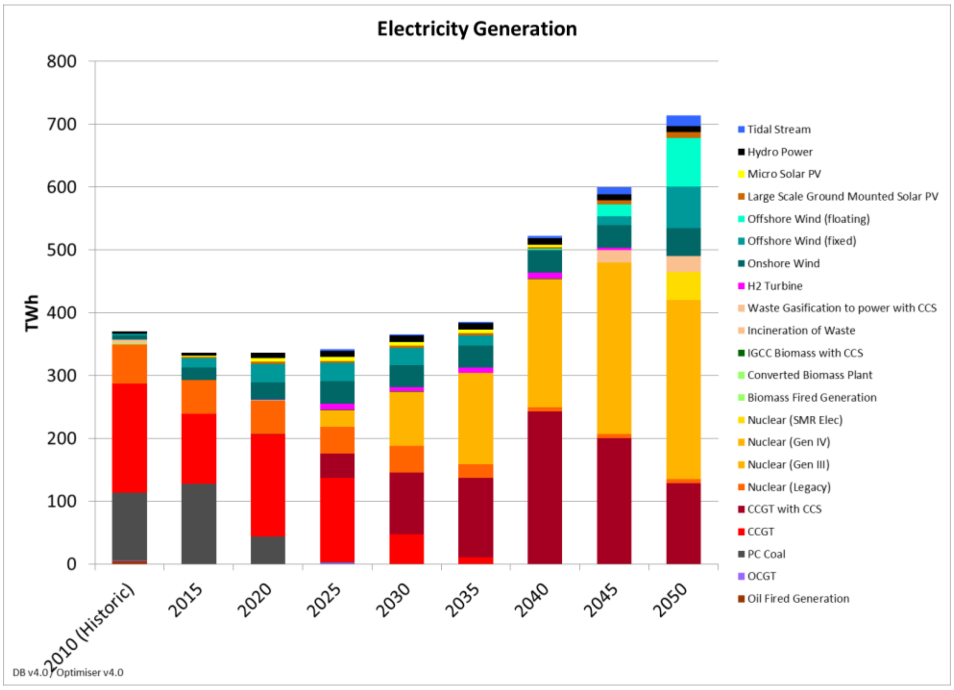


*Figure 39*

## D2.4.10 Large nuclear deployed to the limit of site availability (SMR: central deployment and capex; nuclear lifted from 35GW to 50GW)

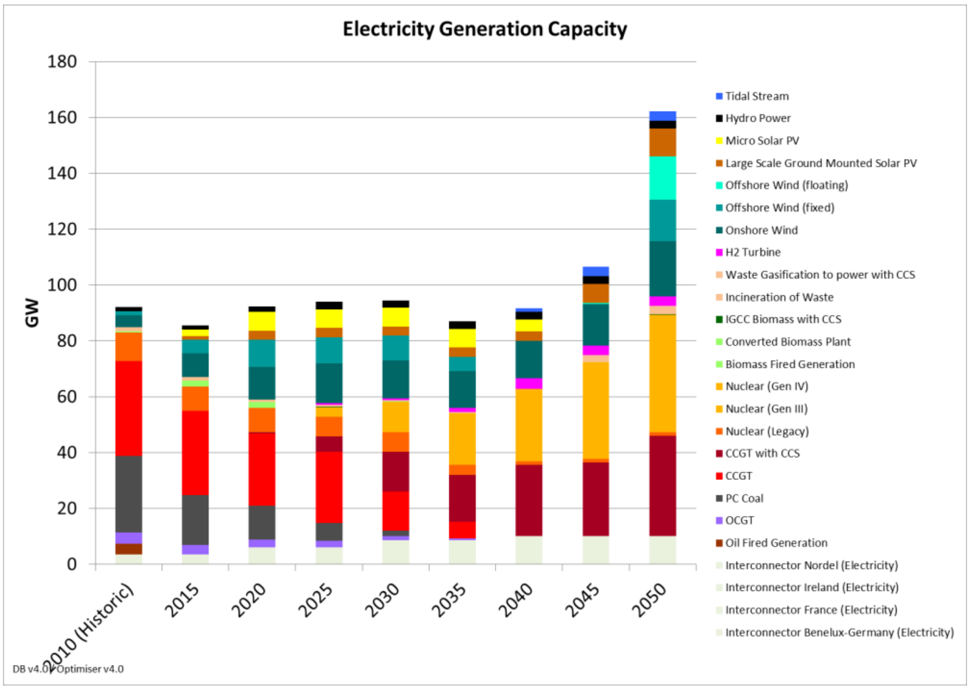


*Figure 40*

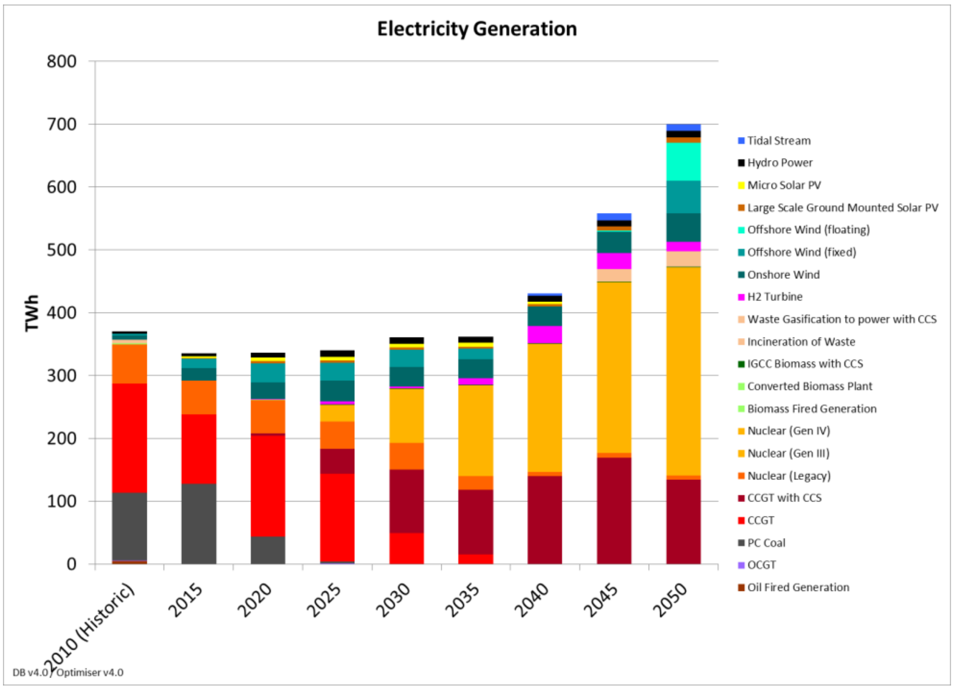


*Figure 41*

## D2.4.11 Large nuclear low and slow

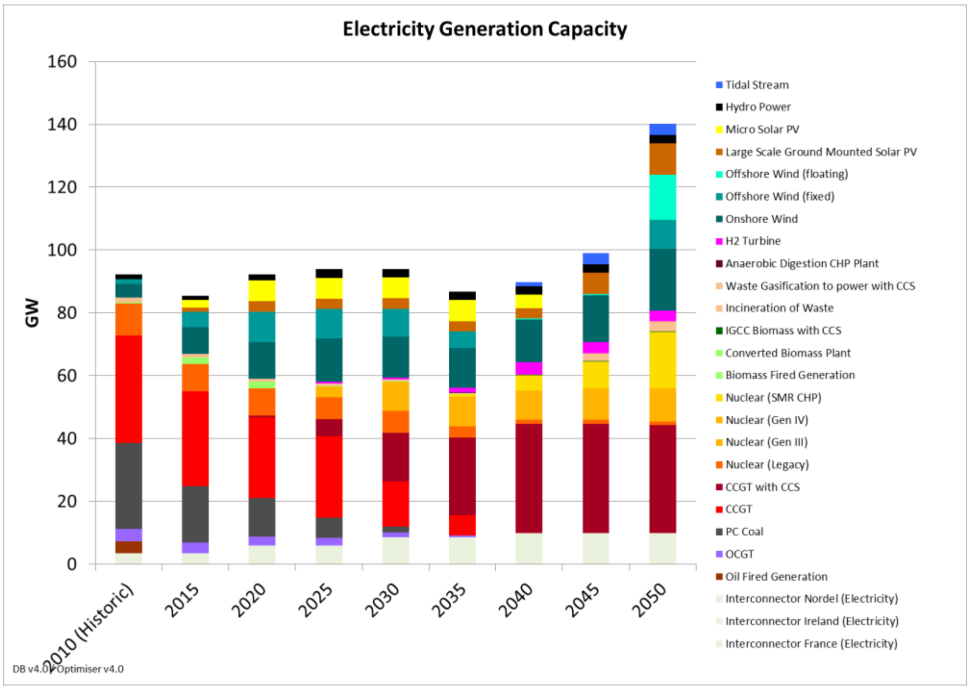


*Figure 42*

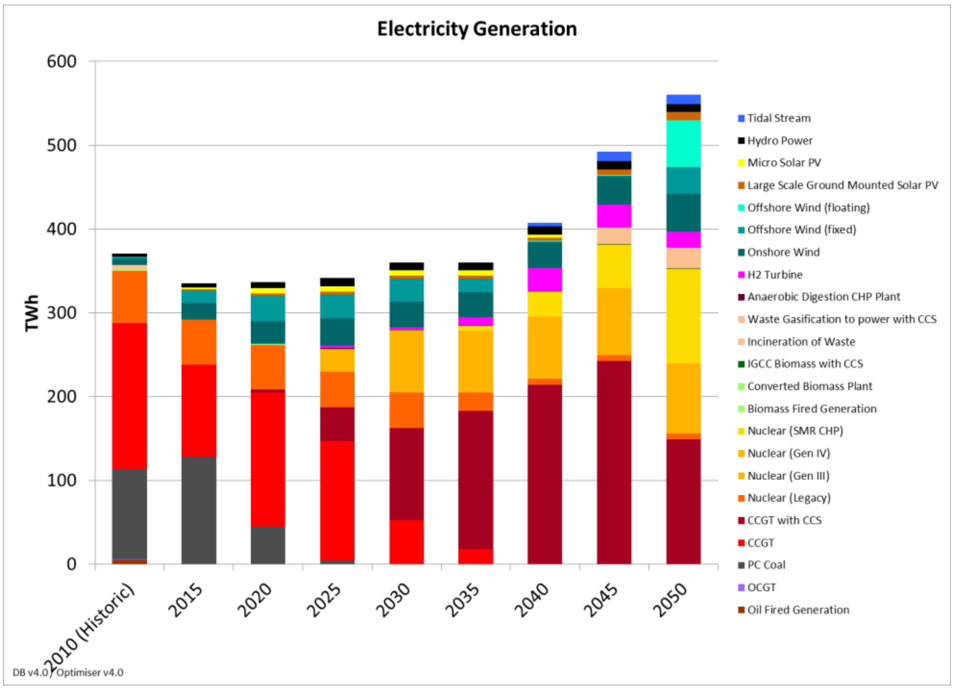


*Figure 43*

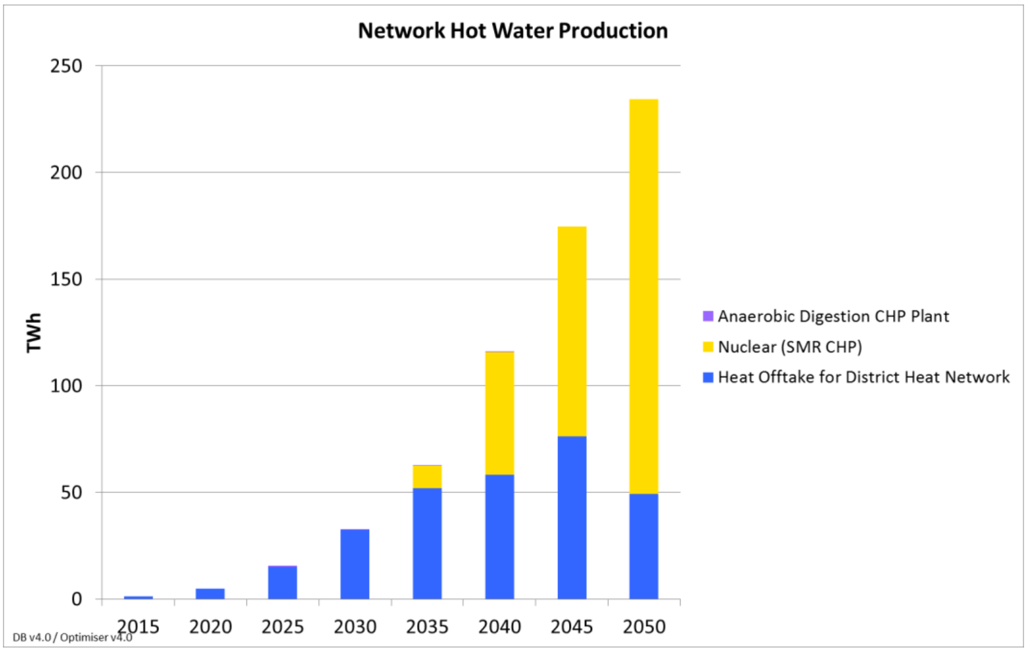
Network Hot Water Production
TWh
250
200
150
100
50
0
2015
2020
2025
2030
2035
2040
2045
2050
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 44*

## D2.4.12 Central deployment date (2030); Very high capex (+35%); CHP possible

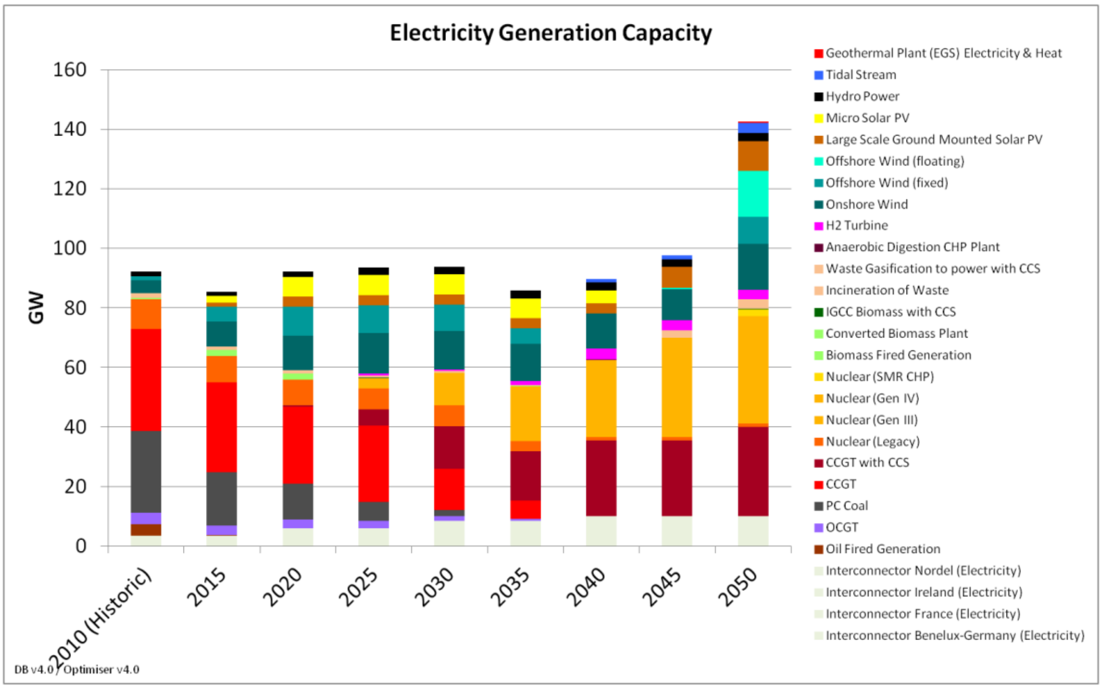


*Figure 45*

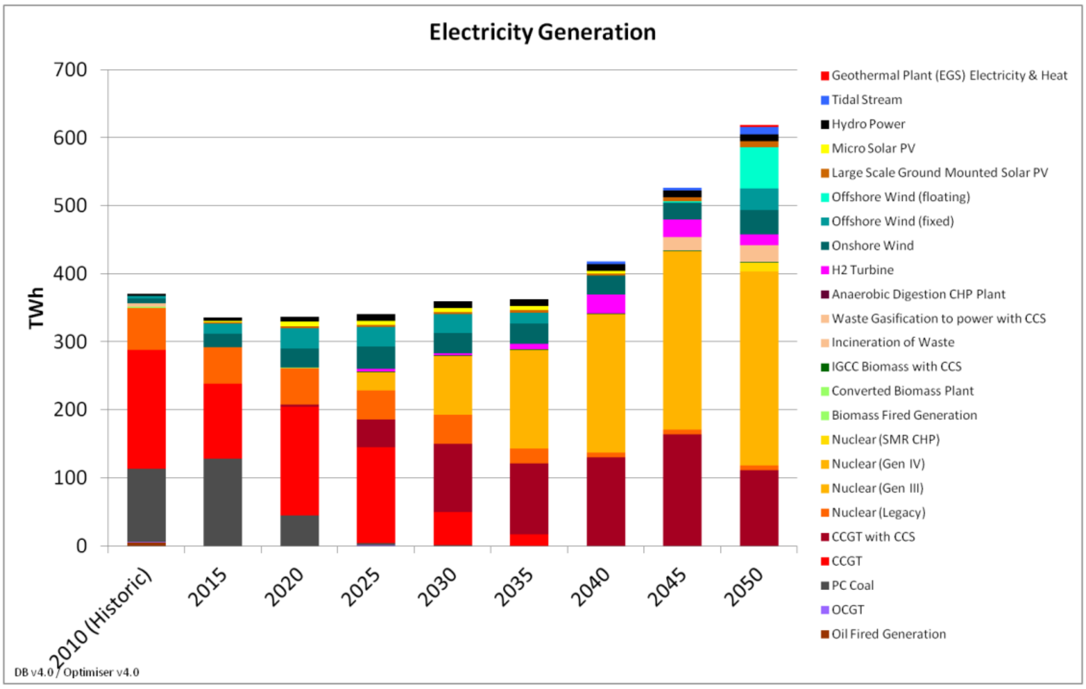


*Figure 46*

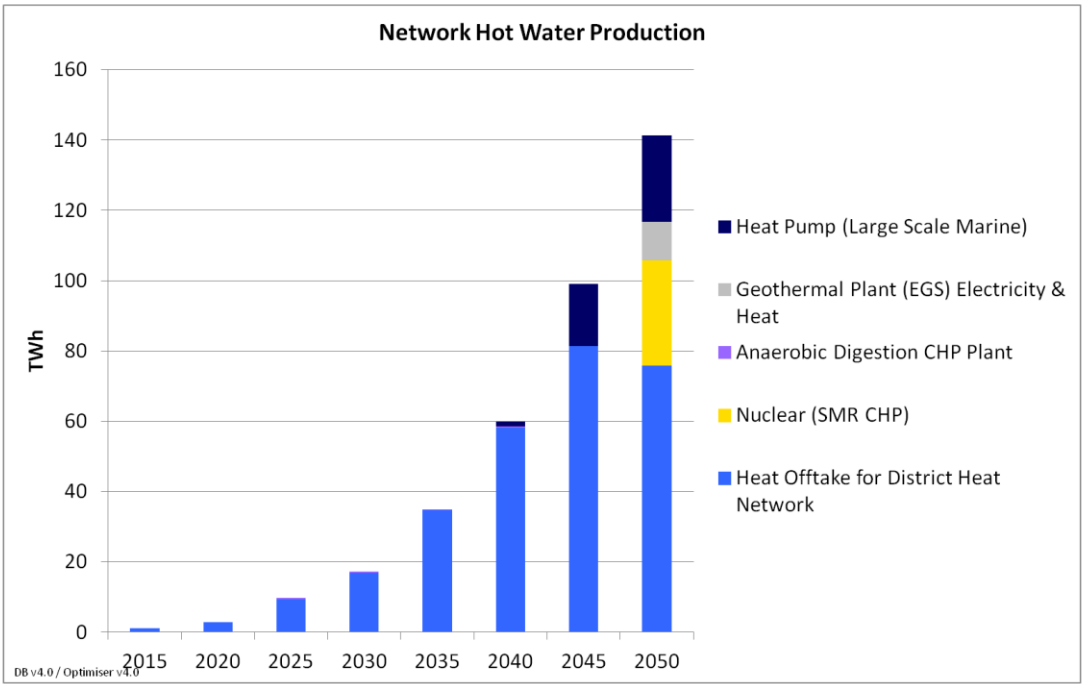
Network Hot Water Production
TWh
160
140
120
100
80
60
40
20
0
2015
2020
2025
2030
2035
2040
2045
2050
DB v4.0 / Optimiser v4.0
Heat Pump (Large Scale Marine)
Geothermal Plant (EGS) Electricity & Heat
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network

*Figure 47*

## D2.4.13 Central deployment date (2030); Central capex, with learner rate from 2030-50; CHP possible

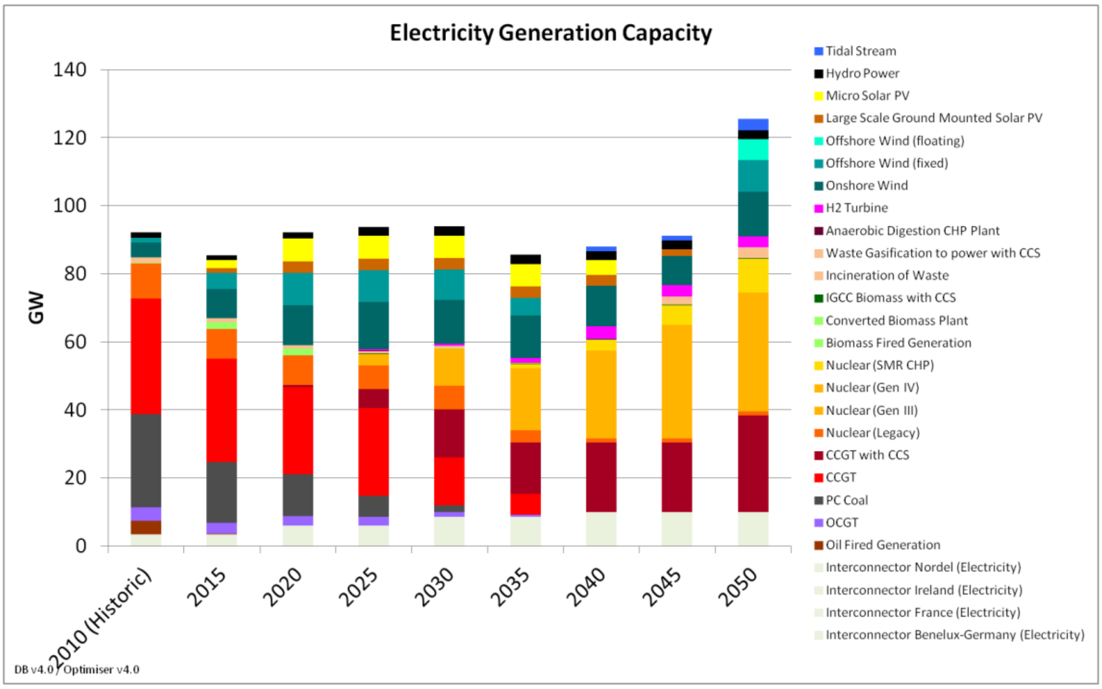


*Figure 48*

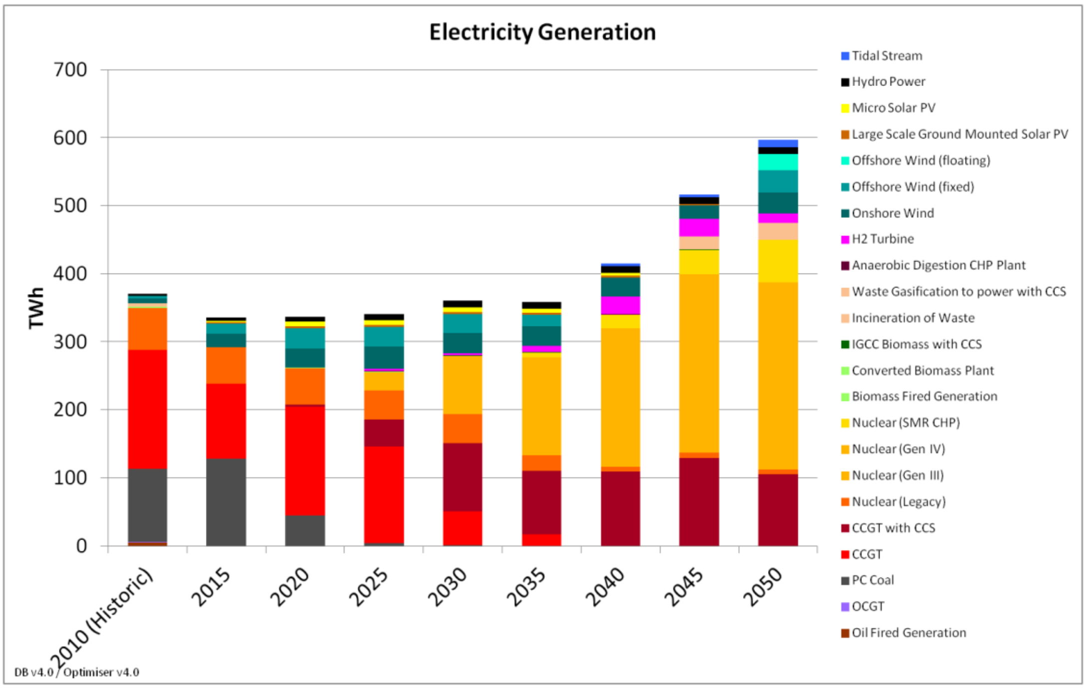


*Figure 49*

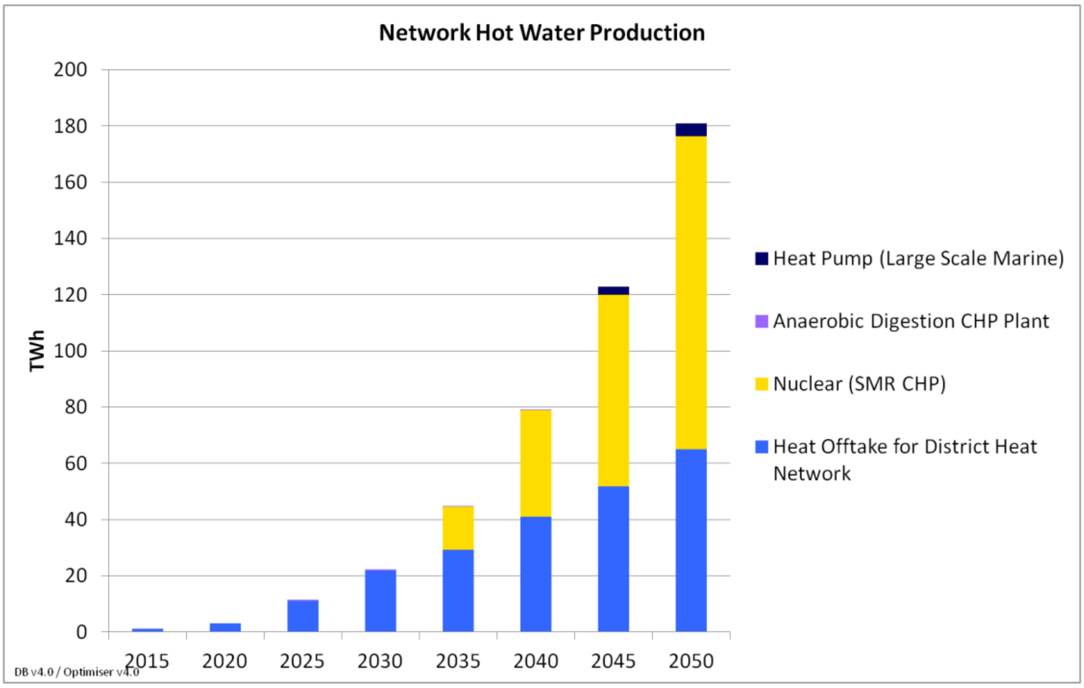
Network Hot Water Production
TWh
200
180
160
140
120
100
80
60
40
20
0
2015
2020
2025
2030
2035
2040
2045
2050
Heat Pump (Large Scale Marine)
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 50*

## D2.4.14 Central deployment date (2030); Central capex; CHP possible; Low gas price

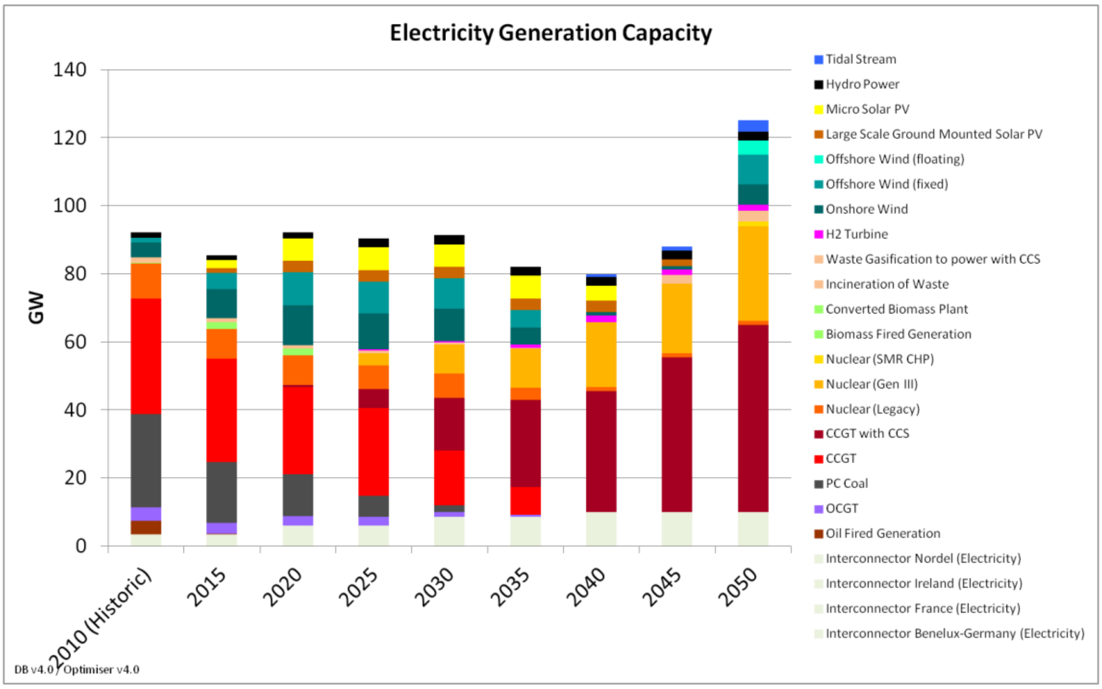


*Figure 51*

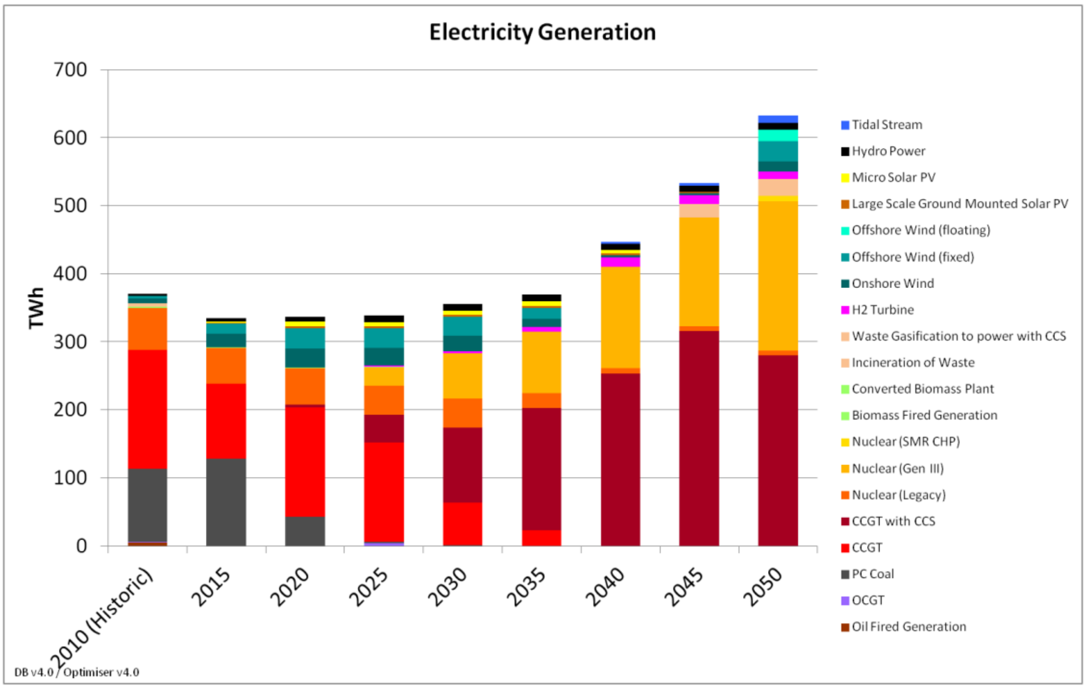


*Figure 52*

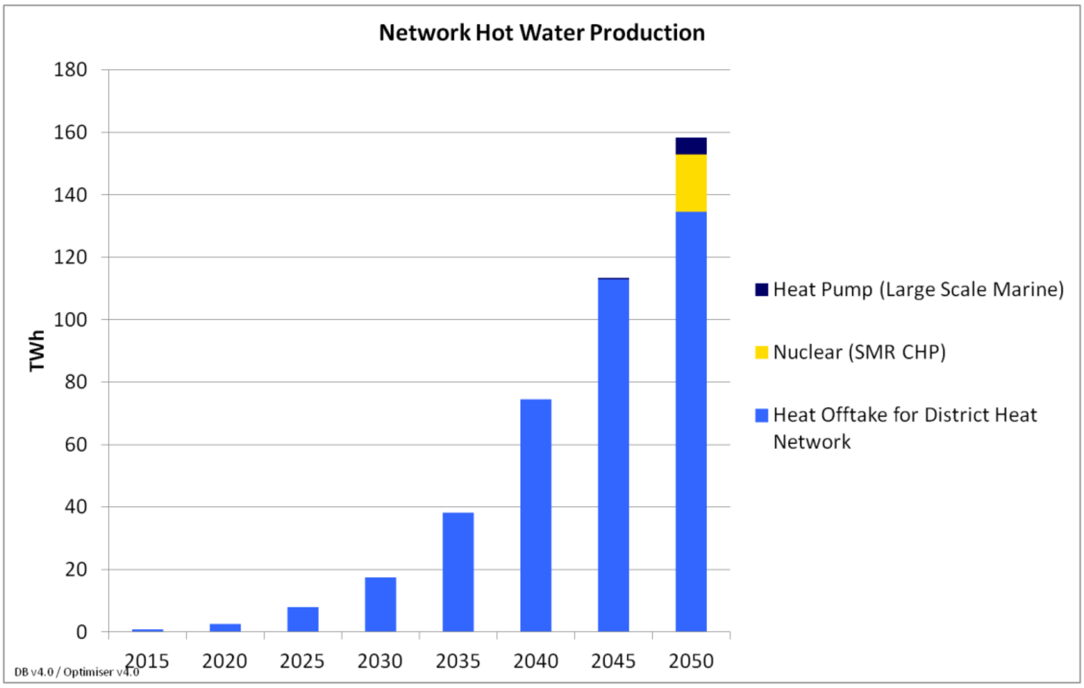
Network Hot Water Production
TWh
180
160
140
120
100
80
60
40
20
0
2015
2020
2025
2030
2035
2040
2045
2050
Heat Pump (Large Scale Marine)
Nuclear (SMR CHP)
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 53*

## D2.4.15 Central deployment date (2030); Central capex; CHP possible; High gas price

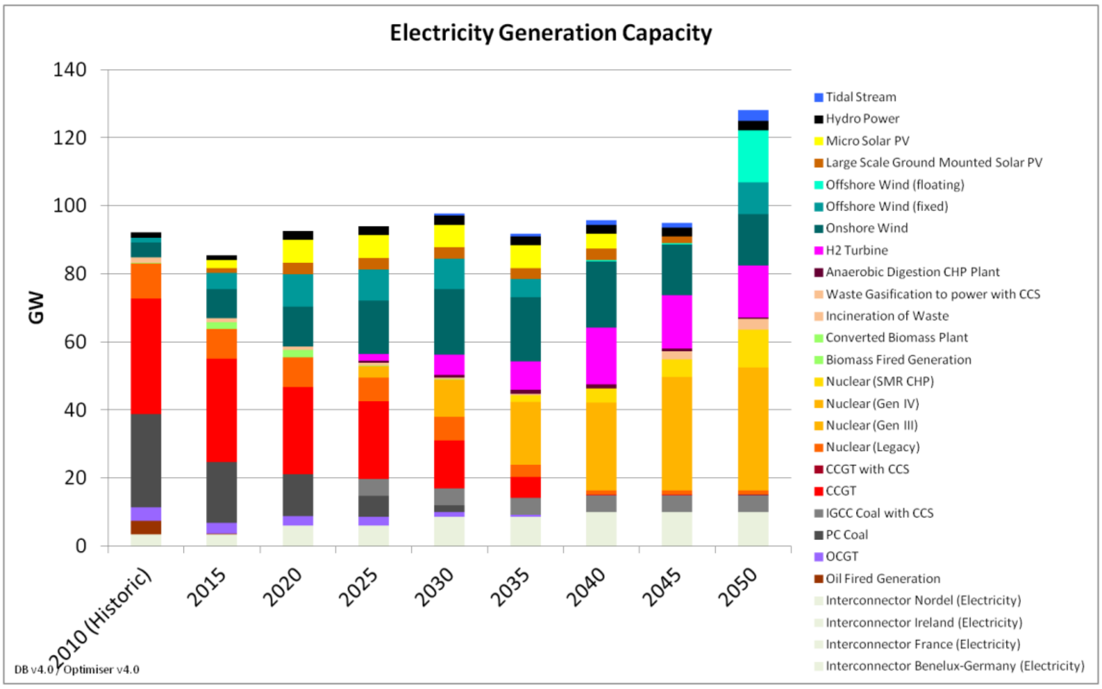


*Figure 54*

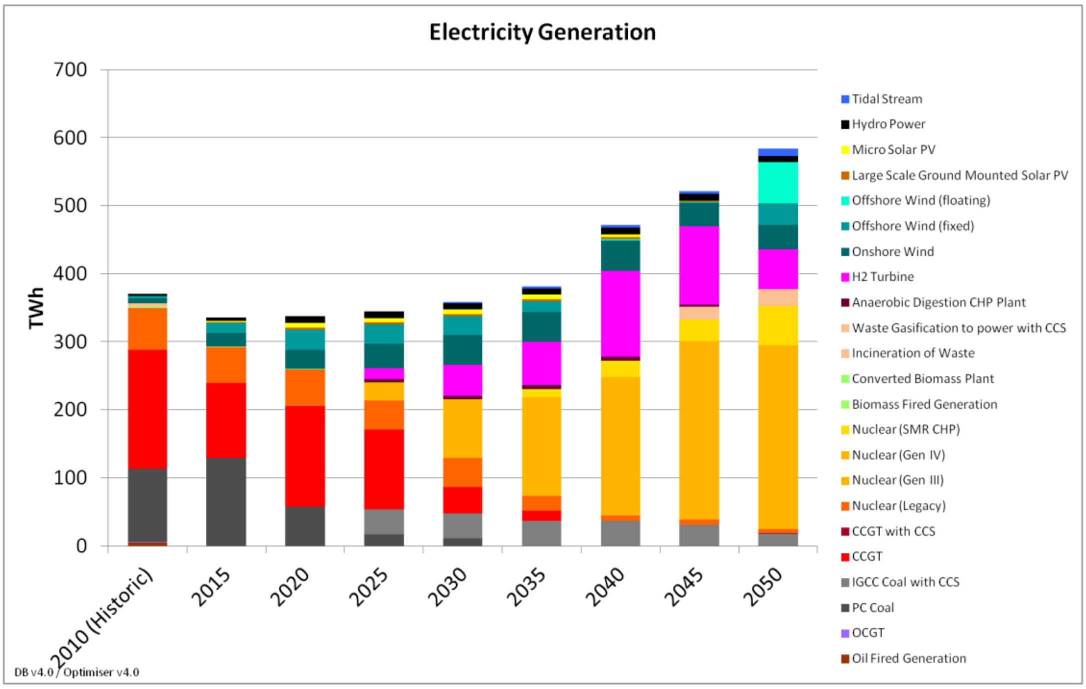


*Figure 55*

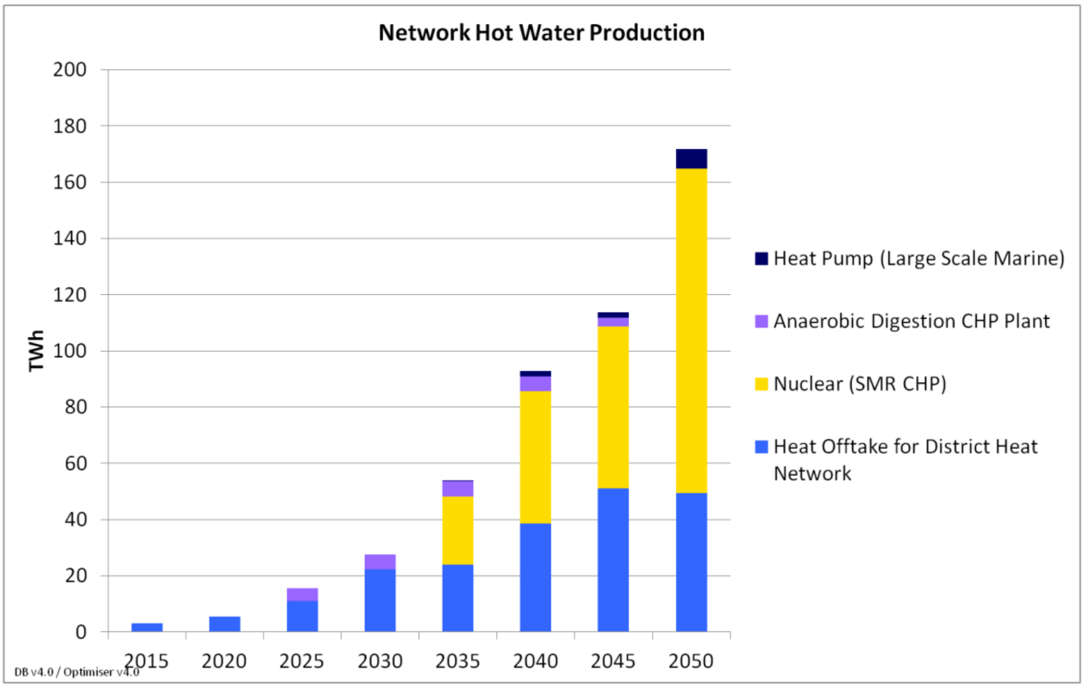
Network Hot Water Production
TWh
200
180
160
140
120
100
80
60
40
20
0
2015
2020
2025
2030
2035
2040
2045
2050
DB v4.0 / Optimiser v4.0
Heat Pump (Large Scale Marine)
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network

*Figure 56*

## D2.4.16 Central deployment date (2030); Central capex; no CHP; Low gas price

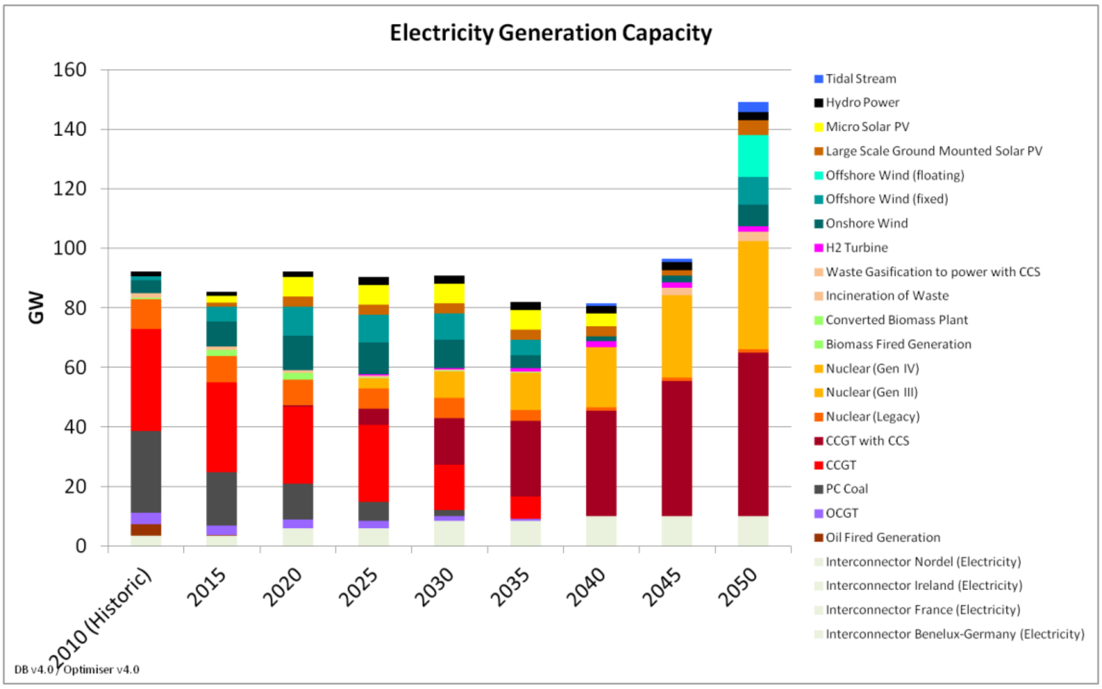


*Figure 57*

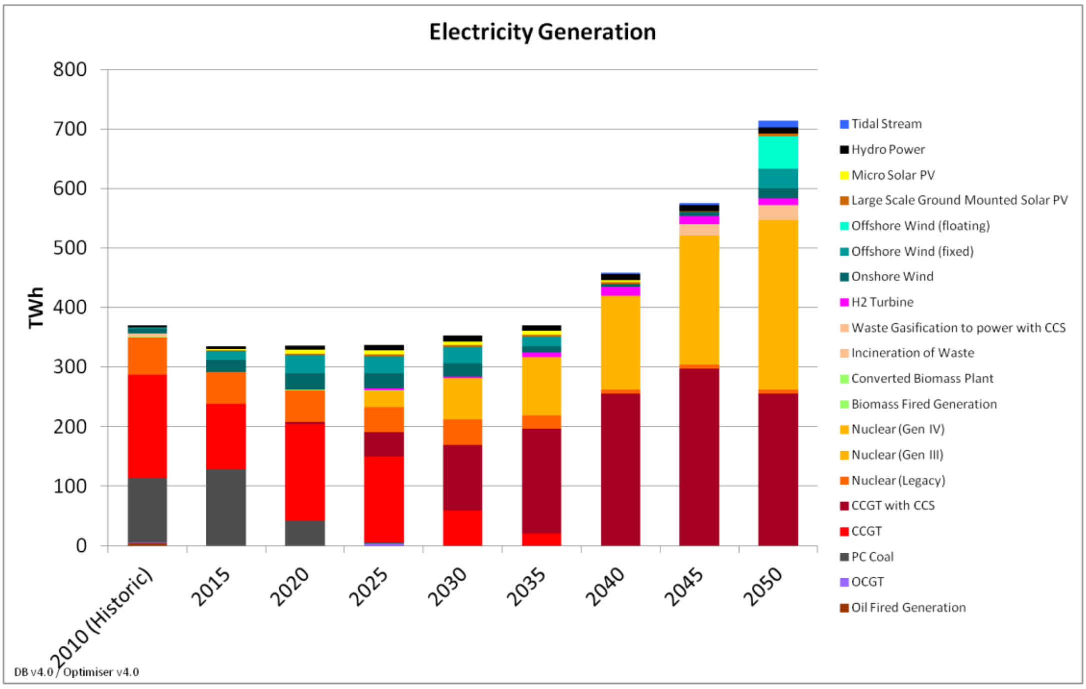


*Figure 58*

## D2.4.17 Central deployment date (2030); Central capex; CHP possible; Slow progress on heat decarbonisation

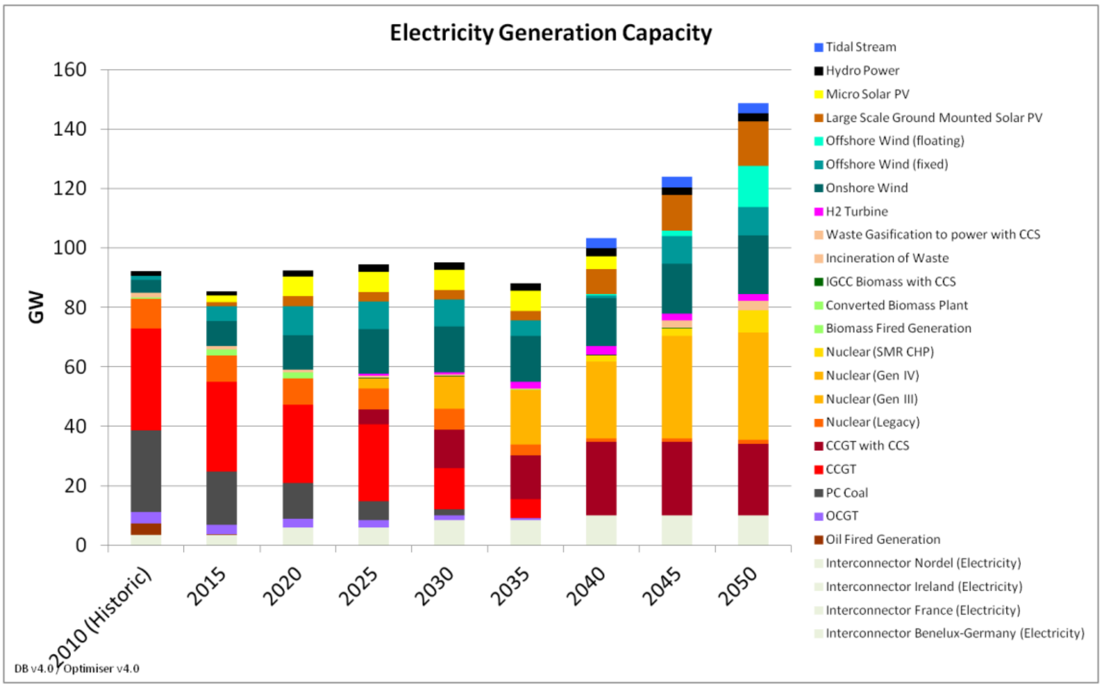


*Figure 59*

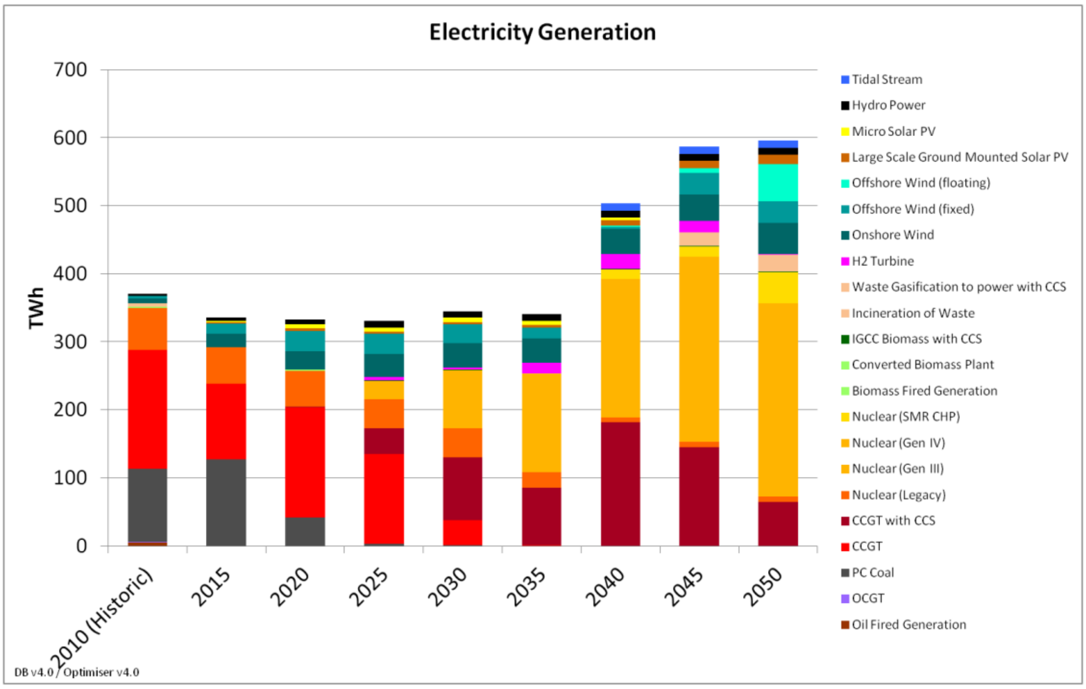


*Figure 60*

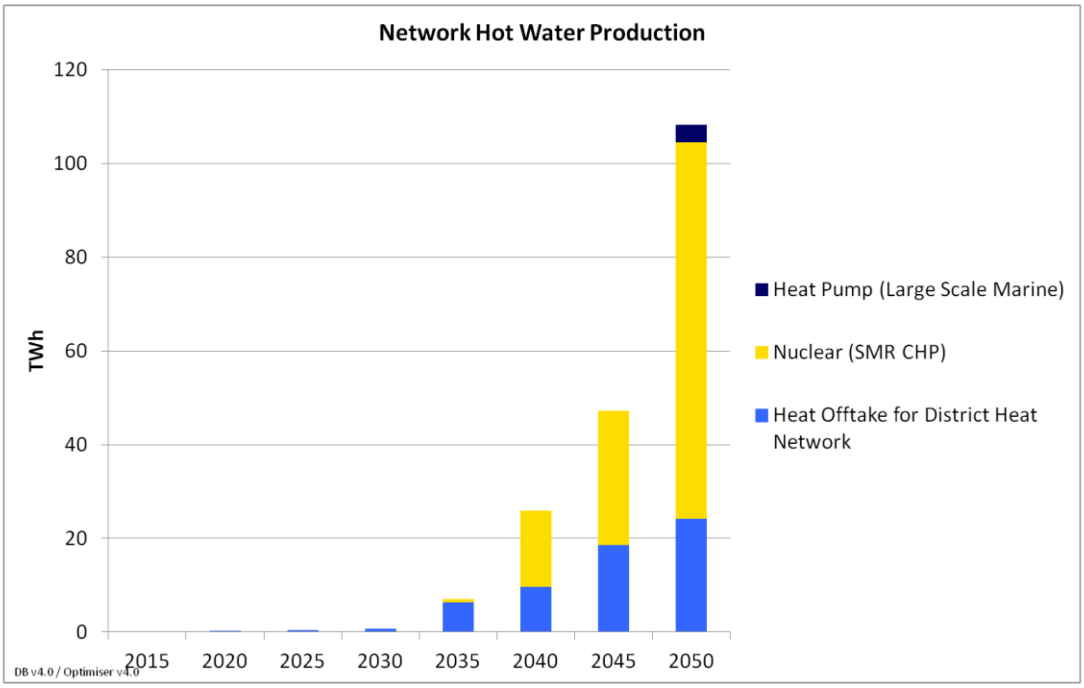
Network Hot Water Production
120
100
80
60
40
20
0
TWh
2015
2020
2025
2030
2035
2040
2045
2050
Heat Pump (Large Scale Marine)
Nuclear (SMR CHP)
Heat Offtake for District Heat Network
DB v4.0 / Optimiser v4.0

*Figure 61*

## D2.5.2 – Vendor 2 technology data

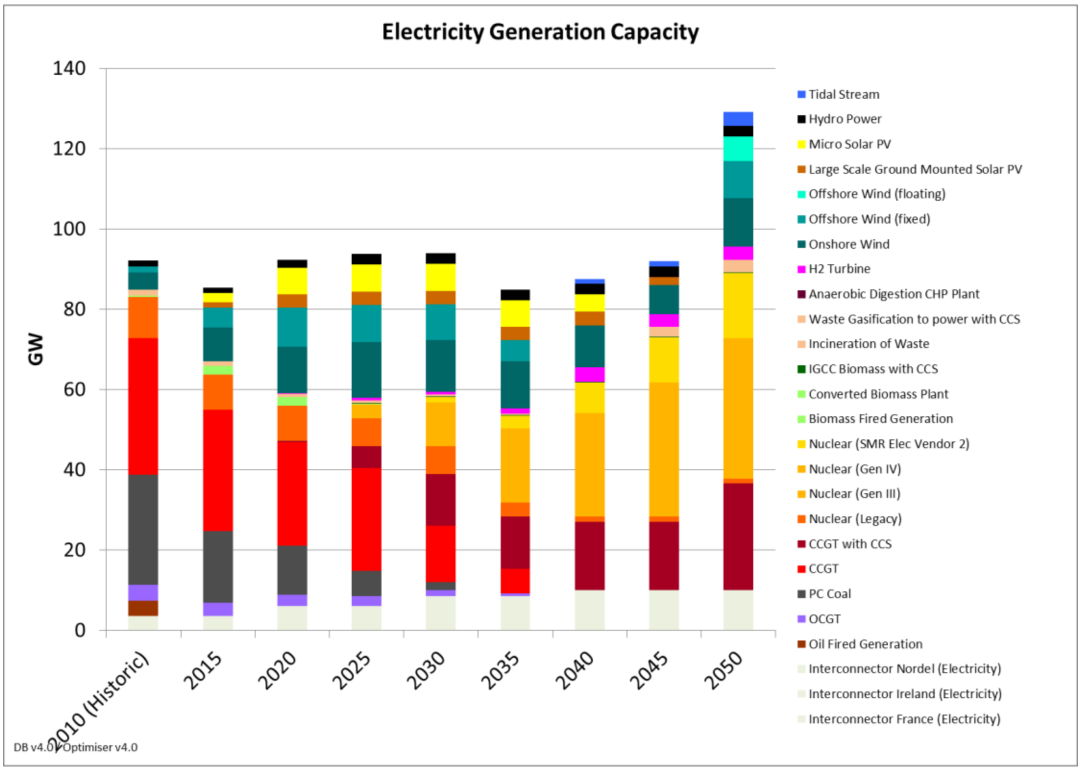


*Figure 62*

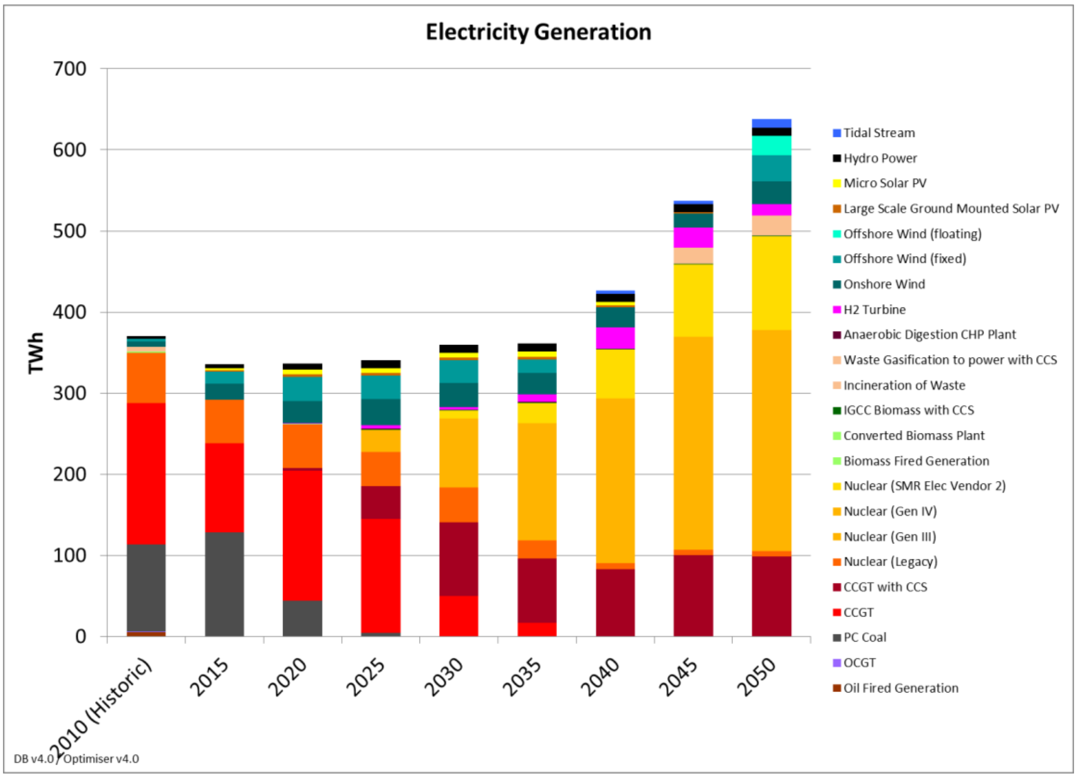


*Figure 63*

## D2.5.6 – Vendor 6 technology data

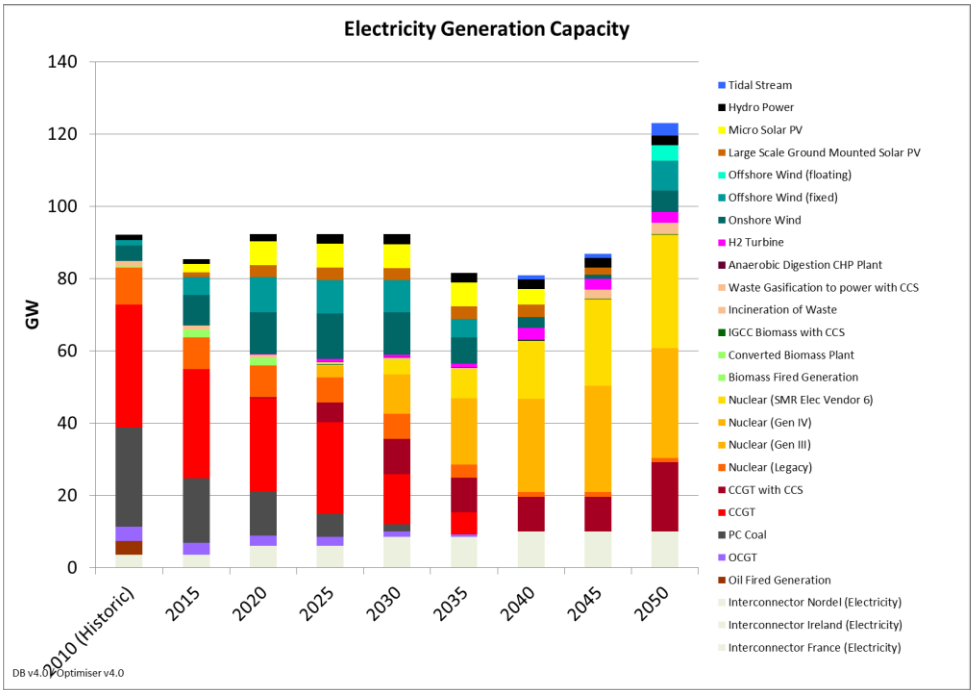


*Figure 64*

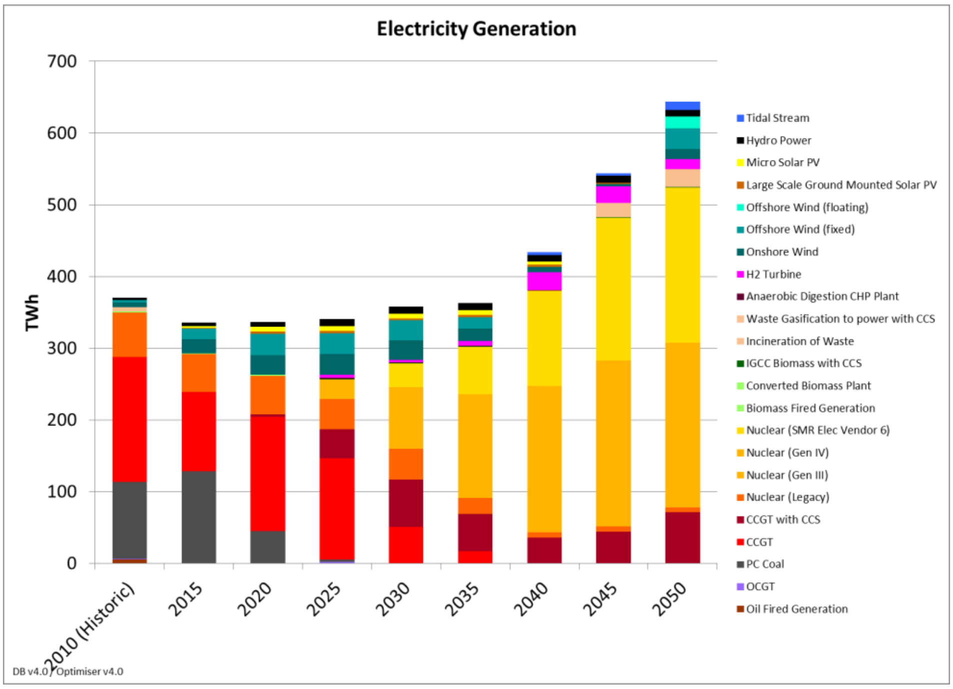


*Figure 65*

## D2.5.7 – Vendor 7 technology data

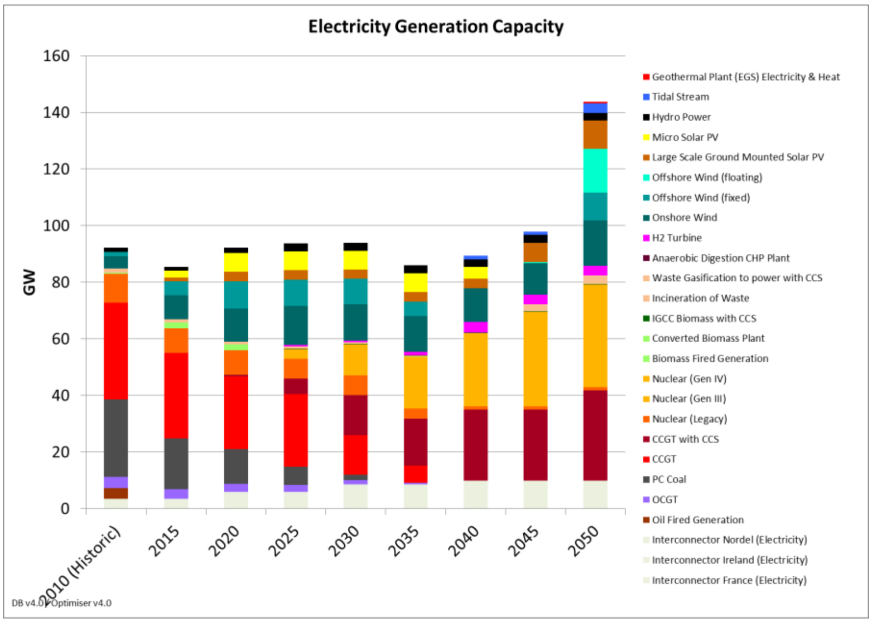


*Figure 66*

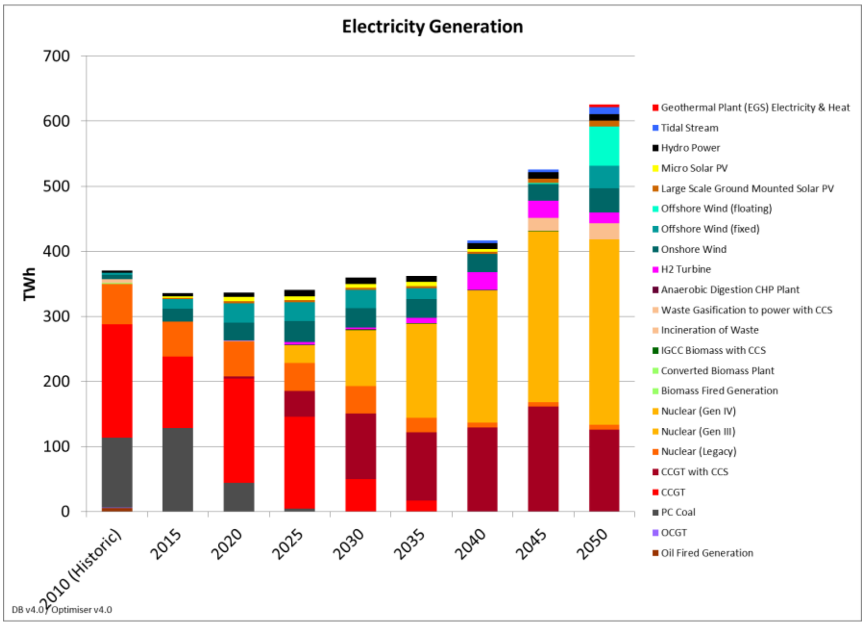


*Figure 67*

## D2.5.15 – Vendor 15 technology data

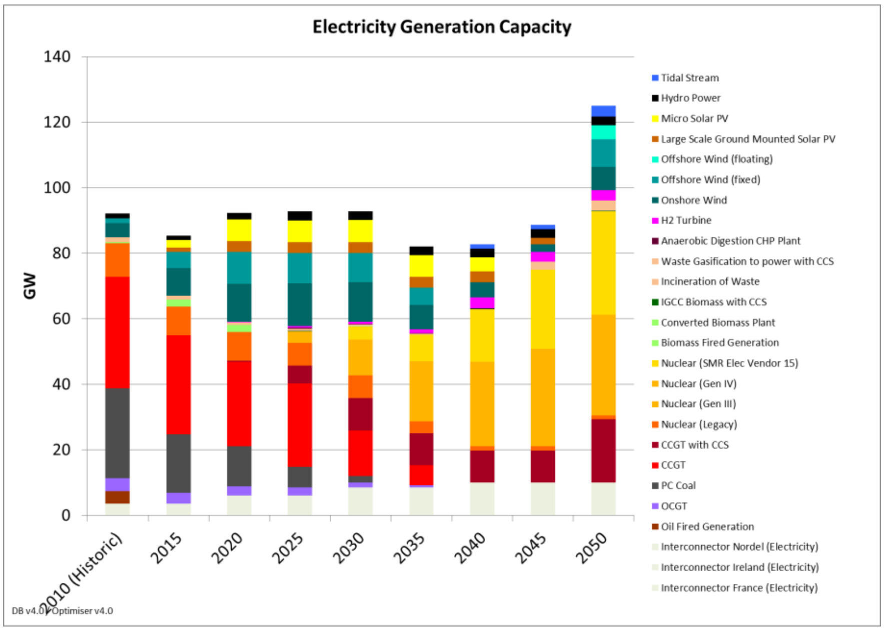


*Figure 68*

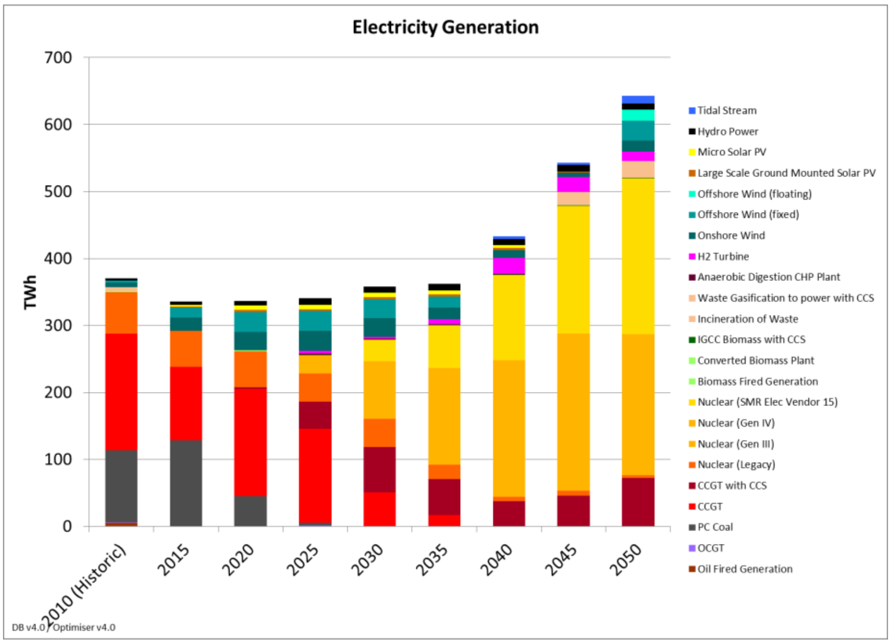


*Figure 69*

## D2.5.17 – Vendor 17 technology data

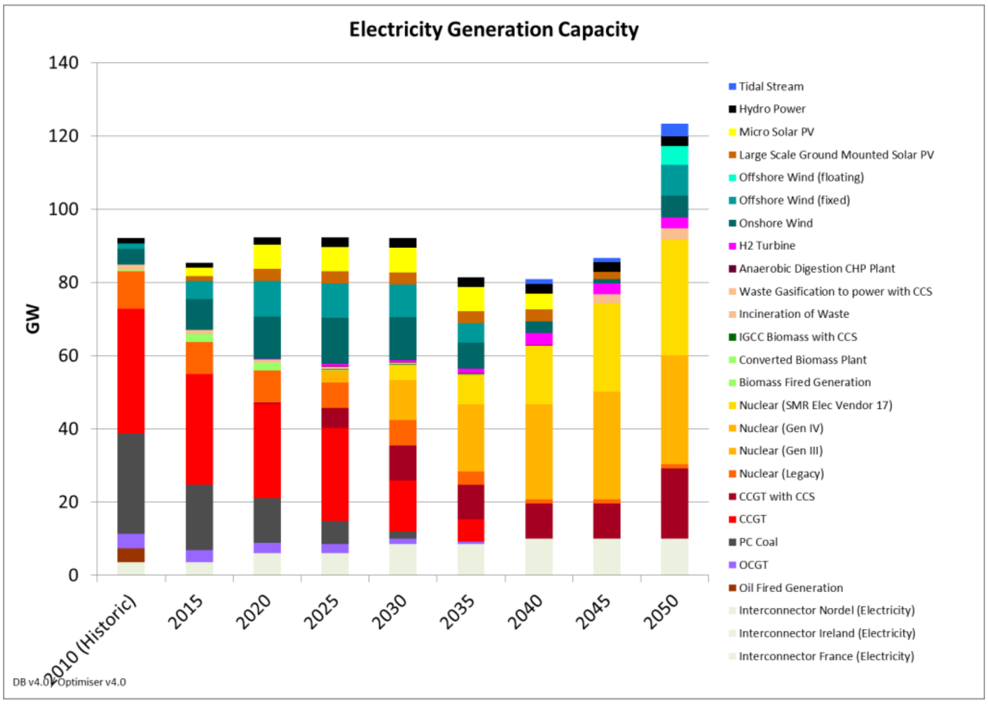


*Figure 70*

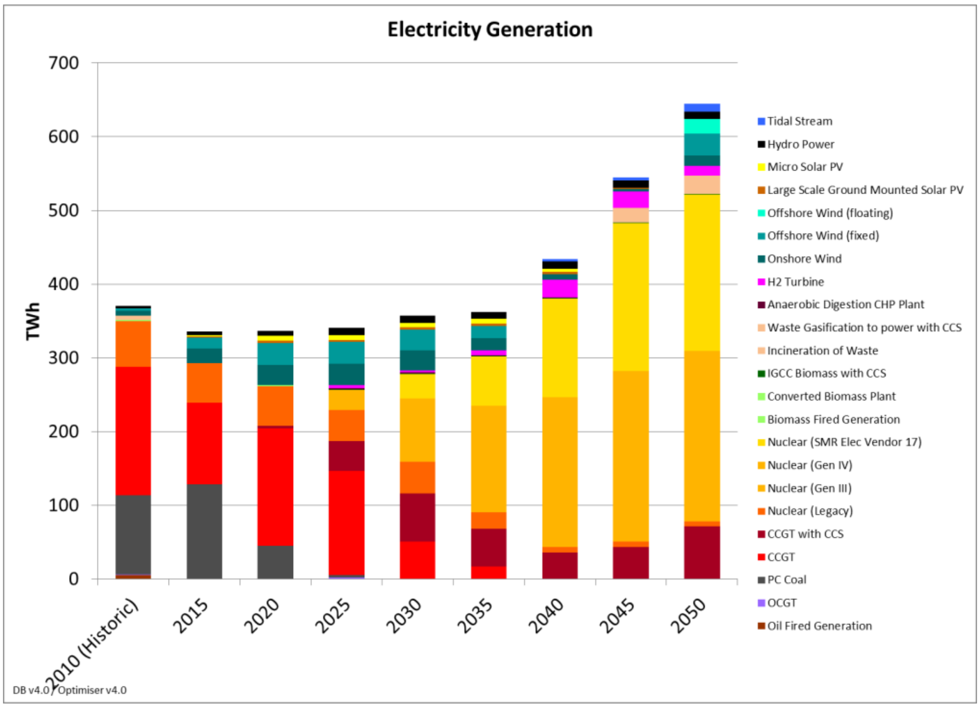


*Figure 71*

## D2.5.SM-HTR – Small modular high temperature reactor

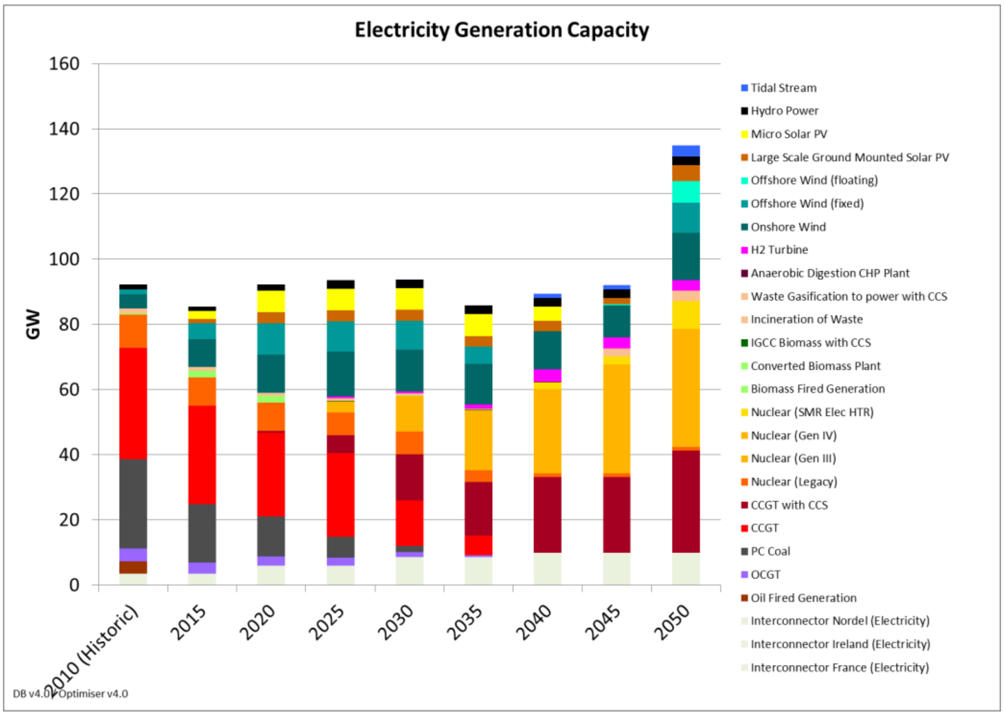


*Figure 72*

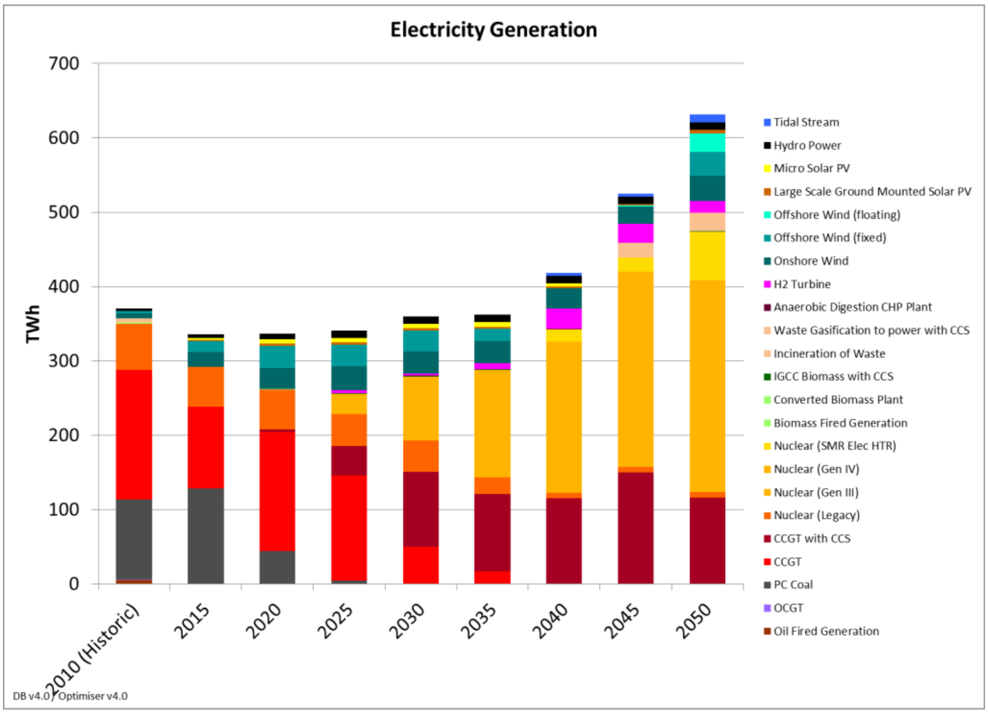


*Figure 73*

## D2.5.SM-SFR – Small modular sodium-cooled fast reactor

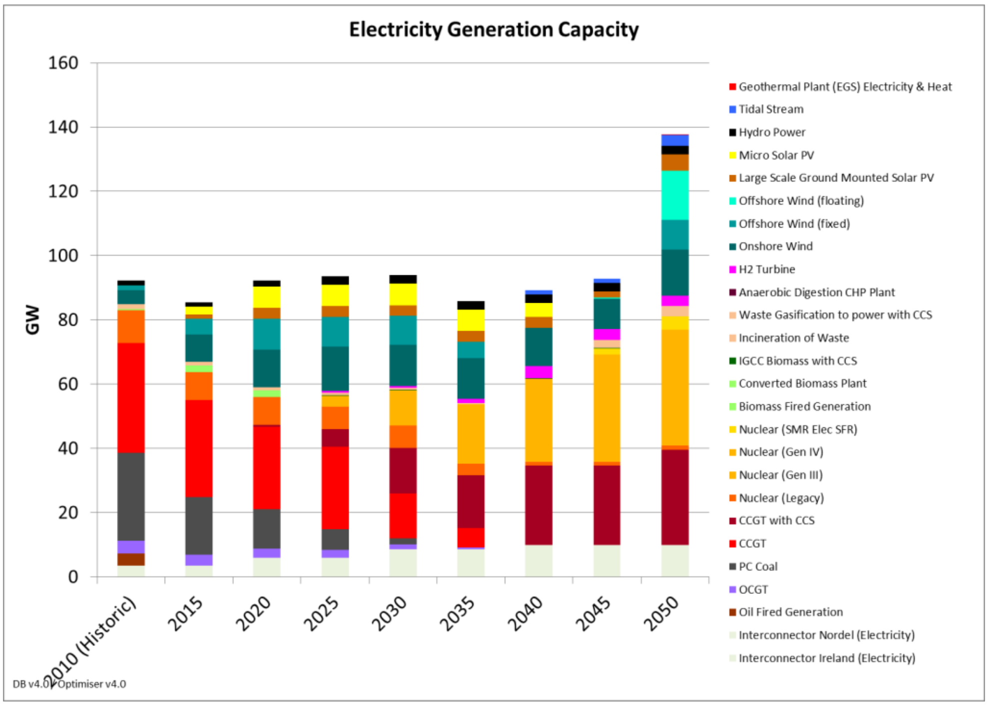


*Figure 74*

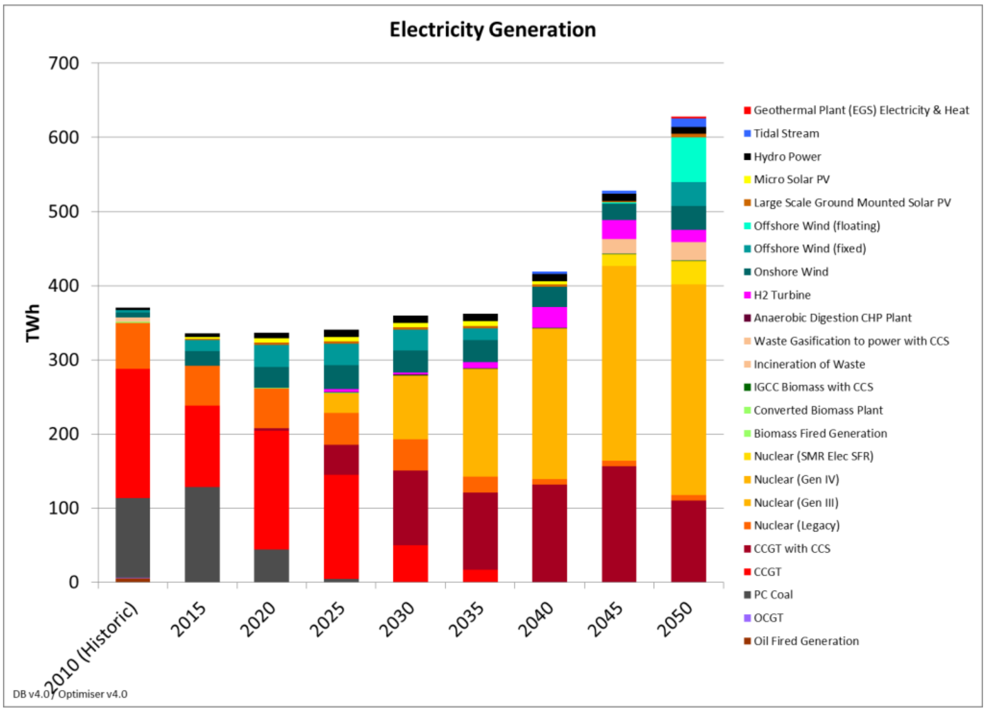


*Figure 75*

## D2.6.1 Near term SMR electricity only (averages over 150 simulations)

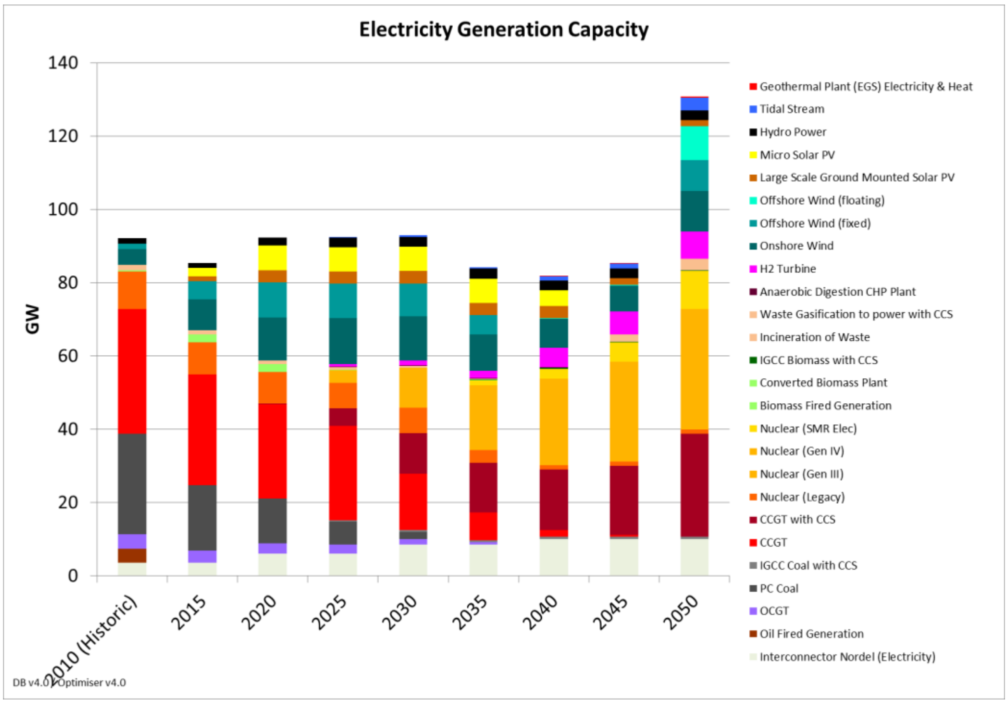


*Figure 76*

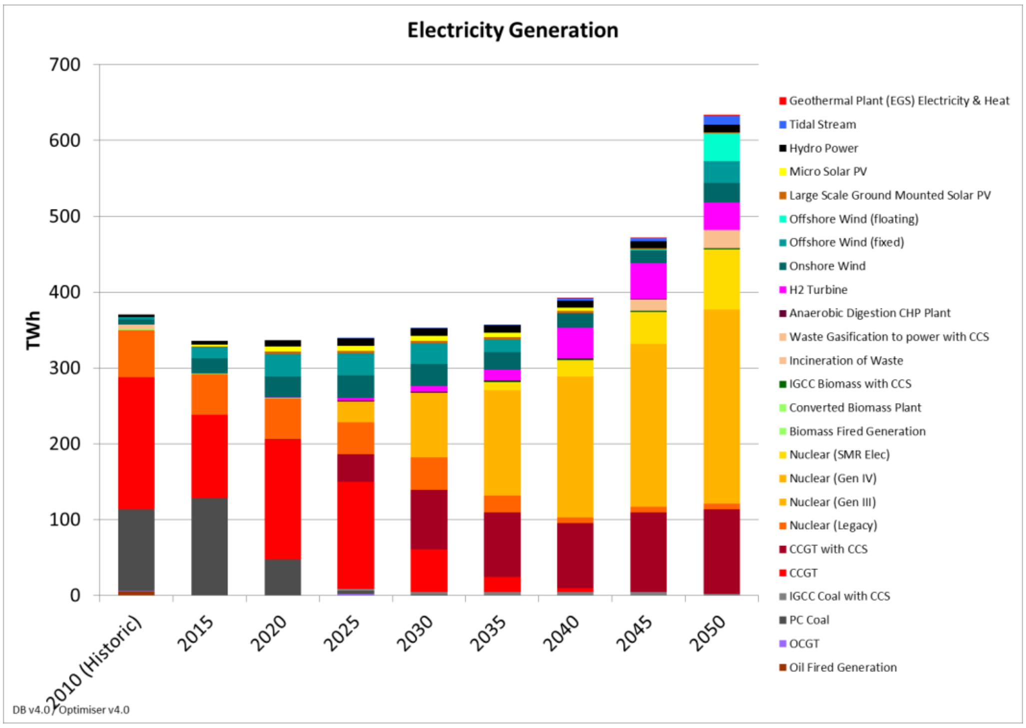


*Figure 77*

## D2.6.2 Near term SMR CHP (averages over 150 simulations)

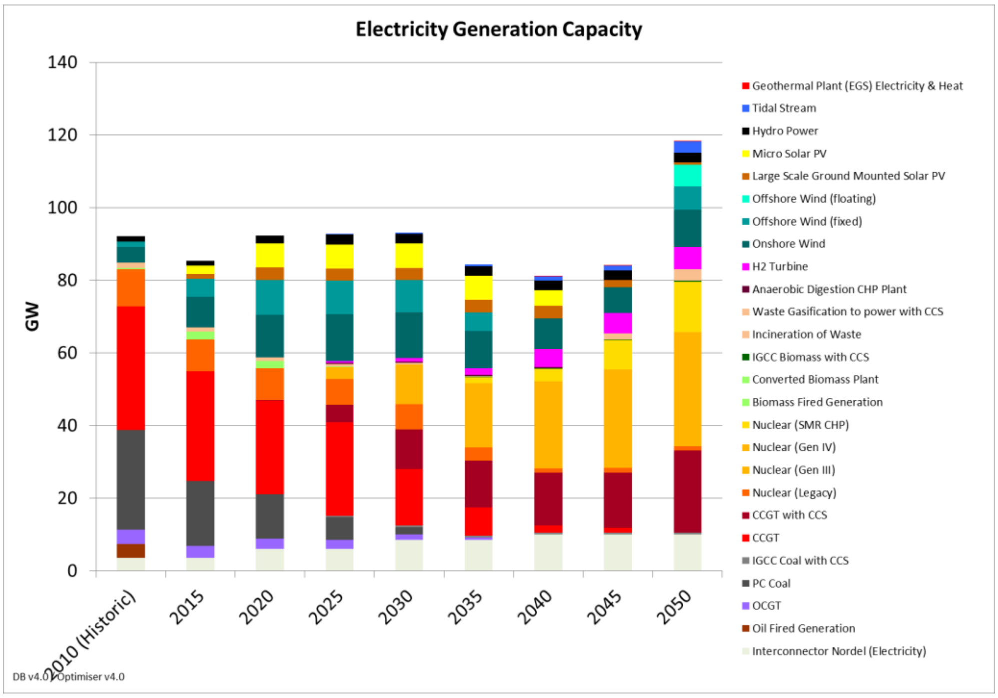


*Figure 78*

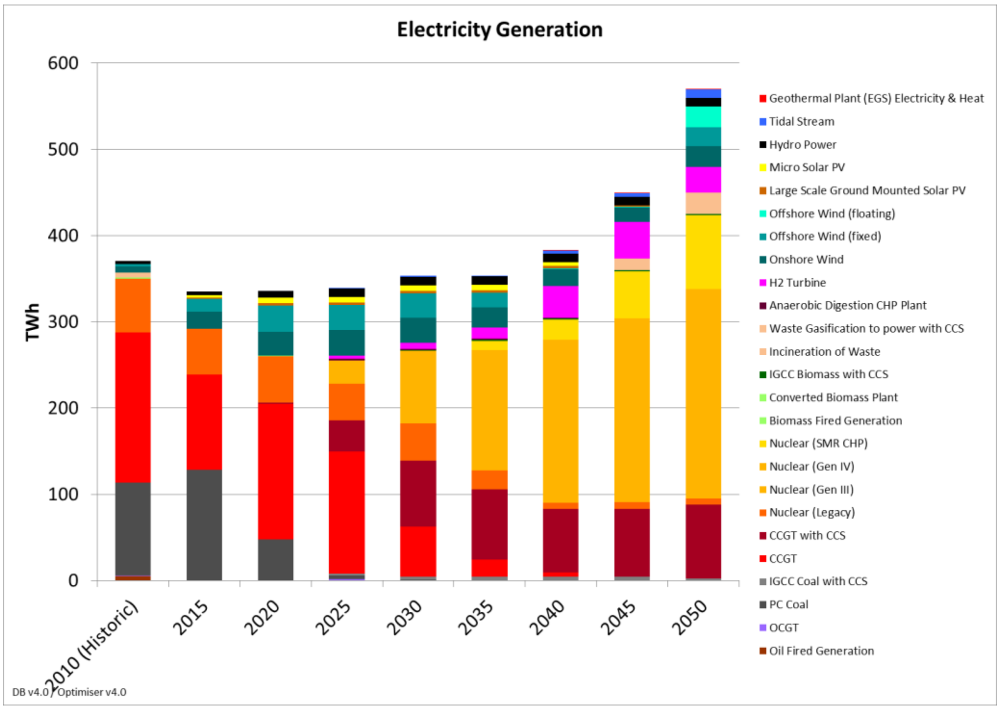


*Figure 79*

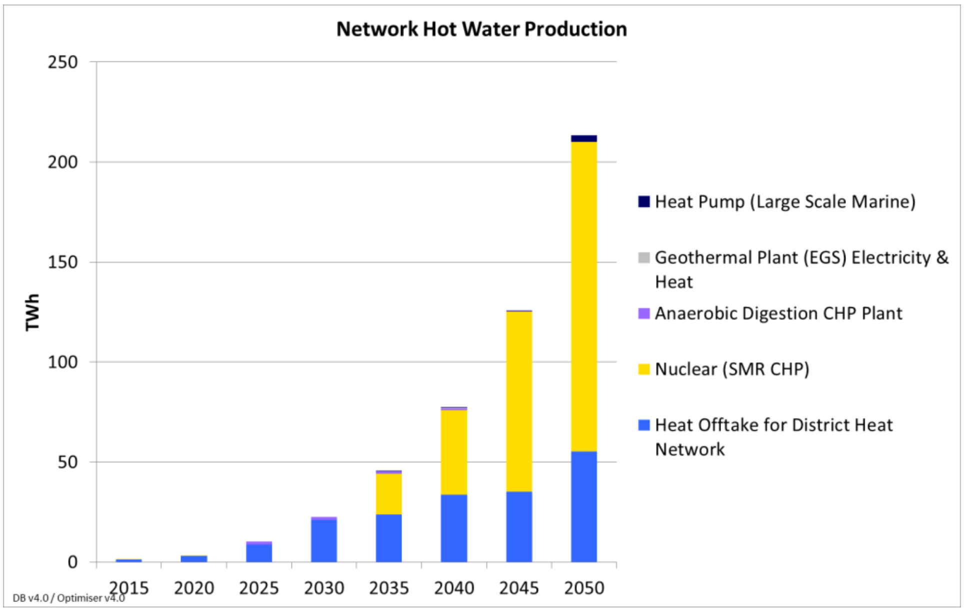
Network Hot Water Production
250
200
150
100
50
0
TWh
2015
2020
2025
2030
2035
2040
2045
2050
DB v4.0 / Optimiser v4.0
Heat Pump (Large Scale Marine)
Geothermal Plant (EGS) Electricity & Heat
Anaerobic Digestion CHP Plant
Nuclear (SMR CHP)
Heat Offtake for District Heat Network

*Figure 80*

## D2.6.3 Emerging technology SMR electricity only (averages over 150 simulations)

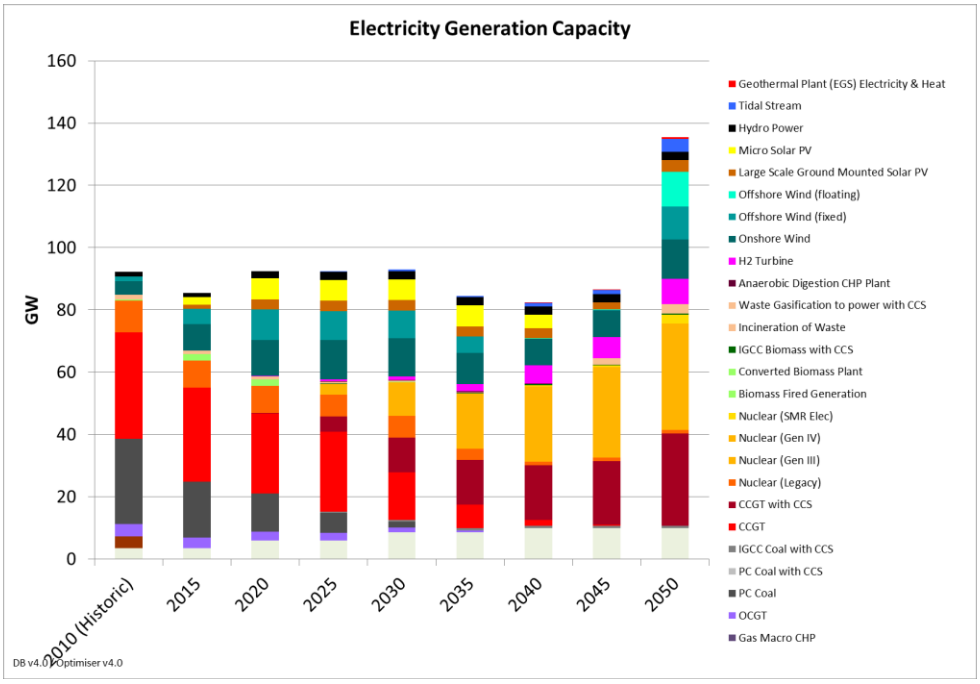


*Figure 81*

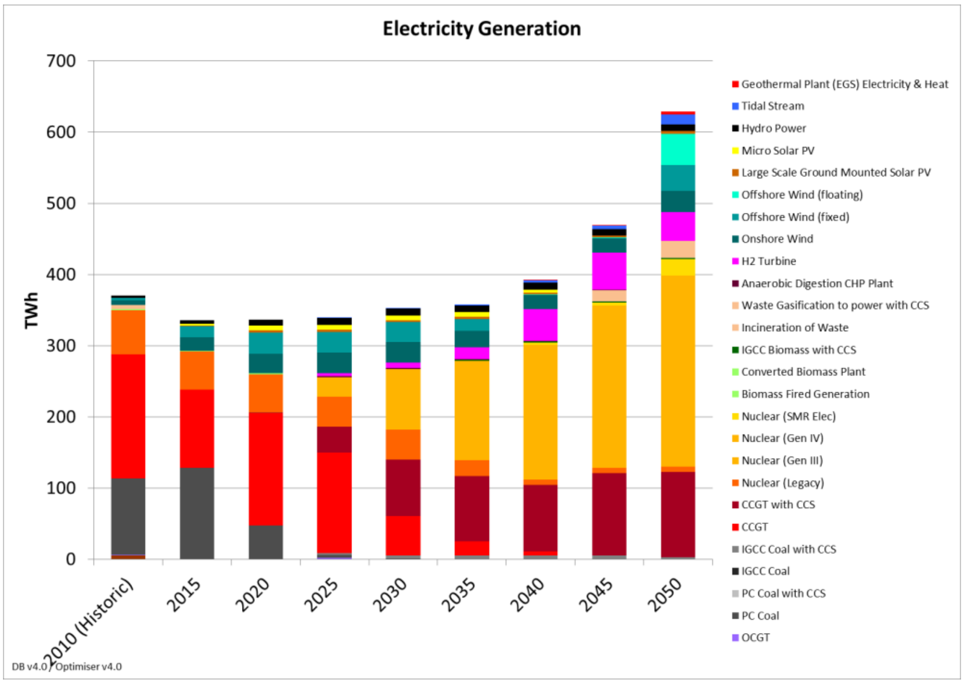


*Figure 82*