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P229 Cost Benefit Analysis: Additional scenarios

A report on a study for Ofgem, October 2010

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Version History

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Executive summary

Some energy is 'lost' in the process of transmitting electricity over a transmission system, largely due to the heating up of lines, cables and transformers as current flows through them. The appropriate treatment of transmission losses in the electricity trading arrangements has long been the subject of some debate in the industry. The current methodology set out in the Balancing and Settlement Code (BSC) allocates transmission losses to trading parties on a uniform basis, without regard to the location of generators or demand customers on the network. However, there have been a number of proposals over the years to allocate losses on a locational basis, the contention being that this would better reflect the extent to which participants give rise to losses. The latest proposal, BSC Modification P229, seeks to introduce seasonal zonal factors for allocating transmission losses.

This study was commissioned by the Ofgem to support its assessment of P229. We have undertaken additional modelling to supplement the cost benefit analysis (CBA) conducted for ELEXON by London Economics and Ventyx (LE/Ventyx) during the industry assessment of the proposed modification. Our analysis explores two additional scenarios with more aggressive renewables deployment pathways to those studied by LE/Ventyx, with the objective of facilitating a fully informed decision on the impacts of P229.

Our study represents the second of three pieces of analysis or Lots commissioned by Ofgem:

- **Lot 1 High level overview** – Lot 1 assesses issues such as the appropriateness of the LE/Ventyx terms of reference, methodology and assumptions, the robustness of the results and the conclusions.
- **Lot 2 Additional Scenario analysis**
- **Lot 3 Additional Analysis** – Lot 3 performs additional analysis of the results of both the original LE/Ventyx work and the new scenarios modelled in Lot 2.

As stated in ELEXON's Final Modification Report, the P229 Modification Group raised concerns that developments planned for Round 3 of Offshore Connection were not included in the LE/Ventyx CBA modelling. Recognising this concern, our ***15 GW Offshore Wind*** scenario models significantly higher levels of offshore wind deployment, with 15 GW of offshore capacity commissioned by 2020.

The ***RES-E Target*** scenario examines the impact of a more ambitious expansion of onshore wind capacity in the period to 2020, in combination with significant offshore wind deployment. Our objective in this scenario was to develop sufficient renewable generation capacity to meet the UK's 2020 targets. The Government's *Renewable Energy Strategy* envisages that around 30% of large-scale electricity generation will need to come from renewable sources by 2020 in order to deliver the UK's overall renewable energy target. The RES-E Target scenario models installed wind capacity of 11 GW onshore and 15 GW offshore by 2020 to meet this target. The LE/Ventyx Reference scenario would undershoot a 30% renewable electricity target by a considerable margin.

In order to assess the potential impact of P229 in each scenario, we have modelled generation dispatch and transmission load flows using a detailed nodal representation of the GB electricity system and PLEXOS, a commercially available market simulation tool developed by Energy Exemplar. The financial years 2011/12 to 2020/21 were modelled on an hourly basis under a 'Base' case (with status quo uniform loss factors) and a 'Change' case (with P229 zonal loss factors). Following the P229 methodology, marginal loss factors were aggregated by season and zone to derive Change case loss factors for the following year.

We have benchmarked our modelling approach and assumptions against the Reference scenario presented in the LE/Ventyx CBA study. This benchmarking exercise aims to provide confidence that conclusions can be drawn across the two studies.

The key component of the CBA emerging from the modelling exercise is the change in production costs when generators are exposed to zonal loss factors under the P229 Change case. Our modelling indicates positive benefits (production cost savings) from the P229 zonal losses modification under all three scenarios that we have studied. The production cost savings occur due to the lower overall generation levels and reduced transmission losses under P229. These savings are associated with changing generation patterns under P229 – switching from coal to gas generation and moving geographically from North to South.

The CBA results, excluding costs associated with NO_x and SO_2 emissions, compare closely between the LE/Ventyx Reference scenario and our Reference benchmark, with total net benefits under P229 of £46.1mn and £47.7mn respectively. This indicates that we can have confidence in comparisons of the CBA results (excluding NO_x and SO_2) from our 15 GW Offshore Wind and RES-E Target scenarios which model very different capacity development pathways to the scenarios presented in the LE/Ventyx study.

The LE/Ventyx CBA study also sought to quantify the value of changes in the level of NO_x and SO_2 emissions under P229. If the valuation of NO_x and SO_2 emission changes is included, the CBA results show a much higher benefit under the LE/Ventyx Reference scenario (£275.2mn) than in our Reference benchmark (£161.1mn). The modelling of future NO_x and SO_2 emission levels is highly sensitive to a number of inputs for which we did not have details of the LE/Ventyx assumptions, so we have not been able to reconcile the differences in the CBA results including NO_x and SO_2.

Our modelling indicates that the benefits of P229 are stable across all three capacity development pathways studied. The three Redpoint scenarios return CBA results excluding NO_x and SO_2 within a narrow range - between £36.6mn and £47.7mn. CBA totals including NO_x and SO_2 are between £131.1mn and £161.1mn.

We have followed the CBA framework set out in the LE/Ventyx study in basing the assessment of P229 upon changes in generation production costs. It is also instructive to consider the potential impact of P229 upon wholesale electricity prices, although a number of caveats should be kept in mind when reviewing the wholesale price results from the Redpoint and LE/Ventyx CBA studies. For example, the price results for both studies are taken from transmission constrained models of the generation sector, whereas the GB wholesale market operates on an unconstrained basis. Moreover, given that the CBA framework is based upon changes in production costs, both studies have assumed that wholesale price formation is based upon generators' short run marginal costs. Adjusting the modelled price results to more accurately reflect the allocation of transmission losses under the BSC market rules, the average wholesale price change under P229 can be considered negligible under each of our scenarios.

1 Introduction

1.1 Study objectives

This study was commissioned by Ofgem to support its assessment of 'P229 - Introduction of a seasonal Zonal Transmission Losses scheme' (P229), a proposed modification to the Balancing and Settlement Code (BSC). We have undertaken additional analysis of P229 to supplement the cost benefit analysis (CBA) conducted for ELEXON by London Economics and Ventyx (LE/Ventyx) during the industry assessment of the proposed modification. Our analysis explores additional scenarios to those studied by LE/Ventyx[1], with the objective of facilitating a fully informed decision by the Authority on the impacts of P229.

Our study represents the second of three pieces of analysis or Lots commissioned by Ofgem:

- **Lot 1 High level overview** – Lot 1 assesses issues such as the appropriateness of the LE/Ventyx terms of reference, methodology and assumptions, the robustness of the results and the conclusions.
- **Lot 2 Additional Scenario analysis**
- **Lot 3 Additional Analysis** – Lot 3 performs additional analysis of the results of both the original LE/Ventyx work and the new scenarios modelled in Lot 2.

As well as performing additional scenario analysis, we have benchmarked our modelling approach and assumptions against the Reference scenario presented in the LE/Ventyx CBA study. This benchmarking exercise aims to provide confidence that robust conclusions can be drawn across the two studies.

1.2 Background

Some energy is 'lost' in the process of transmitting electricity over a transmission system. The majority of transmission losses are associated with the flow of current through lines, cables and transformers, which causes them to heat up and dissipate energy. These 'heating' losses increase with the level of flow and the distance electricity is transmitted.

The appropriate treatment of transmission losses in the electricity trading arrangements has been the subject of some debate since the time of industry privatisation. The current methodology set out in the BSC allocates transmission losses to trading parties on a uniform basis, without regard to the location of generators or demand customers on the network. However, there have been a number of proposals over the years to allocate losses on a locational basis, the contention being that this would better reflect the extent to which participants give rise to losses. Indeed, the BSC has included provisions to enable locational loss factors since the introduction of the New Electricity Trading Arrangements in 2001.

Transmission losses are allocated in the BSC by applying Transmission Loss Multipliers (TLMs) to scale up or down metered volumes for demand and generation. TLMs are calculated for each settlement period according to the following formula:

$$TLM = TLF + 1 + TLMO^{+/-}$$

[1] The LE/Ventyx CBA report is available on the ELEXON website, http://www.elexon.co.uk/documents/modifications/229/p229_proposed_cba_report_v1.0.pdf

The Transmission Losses Adjustment (TLMO$^{+/-}$) uniformly adjusts metered volumes such that 45% of total losses in the period are allocated to 'delivering BM Units' (eg generators) and 55% are allocated to 'offtaking BM Units' (eg customer demand). The Transmission Loss Factor (TLF) is BM Unit specific, thereby enabling losses to be allocated on a locational basis in principle. TLFs are currently set to zero for all BM Units and have no practical effect. Delivering BM Units therefore all face the same TLM, as do all offtaking BM Units.

The proposed modification P229 would introduce non-zero TLFs that vary by season and by zone. There would be 14 TLF zones based on the geographic areas covered by the Grid Supply Point (GSP) Groups. Historical data would be used to calculate a zonal TLF for each season of the following BSC Year.

1.3 Conventions

All modelled results are shown in real 2009 terms.

Net Present Values (NPVs) are calculated using a real post-tax discount rate of 4.42%, consistent with the central rate applied in the LE/Ventyx CBA study.

Following the convention of the LE/Ventyx study, unless otherwise stated input assumptions are set out on a calendar year basis whereas modelling results are presented on a financial (BSC Year) basis.

1.4 Report structure

The report is structured as follows:

- Section 2 explains our methodology and key assumptions
- Section 3 sets out the results of our benchmarking exercise, replicating the Reference scenario presented in the LE/Ventyx CBA study
- Section 4 presents our modelling for a 15 GW Offshore Wind scenario, which is characterised by high levels of offshore wind development relative to the Reference scenario
- Section 5 sets out our modelling results for the RES-E Target scenario, in which the 2020 renewable energy targets are met by developing significant onshore wind capacity in addition to 15 GW of offshore wind, and
- Section 6 compares the results of the three scenarios modelled and summarises our conclusions.

2 Methodology and Assumptions

2.1 Introduction

This section of the report summarises the key elements of our modelling approach and assumptions.

The majority of assumptions are common to the three scenarios modelled in this study and are derived largely from the Reference scenario presented in the LE/Ventyx CBA study. As shown in Table 1, the three scenarios differ in terms of new generation build and, to a limited extent, local transmission reinforcement.

Table 1 Scenario assumptions overview

<table>
<tr><th>Assumption</th><th>Reference scenario benchmark</th><th>15 GW Offshore Wind scenario</th><th>RES-E Target scenario</th></tr>
<tr><td>Offshore wind build</td><td>LE/Ventyx Reference</td><td colspan="2">15 GW by 2020</td></tr>
<tr><td>Onshore wind build</td><td colspan="2">LE/Ventyx Reference</td><td>11GW by 2020</td></tr>
<tr><td>CCGT build</td><td>LE/Ventyx Reference</td><td colspan="2">Partly displaced by wind</td></tr>
<tr><td>Nuclear and coal build</td><td colspan="3">Based on LE/Ventyx Reference</td></tr>
<tr><td>Plant retirements</td><td colspan="3">Based on LE/Ventyx Reference</td></tr>
<tr><td>Commodity prices</td><td colspan="3">Based on LE/Ventyx Reference</td></tr>
<tr><td>Electricity demand</td><td colspan="3">Based on LE/Ventyx Reference and Redpoint analysis</td></tr>
<tr><td>Transmission system</td><td colspan="3">Based on NGET SYS 2008, limited local reinforcement</td></tr>
<tr><td>Generator parameters</td><td colspan="3">Redpoint Energy GB dataset</td></tr>
<tr><td>Interconnectors</td><td colspan="3">Based on LE/Ventyx Reference and Redpoint analysis</td></tr>
<tr><td>Wind profiles</td><td colspan="3">Based on LE/Ventyx Reference and Redpoint analysis</td></tr>
</table>

2.2 Modelling framework

Generation dispatch and transmission load flows were modelled using the PLEXOS market simulation tool developed by Energy Exemplar[2], as described below.

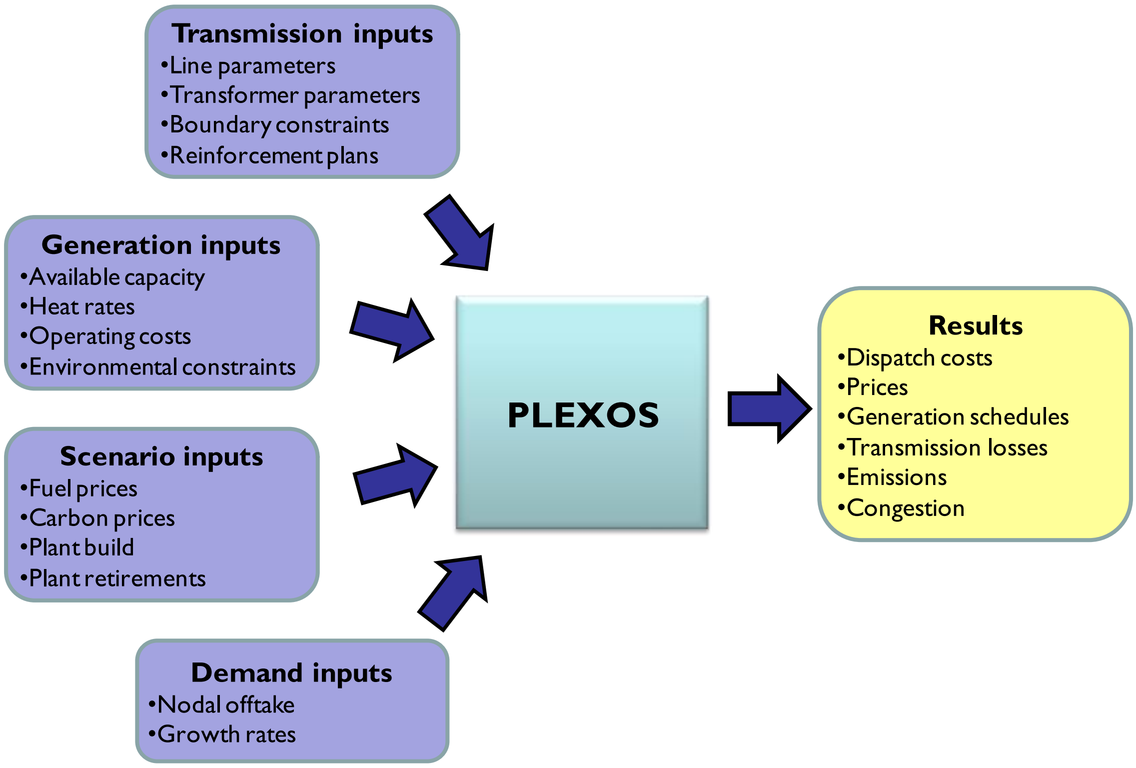
2.2.1 PLEXOS

PLEXOS is a commercially available power market modelling tool, incorporating a dispatch engine based on a detailed representation of generation plant and the transmission system. Redpoint has utilised PLEXOS in

[2] For further details of PLEXOS, please refer to Energy Exemplar's website, www.energyexemplar.com

several studies of the GB electricity market, including our recent assessment of grid access options for DECC. Figure 1 illustrates the key PLEXOS inputs and outputs which are relevant to this study.

Figure 1   PLEXOS inputs and outputs



PLEXOS is highly configurable with respect to transmission network modelling, allowing power markets to be analysed on a system-wide unconstrained basis at the simplest level or alternatively enabling a full DC load flow representation of every transmission node, line and transformer. For this study, PLEXOS was deployed to model the GB system on a nodal basis, mirroring what we understand to be the methodology applied by LE/Ventyx in the ELEXON CBA study.

Modelling the transmission system on a nodal basis leads to constrained dispatch schedules consistent with transmission line thermal ratings. PLEXOS also provides the capability to model contingencies and interface limits on transmission boundaries. For this study, we applied interface limits on the key B6 'Cheviot' boundary between England and Scotland[3].

The PLEXOS dispatch engine takes account of generator technical constraints such as minimum stable levels of generation and minimum up and down times. We modelled a full 365 day by 24 hour representation for each year. Consistent with the LE/Ventyx study, we assumed that plant in the GB electricity market self-dispatch on the basis of short run marginal costs (SRMC), adjusted if appropriate by zonal loss factors.

[3] The B6 'Cheviot' boundary currently has insufficient transfer capacity to comply with the NETS SQSS network planning standards and has been subject to a derogation since the NETA arrangements were extended to Scotland in 2005.

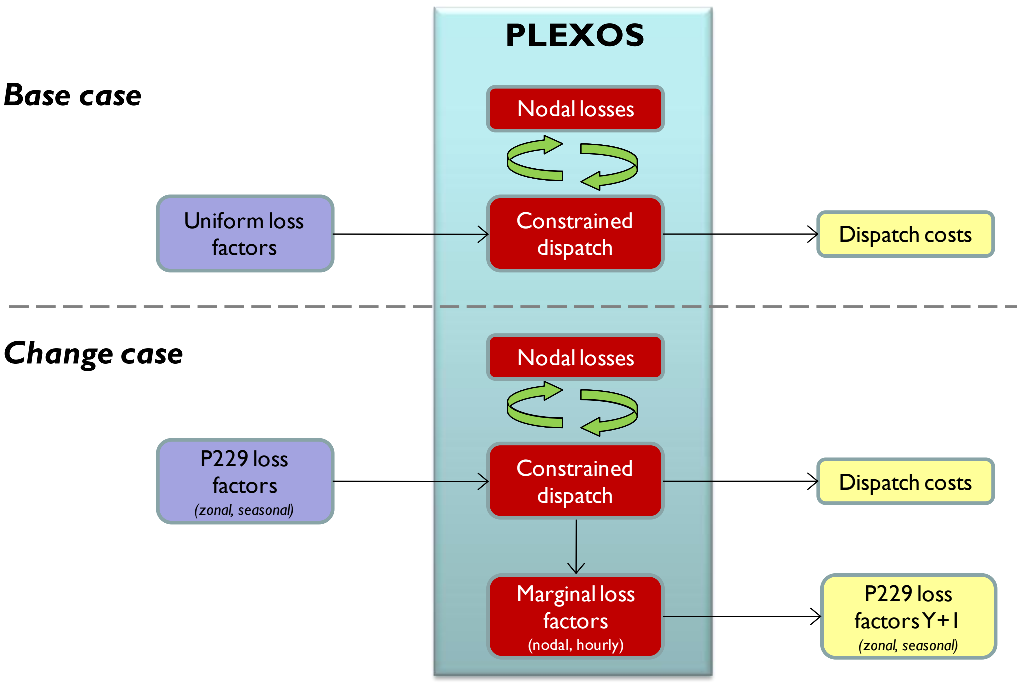
2.2.2 P229 modelling methodology

Before modelling additional scenarios, we first sought to benchmark our modelling approach and assumptions against the Reference scenario presented in the LE/Ventyx CBA study. This involved populating the PLEXOS modelling suite with detailed assumptions on generation, demand, transmission, fuel prices and carbon prices equivalent to those adopted by LE/Ventyx[4]. We then modelled the financial years 2011/12 to 2020/21 under a 'Base' case (with status quo uniform loss factors) and 'Change' case (P229 zonal loss factors).

The modelling process for the Reference scenario and the additional scenarios involved the following steps, as illustrated in Figure 2:

- model generation dispatch under the Base case with generators not exposed to zonal losses
- model generation dispatch under the P229 Change case applying the evolved zonal loss factors[5]
- calculate marginal loss factors for each period and node, using the DC loadflow modelling capability within PLEXOS, and
- aggregate the loss factors by season and zone to derive loss factors for the following year, as per the P229 methodology.

Figure 2 Modelling approach



PLEXOS has the capability to fully optimise generation and transmission, taking account of transmission losses and constraints. This capability is applied to model market arrangements such as those in New

[4] The appropriateness of these assumptions is discussed in the Lot 1 report.

[5] Seasonal zonal loss factors for the first year of the study, 2011/12, were derived by modelling the prior year with generators not exposed to zonal losses.

Zealand and the United States which feature locational marginal pricing (LMP). However, it would be inappropriate to model transmission losses as being fully optimised[6] with generation dispatch under the P229 proposals for the GB market. Under P229, generators will be expected to take account of static (seasonal, zonal) loss factors in their self-dispatch, whereas a fully optimised solution would imply dynamic hourly and nodal loss factors.

For this study, we configured PLEXOS to compute but not optimise transmission losses. We understand that LE/Ventyx applied a similar approach within their modelling framework. Our methodology involved a degree of iteration: generation is first dispatched to meet demand net of losses, line flows and losses are computed, then generation re-dispatched to meet demand including losses, and so on.

2.3 Common assumptions

This section outlines the common assumptions across the three scenarios in the following areas:

- Transmission system
- Commodity prices
- GB electricity demand
- Treatment of embedded generation
- Nuclear and coal build
- Nuclear retirement
- Thermal retirement
- Interconnectors
- Wind profiles
- Plant dataset

Scenario variables are described in Section 2.4.

2.3.1 Transmission system

We have configured a fully nodal representation of the GB transmission network in PLEXOS, using the 2008 edition of National Grid's Seven Year Statement (SYS) as our primary source of data. LE/Ventyx have confirmed that the 2008 SYS was used as a primary reference for their CBA study, and so for consistency we have used this edition as a starting point rather than more recent updates[7].

We populated our PLEXOS model with transmission line parameters – reactance, resistance and seasonal ratings – from the SYS. We have implemented the programme of transmission expansion and line upgrades set out in the 2008 SYS. This includes a number of major reinforcement projects such as the Beauly-Denny upgrade but does not extend beyond the 2014 horizon of the 2008 SYS. Consistent with the approach taken in the LE/Ventyx CBA study, we have not modelled transmission expansion beyond 2014. As a result, we have not incorporated the full set of reinforcements recommended by the Electricity Networks

[6] By 'fully optimised', we mean that transmission losses are included in the objective function of the dispatch algorithm and are therefore subject to cost minimisation.

[7] We have referred to the 2010 SYS to clarify our understanding of the network topography set out in the 2008 SYS and to inform decisions on potential local reinforcements.

Strategy Group (ENSG) in the March 2009 paper, *Our Electricity Transmission Network: A Vision for 2020*. For example, the proposed Eastern and Western offshore HVDC 'bootstraps' were not modelled.

In a limited number of cases, we have modelled localised reinforcement of the transmission system that was not specified in the 2008 SYS in order to accommodate new generation capacity (eg transformer upgrades).

As was the case in previous assessments of zonal losses including the LE/Ventyx study, the transmission network was modelled on an intact basis without considering transmission outages.

2.3.2 Commodity prices

Our modelled scenarios all use the LE/Ventyx CBA Reference assumptions for fuel and carbon prices. These commodity price assumptions are characterised by Brent crude prices rising in real terms over the modelling timeframe from a low of 63 \$/bbl in 2013 to 77 \$/bbl by 2021, NBP gas prices rising from 46 p/th to 55 p/th, coal prices rising to 70 £/t and carbon prices rising to 30 €/t. Figure 3 shows the evolution of annual commodity prices in traded units out to 2021, while Figure 4 shows prices in energy units.

Figure 3 Commodity price assumptions (traded units)

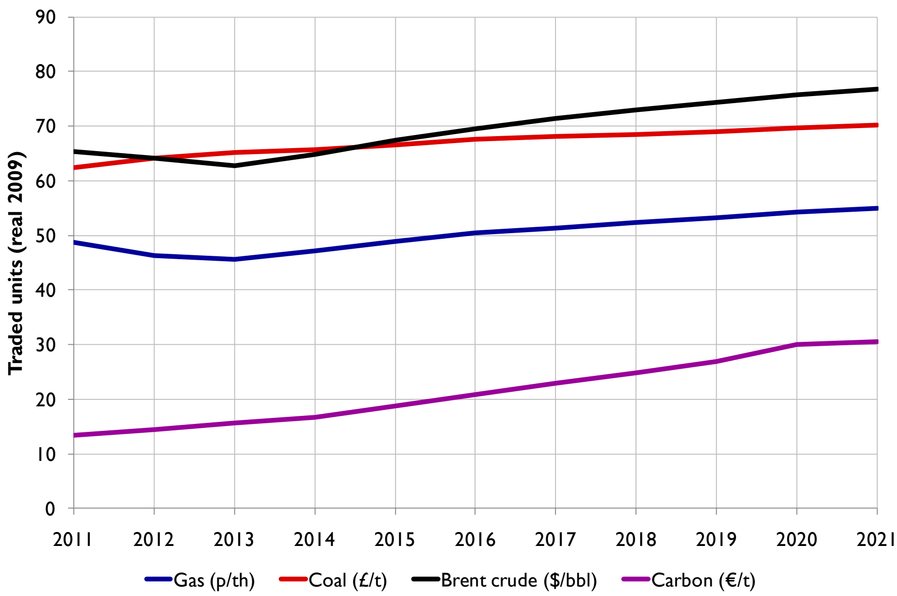
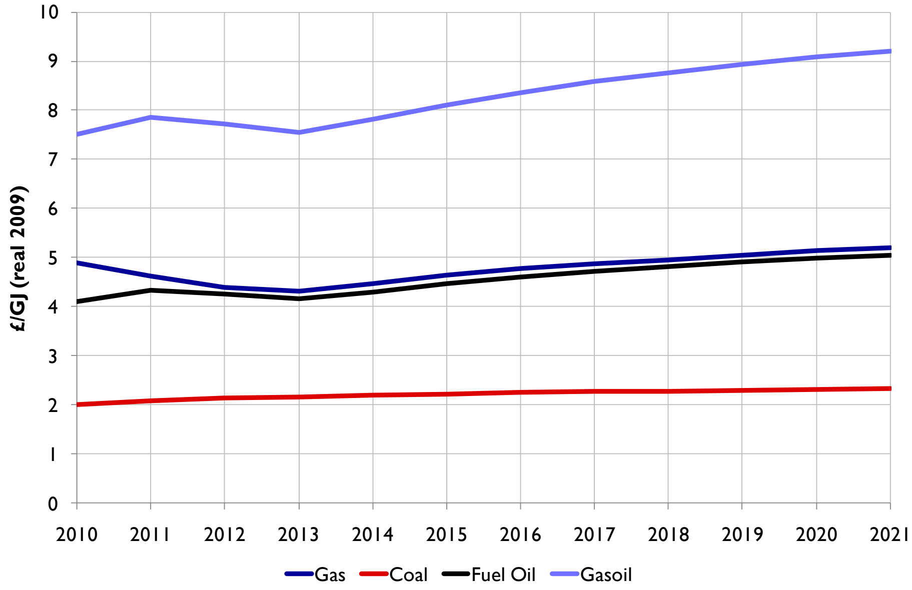
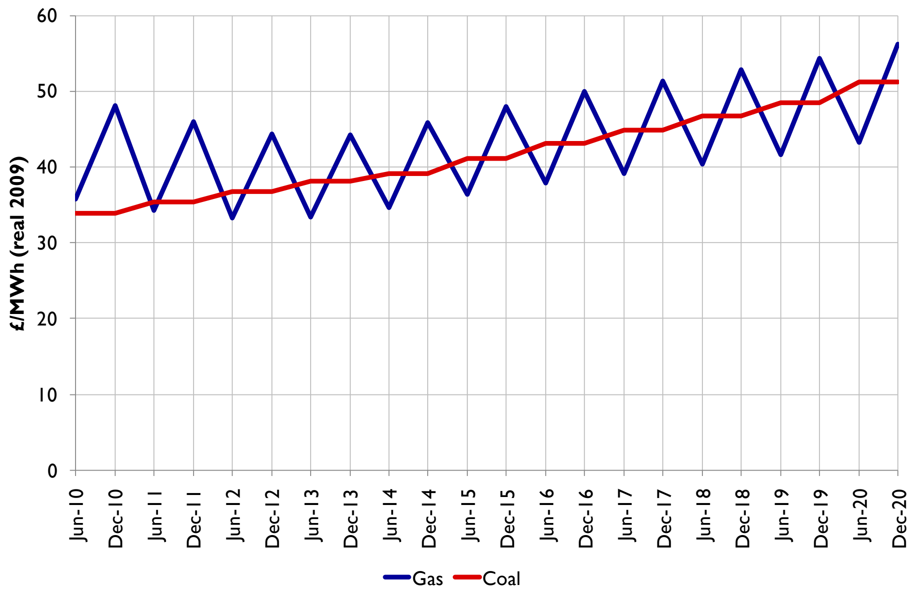


Figure 4 Commodity price assumptions (energy units)



Based on price seasonality information provided by LE/Ventyx, we have assumed that gas prices are 30% lower in the summer than the winter. On a plant SRMC basis, the commodity price assumptions are generally coal-favouring in the winter and gas-favouring in the summer. With the carbon price assumed to rise steadily out to 2020, the commodity price balance gradually shifts in favour of gas plant over the modelling timeframe. Figure 5 shows SRMCs out to 2020 for typical existing gas and coal generators[8] (noting that the gas SRMC incorporates seasonal variation in the gas price whereas coal prices are flat within year).

Figure 5 Typical gas and coal plant SRMCs



[8] Assuming 50% HHV efficiency for a gas-fired CCGT and 36.5% efficiency for a coal plant

Our interpretation of the LE/Ventyx Reference scenario assumptions implies that commodity prices are marginally coal favouring in the summer of 2010, but gas-favouring in subsequent summers. This prior year is modelled in order to derive TLFs for the 2011 /12 financial year under the P229 Change case.

2.3.3 GB electricity demand

The annual energy and peak demand assumptions used in this study are based on information provided by LE/Ventyx. Having clarified the treatment of embedded generation in the LE/Ventyx CBA study, our understanding is that demand was modelled net of the load met by embedded generators. This definition of demand therefore leads to values which are typically lower than those reported by National Grid (inclusive of large embedded generators) or by DECC (inclusive of large and small embedded generators).

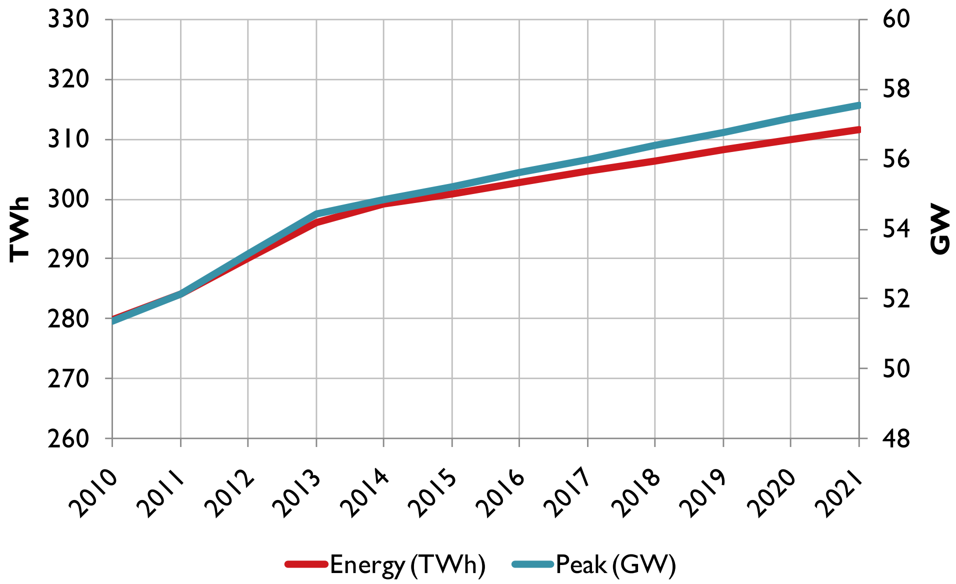
The evolution of energy and peak demand out to 2021 is summarised in Table 2 and illustrated in Figure 6[9].

Table 2 Net GB energy and peak demand

Calendar Year	Peak (GW)	Energy (TWh)
2010	51.3	279.8
2011	52.2	284.1
2012	53.3	290.2
2013	54.4	296.2
2014	54.8	299.2
2015	55.2	301.0
2016	55.6	302.8
2017	56.0	304.6
2018	56.4	306.4
2019	56.8	308.2
2020	57.2	309.9
2021	57.6	311.5

[9] Note that LE/Ventyx provided annual values using the net demand definition from 2011 to 2020. We have interpreted these values as being net of transmission losses and specified on a calendar year basis. Values for 2010 and 2021 were derived by interpolation and by inspection of Figure 4-5 in the LE/Ventyx CBA report.

Figure 6 Evolution of net GB energy and peak demand



An hourly profile of electricity demand was derived from outturn 2008 data published by National Grid and adjusted for outturn transmission losses using data published by ELEXON. This demand profile was then scaled and evolved within the PLEXOS modelling toolkit in order to meet the annual energy and peak values reported by LE/Ventyx. GB demand was allocated to individual transmission nodes using seasonal data in the 2008 SYS. The nodal distribution of demand was held constant from year to year.

2.3.4 Treatment of embedded generation

As noted above, the definition of demand applied in this study excludes demand met by embedded generation. As a result, we have not explicitly modelled existing embedded generators in the PLEXOS dispatch model. ELEXON BM Unit identifiers and National Grid SYS connection agreement types have been used to identify and remove existing embedded generators in our starting GB plant dataset. All the new build generation modelled in the scenario analysis – CCGTs, nuclear, CCS coal, onshore and offshore wind – is assumed to be transmission connected. Our treatment of embedded generation is consistent with our understanding of the approach adopted in the LE/Ventyx CBA study.

2.3.5 Nuclear and coal build

The majority of the new generation investment modelled in the three scenarios comprises gas-fired CCGTs and onshore and offshore wind capacity. The differing scenario assumptions on capacity build for these technologies are set out below in Section 2.4. In addition to the CCGT and wind build, a number of new nuclear and coal projects are assumed to come online towards the end of the study period, consistent with the LE/Ventyx Reference scenario[10]. Assumptions for these projects are set out in Table 3.

[10] Note that the second 'Generic Nuke' coming online in 2020 in the LE/Ventyx study was assumed to be located at Oldbury (OLDS12). Because significant grid reinforcement would be required in our model to accommodate a large nuclear unit on the 132 kV network at Oldbury, we re-located the new plant to the nearby Hinkley Point site.

Table 3 Nuclear and coal build

Plant	Type	Capacity (MW)	Node	Commissioning Date
Wylfa	Nuclear	1650	WYLF40	1/1/2017
Hinkley Point	Nuclear	1650	HINP40	1/1/2020
Teesport	Coal (IGCC[11])	925	TEEP40	1/1/2020
Abernedd Stage 1	Coal (IGCC + CCS)	435	BAGB20	1/1/2020
Blythe	Coal (IGCC + CCS)	1600	BLYT40	1/1/2021
Hatfield	Coal (IGCC + CCS)	800	THOB40	1/1/2021

2.3.6 Nuclear retirement

The remaining Magnox reactors and the majority of AGR plant are set to retire over the next ten years. Our assumed nuclear retirement dates are shown in Table 4, and are consistent with Table 4-11 of the LE/Ventyx CBA report.

Table 4 Nuclear retirements

Plant	Type	Capacity (MW)	Retirement Date
Oldbury	Magnox	475	31/12/2010
Wylfa	Magnox	1009	31/12/2010
Hartlepool	AGR	1207	31/12/2014
Heysham 1	AGR	1165	31/12/2014
Hinkley Point B	AGR	1295	31/12/2016
Hunterston B	AGR	1288	31/12/2016
Dungeness B	AGR	1089	31/12/2018

2.3.7 Thermal retirement

The Large Combustion Plant Directive (LCPD) will lead to the closure of significant thermal generation capacity over the next five years. Coal and oil plant which have opted out of the LCPD must retire by the end of 2015. The remaining coal plant that have opted in to the LCPD will be approaching operating lifetimes of 50 years towards the end of the study period, and may require substantial capital investment to maintain their competitiveness and comply with tightening environmental standards.

For the purposes of this study, we have sought to replicate the retirement decisions modelled in the LE/Ventyx CBA Reference scenario. LE/Ventyx have not published their assumptions on retirement schedules for individual thermal plant, but have indicated the aggregate level of capacity assumed to retire each year by plant type and by TLF zone. Based on this information, our assumptions on closure dates are shown in Table 5.

[11] Integrated Gasification Combined Cycle (IGCC), a generation technology with improved efficiency relative to conventional coal plant.

Table 5 Thermal plant retirements

Plant	Type	Capacity (MW)	Retirement Date
Cockenzie	LCPD Opt-out Coal	1200	31/12/2012
Didcot A	LCPD Opt-out Coal	1960	31/12/2013
Kingsnorth	LCPD Opt-out Coal	1940	31/12/2014
Ferrybridge	LCPD Opt-out Coal	980	31/12/2014
Tilbury	LCPD Opt-out Coal	1041	31/12/2015
Ironbridge	LCPD Opt-out Coal	964	31/12/2015
Littlebrook	Oil	1475	31/12/2015
Grain	Oil	1300	31/12/2015
Fawley	Oil	1002	31/12/2015
Eggborough (Units 1,4)	LCPD Opt-in Coal	970	31/12/2015
Ratcliffe (Unit 1)	LCPD Opt-in Coal	500	31/12/2017
Ratcliffe (Units 2, 3)	LCPD Opt-in Coal	1000	31/12/2018
Ratcliffe (Unit 4)	LCPD Opt-in Coal	500	31/12/2019
Cottam	LCPD Opt-in Coal	1980	31/12/2019
West Burton	LCPD Opt-in Coal	1968	31/12/2019
Peterhead (Unit 2)	Gas	660	31/12/2019
Fiddler's Ferry (Unit 1)	LCPD Opt-in Coal	490	31/12/2020

By adopting this retirement profile, we believe that our assumptions on the zonal distribution of plant closures are broadly consistent with the LE/Ventyx Reference scenario[12].

Opted out coal plant under the LCPD are restricted to 20,000 running hours between January 2008 and their closure date. This restriction is modelled in the PLEXOS dispatch tool by imposing an annual load factor constraint. We used historic data[13] on LCPD plant running hours to March 2010 to determine the remaining hours of operation for each plant.

2.3.8 Interconnectors

Our assumptions on interconnection are shown in Table 6, with the timing and capacity of planned interconnectors based upon the assumptions published by LE/Ventyx.

[12] One exception is that LE/Ventyx indicated the retirement of 1.8 GW of gas-fired capacity in the Northern TLF zone by 2013. We have retained this capacity on the system to provide peaking cover in our study due to the tight capacity margins seen after 2015 in our modelling of the Reference scenario, particularly at times of low wind availability. We have not compared our detailed assumptions (eg hourly wind profiles or plant outage rates) with LE/Ventyx to establish whether capacity margins were materially tighter in our modelling.

[13] See BMRS website http://www.bmreports.com/bsp/bes.php?prefix=LCPD

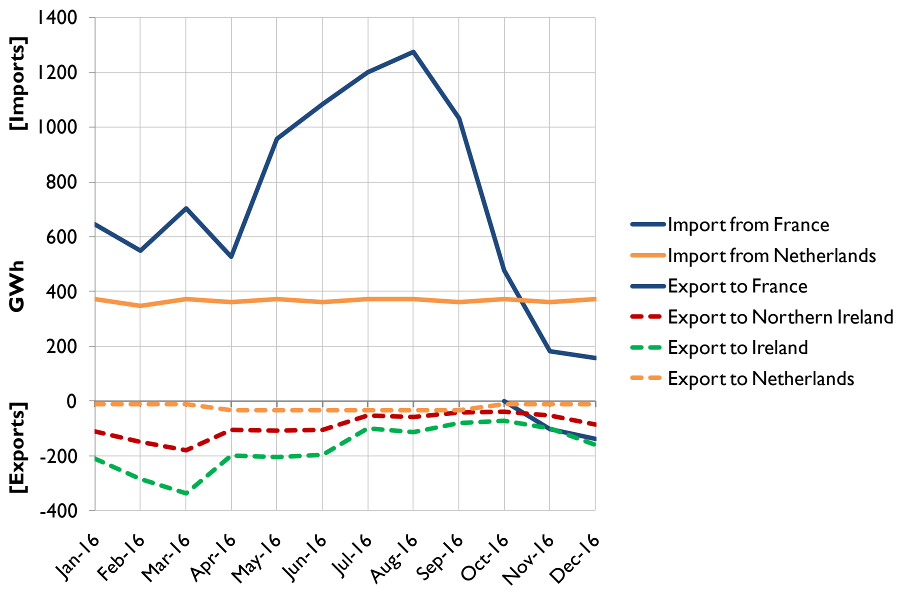
Table 6 Interconnection capacity

Interconnector	Capacity (MW)	GB node	Year
France	2000	SELL40	Online
Northern Ireland (Moyle)	450 (from GB) 80 (to GB)	AUCH20	Online
Netherlands (BritNed)	1000	GRAI40	1/1/2011
Ireland (EirGid East-West)	500	DEES42	1/1/2013
Ireland (Imera East-West)	350	DEES42	1/1/2016

For consistency with the LE/Ventyx CBA study, we have modelled interconnector flows using the same fixed hourly shapes in all scenarios for both the Base and Change cases. LE/Ventyx have not published their detailed assumptions on interconnector flows but have described the general methodology they adopted. In seeking to replicate this methodology, we have used historical flow data from 2007 and 2008 to derive characteristic monthly flow profiles on an EFA[14] block basis for the existing French and Moyle interconnectors. The new interconnectors to Ireland were assumed to follow the same pattern as Moyle. Consistent with our understanding of the LE/Ventyx assumptions, the BritNed interconnector was modelled as importing to GB during peak periods, with a low level of exports off-peak.

Figure 7 shows the assumed monthly profile of imports and exports for each interconnector in a sample year 2016.

Figure 7 Monthly interconnector import and exports for 2016



[14] The Electricity Forward Agreement (EFA) calendar commonly used for GB power trading is composed of four hour blocks. The six blocks that make up a trading day begin at 23:00 and follow at four hour intervals.

2.3.9 Wind profiles

We have modelled wind variability by using historic wind speed data to develop hourly availability profiles for onshore and offshore wind plant. For consistency with the LE/Ventyx study, the modelled availability profiles were equivalent to a 27% annual capacity factor for onshore wind farms and 36% for offshore wind farms, with no geographic variation in profiles. It should be noted that although we matched the LE/Ventyx profiles on an annual average basis, our wind profiles are likely to differ hour by hour.

2.3.10 Plant dataset

We utilised a proprietary Redpoint dataset of GB generation plant for this study[15]. The dataset includes assumptions on parameters such as heat rates, start costs, outage rates, variable operating costs and plant dynamic constraints.

2.4 Scenario variables

The three scenarios modelled in this study are distinguished by differing levels of investment in new wind and CCGT capacity.

The 2009 EU *Directive on the promotion of the use of energy from renewable sources* requires the UK to meet a target of 15% renewable energy in 2020. Given the limitations on expanding the contribution of renewables within the heat and transport sectors, the Government's *Renewable Energy Strategy* (RES) envisages that a target level of around 30% of large-scale electricity generation from renewable sources by 2020 will be necessary to deliver the UK's overall renewable energy target. The Reference scenario presented in the LE/Ventyx CBA study would undershoot a 30% renewable electricity target by a considerable margin. We have therefore developed alternative scenarios to explore the impact of more aggressive renewables deployment on the P229 CBA.

2.4.1 Offshore wind build

The LE/Ventyx Reference scenario assumes that around 5 GW of offshore wind capacity will be commissioned by 2020. LE/Ventyx have presented an annual total for offshore wind capacity together with a regional capacity breakdown for the spot years 2011 and 2020. In order to benchmark the Reference scenario, we have developed an offshore wind capacity build profile consistent with the annual totals and spot year breakdowns provided by LE/Ventyx. We used National Grid's TEC register (as of June 2010 [add link]) to identify candidate offshore projects for development in each region, and then adjusted capacities and timings if necessary to match the LE/Ventyx totals. Onshore connection locations were informed by the TEC register, the SYS and the National Grid *Round 3 Offshore Wind Farm Connection Study* for the Crown Estate[16].

Table 7 shows our assumptions on the evolution of offshore wind capacity by TLF zone for the Reference scenario.

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[15] The LE/Ventyx CBA study utilised a proprietary Ventyx database of the GB electricity market.

[16] See The Crown Estate website: http://www.thecrownestate.co.uk/round3_connection_study.pdf

REDPOINT

Table 7 Offshore wind capacity – Reference scenario

Zone (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
01 - Eastern	664	664	664	664	664	664	664	1,105	1,105	1,105
02 - East Midlands	-	-	-	-	-	-	-	-	-	-
04 - Merseyside & North Wales	-	149	549	735	735	735	735	735	813	1,262
07 - North Western	338	338	338	338	368	368	368	368	368	368
09 - South Eastern	-	201	201	201	201	201	648	657	789	789
11 - South Western	-	-	-	214	706	1,157	1,157	1,157	1,157	1,157
12 - Yorkshire	-	-	-	-	-	-	-	-	210	210
13 - South of Scotland	-	-	-	-	-	-	-	-	-	-
14 - North of Scotland	338	338	338	338	338	338	338	338	368	368
Total	**1,340**	**1,690**	**2,090**	**2,490**	**3,012**	**3,463**	**3,910**	**4,360**	**4,810**	**5,259**

As stated in ELEXON's Final Modification Report, the P229 Modification Group raised concerns that developments planned for Round 3 of Offshore Connection were not included in the LE/Ventyx CBA modelling. Recognising this concern, we have developed the 15 GW Offshore Wind scenario with significantly higher levels of offshore wind development by 2020 compared to the Reference scenario.

By assuming that all the offshore projects currently listed in the TEC register proceed to completion, we obtain around 11 GW of offshore wind capacity by 2020. In order to meet a total installed capacity of 15 GW in 2020, we then modelled the commissioning of an additional 1 GW of offshore capacity in four of the Round 3 zones with the greatest development potential, namely Dogger Bank, Hornsea, Norfolk and the Irish Sea.

Table 8 shows our assumptions on the evolution of offshore wind capacity by TLF zone for the 15 GW Offshore Wind scenario. This offshore wind build profile was also applied to the RES-E Target scenario.

Table 8 Offshore wind capacity – 15 GW Offshore Wind and RES-E Target scenarios

Zone (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
01 - Eastern	1,729	1,729	2,229	2,229	2,729	2,729	3,729	3,729	4,129	4,129
02 - East Midlands	-	-	-	-	-	-	-	400	400	800
04 - Merseyside & North Wales	-	147	441	735	735	735	735	1,735	1,735	1,735
07 - North Western	514	514	847	847	847	847	847	847	847	847
09 - South Eastern	327	831	831	1,201	1,201	1,201	1,201	1,201	1,201	1,201
11 - South Western	-	-	-	302	706	1,110	1,515	1,515	1,515	1,515
12 - Yorkshire	-	-	220	395	395	895	1,395	1,395	2,395	3,395
13 - South of Scotland	-	-	-	450	450	450	450	450	450	450
14 - North of Scotland	-	-	-	-	-	-	-	-	-	1,000
Total	**2,570**	**3,221**	**4,568**	**6,159**	**7,063**	**7,967**	**9,872**	**11,272**	**12,672**	**15,072**

As in the Reference scenario, onshore connection points were informed by the TEC register, SYS and the National Grid / Crown Estate study. Modelling an intact transmission network, we found that the majority of the offshore wind farms included in the study operated unconstrained without additional onshore reinforcement. However, in the North of Scotland zone, we have modelled a reinforcement of the onshore transmission network north of Beauly in 2020 to accommodate the 1 GW of offshore wind capacity assumed in the 15 GW Offshore Wind and RES-E Target scenarios.

2.4.2 Onshore wind build

The LE/Ventyx Reference scenario assumes that around 6 GW of (transmission-connected) onshore wind capacity will be commissioned by 2020. LE/Ventyx have presented an annual total for onshore wind capacity together with a regional capacity breakdown for the spot years 2011 and 2020. Onshore wind development is assumed to be focused in Scotland, with 60% of 2020 installed capacity in the South of Scotland and 40% in the North of Scotland.

In order to benchmark the Reference scenario, we used National Grid's 2008 SYS to identify potential sites for transmission-connected onshore wind projects in Scotland. We then adjusted project capacities and timings if necessary to match the LE/Ventyx totals. Table 9 shows our assumptions on the regional evolution of onshore wind capacity for the Reference scenario. This onshore wind build profile was also applied to the 15 GW Offshore Wind scenario.

Table 9 Onshore wind capacity – Reference and 15 GW Offshore Wind scenarios

Region (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North of Scotland	862	985	1,162	1,349	1,574	1,819	1,998	2,167	2,342	2,524
South of Scotland	2,586	2,711	2,936	3,149	3,401	3,638	3,710	3,741	3,766	3,784
England & Wales	-	-	-	-	-	-	-	-	-	-
Total	**3,448**	**3,696**	**4,098**	**4,498**	**4,976**	**5,458**	**5,709**	**5,908**	**6,108**	**6,308**

The third scenario in this study, RES-E Target, examines the impact of a more ambitious expansion of onshore wind capacity in the period to 2020. Our objective was to develop sufficient onshore wind capacity, in combination with 15 GW offshore wind, to meet the 2020 RES-E target of around 30% of electricity generation from renewable sources. Allowing for generation by existing embedded wind farms[17] and taking account of other renewable sources (eg hydro), we estimated that around 11 GW of transmission-connected onshore wind capacity would be required to meet the 2020 target in this scenario.

We started with the capacity build profile assumed in the Reference scenario and then used National Grid's TEC register and 2010 SYS to identify additional sites for onshore wind development. Table 10 shows our assumptions on the regional evolution of onshore wind capacity for the RES-E Target scenario.

Table 10 Onshore wind capacity – RES-E Target scenario

Region (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North of Scotland	988	1,136	1,449	2,300	2,526	2,771	2,950	3,628	4,566	4,876
South of Scotland	2,875	3,096	3,411	3,699	3,951	4,188	4,322	4,503	4,628	4,725
England & Wales	-	299	299	299	396	580	980	1,280	1,280	1,399
Total	**3,863**	**4,531**	**5,160**	**6,299**	**6,873**	**7,539**	**8,252**	**9,411**	**10,474**	**11,000**

We modelled localised reinforcement of the transmission network (eg, transformer upgrades) in a limited number of cases to alleviate constraints at wind connection sites. However, as outlined above, we have not modelled major network reinforcement plans beyond those specified in the 2008 SYS. As a result, our modelling shows that there will be hours in which some wind plant[18] are required to reduce output due to constraints on the transmission network. In practice further transmission upgrades are likely to occur before 2020, mitigating the incidence of transmission constraints. Nevertheless, our modelling outcome is not inconsistent with the recent Government decision to implement a 'Connect and Manage' regime for transmission access[19], as wind generation investment may proceed in advance of full network reinforcement.

[17] As explained previously, embedded capacity is only modelled implicitly in this and the LE/Ventyx study due to the net demand definition applied.

[18] Note that in our modelling framework, wind farms will be constrained off after other low marginal cost generators such as hydro.

[19] The implementation of the enduring 'Connect and Manage' access regime was confirmed in July 2010 as part of the Annual Energy Statement, http://www.decc.gov.uk/en/content/cms/news/pn10_85/pn10_85.aspx

2.4.3 CCGT build

Gas-fired CCGTs have been the main technology of choice for new generation capacity in the GB electricity market ever since the 1990s 'dash for gas'. A number of CCGT plants are currently either in commissioning or under construction, while several more projects are in the planning phase. For consistency, we have followed the CCGT build assumptions in the LE/Ventyx Reference scenario. However, we have deferred some CCGT projects beyond 2020 in the 15 GW Offshore Wind and RES-E Target scenarios to accommodate higher levels of renewable build. Table 11 shows our assumptions on CCGT build.

Table 11 CCGT build

Plant	Type	Capacity (MW)	Node	Commissioning Date	Scenario
Marchwood	CCGT	850	MAWO40	1/9/2009	All
Langage	CCGT	885	LANG40	1/3/2010	All
Grain 1	CCGT	400	GRAI41	1/4/2010	All
Grain 2	CCGT	800	GRAI41	1/9/2010	All
Severn Power	CCGT	800	USKM20	1/4/2010	All
Staythorpe 1	CCGT	425	STAY41	1/6/2010	All
Staythorpe 2	CCGT	425	STAY41	1/10/2010	All
Staythorpe 3	CCGT	850	STAY41	1/1/2011	All
West Burton	CCGT	1270	WBUR40	1/7/2011	All
Drakelow D 1	CCGT	410	DRAK41	1/1/2015	All
Drakelow D 2	CCGT	410	DRAK42	1/1/2015	All
Drakelow D 3	CCGT	410	DRAK41	1/1/2015	All
Pembroke	CCGT	2000	PEMB40	1/1/2016	All
Thor Cogeneration	CCGT	1020	BRNF40	1/1/2017	Reference
Barking C	CCGT	470	BARP22	1/1/2018	All
Partington	CCGT	860	CARR4A	1/1/2018	All
Amlwch	CCGT	270	AMLW40	1/1/2019	Reference 15 GW Offshore Wind
Sutton Bridge B	CCGT	1305	SUTB4B	1/1/2019	All
Little Barford B	CCGT	475	LITB40	1/1/2020	Reference
South Holland	CCGT	840	SPLN40	1/1/2020	All
Thames Haven	CCGT	840	TILB40	1/1/2020	All

Relative to the Reference scenario, the higher levels of renewable generation in the 15 GW Offshore Wind and RES-E Target scenarios are likely to displace the output of existing generating plant as well as postpone some investments in conventional plant. We have deferred beyond 2020 two CCGT projects in the 15 GW Offshore Wind scenario and three CCGT projects in the RES-E Target scenario, with the aim of maintaining a broadly consistent de-rated peak capacity margin[20] across the three scenarios. We have not

[20] The de-rated peak capacity margin is a measure of expected peak availability compared to peak demand. This takes into account a 'capacity credit' for each generation type, which measures the percentage of maximum potential output that statistically can be shown to contribute to peak

sought to evaluate the investment economics of individual CCGT projects, but have taken the view that projects on northern sites are more likely to be deferred under the current TNUoS[21] charging methodology.

supply. For conventional plant this will cover forced outages, and for intermittent (wind and wave) and variable-output (tidal) renewables it will in addition account for expected output based on probabilistic analysis of resource levels.

[21] The locational element of Transmission Network Use of System (TNUoS) charges currently leads to generation facing higher charges in the north while demand faces higher charges in the south. The charging methodology and tariffs are available from NGET's website, http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

3 Reference scenario benchmark results

3.1 Introduction

This section describes the results for the Reference scenario which we have modelled to benchmark our modelling framework against the LE/Ventyx study. We begin by presenting the cost-benefit analysis (CBA) and then describe the evolution of capacity margins, generation and emissions in the Reference scenario. Finally we set out our TLF and TLM results and consider the potential impact of P229 upon wholesale prices.

3.2 CBA

Table 12 summarises the CBA results for the Reference scenario, excluding changes in NO_x and SO_2 emissions. We have followed the CBA methodology applied in the LE/Ventyx study. The key component of the CBA emerging from the modelling exercise is the difference (delta) in generation production costs between the Base and Change cases. The delta in production costs reflects the impact of P229 loss factors upon generation dispatch costs, carbon emission costs and overall transmission losses. The estimates of P229 implementation and ongoing costs are taken from the LE/Ventyx study, as is the discount rate assumption of 4.42% real. Our modelling of the Reference scenario indicates a total net benefit of £47.7mn from P229 between 2011/12 and 2020/21. This result is comparable to the £46.1mn net benefit[22] reported in the LE/Ventyx study.

Table 12 CBA – Redpoint Reference scenario

Year	Production cost savings (£mn)	Implementation costs (£mn)	Ongoing costs (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	-5.26	-3.85	-0.16	-9.27	-8.88
2012/13	11.85		-0.16	11.69	10.72
2013/14	10.27		-0.16	10.12	8.89
2014/15	6.75		-0.16	6.59	5.54
2015/16	7.07		-0.16	6.91	5.57
2016/17	8.78		-0.16	8.62	6.65
2017/18	8.65		-0.16	8.49	6.28
2018/19	8.38		-0.16	8.22	5.82
2019/20	5.35		-0.16	5.20	3.52
2020/21	5.71		-0.16	5.55	3.60
Total					**47.71**

[22] LE/Ventyx separately modelled 'discounted demand side-benefits' of £1.7mn, leading to a total reported CBA benefit of £47.9mn. We have not modelled demand side-benefits in this study.

The LE/Ventyx CBA study also sought to quantify the value of changes in the level of NO_x and SO_2 emissions under P229. To benchmark these results, we have taken NO_x and SO_2 emission results from our PLEXOS model and applied the emission price assumptions used by LE/Ventyx[23], £2,493/t for NO_x and £1,319/t for SO_2. Table 13 shows our CBA results for the Reference scenario, including changes in NO_x and SO_2 emissions. The modelling shows a reduction in NO_x and SO_2 emissions under the P229 Change case, which leads to an increase in the CBA results if the value of NO_x and SO_2 emissions is included. Our results indicate a total net benefit including NO_x and SO_2 changes of £161.1mn, compared to £275.2mn in the LE/Ventyx study.

Table 13 CBA with SO_2 and NO_x emissions – Redpoint Reference scenario

Year	Change in SO_2 emissions (£mn)	Change in NO_x emissions (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	3.87	17.01	11.60	11.11
2012/13	-3.81	10.02	17.90	16.41
2013/14	-1.16	10.64	19.60	17.22
2014/15	2.47	9.04	18.10	15.22
2015/16	2.04	7.33	16.28	13.11
2016/17	2.56	8.36	19.54	15.08
2017/18	2.56	9.45	20.50	15.15
2018/19	4.02	14.43	26.67	18.87
2019/20	5.72	20.11	31.03	21.03
2020/21	4.82	17.28	27.65	17.94
Total				**161.14**

Consistent with the LE/Ventyx study, our modelling of the Reference scenario therefore shows a positive net benefit for the introduction of zonal loss factors under P229, irrespective of whether the valuation of NO_x and SO_2 emissions is included in the assessment. Table 14 compares our annual discounted CBA results with the LE/Ventyx results for the Reference scenario.

[23] As described on page 44 of the ELEXON CBA report, LE/Ventyx derived their emission price assumptions from a range of available information sources.

Table 14 Comparison of annual discounted CBA results – Redpoint and LE/Ventyx Reference scenarios

Year	Annual discounted CBA excluding NO_x and SO_2 (£mn)		Annual discounted CBA including NO_x and SO_2 (£mn)	
	Redpoint	LE/Ventyx	Redpoint	LE/Ventyx
2011/12	-8.88	2.74	11.11	17.2
2012/13	10.72	6.35	16.41	58.41
2013/14	8.89	5.47	17.22	30.26
2014/15	5.54	4.06	15.22	28.07
2015/16	5.57	2.86	13.11	33.75
2016/17	6.65	3.58	15.08	22.05
2017/18	6.28	2.55	15.15	19.05
2018/19	5.82	6.19	18.87	22.27
2019/20	3.52	5.60	21.03	22.73
2020/21	3.60	6.73	17.94	21.38
Total	**47.71**	**46.12**	**161.14**	**275.16**

Our benchmark modelling of the Reference scenario closely matches the LE/Ventyx study for the overall CBA total without NO_x and SO_2, although the CBA results do differ in individual years. One notable difference from LE/Ventyx is that we find a net disbenefit in the first year, 2011/12. P229 implementation costs are assigned to the Change case in this year, but we also found an increase in production costs under the Change case for 2011/12. We discuss the change in production costs below.

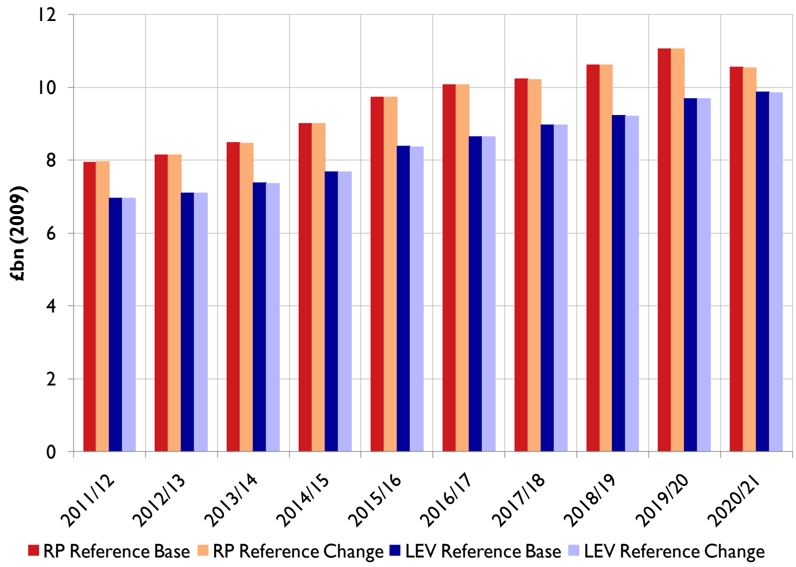
The differential in the Reference scenario CBA results is greater once the valuation of NO_x and SO_2 emission changes is included. Although we used the same NO_x and SO_2 price assumptions as LE/Ventyx, we note that the modelling of future NO_x and SO_2 emission levels is highly sensitive to assumptions on fuel specifications (eg coal sulphur content), plant efficiencies, emissions abatement parameters and LCPD compliance operating regimes. Without access to the detailed assumptions of the LE/Ventyx study, we have not been in a position to fully reconcile the observed differences in NO_x and SO_2 emission results.

3.3 Production cost savings

As shown by the CBA results, the Redpoint and LE/Ventyx modelling indicates that a primary benefit of P229 arises from a reduction in production costs when generators are exposed to zonal loss factors. These production costs savings include the impact of lower overall generation levels due to reduced transmission losses.

Figure 8 compares the annual production costs for the Reference scenario Base and Change cases from the Redpoint and LE/Ventyx studies. Our total production costs are consistently higher than those reported by LE/Ventyx but follow the same trends. Differences in input data assumptions such as plant efficiencies and non-fuel variable operating costs are likely to explain the variance in absolute production costs. However, a detailed comparison of the Redpoint and LE/Ventyx datasets was outside the scope of this project.

Figure 8 **Production costs – Redpoint and LE/Ventyx Reference scenarios**



Although our absolute production costs differ from those reported by LE/Ventyx, the deltas in production costs between the Base and Change cases are broadly consistent. Table 15 compares the annual production savings modelled in the two studies.

Table 15 **Production cost savings – Redpoint and LE/Ventyx Reference scenarios**

Year	Redpoint Reference (£mn)	LE/Ventyx Reference (£mn)
2011/12	-5.26	6.87
2012/13	11.85	7.09
2013/14	10.27	6.40
2014/15	6.75	5.00
2015/16	7.07	3.72
2016/17	8.78	4.82
2017/18	8.65	3.63
2018/19	8.38	8.98
2019/20	5.35	8.49
2020/21	5.71	10.63

Production cost savings under the Change case are observed for the duration of the study period. However, as noted previously, our modelling of the Reference scenario differs from LE/Ventyx in showing a disbenefit (production cost increase) in the first year. Our results showed production costs increasing in the Change case during the summer of 2011, outweighing production cost savings during winter 2011/12.

We believe there are two factors driving the increase in production costs seen in the first year of our study:

- 2011/12 TLFs are derived from transmission flows in a prior year in which generators are not exposed to zonal losses, whereas TLFs in subsequent years are derived from loss-adjusted generation schedules, and
- assumed commodity price movements lead to significant fuel switching in 2011/12 compared to the prior year used for TLF derivation.

The combined effect of these two factors is that the TLFs applied to 2011/12 are derived from a prior year with materially different generation schedules and transmission flows. As illustrated in Figure 5, our interpretation of the LE/Ventyx Reference scenario assumptions is that commodity prices are marginally coal-favouring in the summer of 2010, but gas-favouring in subsequent summers. Table 16 shows that there is a significant switch from coal to gas generation between 2010/11 and 2011/12 in our modelling of the Reference scenario. However, aggregate generation results provided by LE/Ventyx for 2011/12 show coal and gas output levels closer to our results for 2010/11, implying that LE/Ventyx did not see significant fuel switching in 2011/12. The costs of coal and gas generation are very close in summer 2011, and so minor differences in input assumptions such as plant efficiencies or variable operating costs may have a significant impact upon modelled generation outcomes.

Table 16 Coal and gas generation output – Reference scenario

Plant type	Redpoint (GWh)			LE/Ventyx (GWh)	
	2010/11	2011/12 Base	2011/12 Change	2011/12 Base	2011/12 Change
Coal	134,304	110,174	106,719	140,277	139,348
Gas	65,477	96,190	99,253	57,368	58,042

Although LE/Ventyx did not see production cost disbenefits under the Reference scenario, we note that LE/Ventyx reported low or negative production cost savings under their 'Low Gas Prices' and 'Volatile Fuel Prices' scenarios in certain years. In the LE/Ventyx Volatile Fuel Prices scenarios, production cost savings were particularly low in years of falling gas prices (eg 2016/17), which are likely to be associated with coal to gas switching relative to the prior year used for TLF derivation.

3.4 Transmission losses

Figure 9 shows the annual transmission losses arising from our modelling of the Reference scenario, together with the results reported by LE/Ventyx. Overall transmission losses are broadly comparable between the two studies. In common with LE/Ventyx, we found that the application of zonal loss factors in the Change case reduced outturn transmission losses in each year of the study. This reduction in transmission losses drives the production cost savings and CBA benefits observed in the modelling of P229.

Figure 9 Annual transmission losses – Redpoint and LE/Ventyx Reference scenarios

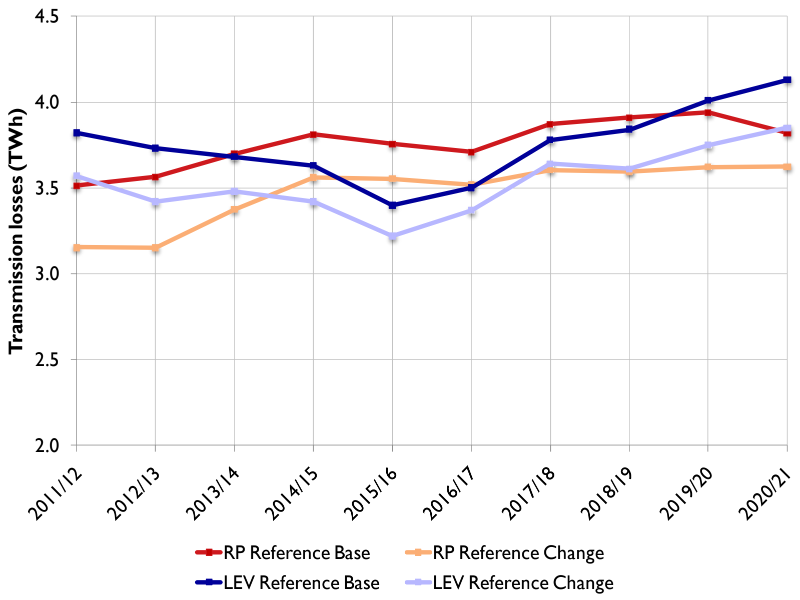


Table 17 shows the annual reduction in transmission losses for the Change case relative to the Base case. Our modelling generally indicates larger transmission loss savings compared to the LE/Ventyx study.

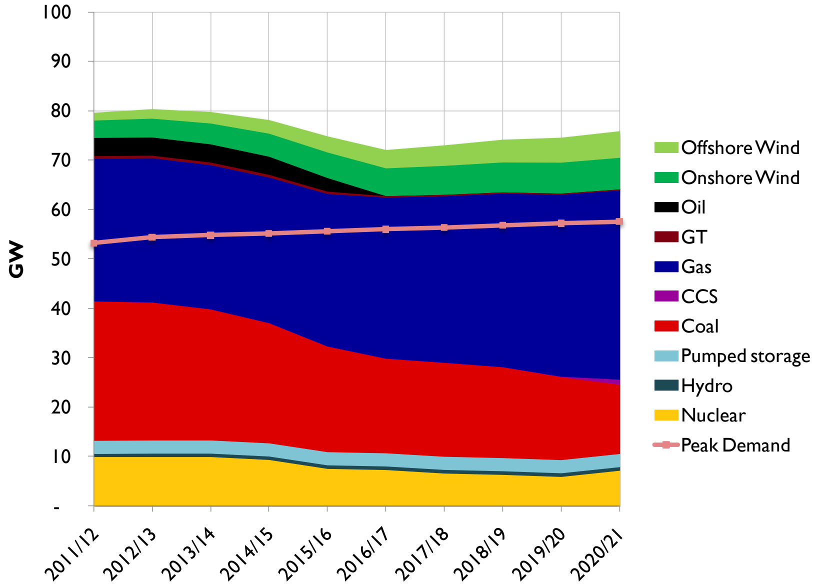
Table 17 Transmission loss savings – Redpoint and LE/Ventyx Reference scenarios

Year	Redpoint change in transmission losses (GWh)	LE/Ventyx change in transmission losses (GWh)
2011/12	361	203
2012/13	414	308
2013/14	324	202
2014/15	254	212
2015/16	203	195
2016/17	190	121
2017/18	265	133
2018/19	317	211
2019/20	319	245
2020/21	199	282

3.5 Installed capacity and margin

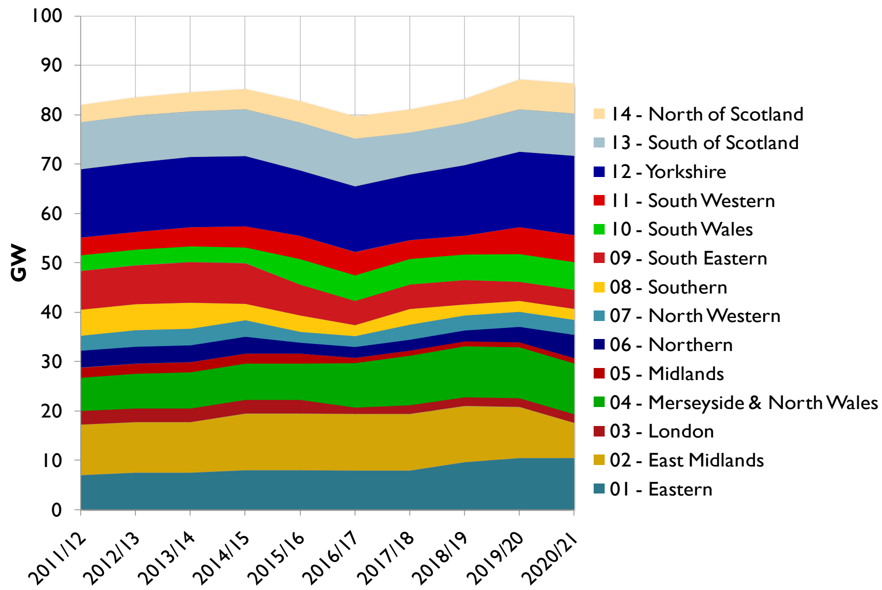
The installed capacity and generation mix provide the background context for the production cost savings and transmission loss reductions observed in modelling the P229 Change case. The Reference scenario is characterised by an increasingly gas dominated capacity mix following the retirement of coal and oil plant and the entry of new CCGTs. Figure 10 shows the evolution of installed capacity by fuel type. Peak demand is also shown for comparison.

Figure 10 Capacity by fuel type – Reference scenario



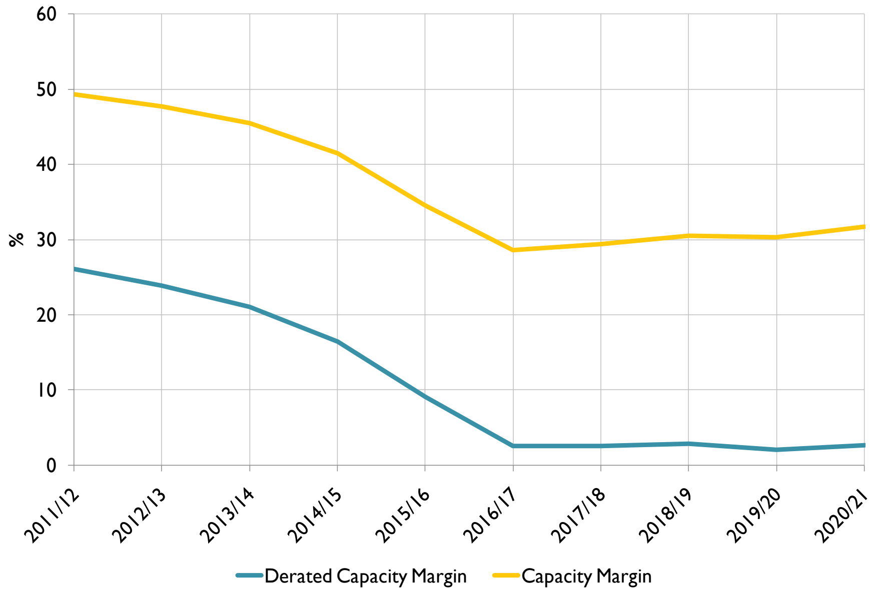
The geographic distribution of generation capacity is illustrated in Figure 11. TLF zones with significant generation capacity include Yorkshire and East Midlands.

Figure 11 Capacity by zone – Reference scenario



The changes in total capacity illustrated above are reflected in the capacity margin. Figure 12 shows two measures of capacity margin – a non-derated margin based on installed capacity and a derated margin reflecting expected availability at peak times. The plant retirement and build profiles assumed for the Reference scenario lead to a sharp fall in capacity margins over the first half of the study, coinciding with the closure of opted-out LCPD plant. De-rated capacity margins are then tight by historical standards from 2016 onwards[24].

Figure 12 Capacity margins – Reference scenario

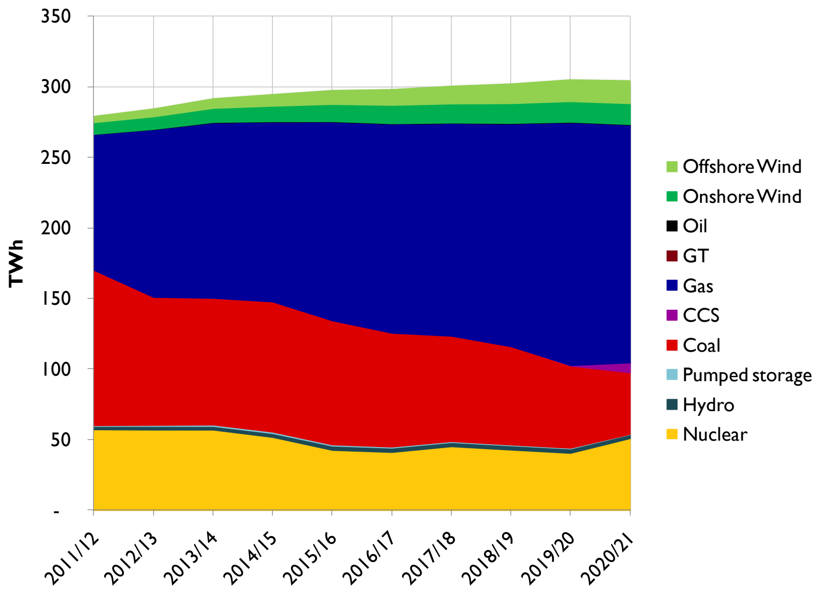


3.6 Generation by fuel type and zone

The Reference scenariois characterised by a progressive shift to gas-fired generation, with gas-fired generation of 96 TWh in 2011/12 increasing to 169 TWh in 2020/21 in the base case. This reflects the assumptions on relative commodity prices and coal plant retirement. The evolution of generation output by fuel type is illustrated in Figure 13 for the Base case.

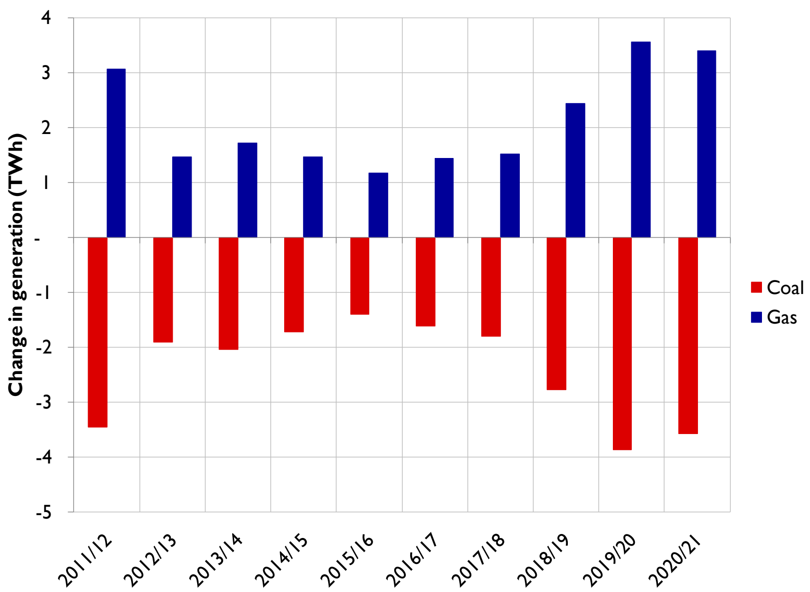
[24] Note that interconnector capacity has been excluded from this capacity margin analysis, as has interconnector export demand. Interconnector flows have been modelled using fixed profiles in this study. In practice, interconnector flows would be expected to respond dynamically to arbitrage opportunities between markets.

Figure 13 Generation by fuel type – Reference scenario Base case



Comparing the Base and Change case runs under the Reference scenario, the key observation is the switch from coal to gas generation when loss factors are applied, as shown in Figure 14.

Figure 14 Change in coal and gas generation – Reference scenario



Zonal generation output is shown for the Reference Base run in Figure 15. The zones with the highest generation output are Yorkshire and East Midlands.

Figure 15 Generation by zone – Reference scenario Base case

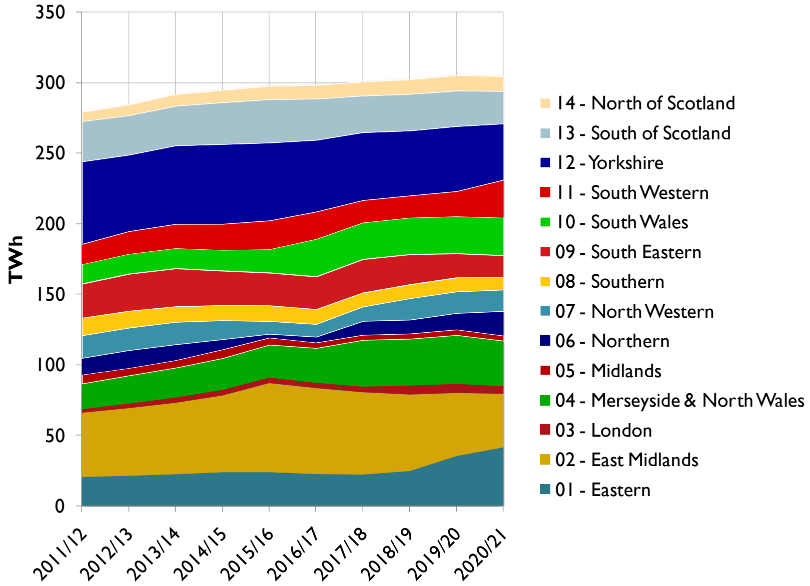
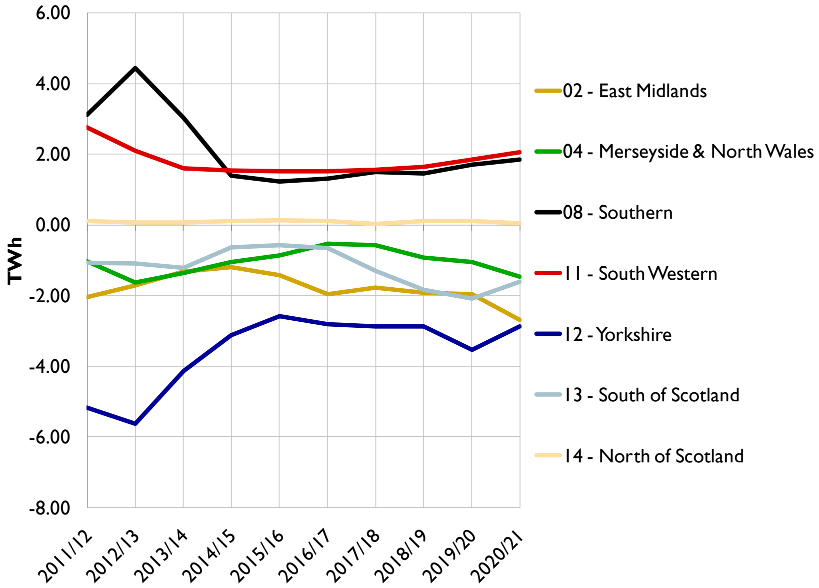


Figure 16 shows the delta in zonal generation between the Base and Change cases for a selection of zones Under the Reference scenario Yorkshire has the largest reduction in generation from the Base to the Change case, followed by East Midlands, South of Scotland and Merseyside & North Wales. The greatest increases in generation are in the Southern and South Western zones.

Figure 16 Generation change by zone – Reference scenario

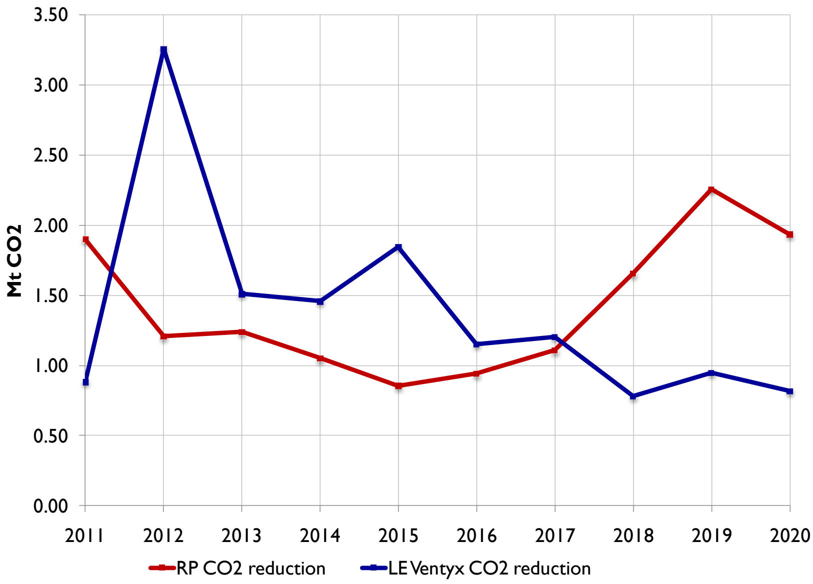


In summary, the application of transmission loss factors in the Change case causes a switch in generation output at the margin from northern, predominantly coal plant to southern, typically gas plant.

3.7 Emissions

The shift from coal to gas generation – together with an overall reduction in generation output due to lower transmission losses – causes carbon emissions to fall in the Change case relative to the Base. Figure 17 illustrates the reduction in CO_2 emissions for the Reference scenario from the Redpoint and LE/Ventyx studies.

Figure 17 CO_2 reduction – Redpoint and LE/Ventyx Reference scenario



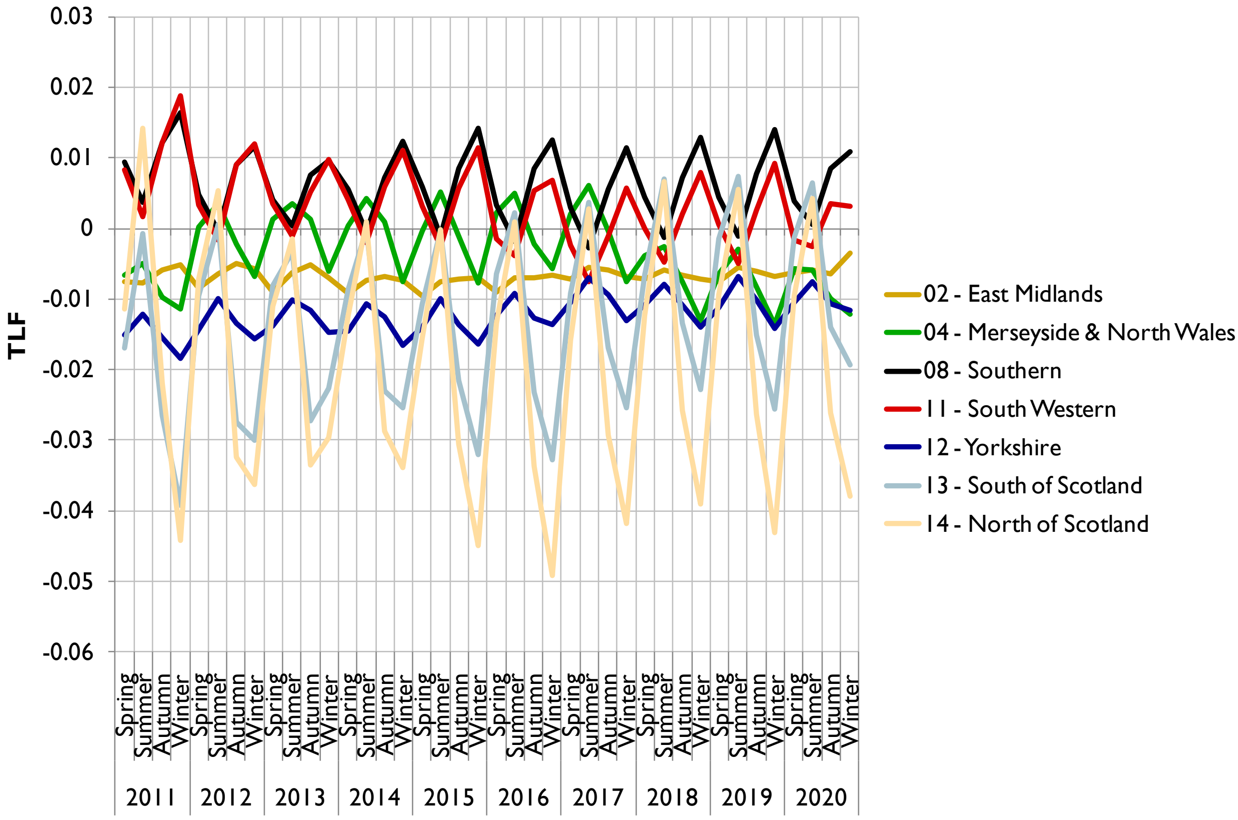
3.8 TLFs and TLMs

Zonal TLFs were calculated for each BSC season[25], using the Change case modelling results from the previous year. Figure 18 shows the evolution of the zonal TLFs in the Reference scenario for a selection of zones. Average seasonal TLFs for all zones are shown in the Appendix.

The TLFs exhibit a strong seasonal pattern, reflecting seasonal variations in the regional generation mix and transmission flows. These seasonal patterns are driven in part by the modelling assumptions on gas price seasonality and wind availability profiles. Consistent with previous studies, southern zones with limited generation resources (eg London) see positive TLFs whereas northern zones in which generation tends to increase marginal transmission losses typically see negative TLFs. While the two Scottish zones have the most negative TLF values in the winter, these zones generally see positive summer TLFs due to lower levels of thermal and renewable generation being modelled over the summer months.

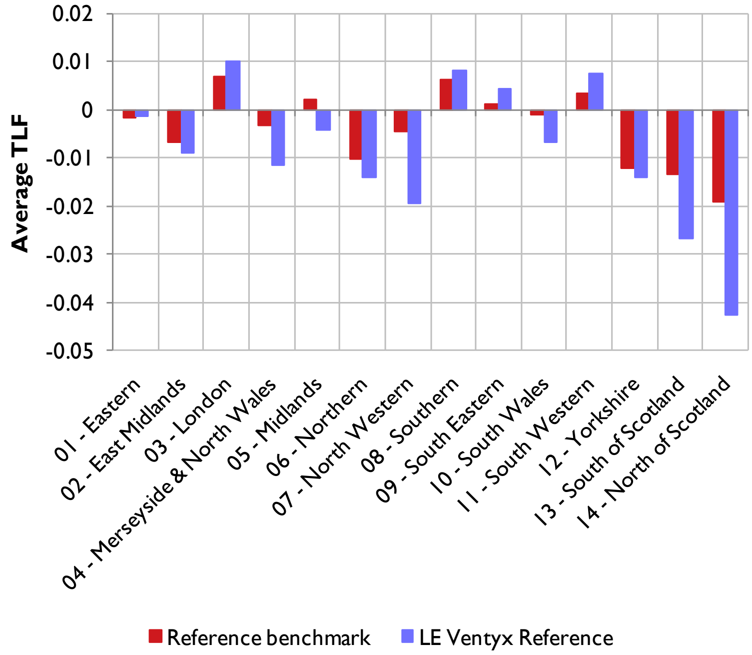
[25] The BSC seasons are Spring (March to May), Summer (June to August), Autumn (September to November) and Winter (December to February). Since the BSC Year runs from April to March, the application of Spring TLFs is split between the start and end of the financial year (ie the TLFs applying in March match those applying in the preceding April and May).

Figure 18 Change case TLFs – Reference scenario



The regional and seasonal patterns of the Change case TLFs arising from our modelling of the Reference scenario are broadly consistent with the results reported by LE/Ventyx. Figure 19 compares the Reference scenario TLFs for each zone (averaged for all years and seasons) from the Redpoint and LE/Ventyx studies.

Figure 19 **Comparison of average TLFs – Reference scenario Change case**



Our understanding, as clarified with ELEXON, is that LE/Ventyx applied TLFs rather than TLMs in their generation dispatch model. We have therefore followed the same approach, applying no transmission loss adjustments in the Base case (TLF equal to zero) and the seasonal zonal TLFs in the Change case.

In practice, TLMs would apply in both the Base and Change cases, and would vary half-hourly depending on actual transmission losses and the geographic distribution of generation and demand. Given that the differential between TLFs and TLMs is uniform across all zones, the choice of modelling TLFs or TLMs does not affect the merit order impact of P229 or the delta in production costs that underpins the CBA.

Although TLFs were applied in the generation dispatch modelling, we have also derived indicative TLMs on a seasonal basis, using the zonal results from PLEXOS for generation, demand and interconnector flows. We have followed the same methodology as ELEXON did in calculating the indicative TLMs published as an appendix to the P229 Assessment Report. Seasonal TLMs for delivering and offtaking units derived from our modelling of the Reference scenario are shown in the Appendix (averaged over the ten year study period).

3.9 Wholesale prices

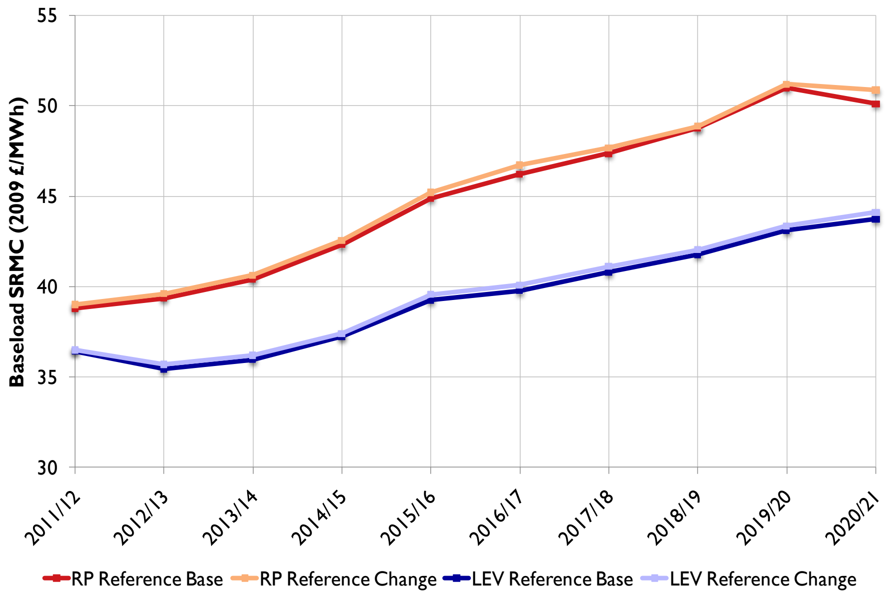
As described above, we have followed the CBA methodology set out in the LE/Ventyx study in basing the assessment of P229 upon changes in generation production costs. It is also instructive to consider the potential impact of P229 upon wholesale electricity prices. We have extracted price results from our PLEXOS modelling runs, as illustrated below. Changes in wholesale prices were also reported for the LE/Ventyx study. However, a number of caveats should be kept in mind in relation to these wholesale price results:

- wholesale price results for both the LE/Ventyx and Redpoint studies are taken from transmission constrained models of the generation sector, whereas the GB electricity market is intended to clear on an unconstrained basis

- both studies assume that wholesale price formation is based upon generators' short run marginal costs (SRMC), and therefore ignore the possibility of alternative bidding behaviours (eg mark-ups to reflect contributions towards fixed and capital costs), and
- we have followed LE/Ventyx in applying TLFs rather than TLMs in the generation dispatch model.

The annual time-weighted SRMC-based prices for the Redpoint and LE/Ventyx Reference scenario modelling runs are shown in Figure 20. As noted previously in the context of production costs, the Redpoint price results are consistently above the LE/Ventyx prices, which points to a difference in input data assumptions such as plant efficiencies or non-fuel variable operating costs.

Figure 20 Baseload SRMC price – Redpoint and LE/Ventyx Reference



The differences in baseload prices between the Base and Change cases are shown in Table 18. In common with LE/Ventyx, we observed slightly higher prices under the Change case with the TLF-based modelling showing an average price increase of around 0.3 £/MWh. We have also estimated the potential change in wholesale prices, had TLMs rather than TLFs been applied in the modelling to more accurately reflect the allocation of transmission losses under the BSC market rules. This TLM-adjusted price differential is shown in the final column.

Table 18 Change in baseload price – Redpoint and LE/Ventyx Reference scenarios

Year	LE/Ventyx (2009 £/MWh)	Redpoint (2009 £/MWh)	TLM-adjusted Redpoint (2009 £/MWh)
2011/12	0.06	0.24	-0.01
2012/13	0.26	0.25	0
2013/14	0.24	0.22	-0.03
2014/15	0.17	0.25	-0.02
2015/16	0.31	0.32	0.02
2016/17	0.32	0.49	0.21
2017/18	0.31	0.31	0.03
2018/19	0.28	0.1	-0.19
2019/20	0.25	0.19	-0.11
2020/21	0.38	0.75	0.46
Average	0.26	0.31	0.04

In practice, generators are exposed to TLMs rather than TLFs. In the Base case (TLMs always less than one) generators would be expected to pass through their share of anticipated transmission losses in the wholesale price. The TLM-adjusted wholesale prices in the Base case are therefore consistently higher than those reported by the TLF-based modelling. In the Change case, the direction of the TLM price adjustment varies over time according to whether the zonal TLFs have under- or over-recovered generators' share of transmission losses. The net impact of TLM adjustments to the Base and Change case wholesale prices is that prices increase under P229 in some years and fall in others. The average TLM-adjusted P229 price change is negligible, at around 0.04 £/MWh.

4 15 GW Offshore Wind scenario results

4.1 Introduction

This section sets out our modelling results for the 15 GW Offshore Wind scenario, which is characterised by a much more aggressive deployment of offshore wind capacity compared to the Reference scenario.

4.2 CBA

Table 19 summarises the CBA results for the 15 GW Offshore Wind scenario, excluding changes in NO_x and SO_2 emissions. Assumptions on implementation and ongoing costs are taken from the Reference scenario. Applying a real discount rate of 4.42%, our modelling indicates a total net benefit of £36.6mn from P229 under this scenario.

Table 19 CBA – 15 GW Offshore Wind scenario

Year	Production cost savings (£mn)	Implementation costs (£mn)	Ongoing costs (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	-3.73	-3.85	-0.16	-7.74	-7.41
2012/13	10.26		-0.16	10.10	9.27
2013/14	8.56		-0.16	8.41	7.38
2014/15	6.98		-0.16	6.82	5.74
2015/16	6.07		-0.16	5.91	4.76
2016/17	8.07		-0.16	7.92	6.11
2017/18	3.80		-0.16	3.64	2.69
2018/19	2.08		-0.16	1.92	1.36
2019/20	4.49		-0.16	4.33	2.93
2020/21	5.93		-0.16	5.78	3.75
Total					**36.57**

A higher overall net benefit of £136mn is observed if the analysis is extended to consider the value of reduced NO_x and SO_2 emissions, as shown in Table 20.

Table 20 CBA with SO_2 and NO_x emissions – 15 GW Offshore Wind scenario

Year	Change in SO_2 emissions (£mn)	Change in NO_x emissions (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	3.27	18.51	14.04	13.45
2012/13	-5.65	9.24	13.70	12.56
2013/14	-1.40	10.89	17.90	15.72
2014/15	1.58	9.65	18.05	15.18
2015/16	1.84	8.00	15.75	12.68
2016/17	2.93	9.84	20.69	15.96
2017/18	2.81	10.65	17.10	12.63
2018/19	3.61	12.43	17.97	12.71
2019/20	3.93	12.87	21.12	14.31
2020/21	2.46	7.75	15.99	10.38
Total				**135.59**

4.3 Losses

The application of zonal loss factors in the Change case of the 15 GW Offshore Wind scenario leads to transmission loss savings in each year studied, as shown in Table 21.

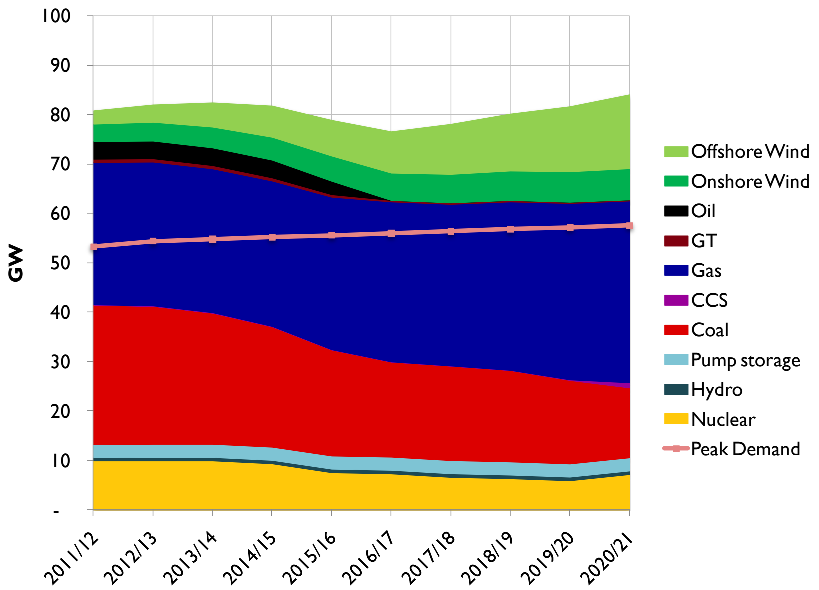
Table 21 Transmission losses – 15 GW Offshore Wind scenario

Year	Base (TWh)	Change (TWh)	Difference (TWh)
2011/12	3.44	3.05	-0.39
2012/13	3.41	3.03	-0.39
2013/14	3.62	3.32	-0.31
2014/15	3.69	3.45	-0.24
2015/16	3.65	3.44	-0.20
2016/17	3.76	3.56	-0.19
2017/18	3.74	3.53	-0.21
2018/19	3.84	3.59	-0.25
2019/20	4.11	3.87	-0.24
2020/21	4.25	4.09	-0.16

4.4 Installed capacity and margin

Figure 21 shows the evolution of generation capacity in the 15 GW Offshore Wind scenario. Retiring coal and oil plant are mainly replaced by gas-fired CCGTs and offshore wind farms in this scenario.

Figure 21 Capacity by fuel type – 15 GW Offshore Wind scenario



The geographic distribution of generation capacity in this scenario is illustrated in Figure 22.

Figure 22 Capacity by zone – 15 GW Offshore Wind scenario

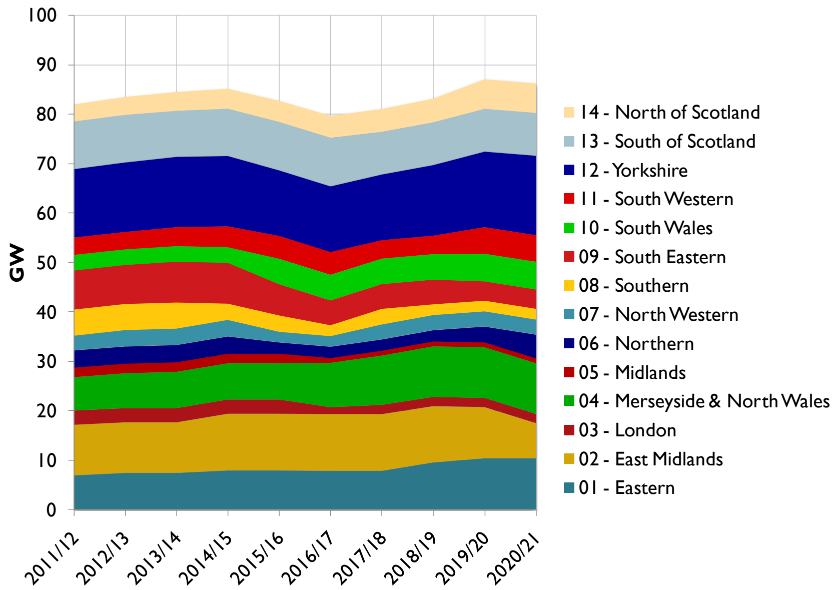
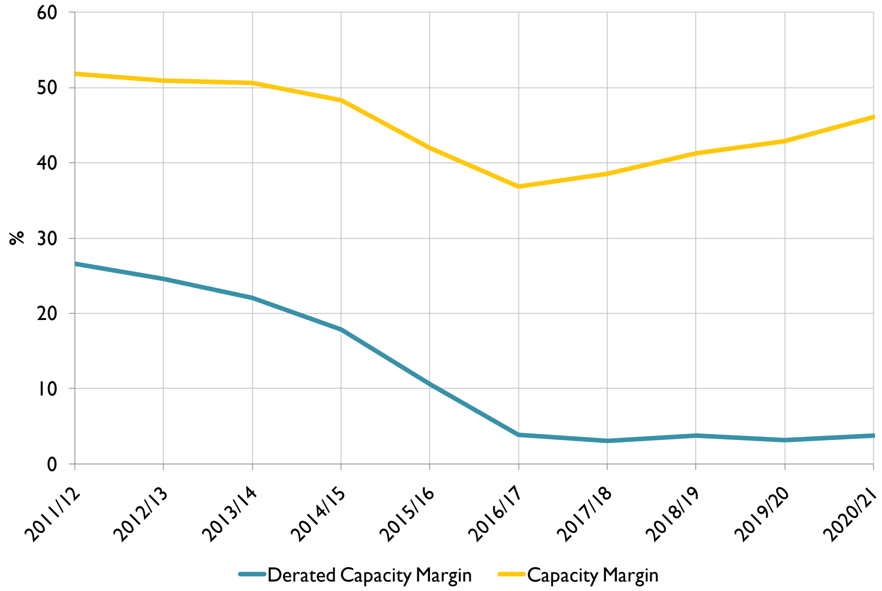


Figure 23 shows the evolution of capacity margins in the 15 GW Offshore Wind scenario. Although the non-derated capacity margin is notably higher than that shown for the Reference scenario, the derated margin is broadly consistent due to the relatively low capacity credit assumed for offshore wind.

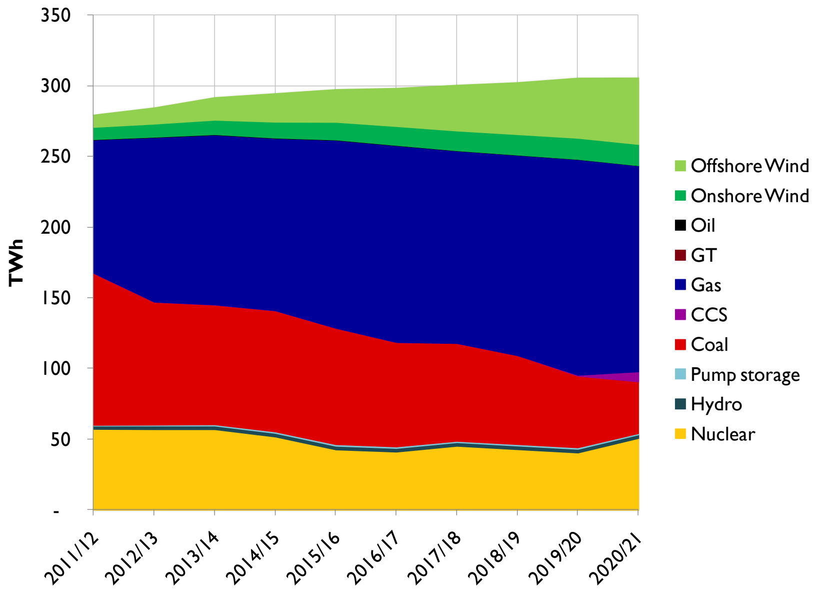
Figure 23 Capacity margins – 15 GW Offshore Wind scenario



4.5 Generation by fuel type and zone

The 15 GW Offshore Wind scenario follows the same trend towards gas-fired generation as the Reference scenario, reflecting the common assumptions on commodity prices and plant retirements. The generation mix in the Base case in shown in Figure 24.

Figure 24 Generation by fuel type – 15 GW Offshore Wind scenario Base case



As in the Reference scenario, the key impact of zonal loss factors in the 15 GW Offshore Wind scenario is to switch coal to gas generation. Figure 25 shows the deltas in gas and coal generation in the Change case compared to the Base case.

Figure 25 Change in generation from coal and gas – 15 GW Offshore Wind scenario

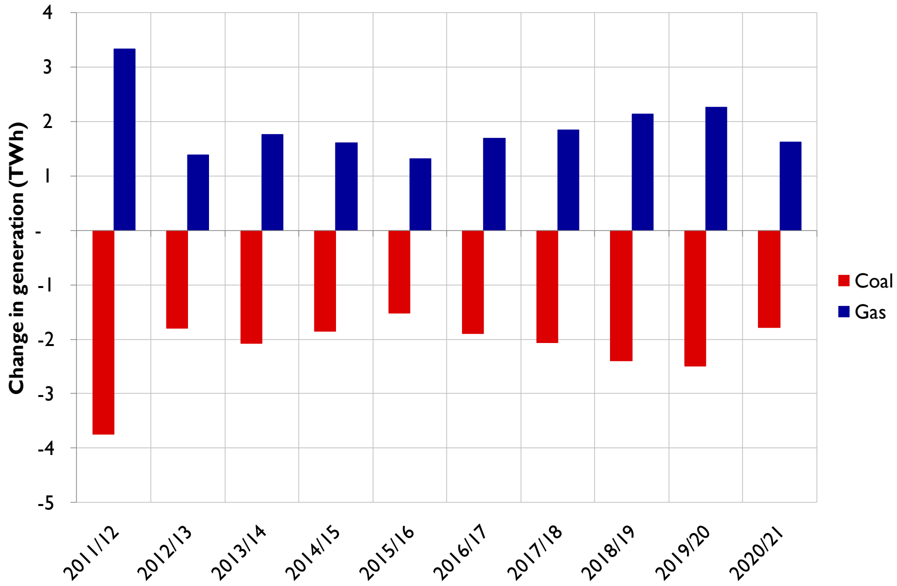


Figure 26 shows the geographic split of generation in the Base case, while Figure 27 shows how the regional pattern of generation changes when zonal loss factors are applied for a selection of zones.

Figure 26 Generation by zone – 15 GW Offshore Wind scenario Base case

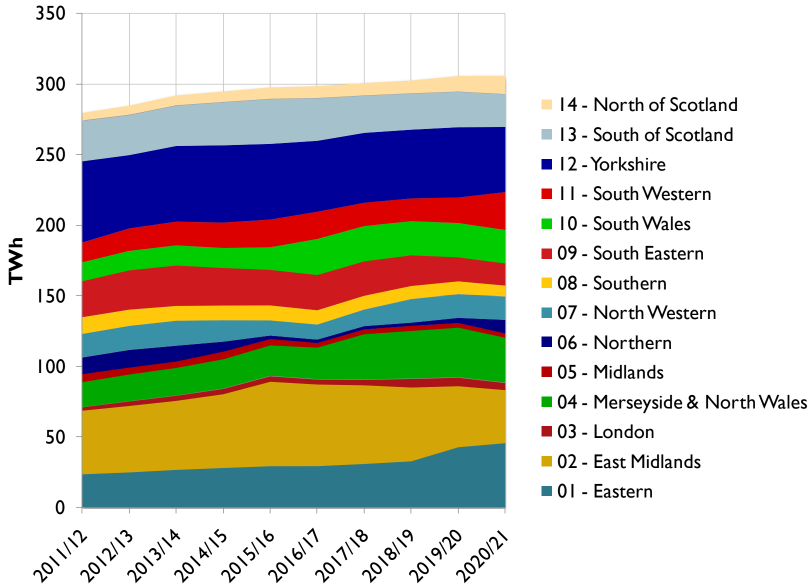
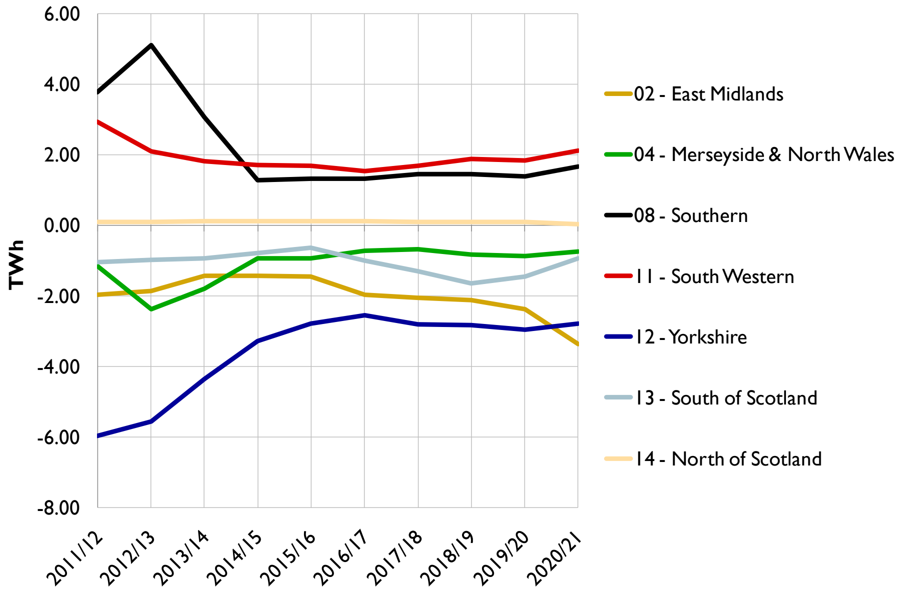


Figure 27 Generation change by zone – 15 GW Offshore Wind scenario

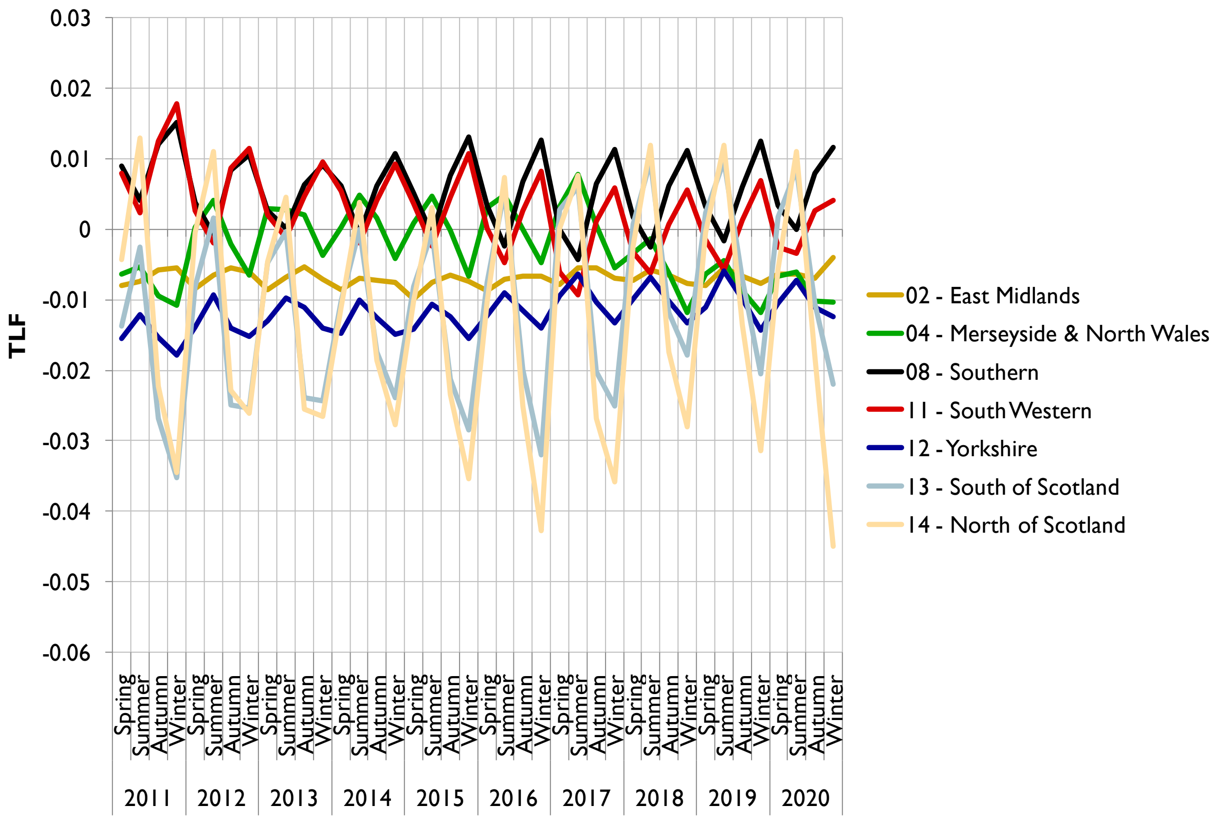


Under the 15 GW Offshore Wind scenario Yorkshire has the largest reduction in generation from Base to Change case, followed by East Midlands, Merseyside & North Wales and South of Scotland. The greatest increase in generation is in the Southern and South Western zones.

4.6 TLFs and TLMs

Figure 28 shows the evolution of a selection of zonal TLFs under the Change case for the 15 GW Offshore Wind scenario. The seasonal and regional pattern of TLFs broadly follows that observed for the Reference scenario. However, the winter TLF values for the Scottish zones are less negative compared to the Reference scenario. Average seasonal TLMs for delivering and offtaking units are shown in the Appendix, together with average seasonal TLFs.

Figure 28 Change case TLFs – 15 GW Offshore Wind scenario



4.7 Wholesale prices

Table 22 shows the change in baseload price arising from the TLF-based modelling of the 15 GW Offshore Wind scenario, together with the TLM-adjusted price differential[26]. Although the introduction of zonal loss factors appears to increase wholesale prices slightly in most years (the second column of the table), the average price change is negligible once the TLM adjustment is applied (third column).

[26] See Section 3 for background on the TLM adjustment

Table 22 Change in baseload price – 15 GW Offshore Wind scenario

Year	Redpoint (2009 £/MWh)	TLM-adjusted Redpoint (2009 £/MWh)
2011/12	0.28	0.04
2012/13	0.24	0.01
2013/14	0.29	0.05
2014/15	0.3	0.04
2015/16	0.29	0.01
2016/17	0.59	0.31
2017/18	0.45	0.18
2018/19	0.07	-0.22
2019/20	-0.01	-0.31
2020/21	0.51	0.21
Average	0.30	0.03

5 RES-E Target scenario results

5.1 Introduction

This section presents the results of the RES-E Target scenario, in which significant onshore and offshore wind capacity is developed so as to meet the UK's 2020 renewable energy targets.

5.2 CBA

Table 23 summarises the CBA results for the RES-E Target scenario, excluding changes in NO_x and SO_2 emissions. Assumptions on implementation and ongoing costs are taken from the Reference scenario. Applying a real discount rate of 4.42%, our modelling indicates a total net benefit of £41.3mn from P229 under this scenario.

Table 23 CBA – RES-E Target scenario

Year	Production cost savings (£mn)	Implementation costs (£mn	Ongoing costs (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	-1.35	-3.85	-0.16	-5.36	-5.13
2012/13	6.87		-0.16	6.71	6.16
2013/14	10.10		-0.16	9.94	8.73
2014/15	5.98		-0.16	5.82	4.90
2015/16	6.82		-0.16	6.66	5.37
2016/17	9.16		-0.16	9.00	6.94
2017/18	8.40		-0.16	8.25	6.09
2018/19	1.96		-0.16	1.81	1.28
2019/20	6.92		-0.16	6.76	4.58
2020/21	3.88		-0.16	3.72	2.41
Total					41.33

As observed in the other scenarios, the overall net benefit is higher if the value of reduced NO_x and SO_2 emissions is included, at £131.1mn as shown in Table 24.

REDPOINT

Table 24 CBA with SO_2 and NO_x emissions – RES-E Target scenario

Year	Change in SO_2 emission (£mn)	Change in NO_x emissions (£mn)	Annual CBA (£mn)	Annual discounted CBA (£mn)
2011/12	2.52	16.57	13.73	13.15
2012/13	-6.28	8.93	9.37	8.59
2013/14	-2.52	10.48	17.90	15.73
2014/15	1.35	9.10	16.27	13.69
2015/16	2.06	8.74	17.46	14.07
2016/17	2.98	9.65	21.63	16.69
2017/18	3.08	10.88	22.21	16.40
2018/19	3.05	10.73	15.59	11.03
2019/20	2.89	9.33	18.98	12.86
2020/21	2.36	7.58	13.65	8.86
Total				131.06

5.3 Losses

The application of zonal loss factors in the Change case of the RES-E Target scenario leads to transmission loss savings in each year studied, as shown in Table 25.

Table 25 Transmission losses – RES-E Target scenario

Year	Base (TWh)	Change (TWh)	Difference (TWh)
2011/12	3.45	3.06	-0.38
2012/13	3.53	3.13	-0.40
2013/14	3.70	3.39	-0.31
2014/15	3.97	3.72	-0.25
2015/16	3.96	3.74	-0.22
2016/17	3.85	3.64	-0.22
2017/18	4.05	3.82	-0.23
2018/19	4.23	3.97	-0.26
2019/20	4.65	4.43	-0.22
2020/21	4.77	4.63	-0.14

5.4 Installed capacity and margin

The evolution of generation capacity in the RES-E Target scenario is shown in Figure 29, while the geographic distribution of generation capacity is illustrated in Figure 30. Wind and gas-fired CCGTs replace retiring coal and oil plant in this scenario.

Figure 29 Capacity by fuel type – RES-E Target scenario

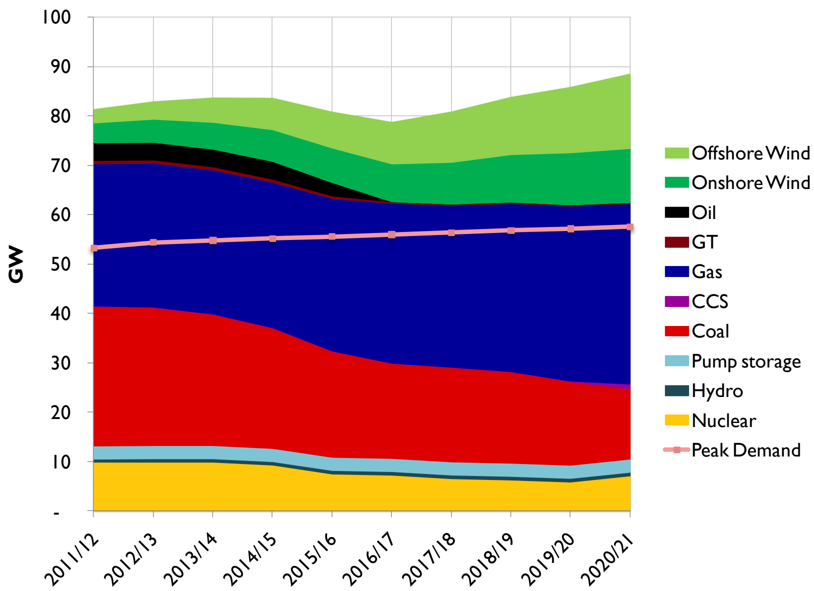


Figure 30 Capacity by zone – RES-E Target scenario

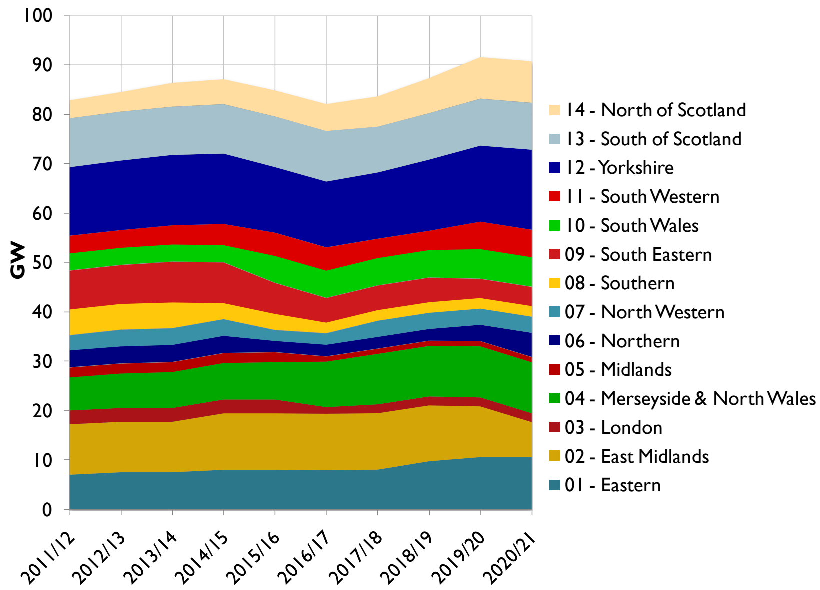
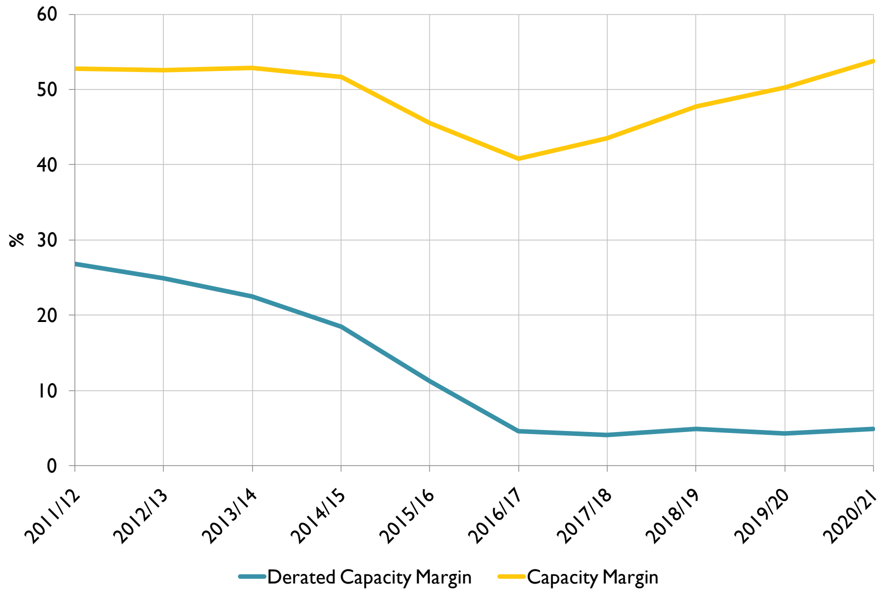


Figure 31 shows the evolution of capacity margins in the RES-E Target scenario. The non-derated capacity margin is higher in this scenario than the 15 GW Offshore Wind and the Reference scenarios but derated margins are broadly consistent due to the relatively low capacity credit assumed for wind.

Figure 31 Capacity and derated capacity RES-E Target Scenario



5.5 Generation by fuel type and zone

The RES-E Target scenario is characterised by a progressive shift away from coal generation towards offshore wind, onshore wind and gas, as shown in Figure 32. As in the other scenarios, the key impact of zonal loss factors in the RES-E Target scenario is to switch coal to gas generation at the margin. Figure 33 shows the deltas in gas and coal generation in the Change case compared to the Base case.

Figure 32 Generation by fuel type – RES-E Target scenario Base case

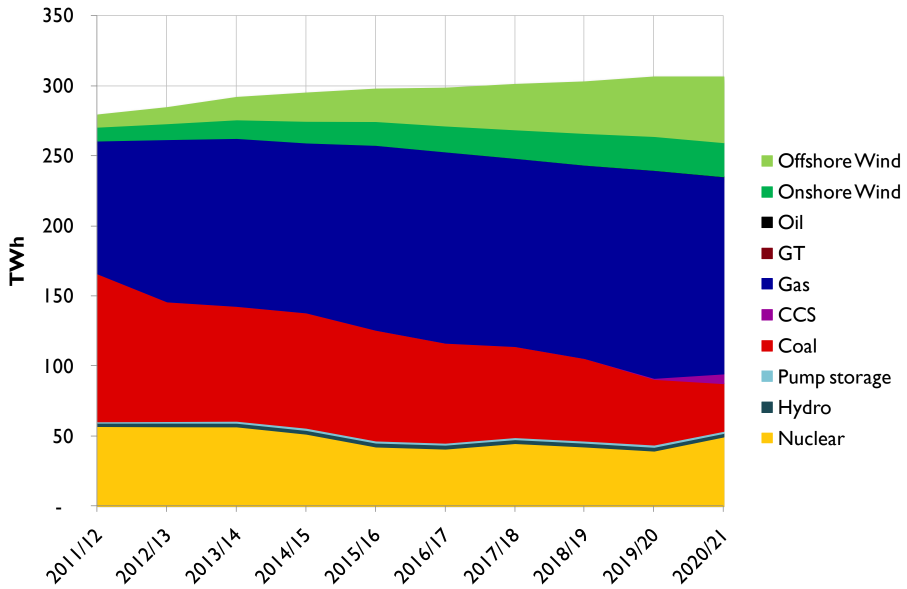


Figure 33 Change in generation from coal and gas – RES-E Target scenario

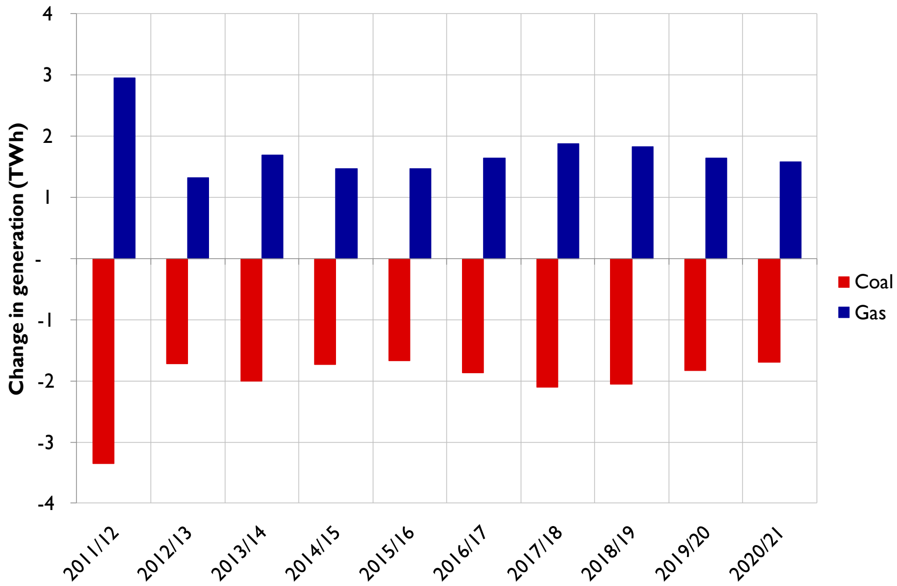


Figure 34 shows the geographic split of generation in the Base case, while Figure 35 shows how the regional pattern of generation changes when zonal loss factors are applied for a selection of zones.

Figure 34 Generation by zone – RES-E Target scenario Base case

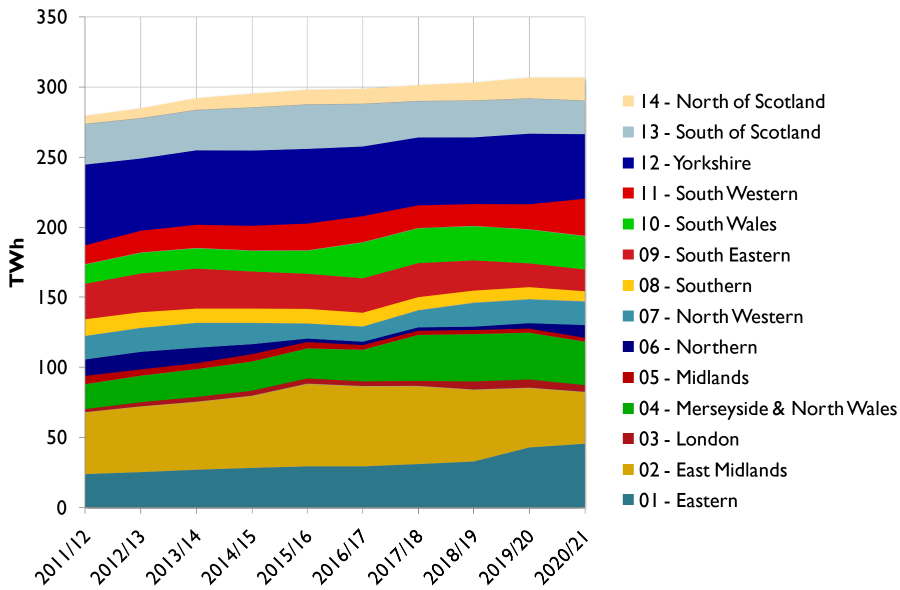
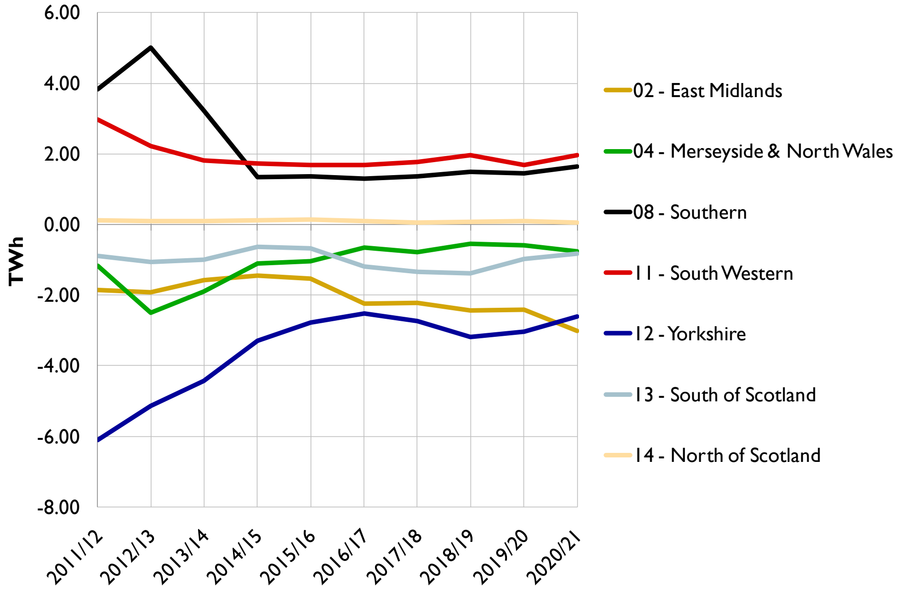


Figure 35 Generation change by zone – RES-E Target scenario

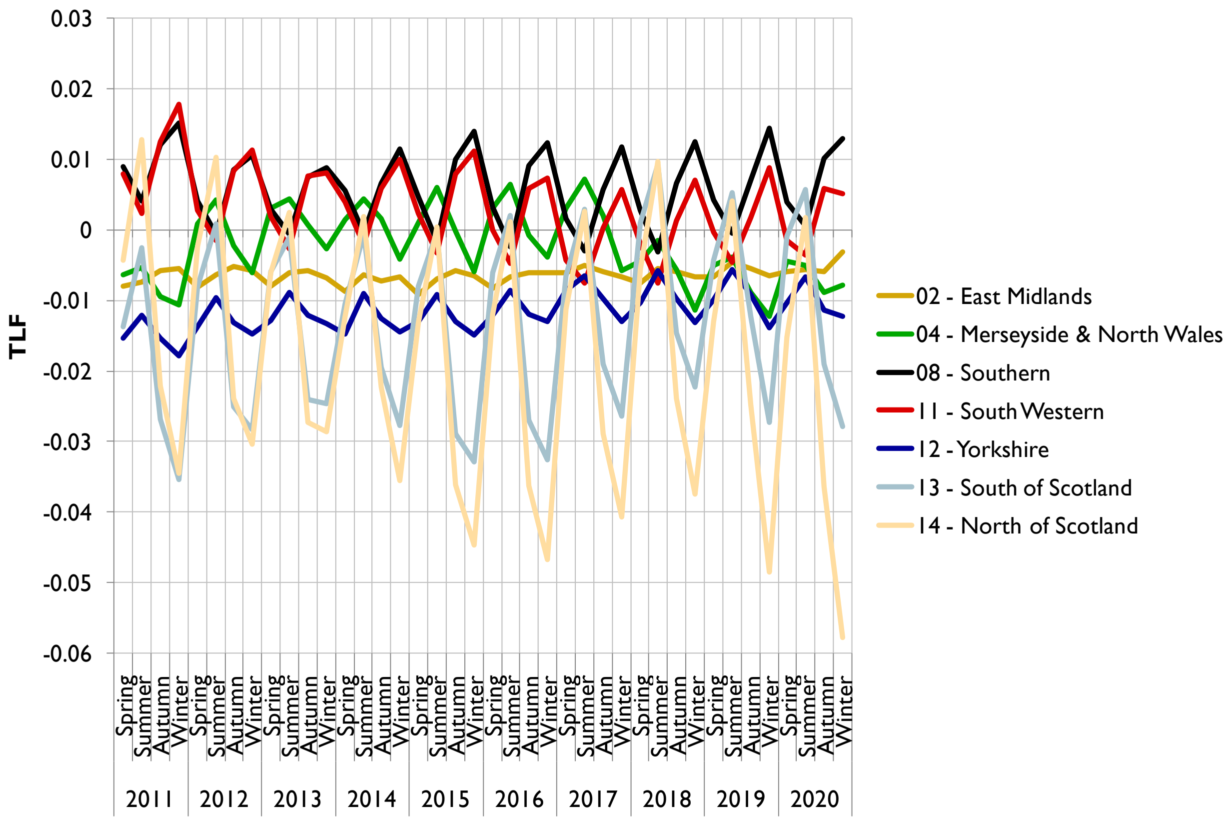


Under the RES-E scenario Yorkshire has the largest reduction in generation from Base to Change case, followed by East Midlands, Merseyside & North Wales and South of Scotland. The greatest increase in generation is in Southern and South Western.

5.6 TLFs and TLMs

Figure 36 shows the evolution of the zonal TLFs for a selection of zones under the Change case for the RES-E Target scenario. The seasonal and regional pattern of TLFs broadly follows that observed for the Reference scenario. Average seasonal TLMs for delivering and offtaking units are shown in the Appendix, together with average seasonal TLFs.

Figure 36 Change case TLFs – RES-E Target scenario



5.7 Wholesale prices

Table 26 shows the change in baseload price arising from the TLF-based modelling of the RES-E Target scenario, together with the TLM-adjusted price differential[27]. Although the introduction of zonal loss factors appears to increase wholesale prices slightly (the second column of the table), the average price change is negligible once the TLM adjustment is applied (third column).

[27] See Section 3 for background on the TLM adjustment

Table 26 Change in baseload price – RES-E Target scenario

Year	Redpoint (2009 £/MWh)	TLM-adjusted Redpoint (2009 £/MWh)
2011/12	0.29	0.05
2012/13	0.22	-0.02
2013/14	0.24	0.01
2014/15	0.27	0
2015/16	0.31	0.02
2016/17	0.38	0.1
2017/18	0.26	-0.01
2018/19	0.38	0.1
2019/20	0.84	0.53
2020/21	0.69	0.37
Average	0.39	0.12

6 Conclusions

6.1 Introduction

This section compares the results across the three scenarios we have modelled and draws conclusions from the analysis.

6.2 CBA

Figure 37 summarises the CBA results for the Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios, excluding changes in NO_x and SO_2 emissions. Our modelling of the P229 zonal transmission charging indicates benefits are stable across all three capacity development pathways modelled. All our scenarios return CBA results within a narrow range - between £36.6mn and £47.7mn. Excluding NO_x and SO_2 impacts, the CBA totals under the Redpoint Reference benchmark and the LE/Ventyx Reference scenario compare closely at £47.7mn and £46.1mn, respectively.

Figure 37 CBA excluding NO_x and SO_2 – Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios

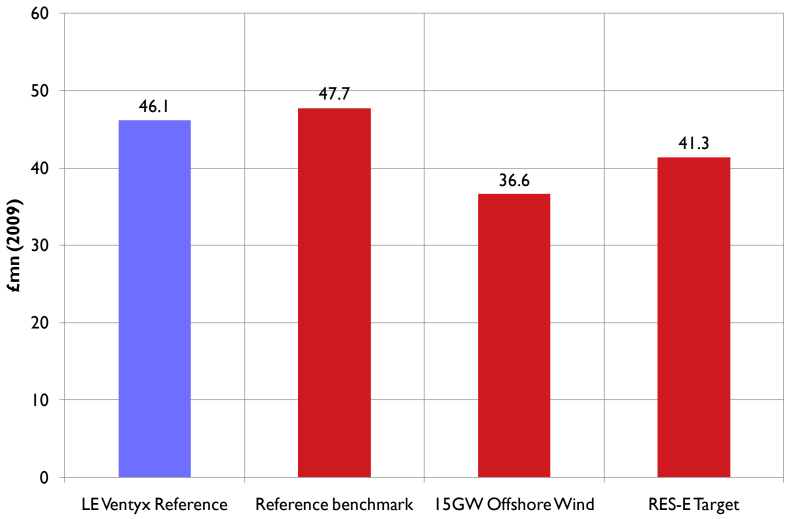
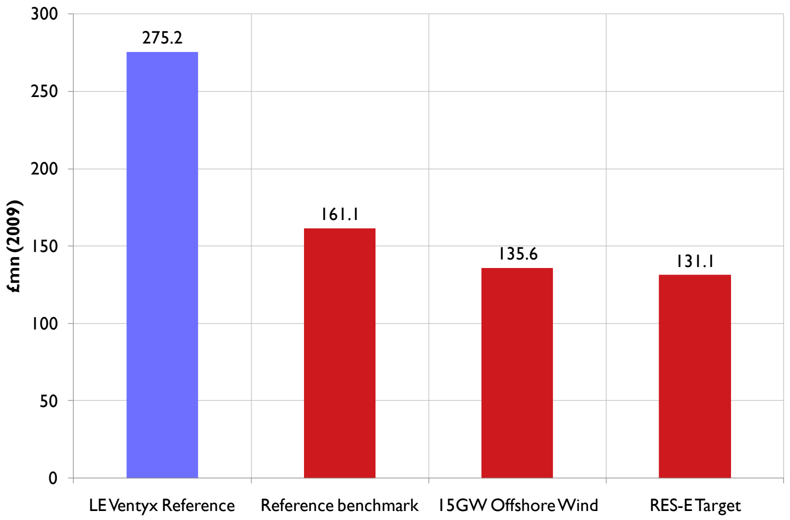


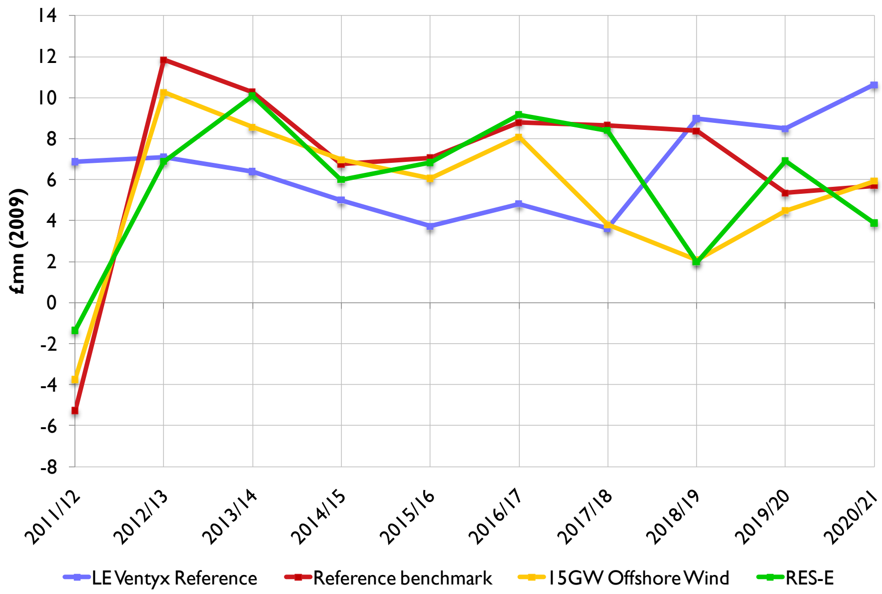
Figure 38 summarises the CBA results for the Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios including changes in NO_x and SO_2 emissions. All scenarios return a positive benefit under P229. The three Redpoint scenarios return CBA totals including NO_x and SO_2 within a narrow range – between £131.1mn and £161.1mn. Our Reference benchmark and the LE/Ventyx Reference scenario CBA results differ more widely if the valuation of NO_x and SO_2 emission changes is included. The modelling of future NO_x and SO_2 emission levels is highly sensitive to a number of inputs for which we did not have details of the LE/Ventyx assumptions, so we have not been able to reconcile the differences in CBA including NO_x and SO_2.

Figure 38 CBA including NO_x and SO_2 – Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios



The annual production cost savings under P229 for all scenarios are compared in Figure 39. The Redpoint and LE/Ventyx scenarios all display a benefit (production cost savings) when generators are exposed to zonal loss factors, after the first year of implementing P229. The production costs savings include the impact of lower overall generation levels due to reduced transmission losses. The three Redpoint scenarios follow a similar pattern of production cost savings over the period modelled. The LE/Ventyx Reference scenario gives annual production cost savings in the same range as our scenarios.

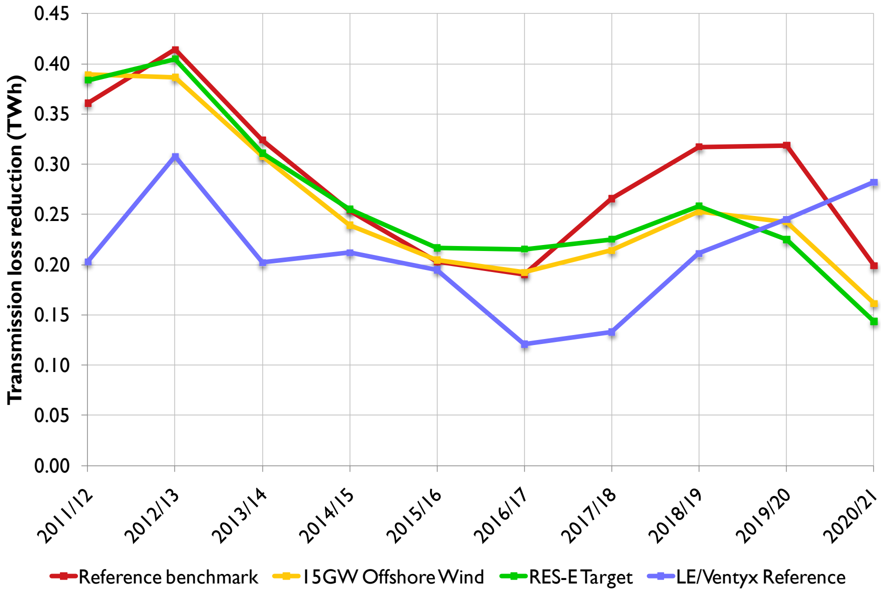
Figure 39 Production cost savings – Redpoint Reference, 15 GW Offshore Wind, RES-E Target, and LE/Ventyx Reference scenarios



6.3 Transmission losses

Figure 40 summarises the reduction in transmission losses for all the Redpoint scenarios and the LE/Ventyx Reference scenario. The outturn transmission losses are reduced in each year of the study under P229 in all scenarios. Overall our scenarios indicate greater transmission loss reductions than the LE/Ventyx Reference scenario. The reduction in transmission losses drives the production cost savings and CBA benefits observed in the modelling of P229.

Figure 40 Transmission loss reductions – Redpoint Reference, 15 GW Offshore Wind, RES-E Target, and LE/Ventyx Reference scenarios



6.4 Emissions

Figure 41 shows the annual reduction in CO_2 emissions modelled under the Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios. The three Redpoint scenarios display very similar CO_2 reduction results to 2017/18, with some variation after this time.

The modelled CO_2 reductions result from the fall in overall generation output due to lower transmission losses, as well as fuel switching from coal to gas.

Figure 41 CO_2 reductions – Redpoint Reference, 15 GW Offshore Wind, RES-E Target and LE/Ventyx Reference scenarios

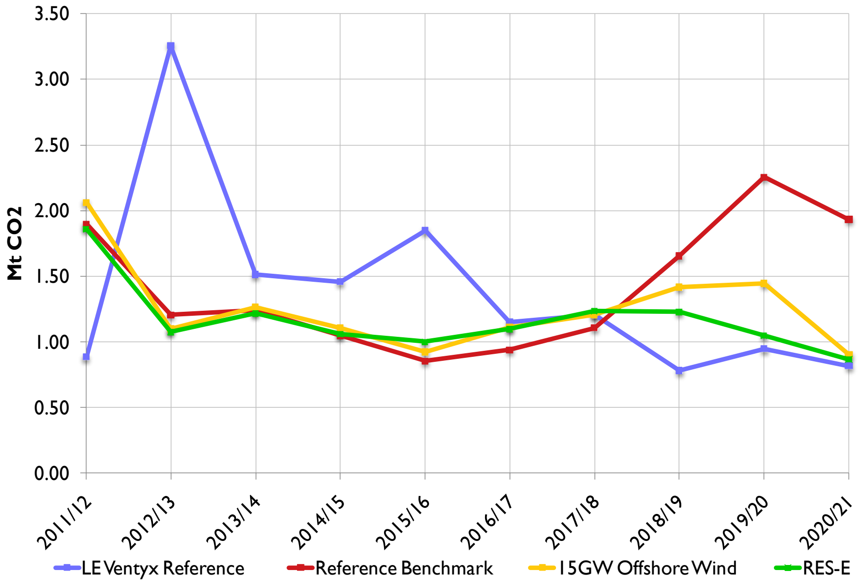
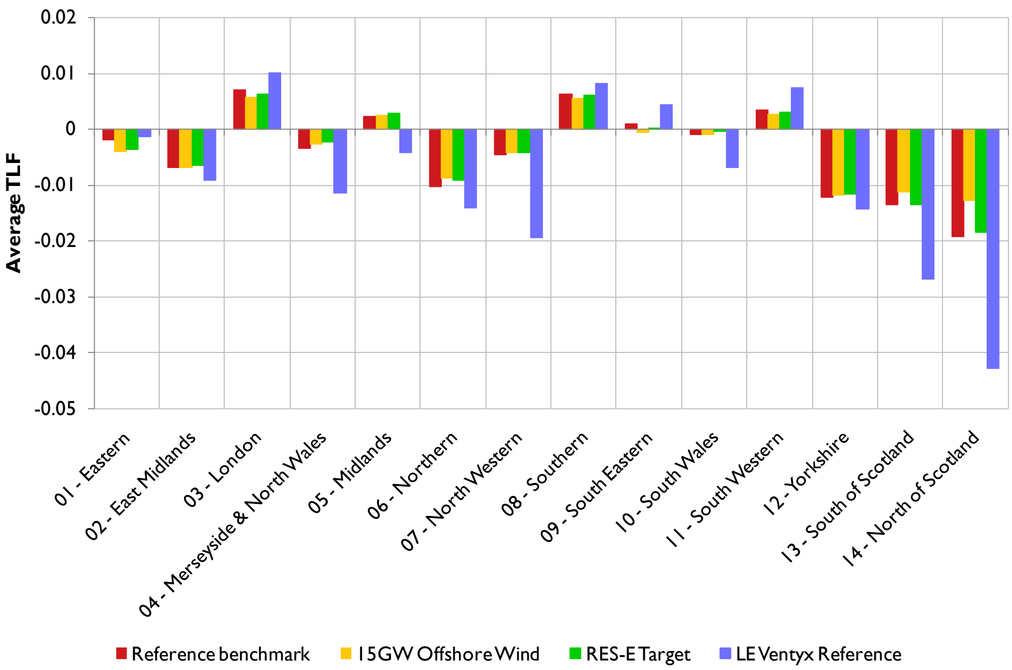


Figure 42 compares the average TLFs (averaged for all years and seasons) under each of the Redpoint scenarios and the LE/Ventyx Reference scenario. In all zones, except Midlands, the sign of the TLF is the same in our Reference benchmark and the LE/Ventyx Reference scenarios. The average TLFs in each zone are within a narrow range under the Redpoint scenarios and tend to be of smaller magnitude than the corresponding average TLF under the LE/Ventyx Reference scenario.

Figure 42 Comparison of average TLFs



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6.5 Prices

Figure 43 shows the change in baseload price with the TLF-based modelling under each of the Redpoint scenarios and the LE/Ventyx Reference scenario. All scenarios result in a small increase in wholesale prices when TLFs are modelled under P229. However, as we outlined previously in Section 3, a number of caveats should be kept in mind when reviewing the wholesale price results from the Redpoint and LE/Ventyx CBA studies. First, the price results for both studies are taken from transmission constrained models of the generation sector, whereas the GB wholesale market operates on an unconstrained basis. Second, the CBA framework is based upon the change in generation production costs under P229 and so both studies have assumed that wholesale price formation is based upon generators' short run marginal costs (SRMC). Third, applying TLMs rather than TLFs in the modelling would more accurately reflect the allocation of transmission losses under the BSC market rules.

Figure 44 shows the change in baseload price had TLMs rather than TLFs been applied in the modelling under each of the Redpoint scenarios. The indicative price changes under P229 are much smaller when the TLM adjustment is applied. Overall the average TLM adjusted price change can be considered negligible under each of our scenarios.

Figure 43 Change in baseload price – Redpoint Reference, 15 GW Offshore Wind, RES-E Target, and LE/Ventyx Reference scenarios

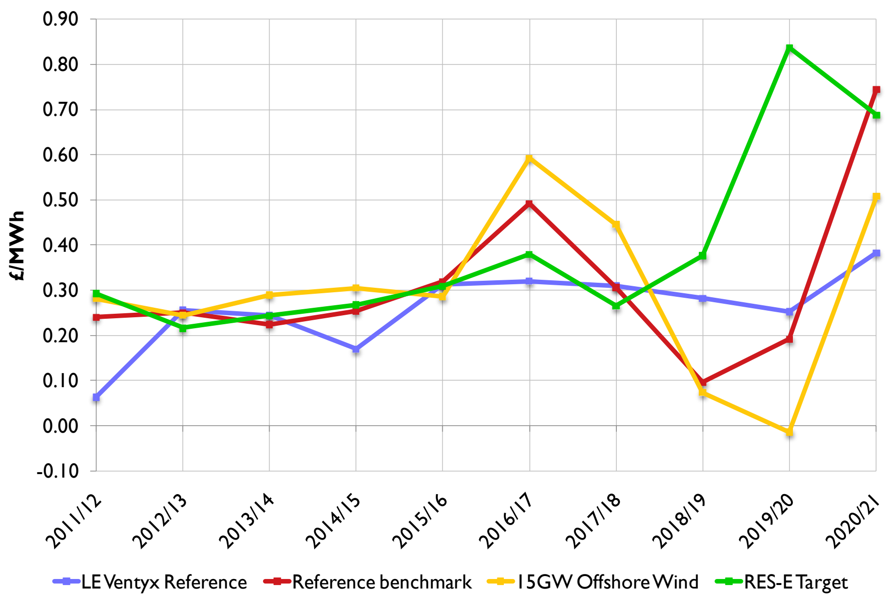
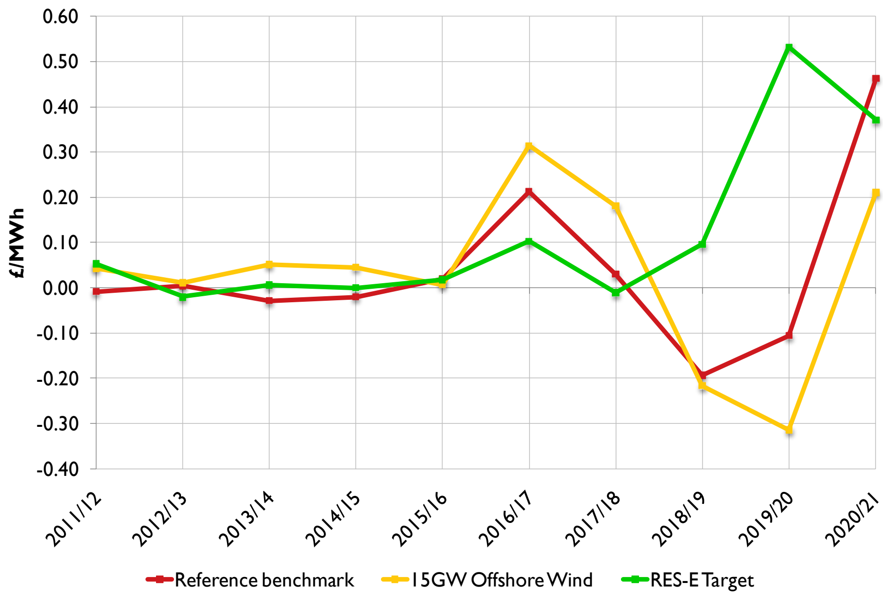


Figure 44 **Change in TLM adjusted baseload price – Redpoint Reference, 15 GW Offshore Wind, and RES-E Target scenarios**



6.6 Summary

Our modelling indicates positive benefits from the P229 zonal losses modification under all the scenarios that we have studied. The key component of the CBA emerging from the modelling exercise is the difference in generation production costs between the Base and Change cases. The production cost savings occur due to the lower overall generation levels and reduced transmission losses under P229. These savings are associated with changing generation patterns under P229 – switching from coal to gas and generation and moving geographically from North to South.

The three Redpoint scenarios model different pathways in capacity development, with differing levels of investment in new wind and CCGT capacity. The Reference scenario models the change in generation capacity in the same way as the LE/Ventyx Reference scenario, with an installed wind capacity base of 6 GW onshore and 5 GW offshore by 2020.

The 15 GW Offshore Wind scenario includes developments planned for Round 3 of Offshore Connection that were not included in the Reference scenario. Under this scenario 15 GW of offshore wind is developed by 2020, while new CCGT capacity is 1.8 GW lower than the Reference scenario.

The RES-E Target scenario models sufficient installed renewable capacity to supply 30% of electricity from renewable sources. This is the expected requirement to meet the UK's 2020 target of 15% of all energy from renewable sources. The installed wind capacity modelled under this scenario comprises 11 GW onshore and 15 GW offshore.

To provide confidence that conclusions can be drawn across our scenario modelling and the LE/Ventyx CBA study, we benchmarked our modelling against the LE/Ventyx Reference scenario, mirroring methodology and input assumptions, to the best of our knowledge. The CBA results, excluding the costs associated with NO_x and SO_2 emissions, compare closely between the LE/Ventyx Reference scenario and our Reference benchmark. This indicates that we can have confidence in comparisons of the CBA results (excluding NO_x and SO_2) from our 15 GW Offshore and RES-E Target scenarios which model very different capacity development pathways to the LE/Ventyx Reference scenario.

A Appendix – Indicative TLFs and TLMs

Table 27 Indicative average TLFs – Reference scenario change case

	Spring	Summer	Autumn	Winter
Zone 1	-0.0043	-0.0070	0.0006	0.0035
Zone 2	-0.0081	-0.0065	-0.0062	-0.0063
Zone 3	0.0049	-0.0002	0.0094	0.0140
Zone 4	-0.0017	0.0011	-0.0039	-0.0092
Zone 5	0.0022	0.0029	0.0023	0.0015
Zone 6	-0.0089	-0.0037	-0.0127	-0.0160
Zone 7	-0.0028	-0.0001	-0.0052	-0.0101
Zone 8	0.0049	-0.0004	0.0082	0.0126
Zone 9	-0.0006	-0.0085	0.0041	0.0091
Zone 10	-0.0018	-0.0012	-0.0006	-0.0001
Zone 11	0.0017	-0.0030	0.0050	0.0096
Zone 12	-0.0127	-0.0091	-0.0121	-0.0148
Zone 13	-0.0079	0.0022	-0.0208	-0.0275
Zone 14	-0.0118	0.0039	-0.0288	-0.0400

Table 28 Indicative average TLFs – 15GW offshore wind scenario change case

	Spring	Summer	Autumn	Winter
Zone 1	-0.0064	-0.0084	-0.0019	0.0004
Zone 2	-0.0082	-0.0065	-0.0062	-0.0066
Zone 3	0.0035	-0.0010	0.0080	0.0124
Zone 4	-0.0012	0.0012	-0.0033	-0.0076
Zone 5	0.0024	0.0028	0.0027	0.0021
Zone 6	-0.0069	-0.0018	-0.0113	-0.0149
Zone 7	-0.0025	-0.0001	-0.0051	-0.0092
Zone 8	0.0038	-0.0009	0.0074	0.0118
Zone 9	-0.0023	-0.0094	0.0023	0.0074
Zone 10	-0.0019	-0.0018	-0.0001	0.0003
Zone 11	0.0008	-0.0035	0.0043	0.0090
Zone 12	-0.0124	-0.0087	-0.0118	-0.0145
Zone 13	-0.0045	0.0038	-0.0184	-0.0255
Zone 14	-0.0049	0.0085	-0.0214	-0.0333

Table 29 Indicative average TLFs – RES-E scenario change case

	Spring	Summer	Autumn	Winter
Zone 1	-0.0060	-0.0080	-0.0013	0.0011
Zone 2	-0.0076	-0.0061	-0.0059	-0.0060
Zone 3	0.0040	-0.0007	0.0087	0.0131
Zone 4	-0.0008	0.0017	-0.0032	-0.0071
Zone 5	0.0028	0.0031	0.0033	0.0026
Zone 6	-0.0073	-0.0020	-0.0122	-0.0151
Zone 7	-0.0027	0.0004	-0.0055	-0.0090
Zone 8	0.0042	-0.0007	0.0083	0.0124
Zone 9	-0.0019	-0.0091	0.0031	0.0081
Zone 10	-0.0016	-0.0021	0.0013	0.0008
Zone 11	0.0011	-0.0035	0.0057	0.0093
Zone 12	-0.0121	-0.0082	-0.0118	-0.0140
Zone 13	-0.0063	0.0022	-0.0216	-0.0285
Zone 14	-0.0095	0.0047	-0.0282	-0.0405

Table 30 Indicative average TLMs – Reference scenario

	Reference Base Delivering				Reference Change Delivering			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	0.995	0.996	0.994	0.994	0.996	0.993	1.001	1.005
Zone 2	0.995	0.996	0.994	0.994	0.992	0.994	0.994	0.995
Zone 3	0.995	0.996	0.994	0.994	1.005	1.000	1.010	1.016
Zone 4	0.995	0.996	0.994	0.994	0.999	1.002	0.996	0.992
Zone 5	0.995	0.996	0.994	0.994	1.003	1.003	1.003	1.003
Zone 6	0.995	0.996	0.994	0.994	0.991	0.997	0.988	0.986
Zone 7	0.995	0.996	0.994	0.994	0.997	1.000	0.995	0.991
Zone 8	0.995	0.996	0.994	0.994	1.005	1.000	1.008	1.014
Zone 9	0.995	0.996	0.994	0.994	1.000	0.992	1.004	1.011
Zone 10	0.995	0.996	0.994	0.994	0.998	0.999	1.000	1.001
Zone 11	0.995	0.996	0.994	0.994	1.002	0.997	1.005	1.011
Zone 12	0.995	0.996	0.994	0.994	0.988	0.991	0.988	0.987
Zone 13	0.995	0.996	0.994	0.994	0.992	1.003	0.979	0.974
Zone 14	0.995	0.996	0.994	0.994	0.988	1.004	0.971	0.962

	Reference Base Offtaking				Reference Change Offtaking			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	1.006	1.005	1.007	1.008	0.999	0.996	1.005	1.008
Zone 2	1.006	1.005	1.007	1.008	0.995	0.996	0.998	0.998
Zone 3	1.006	1.005	1.007	1.008	1.008	1.003	1.014	1.018
Zone 4	1.006	1.005	1.007	1.008	1.002	1.004	1.000	0.995
Zone 5	1.006	1.005	1.007	1.008	1.006	1.006	1.007	1.006
Zone 6	1.006	1.005	1.007	1.008	0.995	0.999	0.992	0.988
Zone 7	1.006	1.005	1.007	1.008	1.001	1.003	0.999	0.994
Zone 8	1.006	1.005	1.007	1.008	1.008	1.002	1.013	1.017
Zone 9	1.006	1.005	1.007	1.008	1.003	0.994	1.008	1.013
Zone 10	1.006	1.005	1.007	1.008	1.002	1.002	1.004	1.004
Zone 11	1.006	1.005	1.007	1.008	1.005	1.000	1.009	1.014
Zone 12	1.006	1.005	1.007	1.008	0.991	0.994	0.992	0.989
Zone 13	1.006	1.005	1.007	1.008	0.996	1.005	0.984	0.977
Zone 14	1.006	1.005	1.007	1.008	0.992	1.007	0.976	0.964

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Table 31 Indicative average TLMs – 15 GW Offshore Wind scenario

	Offshore Base Delivering				Offshore Change Delivering			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	0.995	0.996	0.994	0.994	0.994	0.992	0.998	1.002
Zone 2	0.995	0.996	0.994	0.994	0.992	0.994	0.994	0.995
Zone 3	0.995	0.996	0.994	0.994	1.004	0.999	1.008	1.014
Zone 4	0.995	0.996	0.994	0.994	0.999	1.002	0.997	0.994
Zone 5	0.995	0.996	0.994	0.994	1.003	1.003	1.003	1.003
Zone 6	0.995	0.996	0.994	0.994	0.993	0.999	0.989	0.986
Zone 7	0.995	0.996	0.994	0.994	0.998	1.000	0.995	0.992
Zone 8	0.995	0.996	0.994	0.994	1.004	1.000	1.008	1.013
Zone 9	0.995	0.996	0.994	0.994	0.998	0.991	1.002	1.009
Zone 10	0.995	0.996	0.994	0.994	0.998	0.999	1.000	1.002
Zone 11	0.995	0.996	0.994	0.994	1.001	0.997	1.004	1.010
Zone 12	0.995	0.996	0.994	0.994	0.988	0.992	0.988	0.987
Zone 13	0.995	0.996	0.994	0.994	0.996	1.004	0.982	0.976
Zone 14	0.995	0.996	0.994	0.994	0.995	1.009	0.979	0.968

	Offshore Base Offtaking				Offshore Change Offtaking			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	1.006	1.005	1.007	1.008	0.997	0.995	1.002	1.005
Zone 2	1.006	1.005	1.007	1.008	0.995	0.996	0.998	0.998
Zone 3	1.006	1.005	1.007	1.008	1.007	1.002	1.012	1.017
Zone 4	1.006	1.005	1.007	1.008	1.002	1.004	1.001	0.997
Zone 5	1.006	1.005	1.007	1.008	1.006	1.006	1.007	1.006
Zone 6	1.006	1.005	1.007	1.008	0.997	1.001	0.993	0.989
Zone 7	1.006	1.005	1.007	1.008	1.001	1.003	0.999	0.995
Zone 8	1.006	1.005	1.007	1.008	1.007	1.002	1.012	1.016
Zone 9	1.006	1.005	1.007	1.008	1.001	0.994	1.006	1.012
Zone 10	1.006	1.005	1.007	1.008	1.002	1.001	1.004	1.004
Zone 11	1.006	1.005	1.007	1.008	1.004	1.000	1.008	1.013
Zone 12	1.006	1.005	1.007	1.008	0.991	0.994	0.992	0.990
Zone 13	1.006	1.005	1.007	1.008	0.999	1.007	0.986	0.979
Zone 14	1.006	1.005	1.007	1.008	0.999	1.012	0.983	0.971

Table 32 Indicative average TLMs – RES-E Target scenario

	RES-E Target Base Delivering				RES-E Target Change Delivering			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	0.995	0.996	0.994	0.993	0.994	0.992	0.999	1.002
Zone 2	0.995	0.996	0.994	0.993	0.992	0.994	0.994	0.995
Zone 3	0.995	0.996	0.994	0.993	1.004	1.000	1.009	1.014
Zone 4	0.995	0.996	0.994	0.993	0.999	1.002	0.997	0.994
Zone 5	0.995	0.996	0.994	0.993	1.003	1.003	1.003	1.004
Zone 6	0.995	0.996	0.994	0.993	0.993	0.998	0.988	0.986
Zone 7	0.995	0.996	0.994	0.993	0.997	1.001	0.995	0.992
Zone 8	0.995	0.996	0.994	0.993	1.004	0.999	1.008	1.014
Zone 9	0.995	0.996	0.994	0.993	0.998	0.991	1.003	1.009
Zone 10	0.995	0.996	0.994	0.993	0.998	0.998	1.001	1.002
Zone 11	0.995	0.996	0.994	0.993	1.001	0.997	1.006	1.010
Zone 12	0.995	0.996	0.994	0.993	0.988	0.992	0.988	0.987
Zone 13	0.995	0.996	0.994	0.993	0.994	1.002	0.978	0.973
Zone 14	0.995	0.996	0.994	0.993	0.990	1.005	0.972	0.961

	RES-E Target Base Offtaking				RES-E Target Change Offtaking			
	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter
Zone 1	1.007	1.005	1.008	1.008	0.998	0.995	1.003	1.006
Zone 2	1.007	1.005	1.008	1.008	0.996	0.997	0.999	0.999
Zone 3	1.007	1.005	1.008	1.008	1.008	1.003	1.013	1.018
Zone 4	1.007	1.005	1.008	1.008	1.003	1.005	1.002	0.998
Zone 5	1.007	1.005	1.008	1.008	1.007	1.006	1.008	1.008
Zone 6	1.007	1.005	1.008	1.008	0.997	1.001	0.993	0.990
Zone 7	1.007	1.005	1.008	1.008	1.001	1.004	0.999	0.996
Zone 8	1.007	1.005	1.008	1.008	1.008	1.002	1.013	1.017
Zone 9	1.007	1.005	1.008	1.008	1.002	0.994	1.008	1.013
Zone 10	1.007	1.005	1.008	1.008	1.002	1.001	1.006	1.006
Zone 11	1.007	1.005	1.008	1.008	1.005	1.000	1.010	1.014
Zone 12	1.007	1.005	1.008	1.008	0.992	0.995	0.993	0.991
Zone 13	1.007	1.005	1.008	1.008	0.998	1.005	0.983	0.976
Zone 14	1.007	1.005	1.008	1.008	0.994	1.008	0.977	0.964