THE ECONOMIC LIVES OF ENERGY NETWORK ASSETS
A REPORT FOR OFGEM

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CONTENTS

TABLES IN MAIN REPORT

FIGURES IN MAIN REPORT

1. EXECUTIVE SUMMARY

This report sets out the available evidence on existing statutory, regulatory and technical asset lives for the electricity and gas networks in Great Britain. It also considers:

- a range of possible future scenarios for energy usage, and their effect on the economic life of assets; and
- possible factors that could change the economic and technical lives of these assets over the next few decades.

This section summarises the key elements of the report and then makes some recommendations for how Ofgem should proceed.

1.1. Current position

Table 1.1 summarises the existing positions and our calculations. Each is then considered below. It can be seen that the existing regulatory approach uses lives shorter than the statutory or technical asset lives (for simplicity we have just reported the rate applied to "new" assets in the table; old assets which are either pre-vesting or those established prior to a specified date such as the break-up and sale of the gas distribution networks tend to account for only a small, and diminishing, proportion of the assets).

Table 1.1: Summary of existing positions and calculations

	Statutory life	Existing Regulatory life	Estimated Technical life (range and weighted average)	Estimated Economic life
Electricity transmission	10 – 80	20	10 – 90 (54)	10 – 90 (54)
Electricity distribution	2 -100	20	30 – 140 (73)	30 – 140 (73)
Gas transmission	30 – 100	45	20 – 60 (60)	20 – 45 (45)
Gas distribution	10 - 100	45	0 – 70 (45)[1]	0 – 45 (45)

1.2. Technical life

In our analysis, we looked at the technical life (broadly, how long the asset can be expected to last from an engineering/safety perspective before it becomes either unsafe or not fit for purpose) of each asset class. For regulatory purposes, a single weighted life is needed for each network; we calculate this using "modern equivalent asset value" as the weighting. This gives

[1] In this report, we consider both new and existing network assets, and so have calculated technical asset life ranges for both, for all four networks. In most cases, the ranges for new and existing assets are similar, and so we have only quoted a single range. For gas distribution, there is a major programme of work to replace existing iron pipes with polyethylene (PE) pipes. These new PE pipes are expected to have a significantly longer life – exactly how long is uncertain but figures between 50 and 150 years have been quoted. Because of this significant change in the technical life of a major part of the gas distribution asset base, the average technical life of the gas distribution network can be expected to rise in future. We quote in this report an average age of 45 years, but expect that under reasonable assumptions about the technical life of PE pipes, the average technical life of the gas distribution network could rise to 60 or 70 years in future.

weighted average technical lives ranging from 45 years (gas distribution, low assumption on the technical life of polyethylene (PE) pipes) to 73 years[2] (electricity distribution). More detail about current assets can be found in section 3.

1.3. Economic usefulness

We also considered the likely future use of the networks. Our approach (see section 4) has been to take Ofgem's existing scenarios, from Project Discovery, and extend them into four scenarios that run to 2050 and span the reasonable range of outcomes for electricity and gas demand. Drawing out the key features from these scenarios, and focusing on the common messages, leads to the conclusion that it is almost certain that electricity demand will rise over the next four decades. It is often assumed that gas demand will have a corresponding drop, but our scenarios suggest that this is not inevitable – at least when considering peak gas demand, rather than annual demand. Since networks are sized to peak demand, this could mean that the future need for gas network assets is not much less than the need today, although the uncertainty is much greater for gas (especially distribution) than for electricity.

One conclusion, therefore, is that electricity assets in place today or soon to be built can be expected to be economically useful, and technically viable, at least until 2050. This is also true for gas transmission assets since gas generation will remain an important part of the generation portfolio even if it moves more towards peak rather than base-load provision. For gas distribution networks, the picture is less certain, but it is too early to say that assets will **not** be economically useful in 2050, especially given some of the information concerning the relative costs of gas based heating compared to electric space heating. There is no difficulty from a technical point of view for this continued usefulness.

There are, however, a range of uncertainties which affect the ability to estimate the economic life. As discussed in the report, these uncertainties include:

- the speed with which new high-technology assets are incorporated into the sectors and the impact that their shorter asset lives have on the overall technical life (although the level of investment needed for these shorter-lived assets to have an impact is such that we do not believe this is a significant risk);
- whether aspects of policy will be applied aggressively, such as the decarbonisation of the energy sector through shifting to electricity based heating, or phased in over a longer period; and
- possible technological/product changes such as new materials which may have a shorter-life than existing materials but also a cost differential such that using the new material is cost effective even though assets have to be replaced more frequently.

These uncertainties help explain the more conservative nature of the proposed economic lives for the various assets, especially gas.

[2] 51 years if underground cables, which have very long lives, are excluded.

1.4. Depreciation

When it comes to setting depreciation policy there are two issues to decide:

- the appropriate depreciation asset life; and
- the profile of depreciation.

Our recommendations on both are set out in the table below and then briefly discussed.

Table 1.2: Recommendations on asset lives and depreciation profile

Sample	Depreciation asset life	Depreciation profile
Electricity transmission	45-55	Straight-line or back-end loaded
Electricity distribution	45-55	Straight-line or back-end loaded
Gas transmission	45	Straight-line or front-end loaded
Gas distribution	45	Straight-line or front-end loaded

The rationales for the recommendations are:

1. Electricity transmission and distribution – we recommend using a figure below the existing technical life but significantly above the existing regulatory life. Our discount to technical life reflects some of the uncertainty about the longer-lived assets. Given our expected profile of usage, if a non-straight-line approach were to be adopted a back-end loaded approach would appear to be appropriate. However, utilisation is expected to be high throughout the period and so the rationale for back-end loading is weak.
2. Gas networks, especially distribution, face significant uncertainty, with distribution facing significant policy risk if the shift to electric space heating takes place. This uncertainty ought to be addressed in the near-term and once the major policy issues have been addressed it would be possible to re-evaluate the economic life of the assets. Consequently making a significant change to asset lives at the moment does not appear sensible or justifiable, especially if a further change was then needed at the next price control when a clearer picture about the future for the industry existed. Under all the scenarios the expected profile of usage will drop over time and so, if a non-straight-line based approach were to be adopted we would recommend a front-end loaded approach. There is more justification for using a non-linear profile for gas than there is for electricity.

As noted in section 6 of the report, none of the depreciation profiles actually match the true economic depreciation of the assets under consideration since that is driven by the materials used for the pipes or wires. Consequently a shift away from the current straight-line based approach could be justified if there were strong other reasons, such as fairness or inter-generational equity. For electricity there is sufficient uncertainty that either a straight-line or back-end loaded approach could be appropriate. However, the relatively high utilisation through-out the period minimises the benefits of moving away from straight-line depreciation. As such, erring on the side of caution and not changing until future consumption paths are clearer (especially again linked to the electricity space heating question) would seem appropriate. Gas is less straight-forward and while there is a strong justification for the continuing use of both the gas transmission and distribution networks there is likely to be a shift away from gas usage in the medium- to long-term. As such, a front-end loaded depreciation profile would seem to be appropriate. Our analysis of a sensitivity where the gas distribution network is fully depreciated by 2035 (see section 7 and Annex F for more detail) could provide further justification for front-end loading.

1.5. Implications of the change

The simple modelling in section 6 and the more detailed modelling in section 7 shows, unsurprisingly, that:

- shifting to a longer regulatory asset depreciation life can have a significant impact on asset cash-flows and consequently financial ratios;
- this is exacerbated when linked with an above steady-state level of capex; and
- front- or back-end loading the depreciation profile can also have a significant impact on asset cash-flows.

The implications of these effects on cash-flows will need to be considered by Ofgem as part of its broader financeability assessment under the RIIO principles at each price determination.

1.6. Mitigating the impact through a transition period

Simple modelling in section 6 shows that some mitigation of the cash-flow impacts is possible through the use of a transition period. Two possible options were illustrated:

- keeping existing asset lives for existing assets and only applying the new asset life to new assets; and/or
- gradually introducing the new asset life through a stepped increase.

These, and other transitional arrangements, are not mutually exclusive and so, should Ofgem decide that a transition period is needed, it should be possible to design something that is appropriate.

1.7. Impact on consumer bills

Any change in the depreciation charge will have an impact on consumer bills. In our modelling the base case shows that bills will increase significantly over the 2010-2050 period owing to the network investments that are required. Current combined bills are just under £1,200 per year, and our analysis shows them rising to approximately £1,650 per year (in real terms) by 2050. Changing the depreciation life has an impact but primarily on the profile of prices rather than the end point, where the differences between our "base", "split" and "full" options are so small that it is not possible to say with confidence that there are significant differences between them. While under the existing profile we believe average consumer bills would be roughly constant (ignoring non-network investment issues) over the next decade or two, extending the electricity sector depreciation life would actually lead to reductions, albeit fairly small, during those periods prior to a more rapid increase in prices.

2. BACKGROUND AND APPROACH

2.1. The price control reviews

Earlier this year, Ofgem announced a new approach to network regulation: RIIO (Revenue= Incentives+Innovation+Outputs)[3]. The first price control reviews that will implement this new model of regulation are RIIO-T1 and RIIO-GD1, which will cover transmission and gas distribution respectively. These will set the allowed revenues for the network companies from 2013. Companies' net revenues depend to a significant degree on the depreciation profile of their assets, which is the focus of this document. That profile also determines how the cost of an asset is allocated between present and future consumers.

2.2. Policy context

The UK Government has committed to reducing greenhouse gas emissions by 80% from 1990 levels by 2050. To do this, major changes will be needed to the way that we produce electricity, fuel vehicles, and heat homes and other buildings. The energy sector as a whole will have to be radically different, and this applies to energy networks as much as to how energy is sourced or converted from one form to another. In this report we explore how the networks might be used in future, in a number of scenarios; what that might mean for the network assets needed, including the economic life of those assets; and hence how it would be sensible to depreciate those assets.

2.3. Our approach

In this section we set our approach to assessing the framework for determining the approach to depreciation. A more detailed discussion can be found in section 6.

2.3.1. Technical and economic lives

We start by briefly describing what is meant by the "technical" and "economic" lives of assets. Detailed definitions of "technical life" exist[4] but it can be thought of as the time between the asset being commissioned and it no longer being fit for purpose, for reasons including safety and whether it can perform the function(s) that it was intended to perform.

The "economic" life of an asset is, crudely, the period over which it is useful. An asset can be in excellent condition, but no longer perform any useful function – in which case, it has reached the end of its economic life, if not its technical one.

2.3.2. The use of depreciation

Depreciation is a measure of the reduction in the value of an asset as a result of the passage of time and/or its use. There are a range of approaches to measuring depreciation; the choice of

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[3] More details can be found on the Ofgem website http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

[4] For example, the definition used by Transco: "*The technical asset life ... is the estimated length of time from the date of commission to a point in time when on average the asset falls below minimum acceptable technical and/ or safety performance levels. The estimate is based on sound engineering judgement, known historical performance levels and current technical knowledge. Technical performance levels include compliance with statutory obligations and specifically exclude commercial, financial and accounting considerations*".

which one to use depends on the characteristics of the asset and its use, as well as the purpose of measuring depreciation.

It is important to remember that the aggregate depreciation charge for an asset will be the initial capital cost of the asset, in real terms. So the choice of approach to depreciation does not affect the total revenue raised to cover the cost of the asset, only whether the burden of the cost of the asset is borne by today's consumers, or future consumers.

An appropriate profile of depreciation would set an appropriate phasing of charges to customers, which raises the question of what an appropriate charge is. Ideally, charges to customers should reflect the long run incremental cost of their use of the asset. This is the principle that is currently used in determining the geographic differentiation of network charges, and ideally should be applied over time as well as geographically.

In practice, identifying incremental cost impacts from customers at different dates is difficult. A more practical alternative is to allocate costs reflecting use of the network.

Charging in practice, though, is not just about incremental charges. Fixed costs of the system, which are not related to incremental use of any particular customer, need to be allocated. The allocation of these costs needs to be seen by customers to be "fair". In this context this means finding an appropriate balance of charges between today's customers and future customers. This is a further reason to consider the intensity of use of the network as a determinant of cost allocation - although there are arguments against its use from an economic point of view.

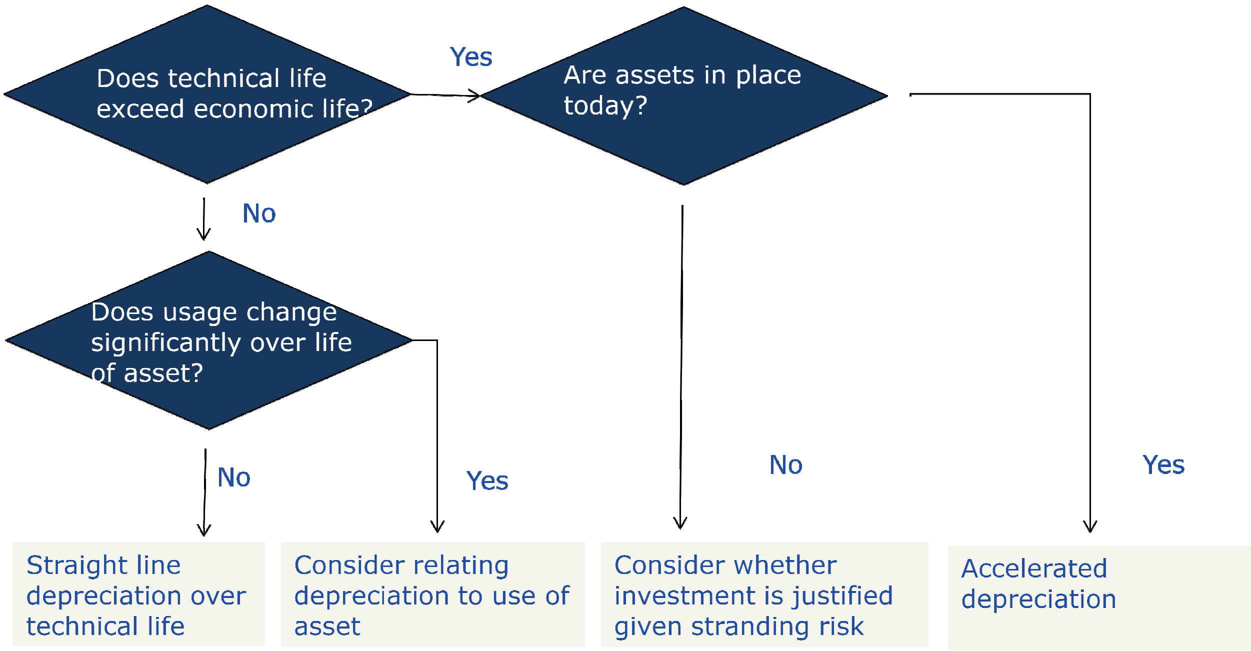
2.3.3. An approach to depreciation

The discussion above suggests that depreciation should be related to the use of the asset.

- If the asset is expected to be operational for longer than it is expected to be useful, i.e. the technical life is longer than the economic life, charging for the asset (i.e. depreciation) should be accelerated. We would expect that the asset would be fully depreciated at the end of its economic life.
- If the asset has not yet been built, and it is expected that the technical life will be longer than the economic life, careful consideration must be given to whether the asset should be constructed.
- If the asset is expected to be used and useful for the whole of its technical life, depreciation will be charged through the entire expected technical life.
- If the use of the asset is expected to increase significantly through the course of its technical life, it may be appropriate to levy greater charges on future customers, and vice versa.

Our approach to assessing depreciation is set out in the figure below.

Figure 2.1: Decision tree on depreciation of assets



2.3.4. Assessing the economic life

The economic life of network assets will fundamentally depend on how networks will be used in the future. If network usage can be expected to show steady growth, it would be a reasonable assumption that all assets built will remain used and useful throughout their technical life.

But we are not in a steady state. The UK energy market faces the prospect of unprecedented change that may occur at a rapid rate – change that is particularly driven by the UK's medium and long term renewable and carbon targets and aspirations.

Prospective change drivers for electricity transmission include the deep reinforcement and extension of the network that may be required to accommodate increasing volumes of renewable generation, particularly onshore wind in Scotland; the construction of offshore transmission assets to support the development of offshore wind; and the need to replace existing transmission assets that are reaching the end of their useful life, a natural consequence of the rapid build in earlier decades

For electricity distribution, drivers include a potential increase in locally generated, often renewable power that will require network expansion and reinforcement; changing patterns of demand as a result of increased electrification, such as a move towards greater use of electric vehicles and electric space heating. The overall impact is likely to be a need for larger networks to accommodate changing flows of electricity and more sophisticated network controls.

Turning to gas, as production from the North Sea declines, flow patterns on the transmission network may change to accommodate potentially increasing flows of LNG. In the longer term the use of both the distribution and transmission network may change if a move is made to electric and/or renewable space heating away from gas, driven by the need to reduce CO_2 emissions.

These changes and potential drivers can be identified, but there is considerable uncertainty around both about whether such changes will occur in practice, and if they do occur, what the timing might be. Any approach to determining economic lives must reflect this uncertainty inherent in today's energy market. Given the scale and range of potential uncertainty the most appropriate way to explore the impact on energy networks is to use a range of 'what if' scenarios as a basis for assessing the possible future need for energy networks.

2.3.5. Using scenarios to assess economic lives and profile of use

Many organisations have developed projections of possible futures for the energy markets in the UK; a list of those we have considered is in Annex E. The scenarios developed explore a variety of potential outcomes for the UK's energy market, in particular evaluating the impact of carbon and renewable targets and aspirations. As there is a wide range of existing scenarios available, we have not created an additional set of scenarios for this project, but have built upon those already developed.

While no long term scenario is likely to be absolutely 'right' or 'wrong,' for our purposes the important thing is that the scenarios adopted must sufficiently explore the major drivers of change and their impact on the usage of the energy networks. In short the scenarios must 'stress test' the usage of the energy networks under a range of future possible outcomes, in particular those that appear likely to arise if the UK is to meet or approach its longer term carbon reduction aspirations. The scenarios are *not* intended to provide forecasts of demand and potential investment; given their role as 'what if' stress tests rather than forecasts, the exact demand or future investment needs of the sector are less important than the implied impact on the economic lives of some network assets that may be shorter than their technical lives.

Furthermore the scenarios are used to explore the impact on the profile of use of the network asset.

2.3.6. Assessing the technical lives

Our approach to assessing the technical lives is based on an analysis of the assets in place today, and their operational lives to date, as well as a consideration of the design and expected operational lives of new assets being installed. The next section has further details on the assets in place today.

3. THE NETWORKS TODAY

In this section we include an overview of the existing electricity and gas networks. We start by setting out how we have used the available information on existing assets to calculate average technical asset lives.

3.1. Calculation of the technical asset lives

The GB energy networks, particularly the electricity networks, have a wide range of technical asset lives ranging from zero (obsolete assets) to about 100 years as discussed in the rest of this section. The number of assets considered in this assessment has been broadly consistent with the categorisations used in the Price Control Reviews and submitted by the companies to Ofgem. In that way a relatively consistent set of asset groups has been used with sufficient disaggregation and robust information to allow a meaningful analysis (overall we have used over 200 asset categories). In our assessment we have adopted the views of the companies about their technical asset lives; under each asset category the average technical asset life corresponds to the arithmetic average of each company asset life weighted by the volume of assets.

In order to arrive at consolidated average technical life of the assets of each network we have calculated an arithmetic average of the technical lives of the various assets in each network weighted by the Modern Equivalent Asset (MEA) value of those assets. The range and distribution of technical lives are shown in Annex G. In this assessment we have considered the unit costs for each of the asset categories resulting from the most recent Price Controls and/or regulatory submissions and indexed them by RPI appropriately. It is also worth noting that in some cases the technical lives of assets currently in the network and those that will replace them could be different. When calculating the network expenditure forecasts we have used both sets of technical lives as applicable.

Because of the large number of assumptions involved in the assessment, and the nature of the calculation, it is important to appreciate that the quoted precision in the results could be somewhat misleading. Firstly, because the weighted average does not take into account the shape of profile of the network (different profiles that would result in a different depreciation revenue stream could have the same average weighted life), secondly because in some cases there are significant changes in the (cumulative) age profile around the 50^{th} percentile and thirdly because the average technical of the network does not describe nor necessarily correspond to any real asset in the network. This would indicate that a range is likely to be a better way of describing the average technical life of the network for new assets.

3.2. Gas transmission

Natural gas is received into the National Transmission System (NTS – see figure 3.1 below) at seven receiving terminals positioned at coastal locations around GB which process the received gas prior to injection into the NTS pipeline system. These are located at:

- St Fergus
- Teesside

- Theddlethorpe
- Easington
- Bacton
- Barrow
- Burton Point

In addition to these coastal receiving terminals there are four LNG importation terminals, which are operated by independent operators that do not form part of the NTS. These are located at:

- Isle of Grain (Grain LNG)
- Milford Haven (South Hook LNG)
- Milford Haven (Dragon LNG)
- Teesside Gasport LNG (dockside re-gasification facility)

NGG owns and operates above ground installations at these gas receiving terminals on a shared site basis and the nature and configuration of these facilities varies by location and the duty required.

Downstream of the receiving terminals, the NTS consists of c. 7,700 kilometres of high integrity, welded steel pipeline operating at a pressures in the range 70-94 barg[5] and 24 compressor stations that supply gas to power stations, a small number of very large industrial and commercial customers and the twelve Local Distribution Zones (LDZs) that collectively comprise the eight gas distribution networks owned and operated by National Grid Gas, Wales and West Utilities, Northern Gas Networks and Scotia Gas Networks. The majority of the NTS was built in the late 1970's and early 1980's for a 70 barg operating pressure and was subsequently uprated for operation at 85 barg following an extensive safety review. Substantial new pipelines have been constructed in recent years to accommodate the newly-constructed LNG terminals and changing importation flows from North Sea gas fields.

As part of the NTS pipeline system, there are a large number of NTS block valve assemblies and pig trap facilities located as above ground installations.

There are also LNG storage facilities located at Avonmouth, Dynevor Arms (de-commissioned), Partington (partly de-commissioned) and Glenmavis that are connected to the NTS and are used to provide a peak gas supply to gas shippers, to supplement NGG's transmission network capacity and to provide a contingency against the risk of emergencies such as system constraints, failures in supply or failures in end user interruption. These LNG storage facilities are owned and operated by LNG Storage, which is a trading division of National Grid Gas (NGG) and are not included as part of this asset review. More detail on the gas transmission network assets can be found in Annex B.

[5] "bar gauge" – a measure of operating pressure

3.3. Gas distribution

There are eight regional gas networks in the UK (see figure 3.2 below) that are operated by four gas distribution gas network operators. These are:

Table 3.1: Gas Distribution Network Companies

Regional Gas Network	Gas Distribution Network Operator
London East of England North West West Midlands	National Grid Gas
Wales and West	Wales and West Utilities
Northern	Northern Gas Networks
Scotland Southern	Scotia Gas Networks

Prior to June 2005, all of the eight individual gas networks were owned and operated by a single entity, National Grid, and prior to this Transco and British Gas plc. Consequently, there has been a relatively consistent and uniform approach to the design, construction and operation & maintenance of the distribution network assets across the country. More detail on the gas distribution network assets can be found in Annex C.

Figure 3.1: National Gas Transmission System[6]

[6] Source: National Grid

Figure 3.2: Gas Distribution Networks[7]

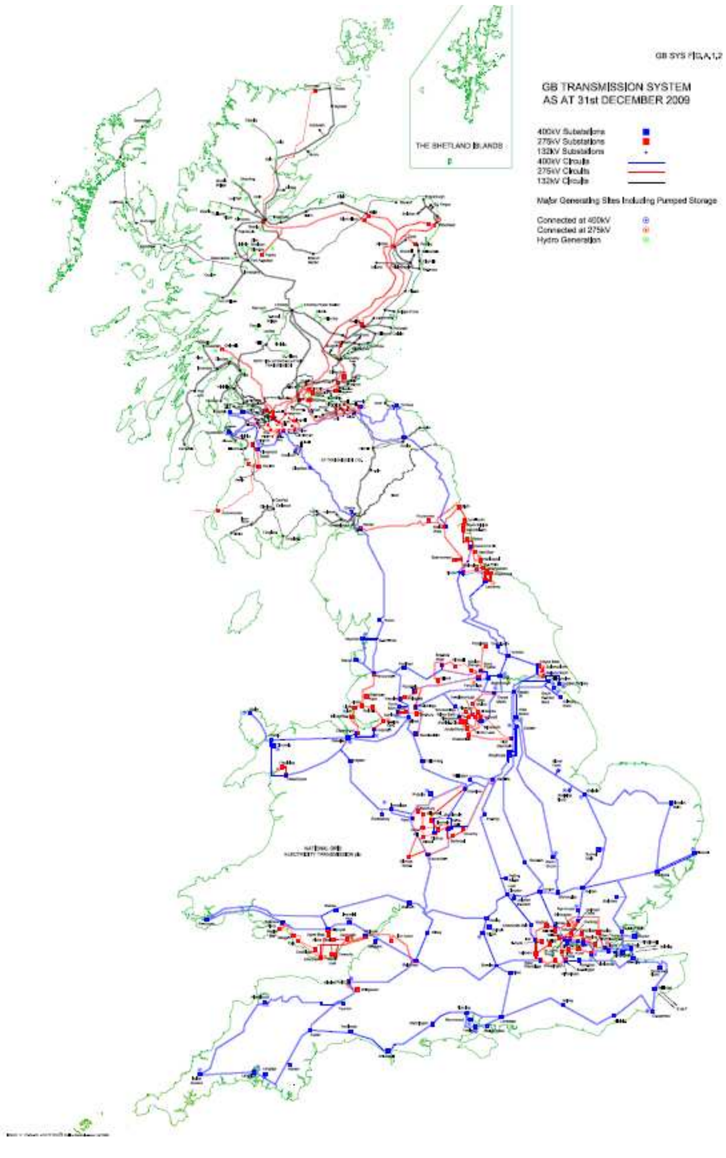
[7] Source: Energy Networks Association

3.4. Electricity transmission

The electricity transmission networks in GB comprise assets operating at 400 kV and 275 kV (and also 132 kV in Scotland). National Grid is responsible for the transmission network in England and Wales. Scottish & Southern and ScottishPower are responsible for the transmission networks in the North and South of Scotland respectively.

Figure 3.3 shows the GB transmission network that in the main links large generating power stations to distribution networks across the country.

Figure 3.3 Electricity transmission networks[8]



[8] Source: National Grid

The age profile for transmission assets is characterised by a peak of investment in the 50s-60s corresponding to the peak of electrification investment in the UK. The total replacement value with modern equivalent assets of the transmission networks in GB is estimated at about £37 billion. About 60% of this replacement value is associated with overhead lines. Charts showing the distribution of asset lives for the four networks can be found in Annex G.

3.5. Electricity distribution

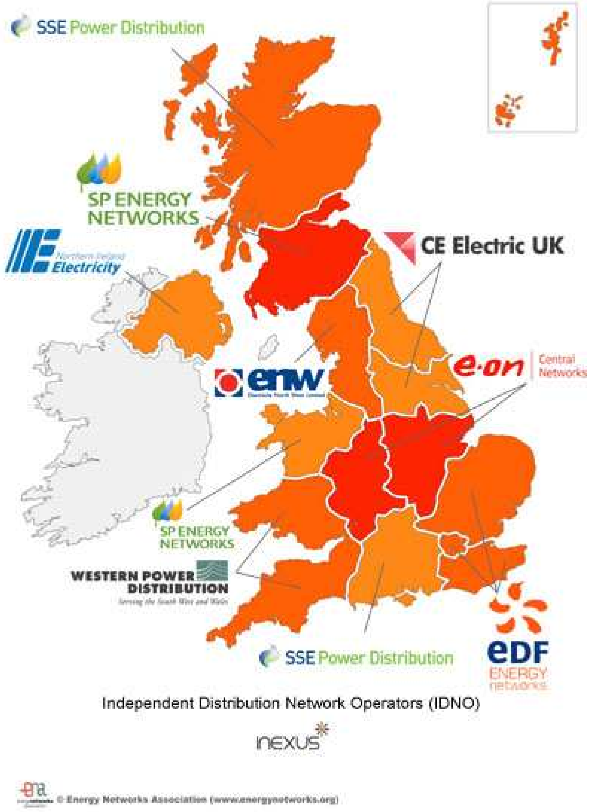
In GB there are 14 distribution network operators (see figure 3.4 below) that are owned by 7 companies as shown in Table 3.2 with the approximate operating region being shown in Figure 3.4.

Table 3.2: Electricity Distribution Network Companies

Area	Company
North East England Yorkshire	CE Electric
East Midlands West Midlands	Central Networks
Eastern England London South East England	UK Power Networks
North West	Electricity North West Ltd
North Wales, Merseyside and Cheshire South Scotland	ScottishPower
North Scotland Southern England	SSE Power Distribution
South Wales South West England	Western Power Distribution

The electricity distribution networks comprise assets ranging from 132 kV assets connected to the transmission system to low voltage mains and services to customer premises.

Figure 3.4: Electricity Distribution Networks[9]



The total modern equivalent replacement value of the GB distribution networks is estimated at about £136 billion. In comparison with the GB transmission networks the distribution networks are characterised by a large proportion of underground cables in terms of its total modern equivalent asset replacement value compared to the whole of the network. About 60% of the replacement value is associated with underground cables. Similarly to the transmission network, its age profile is characterised by a peak of assets installed during the 1950s and 60s although some of the oldest low voltage assets are approaching 100 years old (see Annex G for more detail).

[9] Source: Energy Networks Association. Note that as in table 3.2, the networks in Eastern England, London and South East England are now operated by UK Power Networks.

4. SCENARIOS

As discussed in section 2, how gas and electricity network assets are used in the future will be a key factor in the determination of their appropriate economic lives. In order to determine how the gas and electricity networks may be used over the period to 2050 we have considered a number of scenarios that explore differing drivers on gas and electricity demand (both peak and annual) and assessed the resulting impact on network usage and network investment. These scenarios are intended to provide plausible 'stress tests' for the future development of the electricity and gas networks, by identifying key drivers underpinning their development and defining alternative growth trajectories that may occur. They are not intended to be forecasts.

4.1. Scenarios used

Ofgem has already undertaken a substantial amount of scenario development, covering the period to 2025, for "Project Discovery"; this included a process of consultation with stakeholders. We have built upon these scenarios and extended them to 2050[10] (see annex A for more detail about how we have done this).

Two key drivers underpin the Project Discovery scenarios: economic recovery and growth, and environmental action. Combinations of "rapid" and "slow" values for these two drivers give rise to four scenarios as shown in table 4.1 below.

Table 4.1: Project Discovery scenarios and drivers

		Economic recovery and growth	
		Rapid	**Slow**
Environmental Action	**Rapid**	Green Transition	Green Stimulus
	Slow	Dash for Energy	Slow Growth

Clearly, given the uncertainty and long time period to 2050, these drivers are not the only ones. For robustness, we have considered a selection of other published scenarios, to: draw out common themes, benchmark the Discovery scenarios, and to ensure that we are considering an appropriate view of possible future developments. A list of the scenarios we have considered, with a discussion of the common themes emerging from them, is in Annex E.

A common driver in many scenarios is the aspiration to achieve long term reductions in greenhouse gas emissions, particularly carbon dioxide, and the different pathways that may be taken to achieve, or move towards, these reductions. While the pathways to long term emission reductions are clearly varied, in extending the Project Discovery scenarios to 2050, we have developed some common elements, in particular decarbonising the electricity sector and increased electrification.

In the discussion that follows, we have used the shorthand of referring to the "*Green Transition*" and "*Green Stimulus*" scenarios as "Green", and "*Dash for Energy*" and "*Slow Growth*" as "Less Green".

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[10] This extension has been done by us, rather than by Ofgem, and solely for the purposes of this report. It should not be taken as representing Ofgem's views.

4.2. Key messages

This section highlights some of the key messages from the scenarios. It is worth re-iterating that there is significant uncertainty around the scenarios, and that the messages below should be read as giving only the general direction or trend in each case. This uncertainty is particularly pronounced for gas.

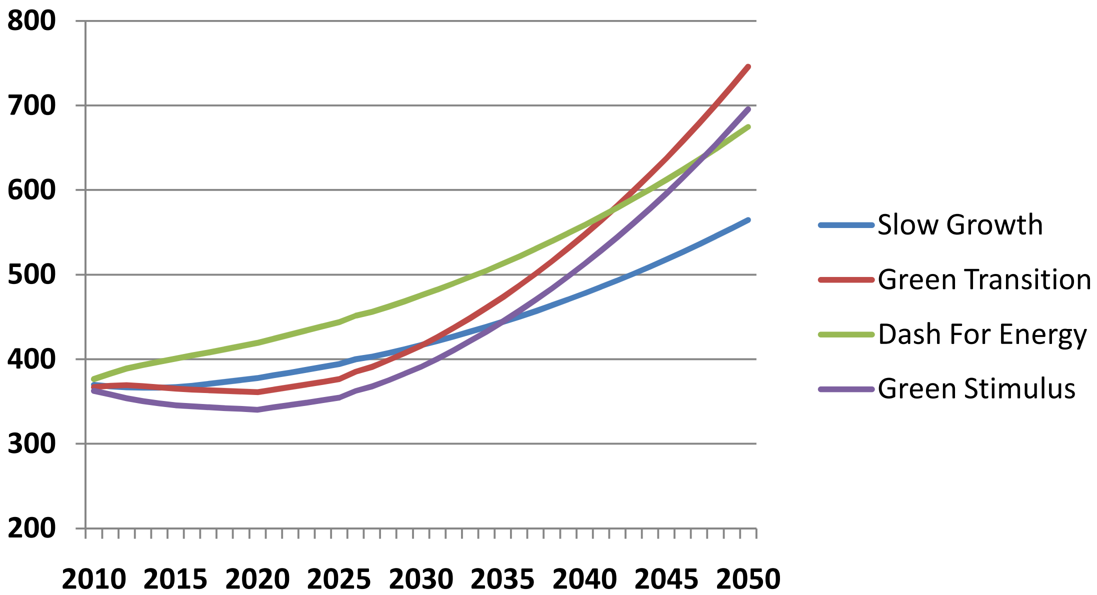
4.2.1. Electricity demand

In "*Dash for Energy*" electricity demand grows at a relatively constant rate over the period to 2050. Demand growth to 2025 is higher than that in the two "Green" scenarios as energy efficiency improvements are less marked in "*Dash for Energy*". Beyond 2025 the penetration of electric vehicles and space heating is more moderate than in the "Green" scenarios. The result is a relatively constant pattern of electricity demand growth to 2050. By 2050 peak electricity demand is highest in "*Dash for Energy*" of all the scenarios due to the constant growth experienced from 2010.

For "*Slow Growth*" a similar pattern of relatively constant electricity demand growth emerges, but the overall demand level is lower than "*Dash for Energy*" due to lower GDP growth assumptions.

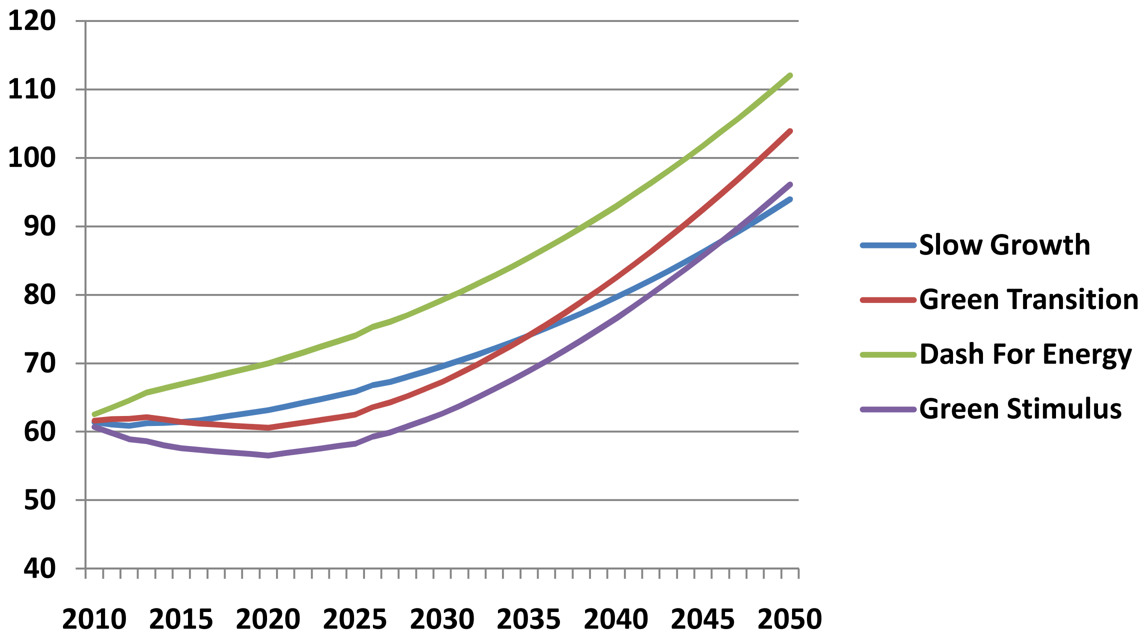
In the two "Green" scenarios the pattern of electricity demand growth is different. Electricity demand growth is muted to 2025, and thereafter begins to rise more rapidly. In "*Green Stimulus*" electricity demand initially falls over the period to 2025 due to a combination of recession, slow economic recovery and energy efficiency measures. Beyond 2025 electricity demand begins to accelerate as electric space heating and electric vehicles enter the market. For "*Green Transition*" a similar demand pattern emerges, although electricity demand is higher due to more rapid economic growth assumptions. By 2050 the annual electricity demand of the two "Green" scenarios is higher than in the other scenarios (figure 4.1).

Figure 4.1: Annual electricity demand (TWh)



However, in terms of peak demand, the results are different, as shown in figure 4.2. By 2050 peak demand in the "Green" scenarios is lower (relative to annual electricity demand) than the "Less Green" scenarios. The relatively slower growth in peak demand is achieved through, for example, greater demand side management measures and penetration of electric vehicles that combine to flatten the load duration curve and so more evenly spread the daily demand load.

Figure 4.2: Peak electricity demand (GW)



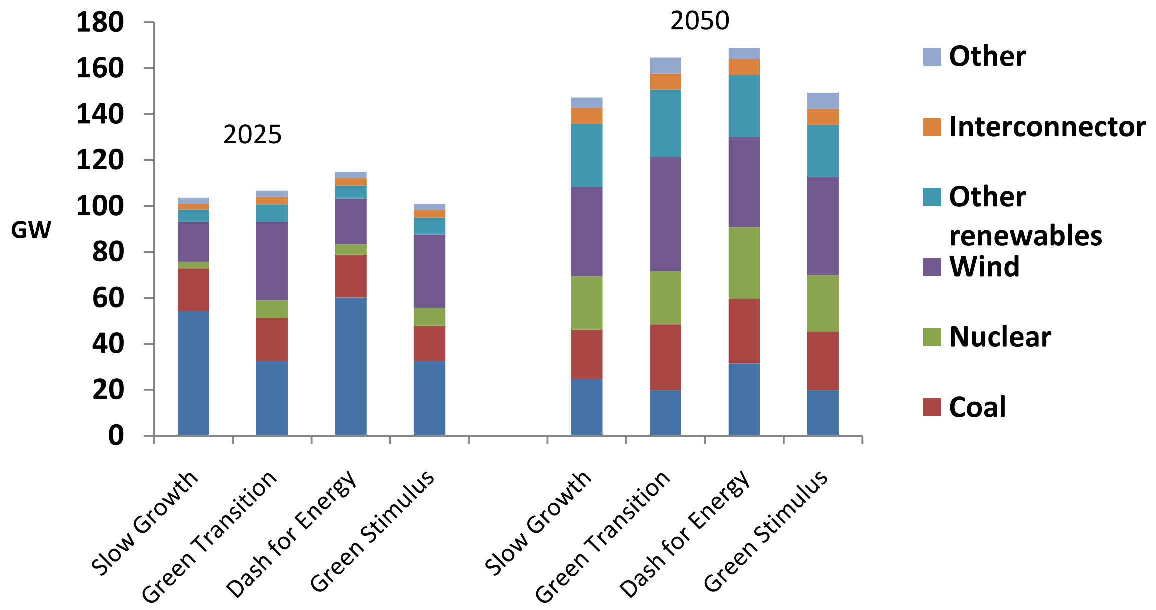
4.2.2. Electricity Generation Mix

Figure 4.3 shows indicative electricity generation mixes for the scenarios in 2025 and 2050. The significant capacity increase required in all scenarios is clearly shown. Capacity requirement is highest in "*Dash for Energy*" reflecting the constant, steady growth in both annual and peak demand electricity demand. The impact of greater demand management measures, leading to a lower electricity demand peak, is reflected in the capacity required for "*Green Transition*"; although annual electricity demand is highest in this scenario and so the network highly utilised, peak demand growth is more moderate and so the capacity required to meet the peak is lower, even with a higher proportion of renewable generation.

For "*Slow Growth*" and "*Green Stimulus*" the capacity requirement follows the same pattern as "*Dash for Energy*" and "*Green Transition*", but overall demand and therefore capacity required is lower.

In terms of the capacity mix, gas-fired capacity grows over the period to 2025 in both "*Dash for Energy*" and "*Slow Growth*", by 2025 gas-fired capacity accounts for around half of installed capacity. In the two "Green" scenarios more renewable and less gas-fired capacity is constructed over the period to 2025, leading to a generation mix in 2020 that provides some 30% of electricity from renewables – a level outlined in the Renewable Energy Strategy as likely to be required to meet the UK's 2020 renewables target.

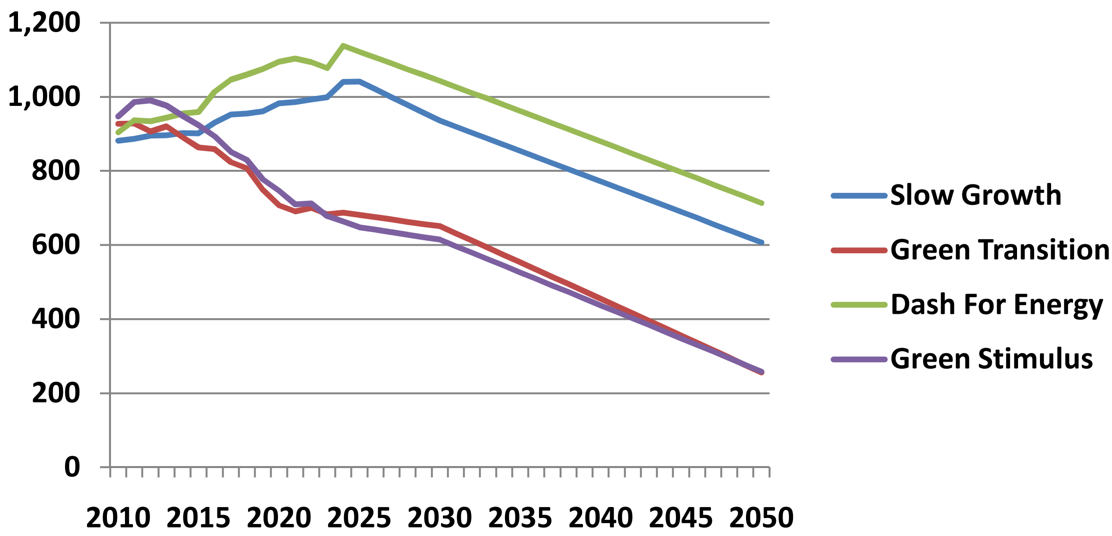
Figure 4.3: Electricity generation mix (GW)



4.2.3. Gas demand

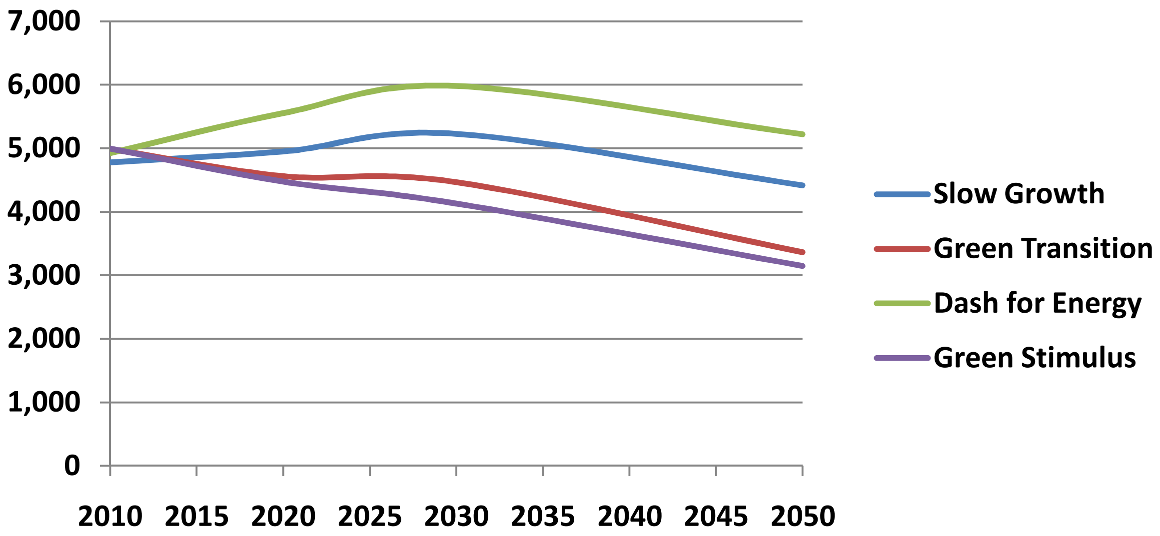
In the two "Green" scenarios, annual gas demand declines over the period to 2050. The decline to 2025 is largely the result of improved energy efficiency and more limited gas used by the electricity generation sector. After 2025, these two factors continue to drive a decline but now a move towards electric and renewable space heating and away from natural gas emerges as an additional driver. In the "Less Green" scenarios gas demand rises to around 2030, and then begins to decline as a proportion of space heating moves to electricity and renewables and demand for gas by the generation sector also declines. This is shown in figure 4.4 below.

Figure 4.4: Annual gas demand excluding exports to Ireland (TWh)



In terms of peak gas demand, an important difference emerges, in that it is more resilient than annual demand (see figure 4.5 below). In "*Dash for Energy"* peak demand grows to 2030, and then declines. However, despite the decline post 2030, peak demand in 2050 remains just above current levels. A similar pattern emerges for "*Slow Growth"*, although peak demand growth is more moderate due to lower GDP growth. In the "Green" scenarios peak demand declines over the period to 2050, but at a considerably slower rate than annual demand. In "*Green Transition"* annual demand declines over 70% by 2050, but peak demand declines by only around 30%.

Figure 4.5: Peak gas demand (GWh/day) excluding exports to Ireland



The resilience of peak demand is linked in particular to the large increase in intermittent generation and the subsequent need to maintain peaking capacity at times of low wind output.

4.3. Issues

A key assumption used in the Project Discovery model is the move from gas space heating to alternatives – in particular renewables and electricity post 2025 – as the UK moves towards a lower carbon energy mix. The results of our initial analysis suggest the move from gas to electricity will have profound effects on:

- the investment required in the electricity network due to the corresponding large increase in electricity demand, particularly at peak; and
- the gas network, which becomes considerably less utilised.

In addition, to support the level of intermittent renewable generation required to meet longer term renewable and carbon targets, a significant increase in overall generation capacity is needed – particularly 'back up' generation needed to ensure security of supply. In our model a significant proportion of the 'back up' generation is gas-fired. It operates at relatively low load factors, but is essential in periods of low wind output – as highlighted above. Indicative cost implications of the implied network build profiles are shown in section 5.

4.3.1. Will overall gas demand inevitably decrease?

The decrease in gas demand is driven by the need to decarbonise the economy as the UK moves towards its longer term goal of reducing emissions by 80% by 2050. Natural gas emits CO_2 when burned and so, if the UK is to meet its long term carbon targets, it must either be replaced by lower carbon sources of energy, or used in conjunction with carbon capture and storage (CCS).

While the introduction of biogas injected into the gas transmission network may help decarbonise gas – biogas is limited by resource availability, in particular feedstock. A National Grid study in 2009[11] indicated that it could, in a 2020 "stretch" scenario where all technical potential was exploited, provide up to 18% of the UK's gas supply.

Carbon capture and storage on gas generation would effectively remove the barrier to continued use of gas in the power sector. It is though an unproven technology at scale, and therefore poses risks of non-delivery. If CCS on gas were proven, at a reasonable cost, this would significantly change the scope for future use of gas.

While total annual gas demand may decline as the UK decarbonises, peak gas demand will not fall at the same rate – despite our assumption that space heating demand moves from gas to renewables and electricity. Electrifying heat demand poses a significant network and generation investment challenge. While electricity demand remains relatively flat throughout the year, heat demand is seasonal – on a peak day heat demand may be some three times higher (~3,000 GWh) than electricity and transport demand combined (~1,000 GWh). As a result, electrifying all heat demand would lead to demand ranging from around 1,200 GWh on a warm day to 4,000 GWh at peak.[12]

The impact of such a variable load would be a large increase in generation plant required to meet the peak day demand – likely to be either coal or gas with CCS capability[13]. The utilisation of this plant would be low, leading to high generation costs. In addition, as outlined above, the investment required in the electricity network to accommodate significantly increased peak demand would also lead to high costs. As a result the overall cost of electrifying heat is likely to be very high.

4.3.2. Network implications of a reduction in gas demand

The reduction in overall gas demand is, in green scenarios, across most types of demand except that from industrial processes. In the "Less Green" scenarios the reduction is largely driven by a reduction in the gas used for electricity generation (and peak demand does not reduce very much if at all). Reductions in different forms of demand are likely to lead to different futures for the gas network, driven by cost.

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[11] "*The Potential for Renewable Gas in the UK*", National Grid, January 2009

[12] "*Gas as an essential fuel in supporting the transition to a low carbon economy*" A discussion paper by National Grid to support Ofgem's RPI-X@20 project, December 2009

[13] Issues around CCS flexibility will need to be considered.

4.4. Possible future developments

In the process of considering scenarios, and possible future investment paths, we have identified a number of potential developments that could be significant drivers of the future need for, and structure of, networks. However, because of the degree of uncertainty around these developments, we have not attempted to quantify them in our work. Our considered view is that they could make particular outcomes more or less likely but that in all likelihood, the outcomes would still remain within the range covered by the scenarios we have considered.

4.4.1. Technological change

As we are considering the outlook for gas and electricity networks for the next four decades, it is possible that future technological developments could significantly shift the conclusions we might reach today. It is also notoriously difficult to predict the impact of technological change with any degree of accuracy. That said, there are some changes that we can point to today as likely to have an effect.

The first of these is the move to a smarter grid. This is likely to smooth electricity demand to some extent, but for our purposes it would have another important effect, namely a change in the type of assets on the grid. Specifically, there will be much more ICT[14] equipment, and this tends to have a relatively short life compared to current network assets which as set out elsewhere in this report tend to have lives of several decades rather than several years.

Clearly this will have an impact on the average asset life, but for the period under consideration we do not expect this to be material. There are two reasons for this:

(1) the existing value of the long-lived network assets will dominate even if significant ICT investment occurs; and

(2) the wholesale transition to smarter grids is likely to take some time and consequently the growth of ICT as a major asset class is likely to be gradual.

The second type of change is that replacements for existing assets may well be made of different materials to the assets they are replacing. These new materials could be designed to last longer than the existing assets, or may be sufficiently cheap that it makes economic sense to use them even though their expected lifetime is less than the materials used for existing assets. This leads us to the next possible driver – the cost of raw materials.

The work presented here is focused on the network assets and does not include the short-lived non-network assets. As noted in the uncertainties section, investment into these assets and a growth in importance is one element which could reduce the average technical life of assets.

While this is an important uncertainty we do not believe it is likely to have a material effect. For example, consider the case of electricity distribution. Currently short-lived assets account for between 1% and 2% of the net book value of the assets. If the £137 billion MEAV is considered, to reduce the existing technical life from 73 years to 63 years, assuming a five year life for the short-lived assets, there would need to be about £25 billion of such assets,

[14] Information and Communications Technology

significantly above the existing value (which will be much smaller when considered against MEAV as opposed to net book value).

Another approach is to consider the asset base per customer. There would need to be around £1,000 of short-lived assets per electricity customer to reach a total of £25 billion. This is well above the likely cost of smart meters, which are likely to be the primary source of these potentially short-lived assets.

So, while there is clearly uncertainty about the impact of short-lived assets, the time it would take to build-up to a sufficient level for this to significantly affect the average technical life and the current unlikely nature of such a high level of investment per customer that would be needed, means that we find it difficult to believe that this will be a material concern over the period to 2050.

4.4.2. Cost of raw materials

The future costs of the materials used to make network assets, such as copper, are impossible to predict. A large shift in these costs could, however, change the relative costs of different types of asset (or different options for the same purpose within the network) to such an extent as to noticeably alter the future asset base.

4.4.3. Policies used to implement decarbonisation

Governments can take several different approaches to decarbonisation. At one (theoretical) extreme, they can simply set a carbon price and not care where reductions were made within the economy, on the basis that those reductions would be made wherever they were cheapest. At the other end, they could mandate specific types of reduction on a sector by sector basis. The reality is likely to fall somewhere in between.

This is relevant to our analysis of the future of networks, since Governments may decide that certain approaches to decarbonisation are the right ones, and require network owners to deliver them. Some current network activities may not be allowed, or at least not to the same degree, in future, and conversely the relative demand on different networks in the economy could shift.

For example, a major drive towards electric vehicles might see a requirement that the electricity distribution network be upgraded to allow all homeowners to charge their vehicles overnight. This would increase use of the electricity network but presumably lead to a corresponding reduction in the use and transport of petrol and diesel around the country. We take no view on whether this policy would be desirable or not; that is not the purpose of this report. The point of this illustrative example is to show that decisions about the way that the economy is decarbonised are likely to lead to shifts in the relative demands placed on different energy networks. It is impossible ahead of time to be sure what those decisions, or shifts, might be.

4.4.4. Uncertainty about the real technical life of some assets

Some network assets, particularly the lower-voltage assets nearer the end-user, have been in place for nearly a century. Assumptions have been made about the expected technical lives of these assets, but the fact that many of them have remained in place well beyond those expected lives, without refurbishment or failure, suggests that these expected lives may be conservative.

4.4.5. Summary

The examples of uncertainties outlined in this section could have an impact on the asset life applied for depreciation. However, while some events would clearly lower the depreciation life, others would increase it. Table 4.2 summarises the possible impacts of the uncertainties discussed in this section.

Table 4.2: Summary of impacts of uncertainties

Event	Impact on average asset life	Rationale
Smart grids/ ICT	Decrease	ICT tends to have a short asset life. Unlikely to be material.
New technology	Unclear	As noted earlier, the impact could go in either direction depending on the cost benefit analysis associated with the new approach/technology.
Increase in cost of raw materials	Increase	More expensive assets could justify increased maintenance to extend the technical life or change the cost benefit analysis underlying health and safety limits on asset lives.
Policy decisions	Decrease	Government decisions on decarbonisation could lead to a wholesale change in approach or technology beyond that suggested by a simple cost-benefit analysis. Shifting between gas and electricity based space heating would be an example that could have a significant impact on asset lives.

Given these sorts of uncertainties, and the uncertainties inherent in looking four decades out at a time of significant policy changes, a conservative approach to depreciation life would seem to be appropriate, with periodic reassessments of the appropriate depreciation life as issues around these, and other, uncertainties become clearer. Consequently, it would be appropriate to review major issues impacting on depreciation life at price reviews.

5. IMPLICATIONS OF SCENARIOS FOR ECONOMIC LIVES OF ASSETS AND FUTURE CAPEX

We set out in this section our views on the implications of the scenarios from the previous section on the use of assets in future and of future investment needs. It should be said at the start that investment is not the focus of this report. Our goal is to assess the most appropriate *economic* and *technical* lives of existing and new assets, and use those to make recommendations as to appropriate depreciation. However, we also wish to consider the implications for cash-flow and financeability, and to do this we need to have broad estimates of future capital spending. This section sets those out for each of the four networks. As can be seen, expenditure is dominated by that for electricity networks, particularly the electricity distribution networks.

5.1. Electricity transmission

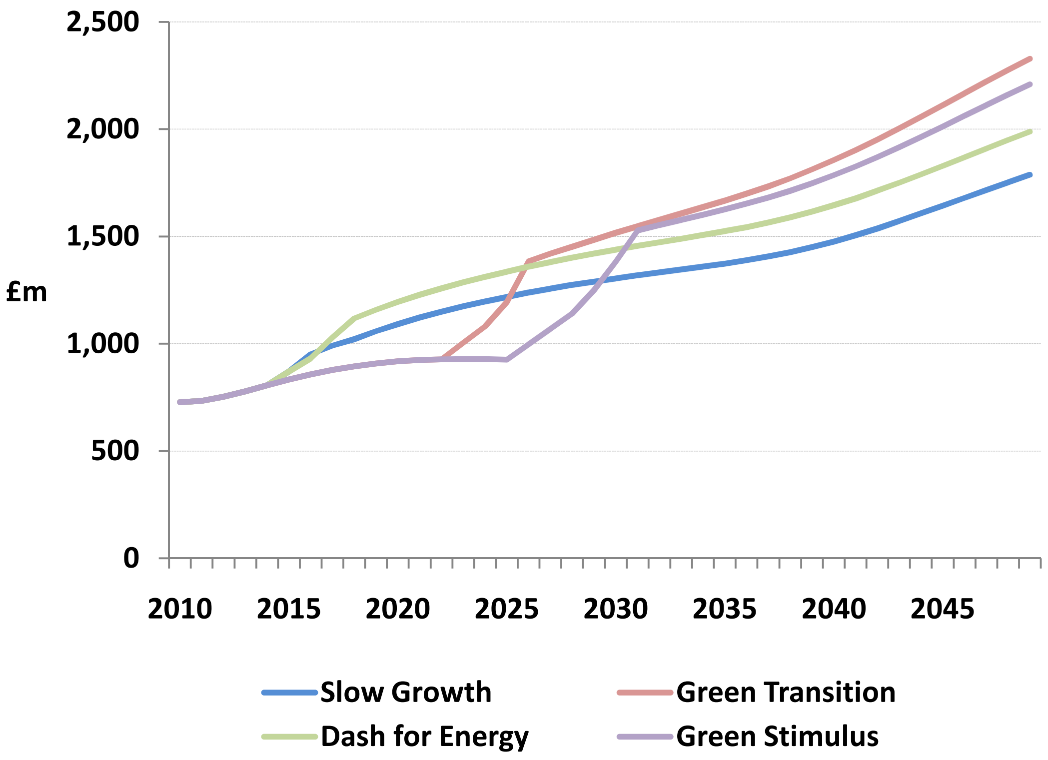
A considerable increase in peak electricity demand is observed by 2050 under all scenarios considered in Section 4 (see Figure 4.2). This growth in peak demand, which under the "*Dash for Energy*" almost doubles, indicates the need for substantial capital expenditure in electricity transmission.

Assuming a distribution of demand throughout the country by 2050 similar to the existing network, the investment requirements in transmission infrastructure to accommodate such growth in peak demand would be substantial. However in practice the reinforcement requirements will be heavily affected by the location, capacity and type of generation operating under each of the scenarios. Hence there is an uncertainty about the level of expenditure required depending on the generation assumptions made. Additional expenditure will be required to accommodate offshore and marine generation.

The growth in peak demand is however not uniform amongst all scenarios. Whereas continuous growth in peak demand over existing levels is obtained under the "*Dash for Energy*" and also under the "*Slow Growth*" scenarios, the two "Green" scenarios only show increases in peak demand from about 2025-2030. However the capital expenditure forecast even in these scenarios indicates the need to gradually increase expenditure to replace ageing assets. These requirements impact equally all the scenarios.

In the case of transmission networks it is considered unlikely that the level of overhead line construction achieved to meet peak demand with the existing network will be achievable into the future particularly under the more aggressive higher peak demand growth scenarios. Higher level of undergrounding and use of other technologies such as DC and offshore links to avoid onshore reinforcements are likely to push up investment requirements. These issues are likely to make transmission investment requirements grow faster relative to distribution reinforcement requirements.

Figure 5.1: Annual capex for the electricity transmission network, by scenario



5.2. Electricity distribution

The increase in electricity peak demand discussed above and in Section 4 will also have a substantial impact on the investment requirements in electricity networks by 2050.

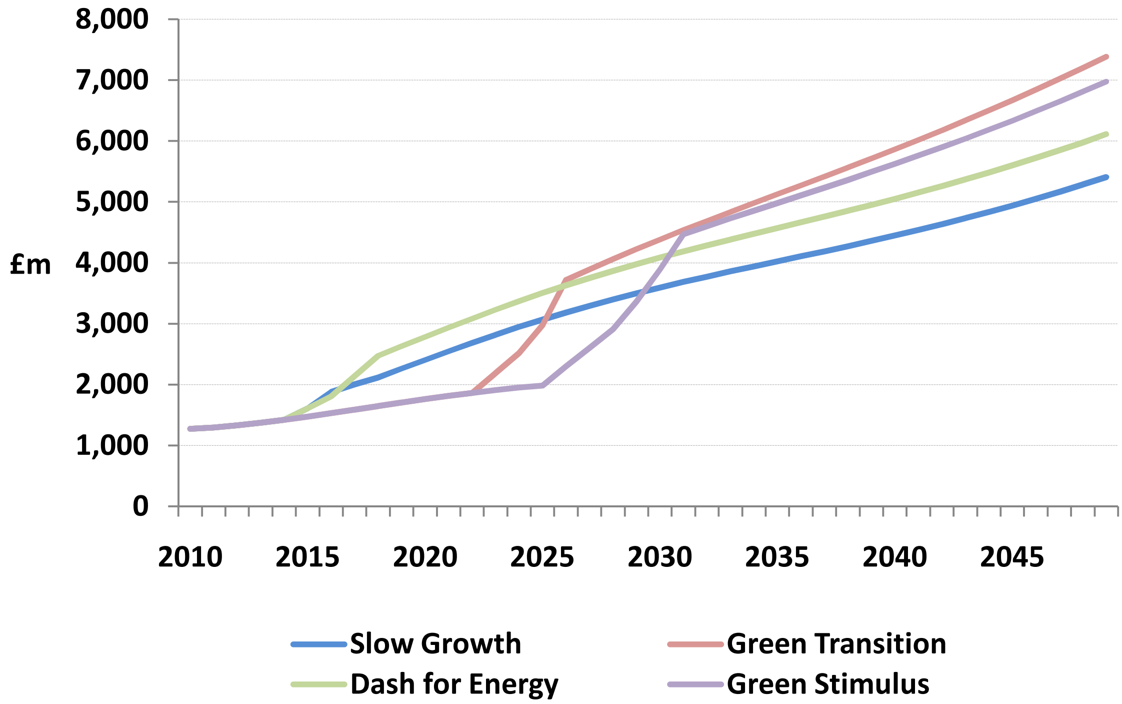
Notwithstanding the growth in peak demand by 2050, the distribution networks will also require significant investments to replace ageing assets in the existing networks, in all the scenarios considered. However future replacement liabilities are heavily influenced by the need to replace underground cables and particularly long lived low voltage mains and services. If the need to replace these assets can be delayed then a reduction in expenditure forecast may be expected.

The assumed reduction in historic overhead line activity to accommodate peak demand growth will also lead to an increase in the expenditure forecast, noting however that its effect will be less marked than in the case of transmission networks as it relates to a much lower proportion of the overall distribution network.

Reductions in historic expenditure levels to accommodate peak demand can also be expected from the large proportion of underground cables in the existing networks given the large proportion of the installation costs related to excavation and reinstatement costs. These costs are relatively insensitive to cable capacity.

Expenditure in communications and control infrastructure in distribution networks particularly those associated with Smart Networks infrastructure will increase in importance and also its replacement spend, considering the relatively shorter technical lives of such equipment (although see the discussion in section 4 on the likely materiality of this infrastructure).

Figure 5.2: Annual capex for the electricity distribution network, by scenario



5.3. Gas transmission

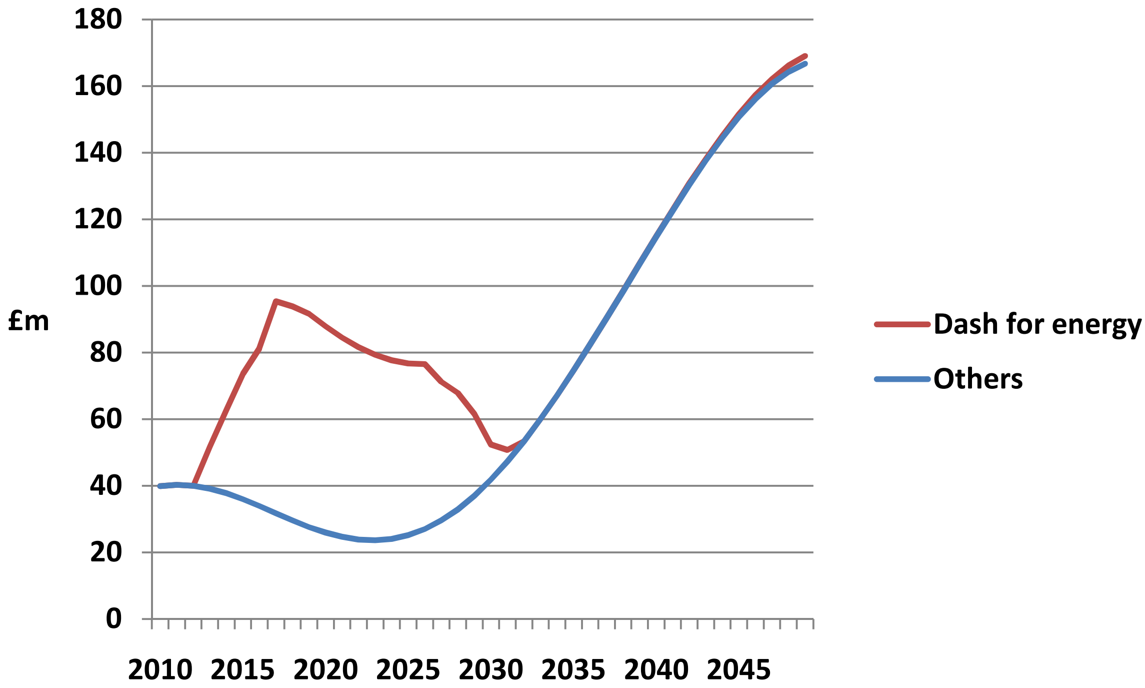
The key message from the extrapolated Project Discovery scenarios discussed in section 4 is a general reduction in the use of gas by 2050. That said, gas is likely to be required as back-up for the generation of electricity by renewables. Some scenarios show an increase in peak (if not overall) usage in the medium term, particularly for generation purposes, which may require investment. CCS, if proven at commercial scale, could maintain the use of gas at a transmission level and thus the infrastructure to supply it. All pipeline assets would thus be required into the long term and we would not necessarily expect any to be redundant.

Any decrease in the use of gas may lead to a reduction in the variation in pressure required from the pipe system, enabling the pipelines to have a longer technical life. Similarly, in the long term compressors may be used less frequently and attain a longer technical life, or may in some cases be redundant. Some degree of updating of compressors and pressure reduction installations may be required to ensure their efficient use under different flow conditions.

The use of biogas to supply the gas distribution network would further tend to reduce the supply required through the transmission system. However, there are a number of constraints on this. First, the technical potential of biogas is 18% of the UK's gas supply. Second, the reliability of biogas plants is not currently known and it may be that some system flexibility of supply will have to be retained in the distribution system. A Distribution Network (DN) may therefore wish to retain the option of supply from the National Transmission System (NTS) for security of supply purposes.

The transmission capital expenditure profile is based on a large element of non-load related expenditure in the short term associated with the reconfiguration of the NTS to accommodate the changing pattern of gas flows as a result of LNG imports. There is a very low level of load-related spend in the short, medium and long term. This is shown in figure 5.3 below. The increase is largely driven by a gradual rise in pipeline replacement expenditure.

Figure 5.3: Annual capex for gas transmission network, by scenario



5.4. Gas distribution

As for transmission the key message for gas distribution from the scenarios is a general reduction in the use of gas by 2050. However, whilst a decrease in demand would see the assets being used less in general, it is not clear that there would be widespread redundancy in the assets.

Any long term decrease in the use of gas which may be achieved may lead to a reduction in the variation in pressure required from the high pressure distribution pipe system, enabling these pipelines to attain a longer technical life. The lower pressure tier pipes would be unaffected by a reduction in flow. Any reduction in flow may see the need to update metering and pressure reduction installations in order that they would continue to measure flow and control pressures and flows through the network systems effectively.

Some scenarios show an increase in peak usage in the medium term, particularly for generation purposes. Any increase in the use of gas for this purpose may, in the medium term, see a need for reinforcement of the distribution assets.

In addition to the use of gas identified as a back-up to renewables in the medium term, the Redpoint report for ENA[15] has identified in its Green Gas scenario that the distribution system

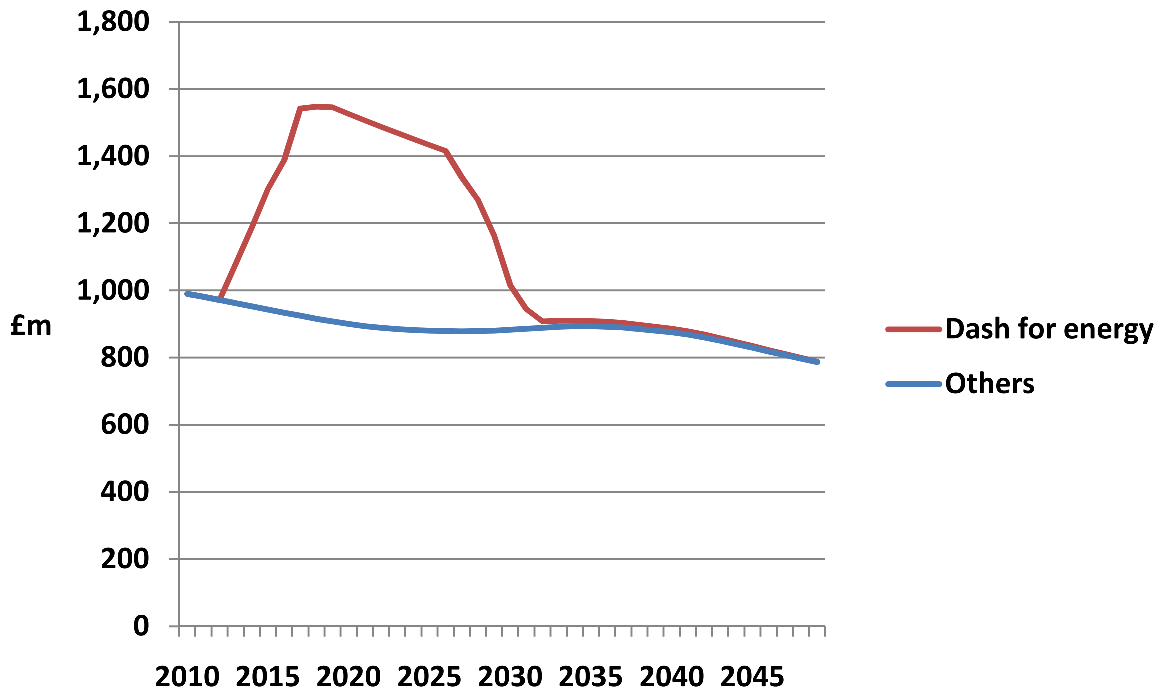
[15] Redpoint "*Gas Future Scenarios Project – A report on a study for the Energy Networks Association Gas Futures Group*", November 2010 http://energynetworks.squarespace.com/storage/ena_publications/ena_gas_future_scenarios_report.pdf

could be used for embedded generation of electricity in the longer term. The potential development of CCS would support the enhanced use of gas at the distribution level. The report also envisages the use of gas for the peak shaving of space heating through the use of dual fuel systems. Each of these scenarios requires the use of a widespread distribution system.

The use of biogas would also require the use of a widespread distribution system. To make use of the continuous supply from a biogas plant, sufficient consumers have to be connected, especially at the lowest gas demand periods. This again supports the view that all distribution assets could be required into the long term. Some development of the system would be required to absorb the biogas. As is discussed above, DNs may choose to retain the option of a full supply from the NTS to ensure security of supply.

The distribution network capital expenditure profile is based on the continued replacement of iron pipes at current levels until the completion of the 30:30 iron mains replacement programme[16] in 2032. Load-related expenditure associated with new connections and reinforcements is generally flat with no significant growth in the short to medium term (except in the "*Dash for Energy*" scenario) and reducing in the long term. This is shown in figure 5.4 below.

Figure 5.4: Annual capex for gas distribution network, by scenario



5.5. Summary

In conclusion, peak gas demand will not necessarily decline, and so it is not clear that any gas network assets will become redundant, although there is likely to be some changes to assets to accommodate new flow patterns. Peak electricity demand is expected to grow significantly in all scenarios, and so assets are expected to be useful for their entire technical life.

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[16] More details can be found on the Health and Safety Executive's website, for example http://www.hse.gov.uk/gas/domestic/gasmain.pdf

6. CONSIDERATION OF DEPRECIATION OPTIONS

We set out below our approach to depreciation, and our recommendations on the depreciation life and profile, and consider their cash-flow implications.

6.1. Issues and approach

As discussed in the Ofgem RIIO financeability report (and the associated CEPA supporting paper[17]), depreciation is an important element of the allowed revenue. Depreciation can be thought of in several ways, two of which are:

- a form of revenue profiling reflecting the way in which future revenue streams (normally associated with tangible assets but potentially reflecting a broader recovery of costs) are to be profiled; or
- a measure of the consumption of capital that takes place when a service is provided today at the expense of the service being provided to a future consumer.

UK, US and some continental European country regulation has focused primarily on the former issue rather than the latter, although from an economic perspective it is the latter that is important. The differences between the approaches were discussed in the previous report. The focus of this section is on the calculation of depreciation.

Additionally, if the return on capital allowed for in price controls is aligned with the cost of capital for the business, investors will (in theory at least) be indifferent to the depreciation method. This is because a change to the schedule of payments will not change the net present value of the future cash flows.

It has been argued that in practice the payments to companies should be affected by the depreciation profile. There are a number of reasons for this. One is the assessment of the business by the rating agencies. Another argument is that a different cost of capital may need to be applied to cash flows of different duration. An assessment of these arguments is beyond the scope of this paper. In this report, we make the assumption that Ofgem will choose an allowed return that is aligned with the cost of capital that is appropriate for the timing and risk of cash flows being considered.

6.1.1. Economic depreciation

From an economic perspective, depreciation is a measure of the consumption of capital that takes place as a service is provided to consumers[18]. It reflects the fact that providing a service to consumers today means that future consumers will have less access to services and so, is at its heart, a measure that is concerned with intergenerational equity since it is assessing the impact that one "generation" of consumers have on the ability of future generations to consume. This is a very different approach to what is normally considered depreciation by accountants, although much of the difference arises from the practical considerations involved in the measurement of

[17] http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/Final%20CEPA%20RPI-X@20%20Financeability%20Report%20May%202010.pdf

[18] As noted in section 2, ideally, charges to customers would reflect the long-run incremental cost of their use of the asset. This would have the benefit of giving the correct economic signals to users of the asset.

depreciation rather than intrinsic underlying theoretical concerns. What neither measure is concerned with is the repayment of the funding associated with the provision of the service; that is a separate (but linked) consideration.

At its purest, an economic measure of depreciation would be provided by:

Equation 6.1: Economic measure of depreciation

$$depn = MEAV_t - MEAV_{t-1}$$

That is, the measure of depreciation is the difference in the Modern Equivalent Asset (replacement) value of the assets between two dates[19]. Of course, the measure needs to be corrected for any investment that has taken place.

However, this approach is not employed by UK regulators - rather, approaches building on accounting principles tend to be used.

6.1.2. Accounting depreciation

This approach depends on two factors:

- the period over which the asset is to be depreciated – the asset life; and
- the profile of the depreciation.

Each of these is discussed in turn before a consideration of its implications.

6.1.3. Asset life

At its simplest the choice about the asset life is a simple consideration of two factors: the technical life of the asset, and its economic life. The depreciation life is then the minimum of the two values:

Equation 6.2: Depreciation life

$$Depn\ Life = \min\{economic\ life, technical\ life\}$$

So, although an asset may have a technical life of 50 years, if the service will not be required after 30 years then the appropriate period to depreciate the asset over is 30 years.

The relationships set out above provide a general framework for considering what asset life should be applied. There are some special cases where, while the basic relationship holds, some care is needed in the application. For example, what is the useful asset life for infrastructure that has a single user whose own useful asset life is different to that of the infrastructure?

Take the example of a gas field and the transmission infrastructure linking this to a national network. Suppose the gas field has an expected life of below 10 years while the transmission infrastructure has a useful asset life of over 30 years. What is the appropriate useful asset life for the transmission line – 10 or 30 years? The answer will, in part, depend on whether there are

[19] See for example the CRI article on long run marginal costs by Ralph Turvey which discusses this issue http://www.bath.ac.uk/management/cri/pubpdf/Technical_Papers/13_Turvey.pdf

alternative uses for the infrastructure. In the case of a gas field there is the possibility that a further gas find will occur which might extend the life of the infrastructure (depending on the timing of the find, the available capacity of the line and so on). As such, the choice of useful asset life could be important since it will affect the speed of recovery as well as the incentives for finding further uses for the infrastructure. While the discussion about gas fields may have limited impact on choices in the UK, the recent push for offshore electricity transmission could face similar issues but on a much larger scale.

6.1.4. Profile of depreciation

When considering the form of depreciation to apply there are multiple approaches possible, including:

- straight-line;
- sum-of-digits; and
- per-unit.

While there are many other forms, these three approaches are able to illustrate the impact of choosing between the different forms. Each is briefly discussed below.

- **Straight-line depreciation** is the standard approach employed for depreciation and is based on making an equal allowance for depreciation for each year of the useful asset life – so if an asset has a 20 year life then 1/20th of the asset value is taken as a depreciation charge each year;
- **Sum-of-digits** is an approach that accelerates depreciation, i.e. front end loads the recovery of the value. The allowance is set by using the formula: (remaining life/sum of years digits)[20]; and
- **Per unit depreciation** is based on estimating the total quantity of service likely to be provided by the asset and then allocating a charge each year based on the level of service being provided in that year – so if utilization is going to change over the life of an asset then the depreciation charge will change accordingly. Further discussion of this approach is provided below.

There are also circumstances where a completely different approach to depreciation is adopted – that of infrastructure renewals charging. This approach, used extensively in the water industry where useful asset lives (especially technical) are far from certain, is based around levying a charge sufficient to maintain the current level of service offered by the assets. Effectively consumers ensure that they pay for the impact that they have on the service offered by the assets. The way in which this is calculated at least in the UK water industry, however, is more focused on the expected cost of repairs and maintenance rather than a direct assessment of the condition of the assets and the service provided.

[20] For example, suppose an asset has a life of 10 years. Then the sum of digits is 1+2+3+4+5+6+7+8+9+10=55, and the depreciation in the first year is 10/55 of the value, in the second year is 9/55 of the value and so on.

6.1.5. The use of per unit depreciation

An approach used in some infrastructure services, such as Dutch airport infrastructure, is to charge per unit depreciation. As noted above, this is an approach that requires an estimate of total demand and then charges a uniform depreciation charge for each unit of demand.

There is a question as to whether this approach is appropriate – a question which could be applied to each of the other approaches but which is not as stark as with per unit depreciation. While it is clear that true economic depreciation cannot be used, should a system that is completely divorced from the reality be used? Per unit depreciation makes this choice most stark because it is effectively saying that the ability to consume a future service is totally dependent on a fixed number of units being available.

This raises the key question of what actually is the driver for depreciation. Is the driver volume related or is it something else? Now, it is standard to believe that the majority of asset costs are fixed (and by turn the majority of revenue) since the return on and of assets are treated as fixed. But is this appropriate? If normal utilisation of an asset has little impact on the ability of the asset to deliver its service and it is other factors like the durability of the material used that determines the life of the asset then is it appropriate from a technical perspective to charge depreciation on a per unit basis?

It is clear that under normal utilisation it is other factors than volume that determine depreciation. This does not mean that per unit depreciation should not be considered, just rather that the rationale for using per unit depreciation, or some/most of the other approaches, will be something other than a technical consideration of true depreciation.

6.2. Implications of depreciation choices

What are the implications of the choices about how depreciation will be charged? They can be considered from two perspectives mirroring the depreciation life and profile issues:

- the period over which cash-flow from depreciation occurs; and
- the profile of the cash-flow.

While the first aspect is quite straight-forward (but obviously important) the second is more complex. This is because the profile of the cash-flow is affected by both the return on and of an asset and by changing the profile of depreciation one affects both:

- the direct depreciation charge; and
- the allowed profit.

The second impact comes through the way that profits are estimated, with the Regulatory Capital Value (RCV) affected by the depreciation charge. A reprofiled depreciation charge leads to a reprofiling of profit which in part offsets the change in the depreciation charge. This is illustrated in the discussions below.

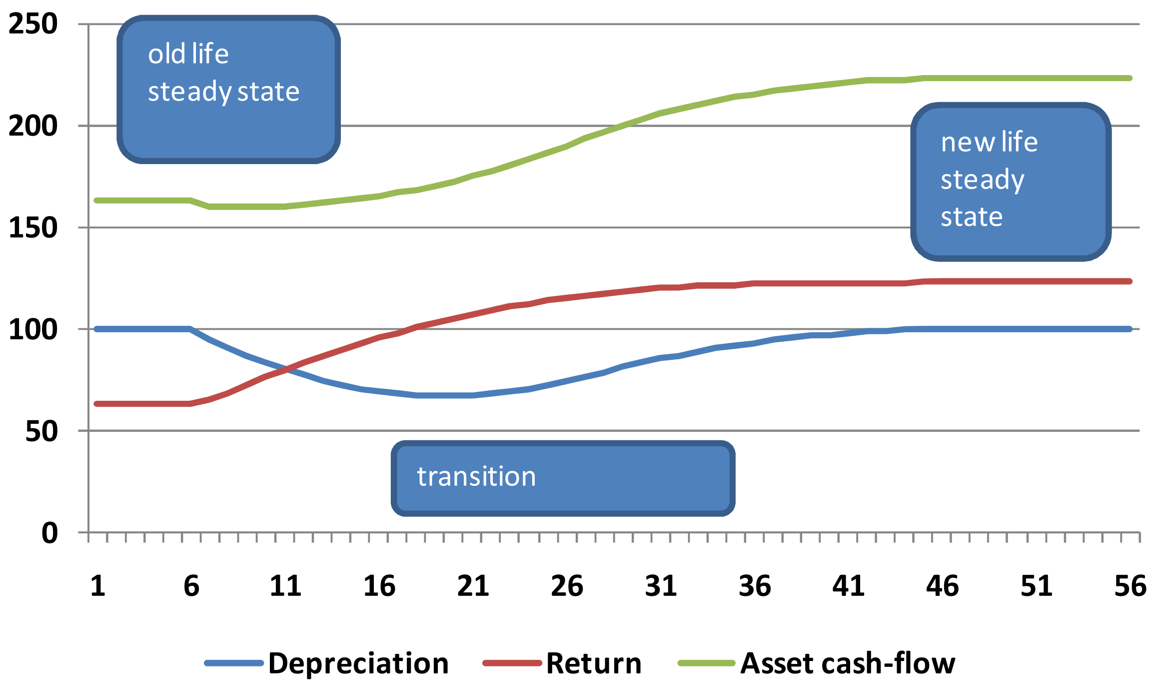
6.3. Depreciation life

A change in the depreciation life of an asset will change the period over which cash-flow occurs. While in a single asset example this may be a simple effect, in a more realistic situation of multiple assets and ongoing investment the effect is less simple. Further, an influence is seen through the allowed profit element that was discussed above.

Consider the following example, based on a simple model that brings out the key features[21]. In a situation where originally assets have been allocated a depreciation life of 20 years, a doubling of the depreciation life to 40 years (with consequent implications for existing assets) has the impact illustrated in the figure below. The example is explained further at the end of this section.

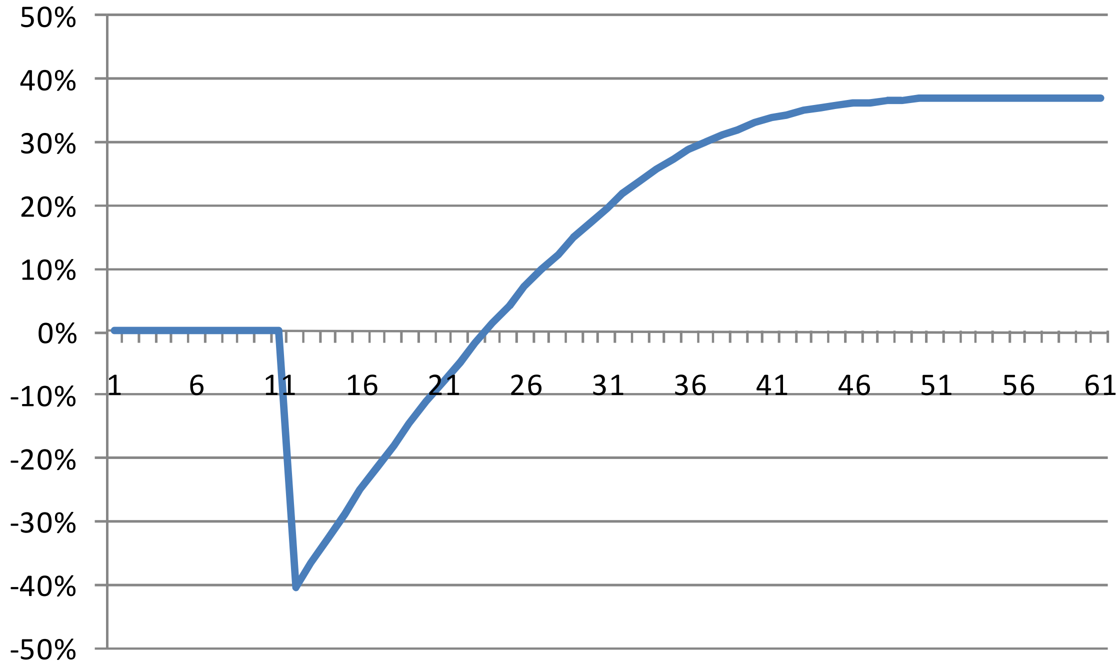
Figure 6.1 shows that starting from an initial equilibrium level there is a significant drop in asset related cash-flows (depreciation and return) which then over time recovers to reach a new equilibrium higher than the original level. In this example the transition takes over 20 years to work through. This is better illustrated in Figure 6.2 where the impact on cash-flows is shown as a percentage change from the original equilibrium level cash-flow.

Figure 6.1: Impact of changing depreciation



[21] More detail on the model can be found in Annex E.

Figure 6.2: Impact of changing depreciation life for all assets



A key question we will return to later in this section is whether there are ways of mitigating this significant cash-flow impact, if that is deemed necessary.

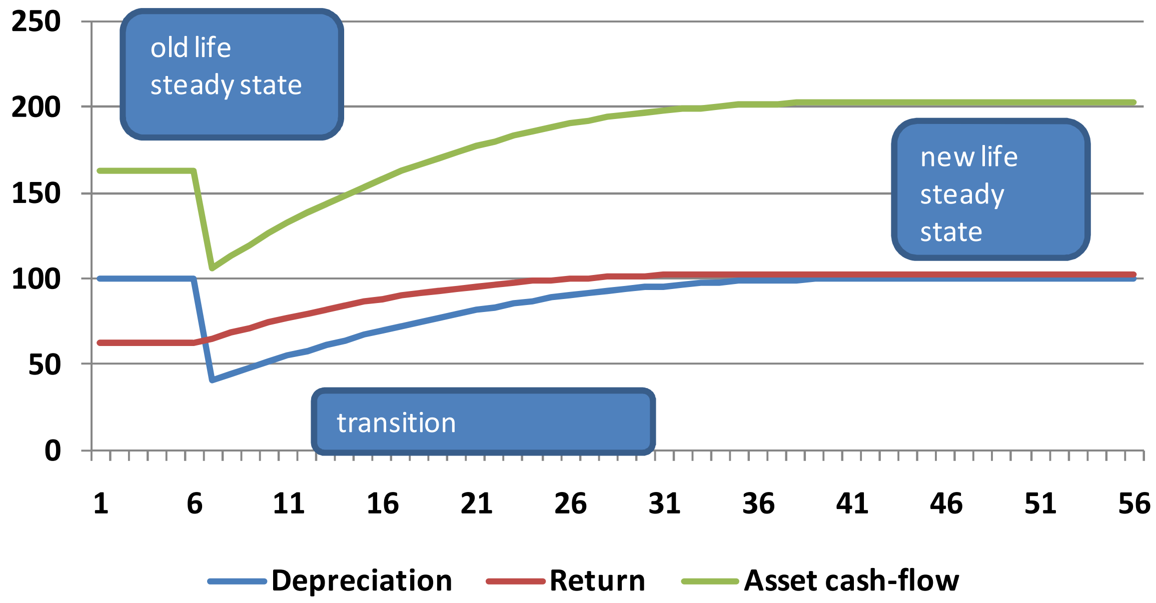
6.4. Depreciation profile

What happens if different depreciation profiles are applied? Consider two approaches:

- Straight-line depreciation; and
- Sum-of-digits.

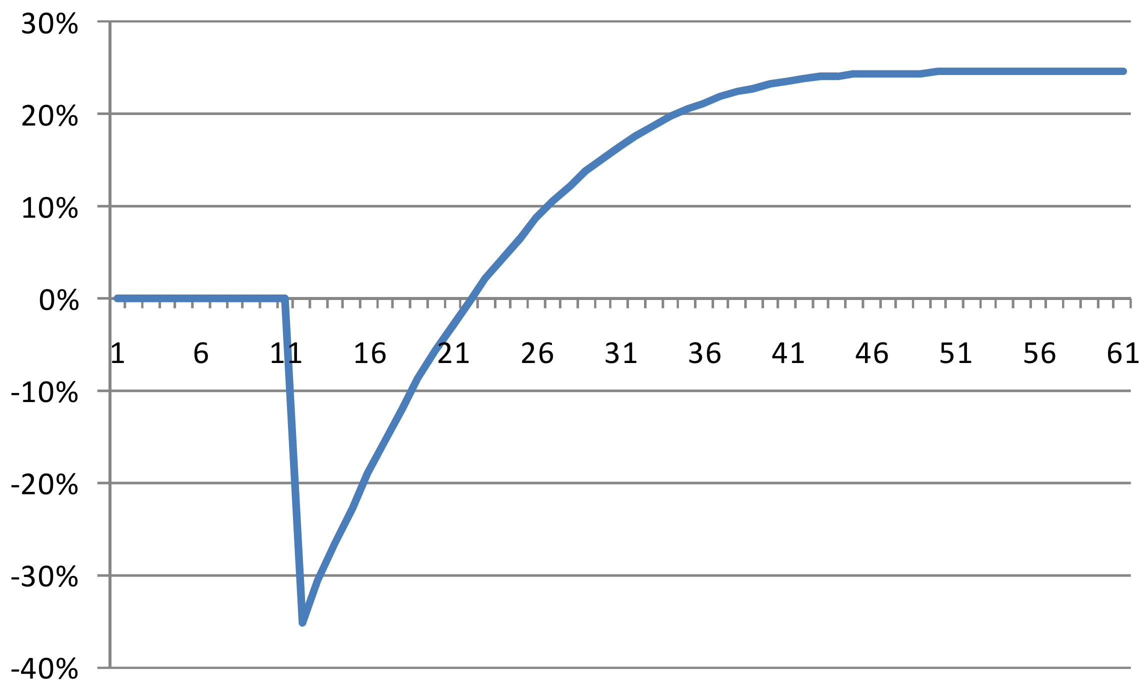
Using the model from above, figure 6.3 illustrates the impact of changing to a front-end loaded sum-of-digits approach.

Figure 6.3: Impact of changing depreciation profile between straight-line depreciation and sum-of-digits



As can be seen, while the move to a 40 year life still causes a dip in the asset based cash-flows, it is not as severe as that seen for straight-line depreciation. Figure 6.4 shows this more explicitly.

Figure 6.4: Proportionate impact of changing profile between straight-line depreciation and sum-of-digits



Obviously a shift to a back-end loaded approach would exacerbate the cash-flow impact which would be further magnified if linked to a change in the asset life.

6.5. Assessment of the profile approaches

When choosing between the different approaches to depreciation profiles it is useful to assess them against some simple assessment criteria. Criteria should include:

- ease of application – how simple is an approach and consequently what implementation issues are associated with it?
- whether the approach mimics the true cost structure of a business; and
- the impact on asset cash-flows.

This latter is important if:

- the credibility of the regulatory regime to guarantee future revenue streams is debatable; or
- the company is unable to finance the transitional cash-flows impacts, or could only do so at a very high cost.

Table 6.1 summarises our view of the three approaches to depreciation profiles against the criteria.

Table 6.1: Assessment of different depreciation profiles

Criteria/Profile	Straight-line	Sum-of-digits	Per unit
Ease of application	Simple	Simple	Potentially difficult. If demand forecast is never updated then potential to play games through the forecast. If updated, then depreciation profiles may change at each periodic review.
Mimicking true cost structure	Depends on the driver of depreciation. If the material degrades at a fixed rate then this may be a good proxy.	Depends on the driver of depreciation. If the material degrades at an increasing or decreasing rate then this may be a good proxy.	Depends on the driver of depreciation. If the material degrades depending on utilisation then this may be a good proxy.
Impact on asset cash-flows	Clear and understood.	Decreasing rate front-end loads revenue while increasing rate back-end loads revenue.	Can front- or back-end load revenues dependent on expectations of utilisation.

Overall it would seem:

- none of the approaches is especially good at mimicking the underlying[22] cost structure for depreciation;
- all three can affect the asset cash-flows; and

[22] Assets do not degrade smoothly over time or (to a first approximation) relative to usage, but tend to last for a certain length of time and then suffer a significant increase in their failure rate.

- straight-line and sum-of-digits are simple to apply.

It is also the case, as noted earlier, that sum of years approaches can mimic the per-unit depreciation approach, if the change in utilisation is expected to be continuous and only in one direction. Consequently, since it would only make sense to apply this more complex approach if there were a significant change, sum-of-digits approaches should be viewed as a working proxy for the per unit approaches.

Further, given the assessment, unless there is an overwhelming case for change, say because of significant expected utilisation changes, the default approach should continue to be straight-line depreciation.

6.6. Transition options

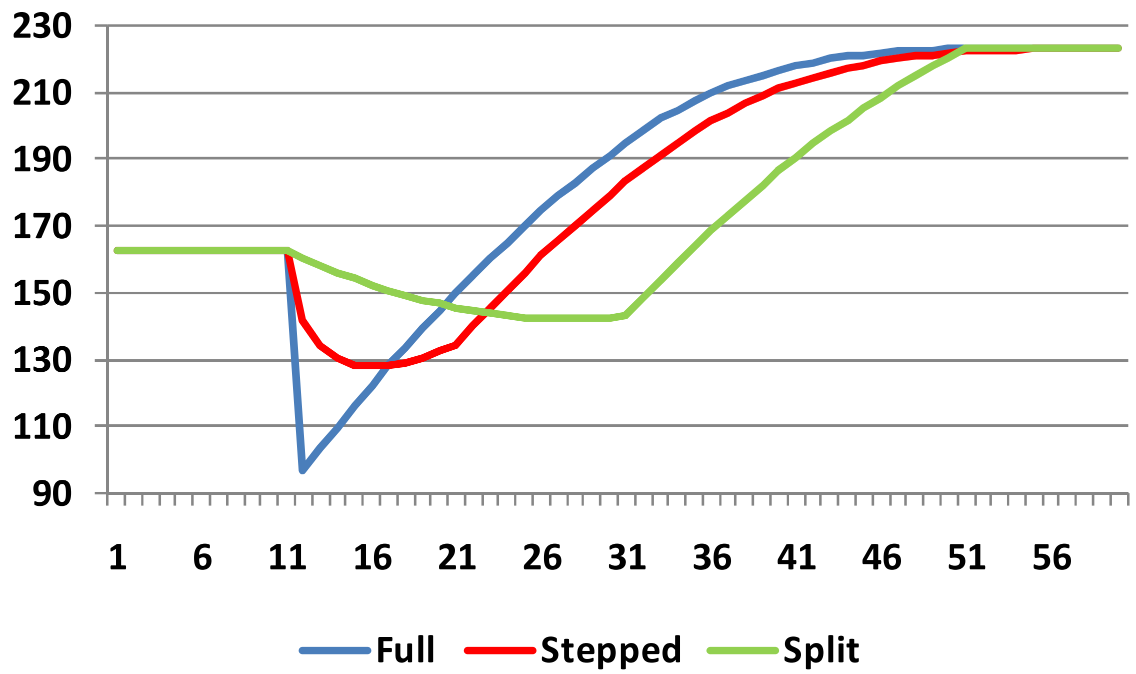
What is clear from the simple models is that any change is likely to have a significant impact on cash-flows. When RIIO raised the possibility of changing, especially lengthening cash-flows, some stakeholders raised concerns raised about the possible impact on the weighted average cost of capital (WACC). While we do not try to resolve that issue here, it is appropriate to consider some possible transition options that Ofgem could apply if it believed they were necessary. We focus only on issues that affect the depreciation life approach rather than the profile since we view the latter as a secondary issue within this overall debate.

Two specific transition options are considered; these are just illustrative of the numerous possible options available to Ofgem. Specifically, we consider the options of applying the change in asset life to:

- only new assets, i.e. leaving existing assets with their existing asset life (our "Split" depreciation life example); and
- all assets but making the increase in a series of steps (our "Stepped" depreciation life example – where the increase occurs in two year steps over a ten year period).

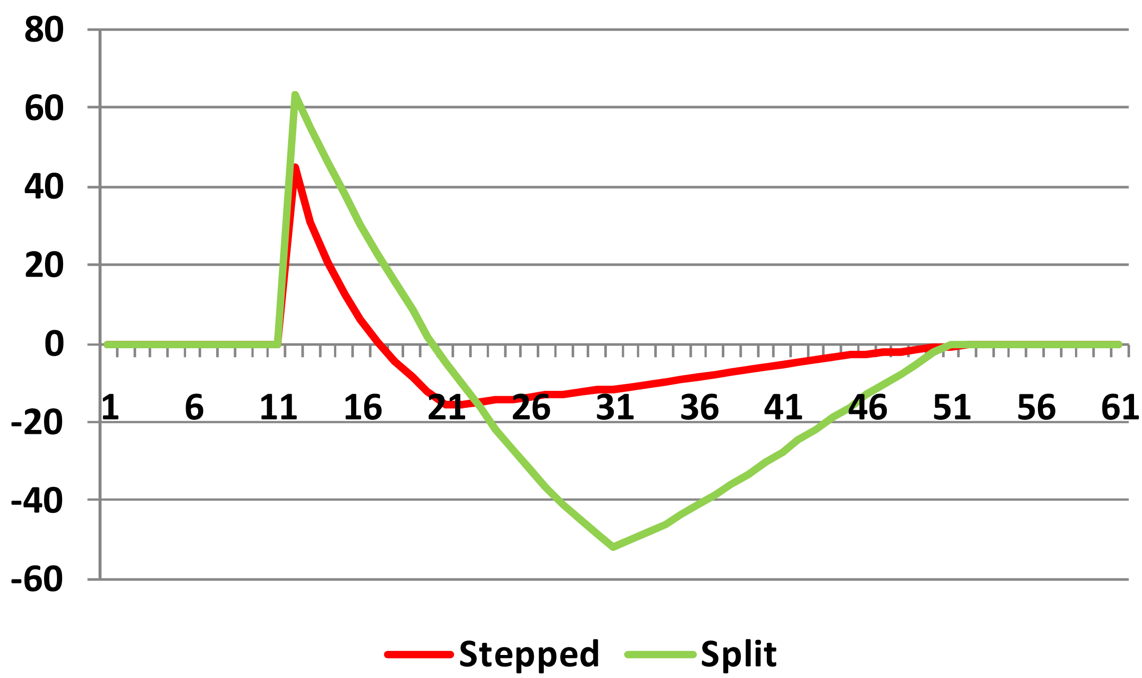
Figures 6.5 and 6.6 illustrate the asset cash-flows in both cases and the proportionate impact on cash-flows.

Figure 6.5: Asset based cash-flows under the three implementation scenarios



As can be seen from the two figures, the mitigation effect of the two approaches can be significant and so while cash-flows are still affected the impact is much reduced. The Stepped approach provides less mitigation than the Split approach, since in the latter some assets will continue with the shorter asset life for 19 years while in the former the assumption is that the steps are completed in 10 years. Obviously the scenario parameters could be changed – for example, so that the steps took longer to complete.

Figure 6.6: Proportionate impact of transition approaches compared to the Full scenario



Overall, it would appear that if Ofgem wished to mitigate some of the cash-flow impacts of the change in asset life this could be done through:

- if appropriate, choosing a front-end loaded profile;
- maintaining the existing asset life for existing assets; or
- making a stepped introduction of the new asset life.

Of course, these approaches are not mutually exclusive. But the real question for Ofgem is whether such transitional support is needed.

7. OUTPUTS OF FINANCIAL MODEL

To illustrate the real-life impact of making changes to the regulatory depreciation a more comprehensive model incorporating estimates to 2050 was developed. This section provides an overview of the underlying assumptions as well as a summary of some of the key outputs. It is not the role of this report to determine whether there is a financeability problem and to establish how to solve one, if it exists. Rather, this section illustrates what might happen. Whether a financeability problem actually arises and how it should be addressed are issues dependent on having better medium-term data and should be a part of the overall price determination undertaken by Ofgem.

Annex F includes a broader selection of output from our analysis, showing the impact of different scenario, capex, depreciation and asset life options.

7.1. Main modelling assumptions:

The table below sets out the key assumptions underlying the financial model.

Table 7.1: Model assumptions

Data/ assumption	Source
Prices	Figures are presented in 2010 prices.
Capex	Figures in section 7 are based on Ofgem's Green Transition Scenario, and assume a linear scaling of historic costs (MEA/GW). Annex F shows the implications of other scenarios and capex assumptions.
Opex	1. Take 2010 opex numbers for each network from Ofgem's current price control model for the appropriate network 2. Calculate opex as a percentage of the 2010 RAV. 3. Run model with Ofgem's current asset lives for all assets, with straight-line depreciation, and keep opex constant as a percentage of the RAV in each year. 4. Use the absolute figures from (3) in all scenarios.
Depreciation	Straight-line.
Electricity network asset lives	Current – 20 years Proposed – 45 years
Gas network asset lives	Current - 45 years Proposed – 45 years (no change)
Depreciation of assets in existence at the start of the model	Existing assets are already 50% depreciated, such that their remaining life is half of their chosen life under the chosen scenario.
Asset life options	We consider three possible options: • Base: Ofgem's current asset lives for both existing and new assets.

Data/ assumption	Source
	• Split: Ofgem's current asset lives for existing assets, and proposed asset lives for new assets. • Full: Proposed asset lives for both existing and new assets. Changes are assumed to occur in 2013 (start of the next price control).
Household energy bills	2010 average household energy bill sourced from Uswitch (4th October 2010); £1,194 (combined bill for electricity and gas). Proportion of this total figure which relates to electricity versus gas sourced from Ofgem's 'Updated household energy bills factsheet 81' (6th August 2009).

7.2. Outputs

7.2.1. High level summary

We start by setting out the total figures for all networks. The figures shown for depreciation and revenue are for the "Base" option; capex and opex figures are the same for all options. Figures are cumulative 2011-2050 inclusive, in £m and 2010 prices.

Table 7.2: High level summary outputs, by network[23]

£m, 2011-50	Capex	Opex	Depreciation	Revenue
Electricity				
Distribution (base, 20 years)	166,492	115,364	116,104	346,975
Distribution (split, 45 years)			68,785	321,117
Distribution (split, 55 years)			59,499	315,116
Transmission	59,062	21,934	44,690	113,912
Gas				
Distribution (45 years)	35,338	47,920	30,031	132,851
Distribution (15 yrs in 2020)*	15,246	28,299	29,753	85,785
Transmission	2,929	2,517	4,766	14,607

** Gas distribution variant figures for 2011-35 only. This variant is defined in the section below on gas networks.*

The figures are clearly dominated by electricity distribution, which accounts for nearly two-thirds of the capex. This is driven by the need to strengthen the network to deal with large-scale electrification of heat and transport.

We now explore the results for each network in more detail. For each network we show the annual depreciation profile under each option and the revenue. Graphs showing the *relative* impacts of these three options can be found in Annex F, along with a more detailed analysis of several scenario/ option combinations. We also set out the financeability implications including

[23] There is significant uncertainty inherent in forecasting four decades into the future, so figures in this table should be taken as illustrative rather than precise forecasts.

gearing levels and a summary of impacts on financial ratios. The model tests the financeability of the network operators[24], by calculating certain financial ratios, listed in table 7.3 below.

Table 7.3: Financial ratio tests

Ratio
Funds from operations, divided by interest
Funds from operations, divided by net debt
Gearing, defined as net debt divided by closing RAV
Post-maintenance interest cover ratio

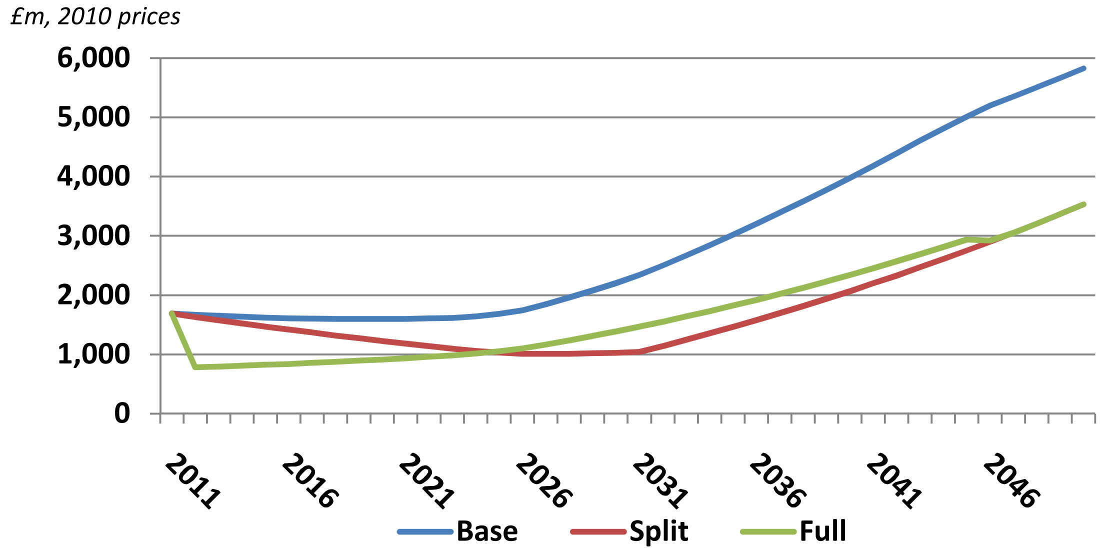
7.2.2. Electricity Distribution Network

As the chart below shows, for both electricity transmission and distribution, depreciation rises under all depreciation options. The level of depreciation continues to grow over time, because of the high and increasing levels of investment in the network (particularly electricity distribution - see figure 5.2).

The second graph for each network shows revenue under each option; it has the same fundamental shape as that for depreciation above, although the relative differences are smaller because depreciation is only one element of revenue.

Gearing levels are, as expected, higher in the "full" option, since this shows a significant fall in depreciation and hence revenue compared to the other options, at least until 2020. Thereafter, gearing levels for all options converge, although gearing remains higher in the options where at least some asset lives are changed. In *all* cases for electricity distribution, gearing levels rise over the long term, while the levels in transmission are more constant.

Figure 7.1: Electricity distribution: annual asset depreciation, by year



[24] In fact the model tests the financeability of the operators of each network in aggregate – e.g. the financeability tests are applied to the sum of all DNOs. They therefore do not necessarily represent the possible impacts on any particular company.

Figure 7.2: Electricity distribution annual network revenue, by year

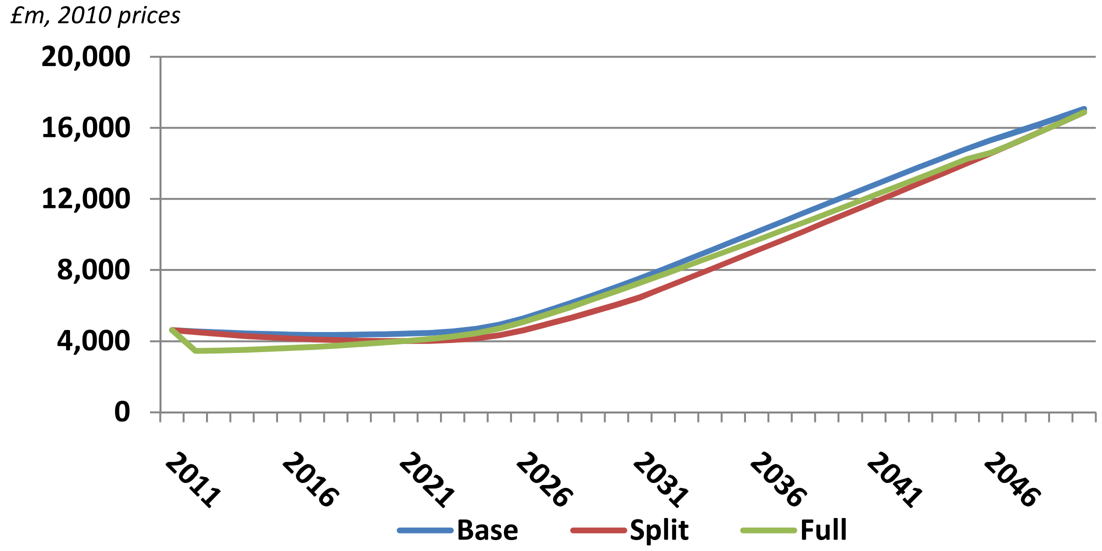


Figure 7.3: Electricity distribution annual network gearing, by year

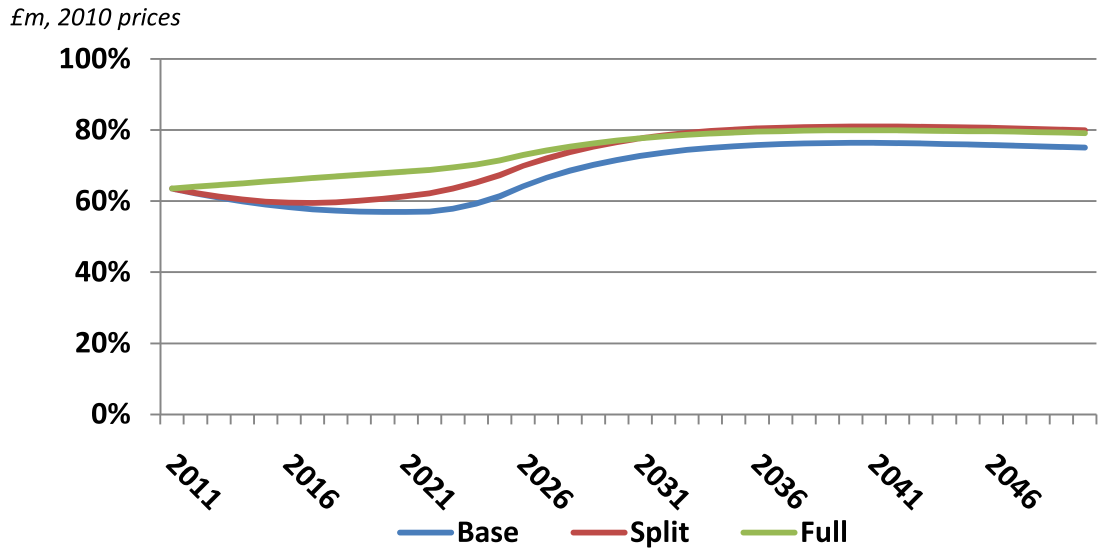


Table 7.4: Electricity distribution: financial ratios over the whole modelling period (2011-50)

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	5.6	4.6 - 7.1	3.8	2.6 - 6.4	3.2	2.7 - 6.3
Funds from operations / net debt	20%	16% - 25%	13%	9% - 23%	11%	9% - 23%
Gearing (net debt / closing RAV)	68%	57% - 76%	72%	60% - 81%	74%	64% - 80%
Post-maintenance interest cover ratio	2.0	1.7 - 2.3	1.9	1.6 - 2.2	1.8	1.7 - 2.1

7.2.3. Electricity Transmission Network

We now present the results for the electricity transmission network. The most significant difference between the results for the two networks is seen in the financial ratios section. The values shown for electricity transmission are generally higher (where a high value reflects a stronger financial position – and lower where it does not). This is seen with both the "split" and the "full" options, suggesting that the impact is driven by the treatment of new assets rather than the treatment of existing ones.

Figure 7.4: Electricity transmission: annual asset depreciation, by year

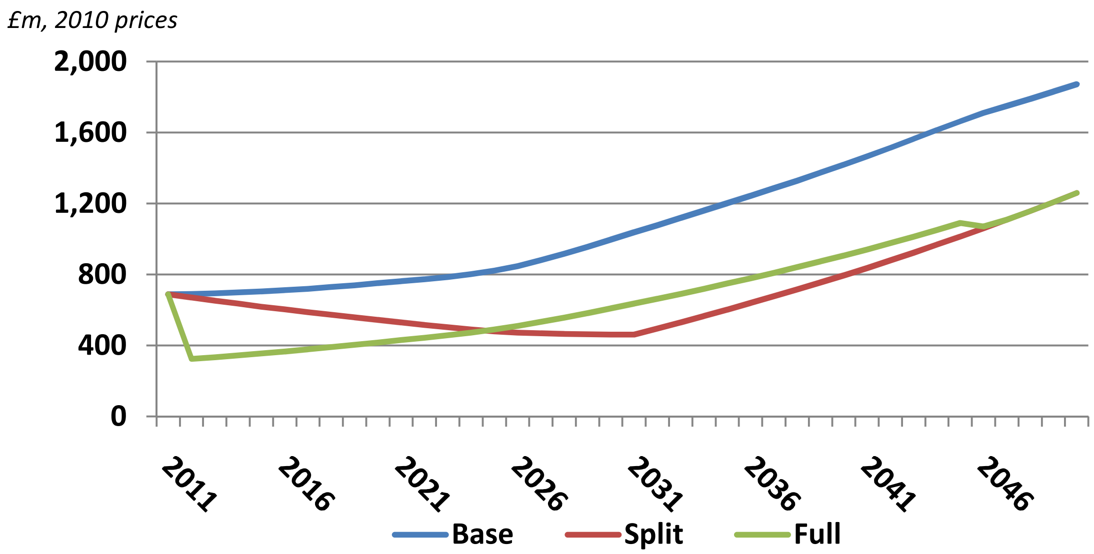


Figure 7.5: Electricity transmission annual network revenue, by year

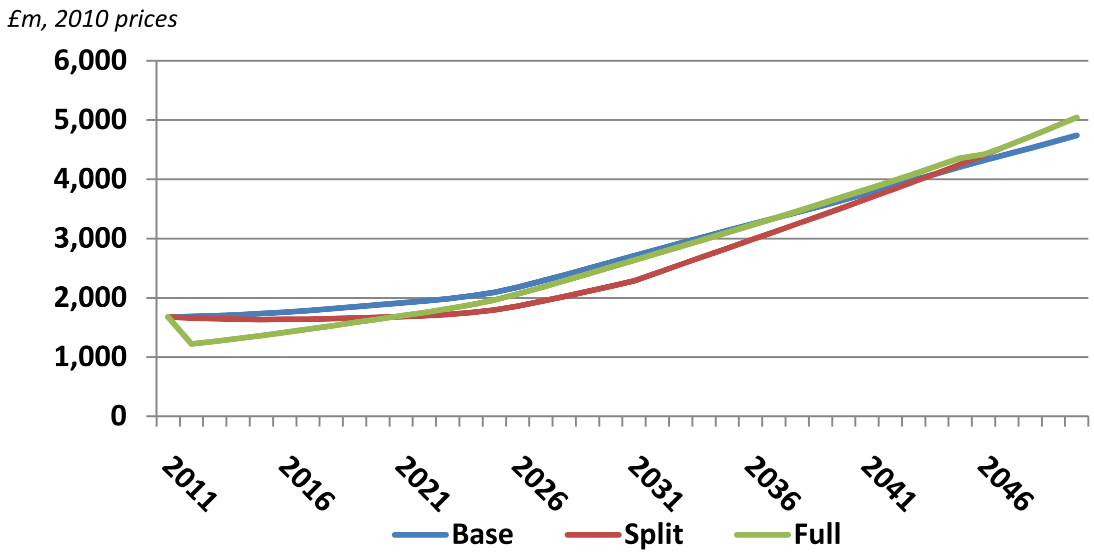


Figure 7.6: Electricity transmission: annual network gearing, by year

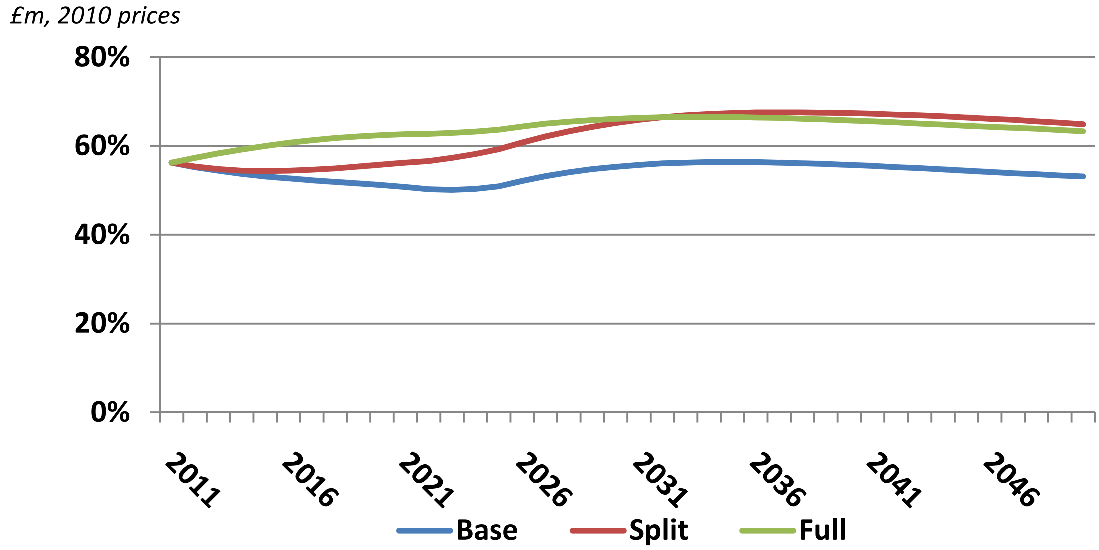


Table 7.5: Electricity transmission: financial ratios over the whole modelling period (2011-50)

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	6.9	6.4 - 7.5	4.2	3.2 - 7	3.7	3.4 - 7
Funds from operations / net debt	25%	23% - 28%	15%	11% - 26%	13%	12% - 26%
Gearing (net debt / closing RAV)	54%	50% - 56%	62%	54% - 68%	64%	56% - 67%
Post-maintenance interest cover ratio	2.5	2.4 - 2.7	2.2	2 - 2.5	2.2	2.1 - 2.4

7.2.4. Gas Distribution Network

Both Ofgem's current asset lives and the proposed asset lives give gas distribution and transmissions assets a life of 45 years. Therefore there is no difference between the three scenarios, and so each graph only shows a single line.

The most striking aspect is the very low gearing seen, which is driven by the relatively low levels of investment.

Figure 7.7: Gas distribution: annual asset depreciation, by year

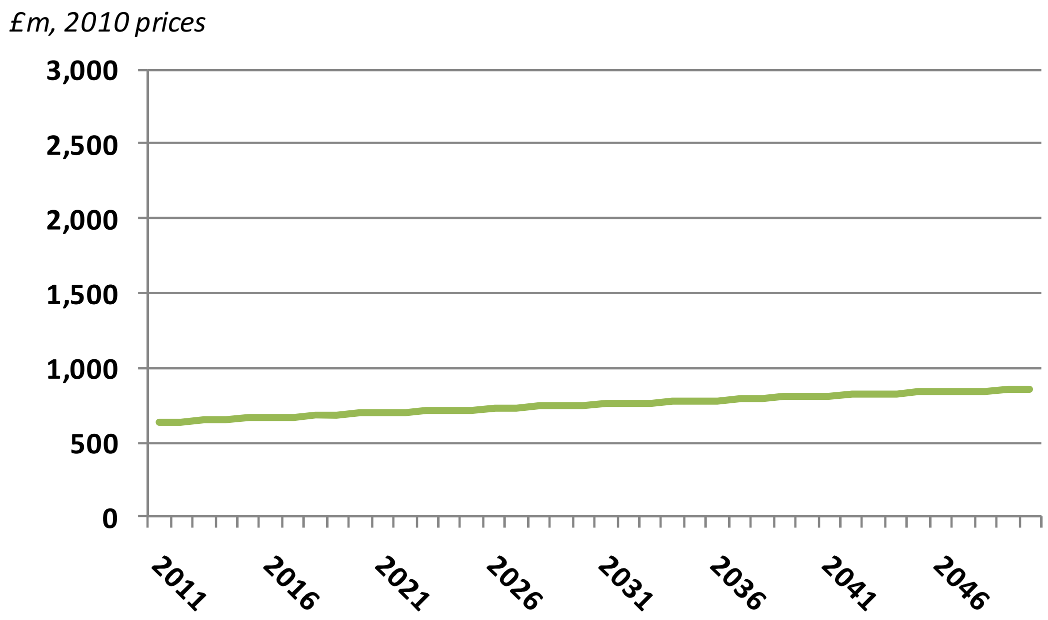


Figure 7.8: Gas distribution: annual network revenue, by year

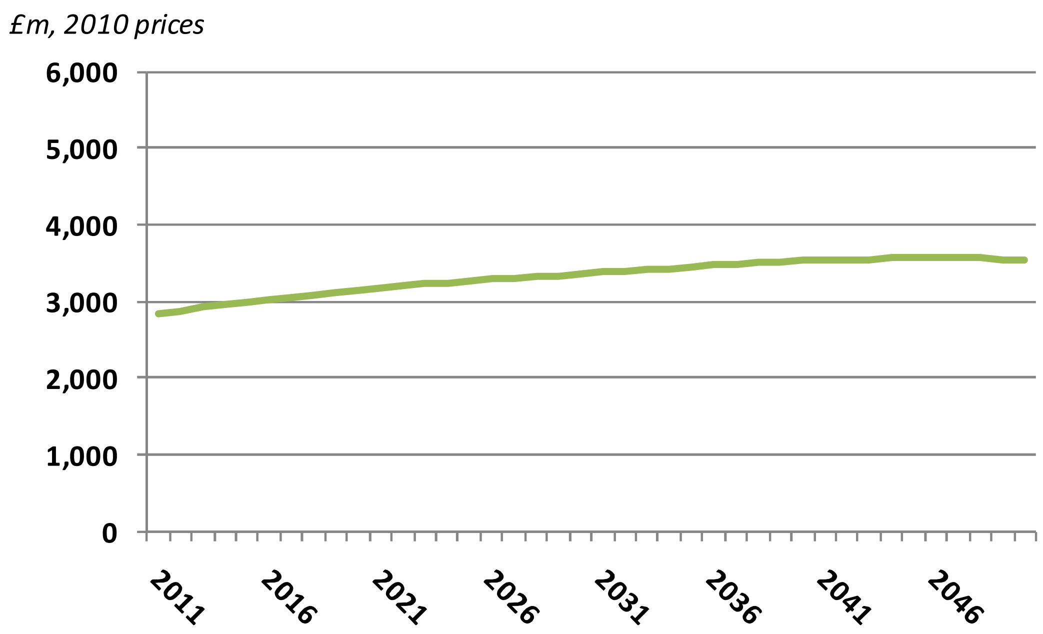
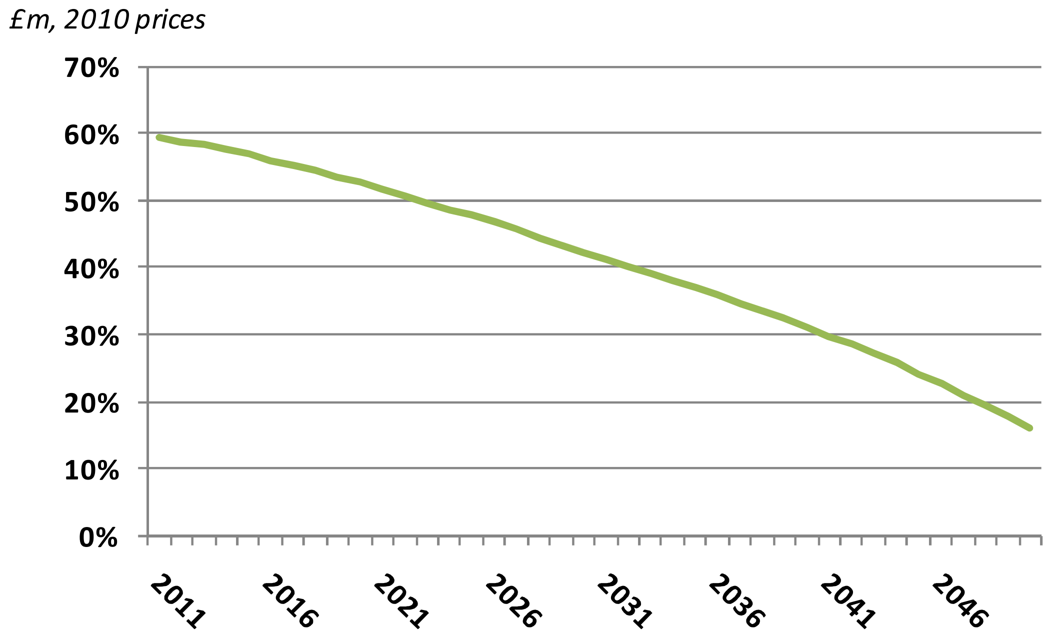


Figure 7.9: Gas distribution: annual network gearing, by year



For the gas distribution network, we also consider a variant where the lives for all assets are set to 15 years in 2020, and all assets are fully depreciated by 2035. This shows (see figure below) a very much increased annual depreciation charge in the period to 2035. This would translate into higher network revenues, and higher costs to consumers. Since (by assumption) in this "declining" scenario, the gas network is being used less, and by fewer customers, the increase in total depreciation and revenue may be compounded by being spread over fewer and fewer units of gas and customers. There could, therefore, be very high charges for remaining gas customers post-2020, in this variant.

The variant is clearly an extreme case, and so caution should be used in drawing conclusions from it. However, it does suggest that consideration should be given to front-loading depreciation for gas network assets. This is consistent with our broad conclusion that use of the gas network will remain constant or decline over time.

Figure 7.10: Annual asset depreciation, by year, for 'variant' scenario versus '45 year' scenario

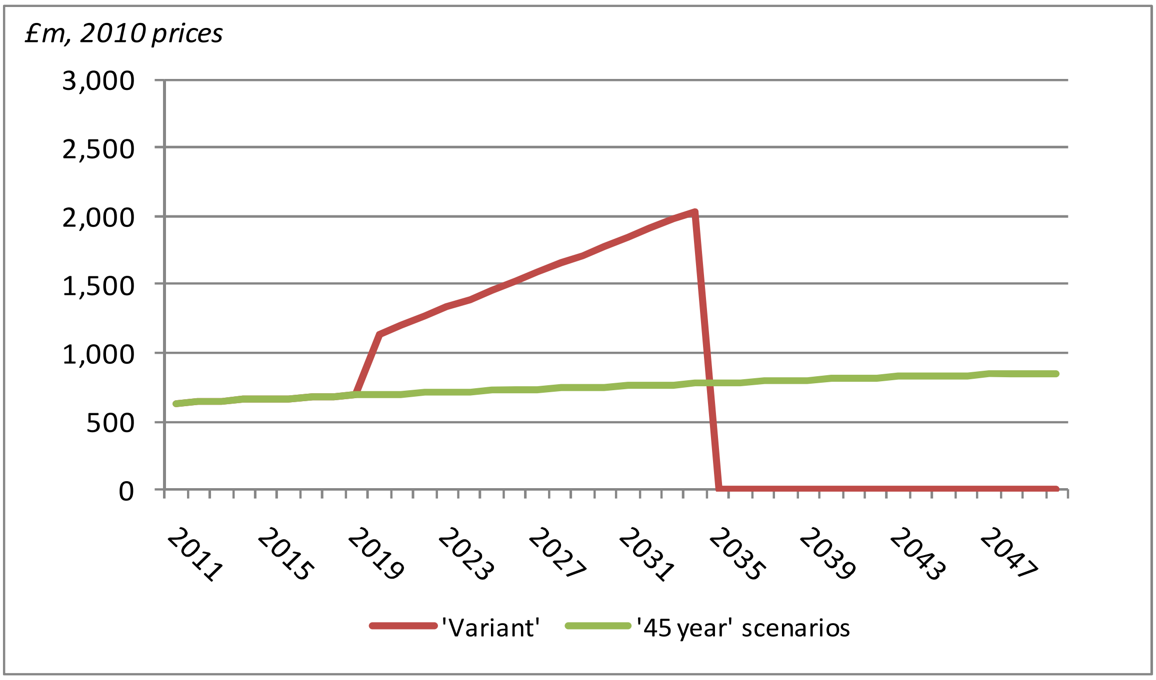


Table 7.6: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	7.1	4.4 - 15.7	7.1	4.4 - 15.7	7.1	4.4 - 15.7
Funds from operations / net debt	25%	15% - 58%	25%	15% - 58%	25%	15% - 58%
Gearing (net debt / closing RAV)	41%	16% - 59%	41%	16% - 59%	41%	16% - 59%
Post-maintenance interest cover ratio	3.9	2.4 - 8.4	3.9	2.4 - 8.4	3.9	2.4 - 8.4

Levels of investment in this scenario are low, leading to very low levels of gearing.

Figure 7.11: Gas transmission: annual asset depreciation, by year

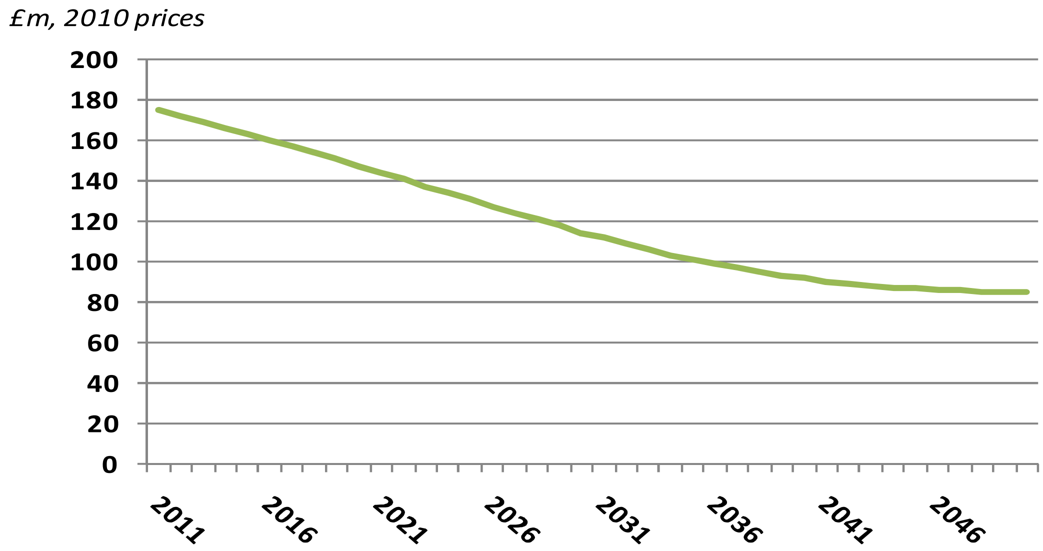


Figure 7.12: Gas transmission: annual network revenue, by year

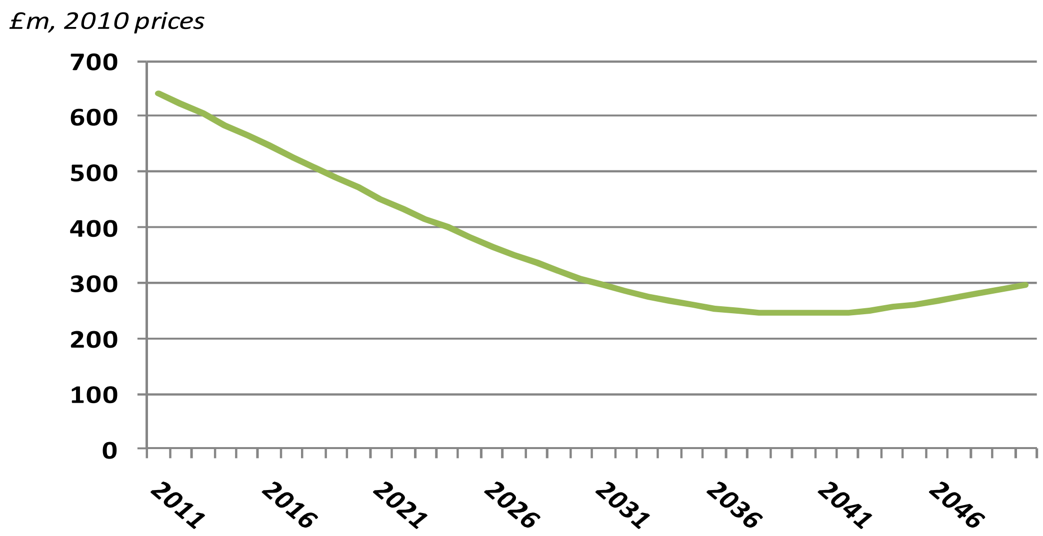


Figure 7.13: Gas transmission: annual network gearing, by year

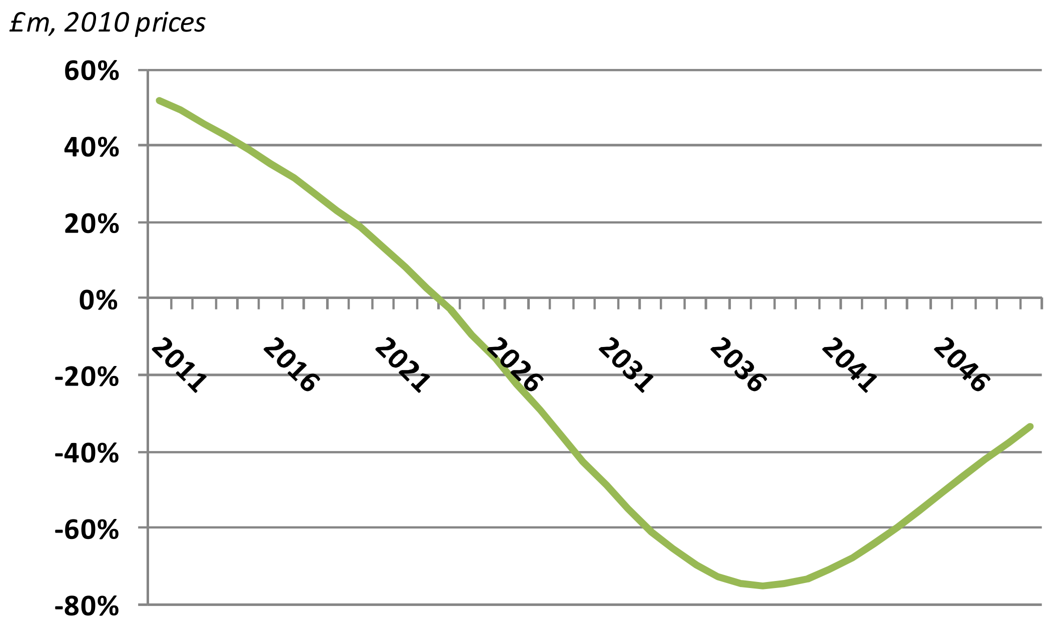


Table 7.7: Gas Transmission: financial ratios over the whole modelling period (2011-50)

Financial ratios	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	13.3	4.8 - 52	13.3	4.8 - 52	13.3	4.8 - 52
Funds from operations / net debt	71%	19% - 401%	71%	19% - 401%	71%	19% - 401%
Gearing (net debt / closing RAV)	-24%	-75% - 52%	-24%	-75% - 52%	-24%	-75% - 52%
Post-maintenance interest cover ratio	6.5	2.6 - 24.7	6.5	2.6 - 24.7	6.5	2.6 - 24.7

7.3. Impact on average household bill

This section shows the impact of changes in the average household energy bill over time, with changes over five year periods in the figures below. To calculate this, the model works out the increase in total network costs, and assumes this change will be passed through directly to consumers, increasing their total costs by that amount. This amount is divided between the number of UK households[25] to calculate the change in the average household bill[26]. We show the

[25] 26.7m in 2010, source: ONS

[26] Source: 2010 average household energy bill £1,194 sourced from Uswitch (4th October 2010). The proportion of this total figure which relates to electricity versus gas was sourced from Ofgem's "*Updated household energy bills factsheet 81*" (6th August 2009).

impact on the overall household energy bill, with the cost impact from each network shown separately. The impact of each asset life/ depreciation option is shown on a separate graph.

Since bill impacts can be positive or negative, the graphs show both increases and decreases to the bill. For each five-year period, decreases are shown in the left hand column (labelled with a 'down' arrow) while increases are shown in the right hand column (labelled with an 'up' arrow).

As the graphs below show, the increase in electricity bills is greater than the decrease in gas bills, so the combined bill rises under all options. The difference between impacts across all options is though of the order of 5%, so it is difficult to conclude that any one option is clearly more expensive than another[27].

Figure 7.14: Change in the average household combined bill – 'Base' option

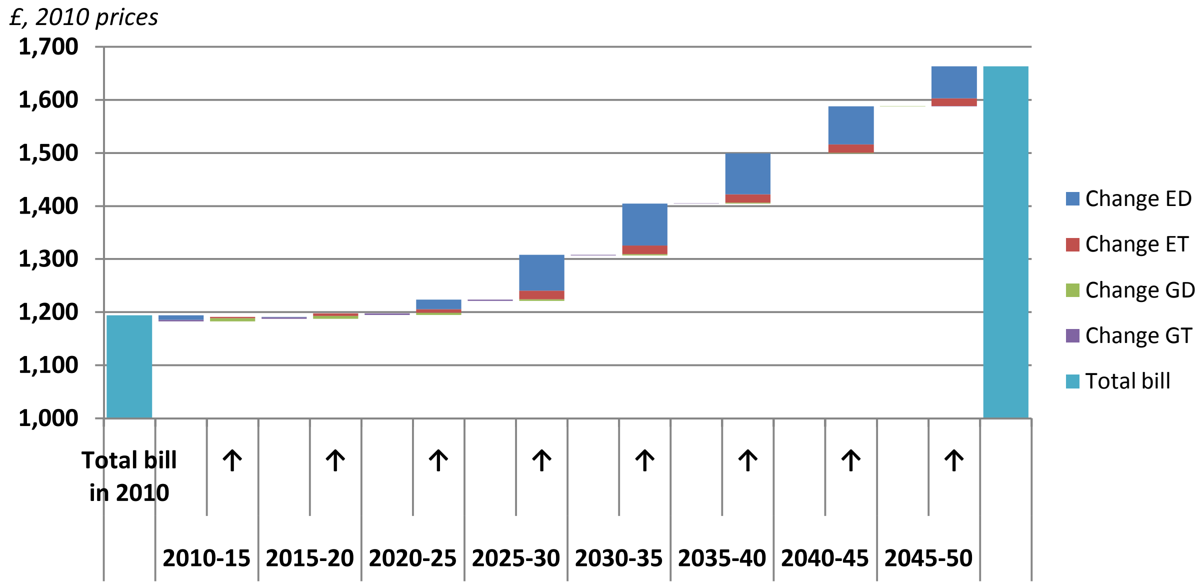


Figure 7.15: Change in the average household combined bill - 'Split' option

[27] This analysis focuses on the relative bill impacts of future investment in the electricity and gas networks. To avoid complicating the picture, it does not consider the extent to which domestic gas demand shifts to electricity (because for example of an increase in electric heating). It also does not consider whether all those currently connected to the gas network will still be connected in future.

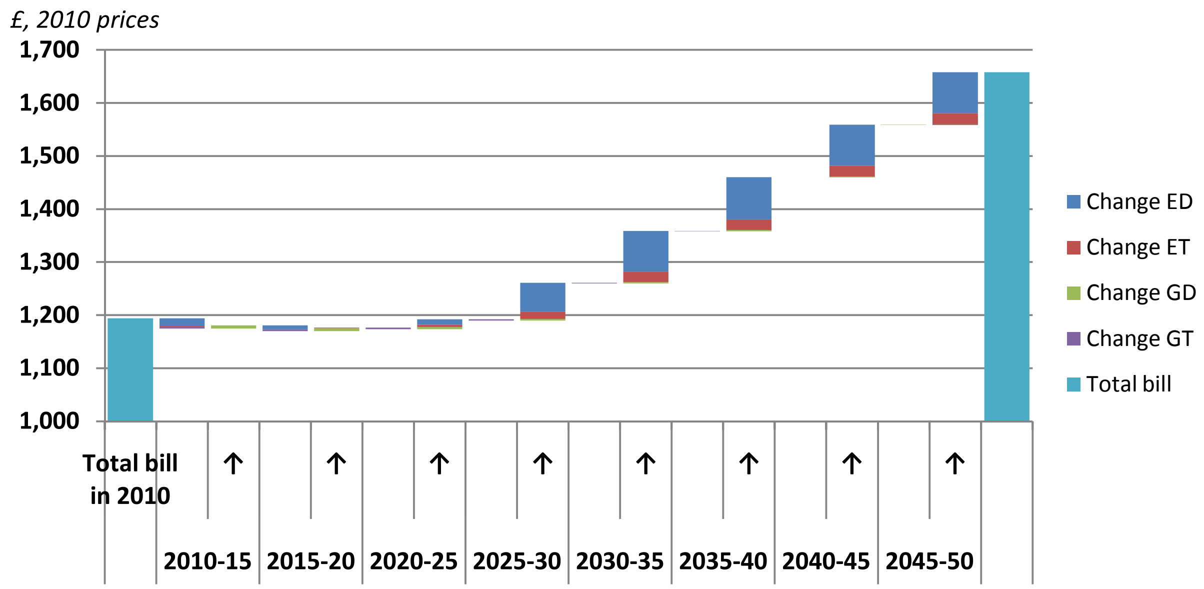
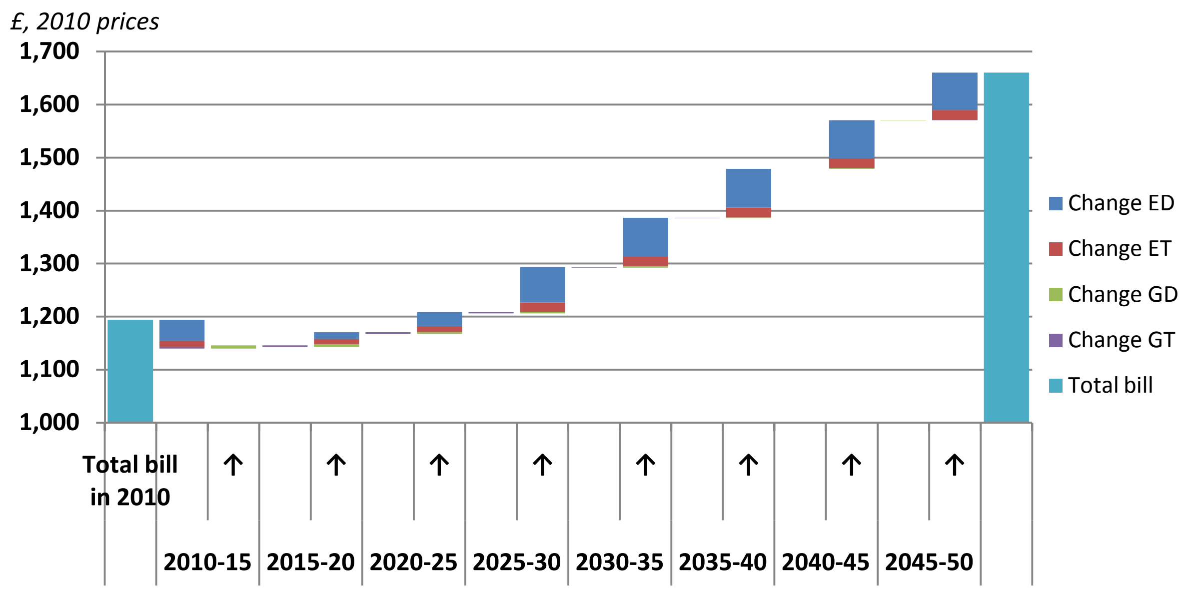


Figure 7.16: Change in the average household combined bill - 'Full' option



ANNEX A: EXTRAPOLATING THE PROJECT DISCOVERY SCENARIOS

We set out in this section how we have extrapolated the Project Discovery scenarios, which ran to 2025, to 2050. Clearly the assumptions we have made are not the only ones that could have been used, but we have attempted to retain the essential character of each of the four scenarios.

Drivers

There is a range of factors that will influence future patterns of energy demand. For example, economic growth, consumer responses to energy efficiency initiatives and technological developments will all influence our levels of energy use. Over the period covered by our analysis, one of the key drivers of energy demand will be the implementation of measures designed to achieve environmental targets and aspirations. Such measures will depend on the political or public desire to achieve them, factors driven by the extent to which policy is credible, long-term and well-designed. Within this framework, drivers include:

- The extent to which transport and heat are electrified
- The scale of deployment of low carbon electricity generation
- The effectiveness of energy efficiency measures (the degree of consumer participation in energy markets is a large part of this)
- The extent to which energy production is distributed or embedded (for example, household generation)
- The extent to which energy demand profiles can be shifted or made more flexible to meet more variable supply (for example, from wind generation).

Renewable electricity

The "Green" Project Discovery Scenarios (Green Stimulus and Green Transition) assume that the contribution of renewables to both electricity output and space heating by 2020 is sufficient to meet the UK's target of 15% of primary energy demand to be met from renewables by 2020. The assumptions draw on the work of the 2009 Renewable Energy Strategy[28], which showed, by 2020, around 30% of electricity and 12% of space heating coming from renewables.

The Project Discovery model assumes that the contribution of renewables to space heating increases at either a 'low' or a 'high' rate. Space heating demand satisfied by renewables is a direct substitute for gas. Over the period to 2025, it is assumed that there is no move towards electric space heating from natural gas – an assumption similar to that in work undertaken by the Committee on Climate Change.

However, for the period between 2025 and 2050, simply extrapolating the contribution of renewables to space heating will lead to an unfeasible contribution from air or ground source heat pumps to achieve the resulting energy output. In addition, as work by DECC and the Committee on Change Committee suggests, beyond 2025, a move towards electric space heating is assumed to begin - slowly at first, but rising over the period to 2050. As a result, by 2050 in

[28] DECC "*The UK Renewable Energy Strategy*", July 2009

the "Green" scenarios we assume that 80% of space heating will be provided by an equal split between electricity and renewables.

In the "Less Green" scenarios ("*Dash for Energy*" and "*Slow Growth*") the Project Discovery work assumes a lower contribution of renewables overall. Tables A.1 and A.2 show the resulting assumptions for the rapid and slow environmental action scenarios for 2020, 2030 and 2050.

Table A.1: Contribution of renewables to electricity output

	2020	2030	2050
Rapid Environmental Action	30%	38%	50%
Slow Environmental Action	15%	20%	30%

Table A.2: Contribution of renewables and electricity to heating, by scenario

		2020	2050
Green	Renewables	12%	40%
	Electric Heating	0%	40%
Less Green	Renewables	4%	15%
	Electric heating	0%	15%

While at the upper end, the figure of 50% electricity from renewables is within the range of values in DECC's 2050 pathways work (up to 66% in pathway Gamma). It is also within the range included in the McKinsey Roadmap 2050 work for the European Climate Foundation (40-80%), although that work looked at the EU electricity system as a whole, rather than the UK in isolation. It is somewhat higher than in the scenarios in the UKERC analysis, as these assume a great deal of nuclear, and the scenario set out by Eurelectric, the European electricity industry body, which includes 38% of renewables at an EU level. Since we are using the scenarios to stress-test the network, the fact that the value is high by comparison with other published figures should not cause any concern.

The figure of 80% of heat from renewables or electric heating is within the range set out in the DECC pathways. Pathway Gamma, for example, shows 89% of heat coming from a combination of air-source heat-pumps, ground-source heat-pumps and geothermal.

Long term energy efficiency improvements

In the "Green" scenarios it is assumed that energy efficiency improves at a robust rate over the period to 2025 – limiting electricity and gas demand growth. Beyond 2025 we assume that the rate of energy efficiency improvement begins to slow as the 'low hanging' energy efficiency fruit are realised.

Table A.3 shows how the energy efficiency assumptions differ between the rapid and slow environmental action scenarios in the Project Discovery period (2010-2025) and the assumptions made for energy efficiency improvement over the period beyond to 2050.

Table A.3: Energy efficiency improvements (% p.a.)

	2010-2025		2025-2030		2030-2050	
	Gas	**Electricity**	**Gas**	**Electricity**	**Gas**	**Electricity**
Rapid environmental action (“Green”)	-0.75	-1.5	-0.4	-0.5	-0.2	-0.25
Slow environmental action (“Less Green”)	-0.25	-0.25	-0.125	-0.2	-0.1	-0.1

Electric vehicles

In assessing the impact on future electricity demand of the electric vehicles, we have built upon the assumptions in Project Discovery. We have assumed that dependence on the car continues in the longer term, in common with DECC’s Pathways analysis – leading to a 45% increase in the number of electric vehicles. For the “Green” scenarios, we assume 80% of vehicles will be electric by 2050. For the “Less Green” scenarios, we have continued the assumption in Project Discovery that electric vehicles are a third the level of the “Green” scenarios.

The results of our assumptions, in terms of number of electric vehicles, are shown in table A.4.

Table A.4: Number of electric vehicles (million)

	2020	**2030**	**2050**
Rapid Environmental Action (“Green”)	2.7	14	40
Slow Environmental Action (“Less Green”	0.8	4	12

Modelling the impact on the electricity sector and the generation mix

In order to determine the impact of the resulting gas and electricity demands on the electricity generation mix, we have not modified and extrapolated the Project Discovery model from 2025 to 2050. The modification required is extensive and project time pressures too great to complete a full modification. As a result we have taken the electricity demand determined by the Project Discovery model to 2050, the generation mix resulting in 2025 from the model for the four scenarios, combined with the contribution of renewables to electricity demand over the period to 2050. These figures have then been fed into SKM’s generation dispatch model to determine generation mix over the period to 2050 for each of the Project Discovery scenarios.

The resulting generation mix and output is then used to determine annual and peak day gas demand of the electricity sector in each Project Discovery scenario. The resulting gas demand of the electricity sector is then fed back into the Project Discovery model to determine overall impact on annual and peak gas demand.

ANNEX B: DETAIL OF EXISTING GAS TRANSMISSION ASSETS

This Annex provides, for the various asset groups within the Gas Transmission sector, a consideration of:

- The age profile of the existing assets;
- The technical lives of the assets;
- Costs for replacement (also referred to as the 'Modern Equivalent Asset' (MEA) cost) and maintenance; and
- The evolution of demand and its impact on network expansion and utilisation.

For the purposes of this report, the NTS is categorised into the following asset groups:

1. NTS Entry Point Above Ground Installations and Valve Installations
2. NTS Pipelines
3. Compressor Sites

National Gas Transmission Above Ground Installations

There are a number of above ground installations (AGIs) on the National Transmission System. These consist of: (i) Entry/Exit Point Installations; (ii) Block Valve Installations; (iii) Pig Trap Installations; (iv) Offtake Installations (supplying industrial customers from the NTS); and (v) Multi-Junction Installations. The tables below show the approximate numbers and age profiles of these asset sub-groups:

(i) Entry/Exit Point Installations

These installations facilitate the entry and exit of gas to and from the NTS with respect to beach entry terminals and gas storage facilities.

Table B.1 Entry/ exit installations

Year of construction	Nos.	Design Life
1965-1970	2	40
1971-1975	2	40
1976-1980	1	40
1981-1985	2	40
1986-1990	0	40
1991-1995	2	40
1996-2000	2	40
2001-2005	1	40
2006-2010	3	40
Totals	**15**	

(ii) Block Valve Installations

These block valve installations provide a means of isolating sections of NTS pipeline – e.g. in the case of an emergency or to facilitate a pipeline shutdown for maintenance.

Table B.2: Block Valve Installations

Year of Construction	Nos.	Design Life
1965-1970	45	40
1971-1975	79	40
1976-1980	81	40
1981-1985	16	40
1986-1990	8	40
1991-1995	8	40
1996-2000	3	40
2001-2005	3	40
2006-2010	3	40
Totals	**246**	

(iii) Pig Trap Installations

Pig trap installations are installed at strategic locations along the pipeline length to facilitate the passage of on-line, condition monitoring pipeline inspection gauges ('PIGS').

Table B.3: Pig Trap Installations

Year of Construction	Nos.	Design Life
1965-1970	3	40
1971-1975	10	40
1976-1980	7	40
1981-1985	3	40
1986-1990	0	40
1991-1995	0	40
1996-2000	0	40
2001-2005	1	40
2006-2010	1	40
Totals	**25**	

(iv) Offtake Installations

These Offtake Installations are used primarily for the supply of gas to industrial customers supplied directly from the NTS.

Table B.4: Offtake installations

Year of Construction	Nos.	Design Life
1965-1970	2	40
1971-1975	2	40
1976-1980	1	40
1981-1985	0	40
1986-1990	0	40
1991-1995	13	40
1996-2000	17	40
2001-2005	5	40
2006-2010	5	40
Totals	**45**	

(v) Multi-Junction Installations

Multi-Junction Installations are where two or more NTS pipelines are connected together via a complex valving arrangement.

Table B.5: Multi-Junction Installations

Year of Construction	Nos.	Design Life
1965-1970	11	40
1971-1975	14	40
1976-1980	14	40
1981-1985	6	40
1986-1990	3	40
1991-1995	8	40
1996-2000	5	40
2001-2005	2	40
2006-2010	5	40
UNK	3	40
Totals	**71**	

National Gas Transmission System Pipelines

The National Transmission System (NTS) pipeline system consists of approx. 7,660 kms of high integrity, welded steel pipe operating at pressures in the range 70-94 barg. Table 6 below shows the breakdown of the NTS pipeline system by diameter and age profile.

Table B.6: NTS Pipelines

Pipe Diameter (mm)	Length (km)	Mean Build Date (year)
150	10	1971
200	5	1980
250	0	n/a
300	75	1975
350	20	1970
400	0	n/a
450	200	1980
500	50	1970
600	1,100	1978
750	500	1970
900	3,600	1978
1,050	1,300	1990
1,200	800	2006
Total	**7,660**	

NTS pipelines are designed for an operating life of 40 years in accordance with the requirements of *'IGE/TD/1 Steel Pipelines for High Pressure Gas Transmi*ssion', although pipeline integrity will allow for a considerably extended technical life in most cases – i.e. c. 100 years for modern pipelines.

Gas Compressor Sites

Gas must be compressed in order to move it through long lengths of transmission pipeline. There are 25 compressor sites installed across the NTS and each has a number of compressor units installed. Table 7 below shows: (i) the location of these assets; (ii) the installed horsepower in MW; (iii) the estimated build date; and (iv) the estimated asset life.

Table B.7: NTS Compressor Sites

Location	Unit	Power Rating (MW)	Power Source G - Gas E - Elec	Year Built	Asset Life (years)
Aberdeen	A	30.5	G	1997	20
	B	30.5	G	1997	20
	C	30.5	G	2000	20
Alrewas	A	12.0	G	1969	20
	B	12.0	G	1969	20
	C	15.5	G	2001	20
Avonbridge	1A	30.5	G	2004	20
	1B	13.4	G	2004	20
	2A	30.5	G	2004	20
	2B	13.4	G	2004	20
Aylesbury*	A	18.5	G	1999	20
	B	18.5	G	1999	20
Bishop Auckland	A	31.4	G	1997	20
	B	31.4	G	1997	20
Cambridge	A	12.0	G	1974	20
	B	12.0	G	1974	20
	C	13.4	G	2001	20
Carnforth*	A	24.7	G	1989	20
	B	24.7	G	1997	20
	C	30.5	G	1998	20
Chelmsford	A	12.0	G	1973	20
	B	12.0	G	1973	20
Churchover	A	8.0	G	1971	20
	B	8.0	G	1971	20
	D	15.5	G	2000	20
	E	15.0	E	UNK	20
Diss	A	12.0	G	1977	20
	B	12.0	G	1977	20
	C	12.0	G	1977	20
Felindre (new site)	A	30.0	G	UNK	UNK
	B	15.0	E	UNK	UNK
	C	15.0	E	UNK	UNK
Hatton*	A	24.7	G	1989	20
	B	24.7	G	1990	20
	C	24.7	G	1990	20
	E1	25.0	E	UNK	UNK
	E2	15.0	E	UNK	UNK
Huntingdon	A	12.0	G	1987	20
	B	12.0	G	1987	20
	C	12.0	G	1993	20
Kings Lynn	A	12.0	G	1977	20
	B	12.0	G	1977	20

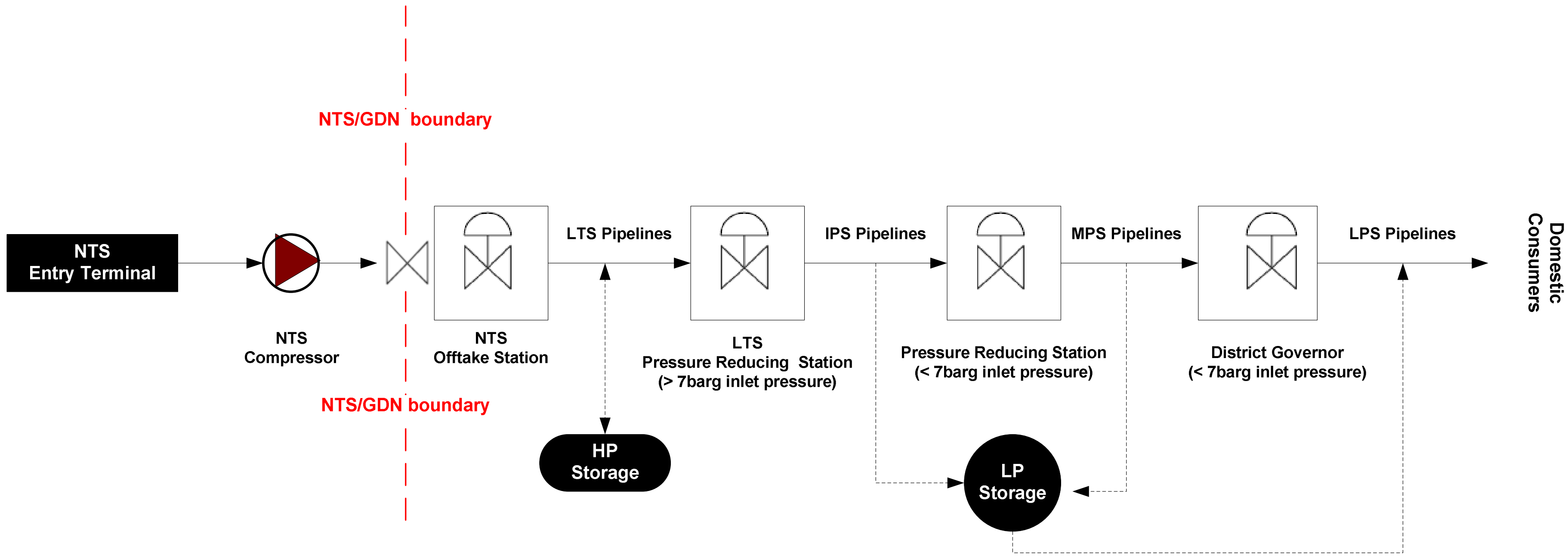
Location	Unit	Power Rating (MW)	Power Source G - Gas E - Elec	Year Built	Asset Life (years)
	C D	13.4 13.4	G G	2002 2002	20 20
Kirriemuir	A B C D E	12.0 12.0 12.0 24.7 35.0	G G G G E	1976 1976 1976 1976 UNK	20 20 20 20 UNK
Lockerley	A B	8.0 8.0	E E	1998 1998	20 20
Moffat	A B	22.7 22.7	G G	1979 1979	20 20
Nether Kellett	A B	13.4 13.4	G G	2002 2002	20 20
Peterborough	A B C D	12.0 12.0 12.0 35.0	G G G E	1970 1970 1970 UNK	20 20 20 UNK
St Fergus	1A 1B 1C 1D 2A 2B 2D 3A 3B	12.0 12.0 12.0 12.0 22.7 12.6 22.7 24.0 24.0	G G G G G G G E E	1975 1975 1975 1975 1975 1975 1975 UNK UNK	20 20 20 20 20 20 20 UNK UNK
Warrington	A B	24.7 24.7	G G	1983 1983	20 20
Wisbech	A B	22.7 12.6	G G	1979 1979	20 20
Wooler	A B	30.5 30.5	G G	1997 1997	20 20
Wormington*	A B C	12.0 12.0 15.0	G G E	1990 1992 2008	20 20 20

* There is a level of uncertainty over the 'Year Built' dates for these sites and confirmation should be sought from NGG.

The Boundary between Gas Transmission and Distribution

The boundary between the gas transmission sector and the gas distribution sector is shown diagrammatically in Figure B.1 on the next page.

Figure B.1: Boundary Between the Gas Transmission ad Gas Distribution Systems



NTS	National Transmission System (> 70 barg)
LTS	Local Transmission System (7 barg to 70 barg)
IPS	Intermediate Pressure System (2 barg to 7 barg)
MPS	Medium Pressure System (75mbarg to 2 barg)
LPS	Low Pressure System (< 75mbarg)

ANNEX C: DETAIL OF EXISTING GAS DISTRIBUTION ASSETS

For the purposes of this report, the GDN assets are categorised into the following asset groups:

National Transmission System (NTS) Offtake Installations

These installations are connected to the NTS and reduce the pressure of the gas from a level of c.85 barg to a suitable pressure for injection into the Local Transmission System (LTS) pipelines that convey gas at elevated pressure throughout the GDN. There are a limited number of high volume gas users connected to the LTS pipeline system and these include power generators and various industrial & commercial end users. There are approximately 106 offtake stations supplying gas from the NTS into the regional GDNs.

NTS Offtake Installations are relatively large and complex facilities and there are a number of components that comprise the overall facility including:

- pig traps
- filters
- meters
- pre-heaters (boilers)
- pressure regulators
- telemetry equipment
- chromatographs
- odorant injection equipment
- electrical and instrumentation equipment

Each of the above is subject to a different inspection and replacement regime and so it is difficult to develop a single technical asset life for a complete station as there are certain drivers that influence the replacement cycle and these include: (i) equipment wear out; (ii) faults; (iii) capacity upgrades; and (iv) equipment obsolescence.

The technical asset life of a typical NTS Offtake Installation is 25 years.

The age profile of these installations is broadly the same as for the LTS pipeline system as described below. The rationale for this is that the stations were constructed in conjunction with the roll-out of the LTS pipeline network. Table C.1 below shows the age profile of NTS Offtake Installations.

Table C.1: Age Profile of NTS Offtake Installations

Year of Construction	Nos.	Estimated Proportion %
1954-1963	3	3.0%
1964-1973	50	48.0%
1974-1983	25	25.0%
1984-1993	11	9.0%
1994-2003	11	9.0%
2004-2010	6	6.0%
Total	**106**	**100%**

Local Transmission System (LTS) Pipelines

These pipelines that are constructed of high integrity, welded steel and are typically operated in the pressure range 7 barg to 75 barg. These are higher operating pressure bulk supply pipelines that convey gas throughout the GDN prior to decompression for injection into the lower operating pressure pipeline systems within the GDN. There are approx 13,000 kms of LTS pipeline operating within the GDNs.

The age profile[29] of LTS pipelines in the GDNs during 2008 is shown below in Table C.2:

Table C.2: Age Profile of LTS Pipelines

Year of Construction	Length (kms)	Estimated Proportion %
1954-1963	351	3.0%
1964-1973	5,616	48.0%
1974-1983	2,925	25.0%
1984-1993	1,053	9.0%
1994-2003	1,053	9.0%
2004-2010	702	6.0%
Total	**11,700**	**100%**

The GB industry standard *'IGE/TD/1 Steel Pipelines for High Pressure Gas Transmission'* contains comprehensive and detailed recommendations for gas transmission pipeline design, construction and operations & maintenance. There are also legislative requirements for pipeline operation under the Pipeline Safety Regulations 1996. IGE/TD/1 assumes a pipeline 'design fatigue life' of 40 years based on a stipulated level of pressure cycling. However, this design fatigue life may be considerably extended through revalidation and condition monitoring.

The replacement costs for LTS pipelines are dependent on the diameter of the pipeline being replaced.

The routine maintenance of LTS pipelines comprises various aerial and foot patrol surveillance surveys, risk assessment (TD1) surveys and monitoring of cathodic protection potentials. Other maintenance costs include on-line inspection (OLI) surveys that are undertaken on an irregular basis, which means that the profile of pipeline maintenance expenditure is not smooth. In terms of the maintenance cost of the higher pressure local transmission systems within the GDNs, LTS pipeline maintenance represents around 20% of overall LTS expenditure with the greater proportion of maintenance expenditure being incurred on the LTS pressure reducing stations (see below).

[29] The LTS pipelines in some regional networks were built in the era of manufactured gas (prior to the introduction of natural gas in the late 1960's and early 1970's) and there were no approved standards or quality control measures for pipeline design and construction in place at that time. Recommendations on the installation of steel pipelines for high pressure gas transmission were progressively published by the Institution of Gas Engineers between 1965 and 1977 until they were finally consolidated in the industry standard IGE/TD/1. These pipelines should be assumed to be at, or close to, the end of their useful operating lives

Storage Installations

There are two categories of storage assets that are used within the gas distribution networks in order to manage its profile of diurnal gas demand during winter months. These are: a) high pressure gas storage vessels (bullets), which are normally constructed as above ground vessels; and b) low pressure gas holders.

High Pressure Vessels

High pressure storage facilities consisting of multiple above ground pressure vessels (bullets) or below ground sealed pipe lengths (pipe arrays) are used for this purpose. There are approximately 100 of these above ground, high pressure storage vessels operated by all the gas distribution network operators. In addition to this, Northern Gas Networks operates a 28-vessel underground array for gas storage purposes, which, we understand, will shortly be decommissioned. The routine maintenance costs associated with high pressure storage installations are not significant and major maintenance is carried out infrequently. The GDNs do not report their costs for HP storage maintenance separately but these costs are included within the overall 'storage' cost category which is dominated by low pressure holder maintenance (see below). Additionally, these assets are not subject to a replacement regime and are generally retired at the end of their useful working lives with diurnal storage requirements being provided by other means – e.g. LTS pipeline linepack and interruptible capacity.

The majority of these HP vessels were installed during the late 1960's /early 1970's and there has been no further installation since this time. The age profile of these assets is therefore estimated at 35-45 years.

The approximate number of these HP vessels across the various GDNs is as follows:

• National Grid Gas	22
• Scotia Gas Networks	51
• Northern Gas Networks	7
• Wales & West Utilities	15
Total	**95**

The Technical Asset life of high pressure storage vessels is 65 years and there is a zero replacement value as these assets would probably not be replaced.

Low Pressure Holders

These facilities store large quantities of gas at low pressure and there are approximately 330 of these holders in operational use throughout the GDNs. There are two types of LP holder: (i) spiral guided; and (ii) column-guided and there is an ongoing programme of decommissioning and demolition of these holders although some remain strategically important for diurnal gas demand management. The maintenance costs of these holders are driven by requirements for calendar-based inspections and painting. Varying levels of inspections are carried out on a: (i) weekly; (ii) quarterly; (iii) annual; (iv) bi-annual; (v) 5-yearly; and (vi) 10-yearly basis. The painting cycle for each gas distribution network operator varies between 10 and 15 years, depending on environmental conditions.

These holders were constructed in the pre-natural gas era (pre-1960's) and are a legacy from the days of manufactured gas from coal. There is no replacement regime for these assets as they are maintained in a safe operating condition until such time as they can be decommissioned and demolished. The costs of demolition are normally funded through associated land disposal.

The approximate number of LP holders across the various GDNs is as follows

- National Grid Gas 87
- Scotia Gas Networks 72
- Northern Gas Networks 44
- Wales & West Utilities 14

Total 217

The technical asset life of low pressure holders is generally regarded as being 80 years.

There is a zero replacement value for these LP holder assets as the assets would not be replaced.

Local Transmission System (LTS) Pressure Reducing Stations (> 7barg inlet AGIs)

These installations are connected to the GDN's LTS pipeline system and reduce the operating pressure down to a level (c. 2 barg to 7 barg) that is appropriate for distribution throughout towns and cities to industrial and commercial and domestic end use customers. There are approximately 1,600 of these pressure reducing stations supplying gas from the higher pressure distribution networks into the lower operating pressure tiers.

As for NTS Offtake Installations (see Section 2.1 above), there are a number of separate plant and equipment components that comprise a LTS pressure reducing station (PRS), although the annual maintenance and replacement costs are generally lower than for NTS Offtake Installations.

The age profile of these assets is consistent with the LTS Pipeline age profile as the PRSs were installed as the LTS pipeline system was rolled out across the country. Table C.3 shows the estimated age profile for LTS Pressure Reducing Stations:

Table C.3: Age Profile of LTS Pressure Reducing Stations

Year of Construction	Nos.	Estimated Proportion %
1954-1963	50	3.0%
1964-1973	720	48.0%
1974-1983	378	25.0%
1984-1993	140	9.0%
1994-2003	140	9.0%
2004-2010	95	6.0%
Total	**1,523**	**100%**

Distribution Pressure Regulating Installations (< 7barg inlet governors)

These installations further reduce the gas operating pressure down to low pressure (c. 0.075 barg) for supply to domestic end users or one-off commercial customers. There are numerous installations of this type across the GDNs and may be installed as above ground units or below ground units.

The approximate numbers of these installations across the various GDNs is as shown below in Table C.4

Table C.4: Distribution Governor Installations

GDN	District Governors	I&C Governors
National Grid Gas	9,313	5,469
Scotia Gas Networks	6,905	1,921
Northern Gas Networks	2,349	244
Wales and West Utilities	3,067	1,962
Totals	**21,634**	**9,596**

The maintenance activity is primarily associated with visual inspections and occasional diagnostic checks and full installation replacement is rarely undertaken. In most cases, soft parts replacement of moving components is carried out every few years.

The above refers to distribution pressure regulating installations that supply gas into low pressure networks for supply to, primarily, domestic customers. There are also dedicated pressure regulating installations that are part of the gas supply infrastructure supplying one-off industrial and commercial customers.

There is no data currently available to assess the age profile of these installations.

Distribution Network (< 7barg)

Distribution mains are the most significant asset group within the gas distribution networks and are constructed of varying pipe materials and age profile within three separate pressure tiers. These pressure tiers are: (i) intermediate pressure; (ii) medium pressure; and (iii) low pressure.

Intermediate Pressure System (IPS) Pipelines (7 barg > IPS > 2 barg)

These pipelines are constructed of either welded and cathodically-protected steel or high density polyethylene (HDPE) pipe material and are typically operated at c. 2barg to 7barg.

Medium Pressure System (MPS) Pipelines (2 barg > MPS > 0.075 barg)

These pipelines are constructed of a mix of material depending on the age of the installed pipe. Since the late 1970's/early 1980's the preferred material for pipe construction is medium density polyethylene (MDPE) pipe material although there steel pipelines and some (legacy) ductile iron and cast iron pipes in existence, which are the subject of an ongoing mains replacement programme. These pipes have a typical operating pressure of 2 barg

Low Pressure System (LPS) Pipelines (0.075 barg > LPS)

These pipelines represent the largest proportion of the GDN's asset base. Medium density polyethylene (MDPE) pipe is the preferred material for the LPS however, there is a substantial amount of older pipe installed that comprises cast iron, spun iron, ductile iron, asbestos and PVC that are routinely replaced as part of an established mains replacement programme. These pipes have a typical operating pressure range of 0.021 barg to 0.075 barg.

Service Pipes

These are small diameter, typically less than 2" diameter pipes constructed of PE or steel, that are used to connect individual properties to the gas distribution mains network(s) and supply end users with gas via the gas meter[30]. There are approximately 21.4 million gas service pipes in use of materials comprising polyethylene (newer) and steel (older).

A small population of gas service pipes are supplied from medium pressure mains and there are service governors installed to reduce the operating pressure for consumption in appliances in the home. There are approximately 82,000 of these service governors installed broken down by GDN as follows:

• National Grid Gas	37,146
• Scotia Gas Networks	27,636
• Northern Gas Networks	2,996
• Wales & West Utilities	13,917
Total	**81,695**

Maintenance Costs

Maintenance costs for distribution mains vary widely across the gas distribution networks. The GDNs reporting on distribution network maintenance costs is not consistent making comparisons between networks extremely difficult. The vast majority of maintenance activity is concentrated in the low pressure (<0.075 barg) metallic (non-PE) network as this is where the majority of leaks and third party damages occur. Analysis by Ofgem's consultants carried out during the 2007-2013 Gas Distribution Price Control Review (GDPCR) showed that the key cost drivers for distribution mains network maintenance are based on: (i) leakage control and the length of metallic (non-PE main); and (ii) repairing escapes.

Age Profile

The technical asset lives of the distribution network mains and services are as follows:

• cast iron mains	40 years
• ductile iron mains	30 years
• steel mains (unprotected)	30 years

[30] Note: gas meters are not owned by the GDNs as meter ownership is a competitive activity operating within a Meter Asset Management (MAM) regime

• steel mains (protected)	70 years
• PE (MDPE) mains	50 years (LPS and MPS mains)
• PE (HDPE) mains	50 years
• PE service pipes	50 years
• steel service pipes	35 years
• service governors	35 years

ANNEX D: SCENARIOS CONSIDERED

List of scenarios

Table D.1 below lists the scenarios that we have considered as comparators and checks for the Discovery scenarios. We have attempted to gather a wide sample of scenarios, and so some of them are not directly comparable to those from Discovery (for example, because they do not focus solely on the UK). We have therefore used our judgment in determining what those scenarios might imply about the range of possible futures that we should consider.

Table D.1: Scenarios considered

Title	Source
Building a roadmap for 2050 for heat	Combined Heat & Power Association
Building a Low Carbon Economy	Committee on Climate Change
2050 pathways analysis	DECC
Energy Markets Outlook 2009	DECC/ Ofgem
Our electricity transmission system: a vision for 2020, appendix extending to 2030	Electricity Networks Strategy Group (ENSG)
Gas Future Scenarios Project	Redpoint, for the Energy Networks Association
Role of electricity in 2050	Eurelectric
Roadmap 2050	European Climate Foundation
Energy (R)evolution	Greenpeace and European Renewable Energy Council
World Energy Outlook	IEA
Presentation to 'Transporting Britain's Energy' conference 2010	National Grid
Long-term Electricity Network Scenarios (LENS)	Ofgem
Gas: At the Centre of a Low Carbon Future	Pöyry, for Oil & Gas UK
Future Energy Systems in Europe	STOA (European Parliament)
Making the transition to a secure and low-carbon energy system	UK Energy Research Centre
Energy Policy Scenarios	World Energy Council (WEC)

Common themes

Given the breadth of these scenarios, there are few if any elements common to all of them. For those scenarios which achieve or exceed the UK's 80% greenhouse gas emissions reduction target for 2050, there are though some frequently repeated messages. These are about the importance of energy efficiency and the decline in overall gas demand[31]. There is also a push

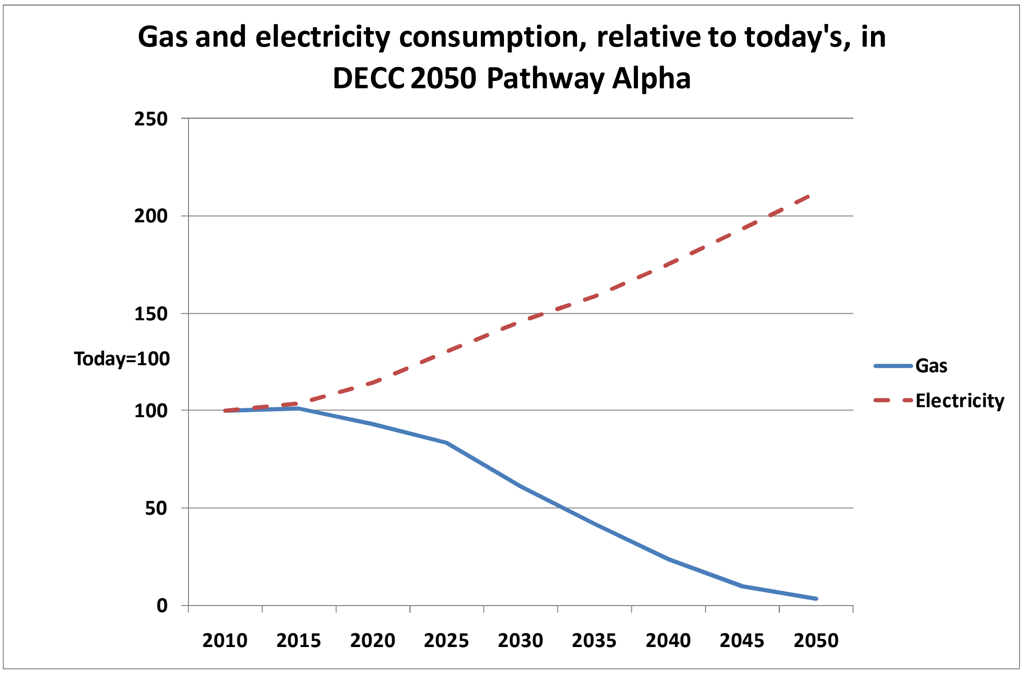
[31] Unless emissions are captured or offset in some way, or renewable gas sources are used, this is inevitable, since total emissions from UK gas consumption at present exceed allowed emissions in 2050. In some scenarios – such as many of the DECC 2050 pathways – the decline in gas demand can be over 90%.

towards electrification of transport and heat, although the exact extent of this varies depending on for example future use of biofuels for those purposes. Electricity demand is therefore expected to rise significantly. A rise in total *energy* demand is by no means universal however; for example, in some of the DECC 2050 scenarios and many of the Ofgem LENS scenarios, total energy demand in 2050 is at or below today's levels, but there is a shift towards electricity and away from gas and oil consumption. Growth in renewables is common to almost all scenarios, and in most but not all[32] cases significant growth in nuclear and carbon capture and storage (CCS) is also seen.

Not all scenarios, of course, achieve the UK's 2050 target, or the interim targets set for 2020 with respect to emissions and renewables deployment. These "less green" scenarios are in general more varied than the "green" ones, and indeed the table above includes "baseline" scenarios, where little or no effort is made to reduce greenhouse gas emissions. We have not included these in our range of possible outcomes; as a guide, we have assumed that the degree of environmental effort implied by the "Dash for Energy" and "Slow Growth" Project Discovery scenarios to 2025 continues to 2050.

For the scenarios which show more emissions reduction effort than the baseline scenarios, but not enough to achieve the 2050 target, common themes are rarer. Even in these scenarios, though, a rise in total electricity demand is seen, even if driven more by economic growth than by electrification of vehicles and heating. Gas demand drops by 2050, but the eventual drop by 2050 can be preceded by a rise in demand over the next 1-2 decades. This move can be quite stark, as illustrated by the graph below.

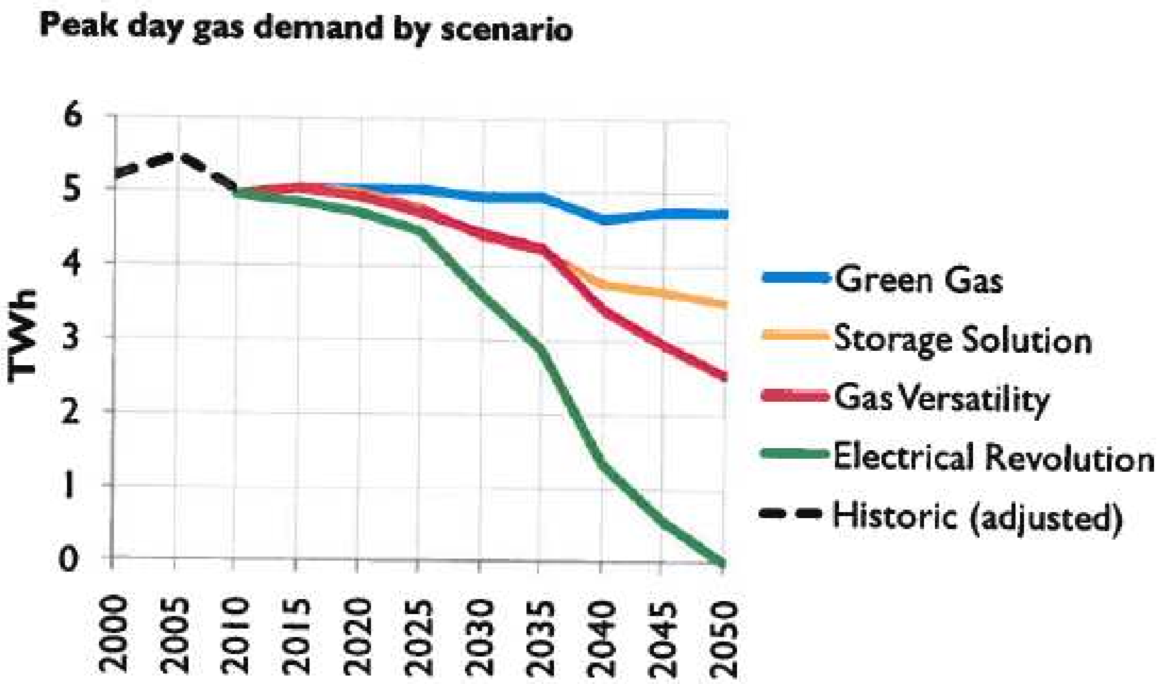
Figure D.1: Gas and electricity consumption in DECC 2050 pathway Alpha



[32] In the "*Big Transmission and Distribution*" scenario from the LENS project, for example, there is no nuclear generation at all in 2050.

Some reports, such as "*Gas: At the Centre of a Low Carbon Future*", query whether a move away from gas to the extent seen in, for example, the DECC Pathways is appropriate, but do not quantify what a more reasonable gas demand level might be in future. The Energy Networks Association report on gas scenarios does quantify, and shows a broader range of future peak gas demands, as in figure D.2 below[33]. Note, however, that its "electrical revolution" scenario shows a similar drop to DECC's "Pathway Alpha", and that in all scenarios, peak demand is at or below today's levels.

Figure D.2: Peak gas demand, Redpoint report for the Energy Networks Association



[33] Source: Figure 9 from "*Gas Future Scenarios Project*", Redpoint for Energy Networks Association, 15 November 2010 http://energynetworks.squarespace.com/storage/ena_publications/ena_gas_future_scenarios_report.pdf

ANNEX E: SIMPLE MODEL OF DEPRECIATION PROFILE AND CASH-FLOW

To illustrate the impact of changes in some of the key parameters while abstracting from the complexity of the reality of the situation a simple model was established. This model is based on an annual capex charge of 100 which is built into a RAB on the basis of actually spending the 100. Depreciation is then subtracted from this. The model considers a period of 100 years so that if a perturbation occurs there is sufficient time to reach a new steady state.

The model calculates an asset cash-flow which incorporates:

- the depreciation charge; and
- a return on the RAB.

The first of these is dependent on the two key parameters discussed extensively in the main report, namely:

- the depreciation life; and
- the depreciation profile.

Both these variables can be adjusted with the options being:

- any depreciation life; and
- a choice of straight-line, front-end and back-end loaded profiles.

In addition there are options where any change to the depreciation life is:

- only applied to new assets; or
- takes place in a stepped manner over a transition period.

The return on the RAB is set as a simple application of a constant WACC to the average RAB in a year.

What the model shows is that when a change to one of the variables takes place the impact is seen through both the cash-flow elements. For example, extending the depreciation life:

- reduces the annual depreciation charge; and
- increases the return on the RAB since the RAB reduces at a slower rate owing to the reduction in the depreciation charge.

Consequently there is an off-setting effect within the cash-flow. Further, if a step change occurs, once a transition period has been completed there will be a new steady state level of cash-flow and RAB. As seen in the examples presented in section 6, the increase in the depreciation life leads to a higher future steady state cash-flow since the depreciation charge recovers to its original level but with a higher RAB leading to a higher level of return.

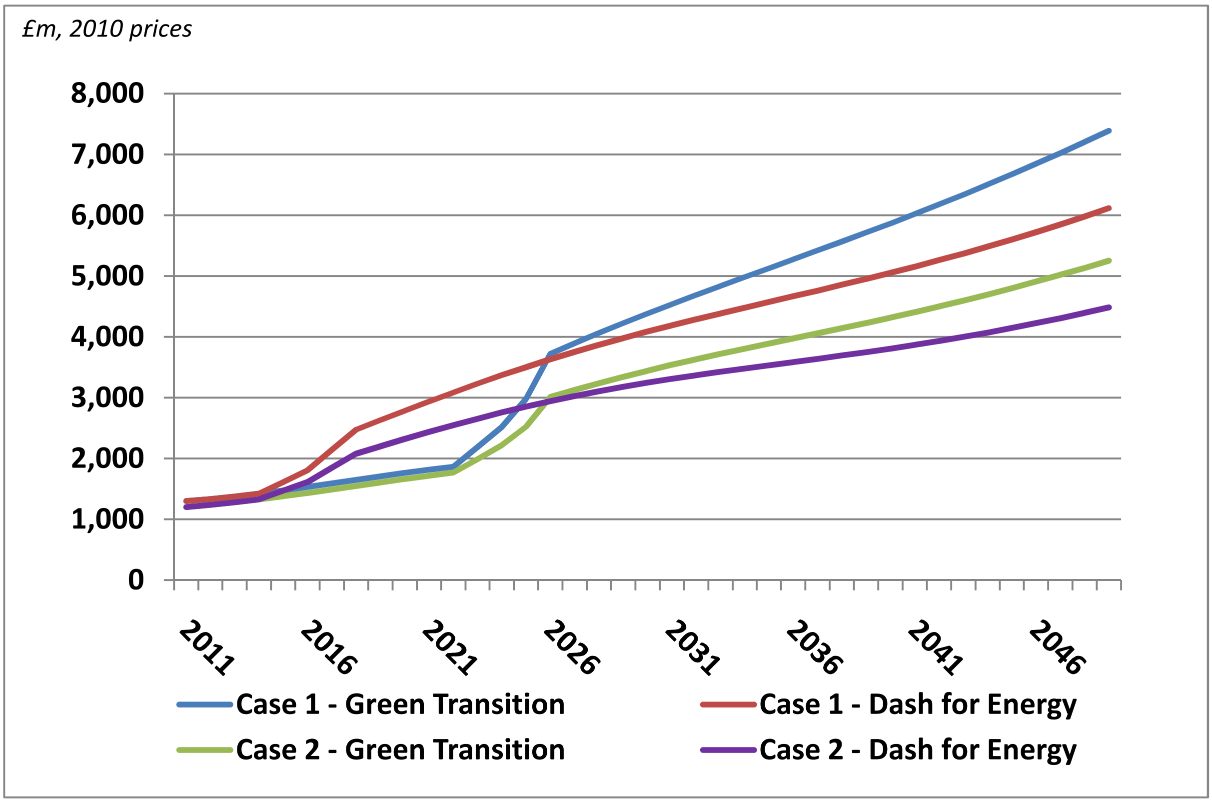
The transition can take quite a significant period.

ANNEX F: MODEL OUTPUTS FOR SCENARIOS FROM 2010 TO 2050

This annex gives more detail on the output from the financial model for the combinations of energy scenarios[34] and asset life options[35] discussed above. This annex expands on the summary given in section 7. We also show a number of sensitivities, to test the robustness of our conclusions to changes in key assumptions. For example, we investigate the changes in depreciation, revenue and gearing that result from considering asset lives of 40, 45, 50 and 55 years. We show both absolute and relative differences (relative differences are shown compared to the "base" option with a 45 year asset life).

We also test a capex sensitivity. In the analysis in the body of the report, we used projections of future capex based on a linear scaling of historic costs (Modern Equivalent Asset Value per GW). In this section, we show the results of a more speculative reduction in distribution spend due to the economies of scale in trenching of underground cables (UGC) and higher cost in transmission due to the difficulties in building overhead lines (OHL). In transmission, there is an assumed gradual shift of historic OHL spend onto UGC (at a higher specific cost), reaching 80% by 2050 (i.e. by 2050 in 80% of the cases where historically OHL could be built, other technology will have to be used). The differences are shown in figures F.1 and F.2 below, and in tables F.1 to F.4.

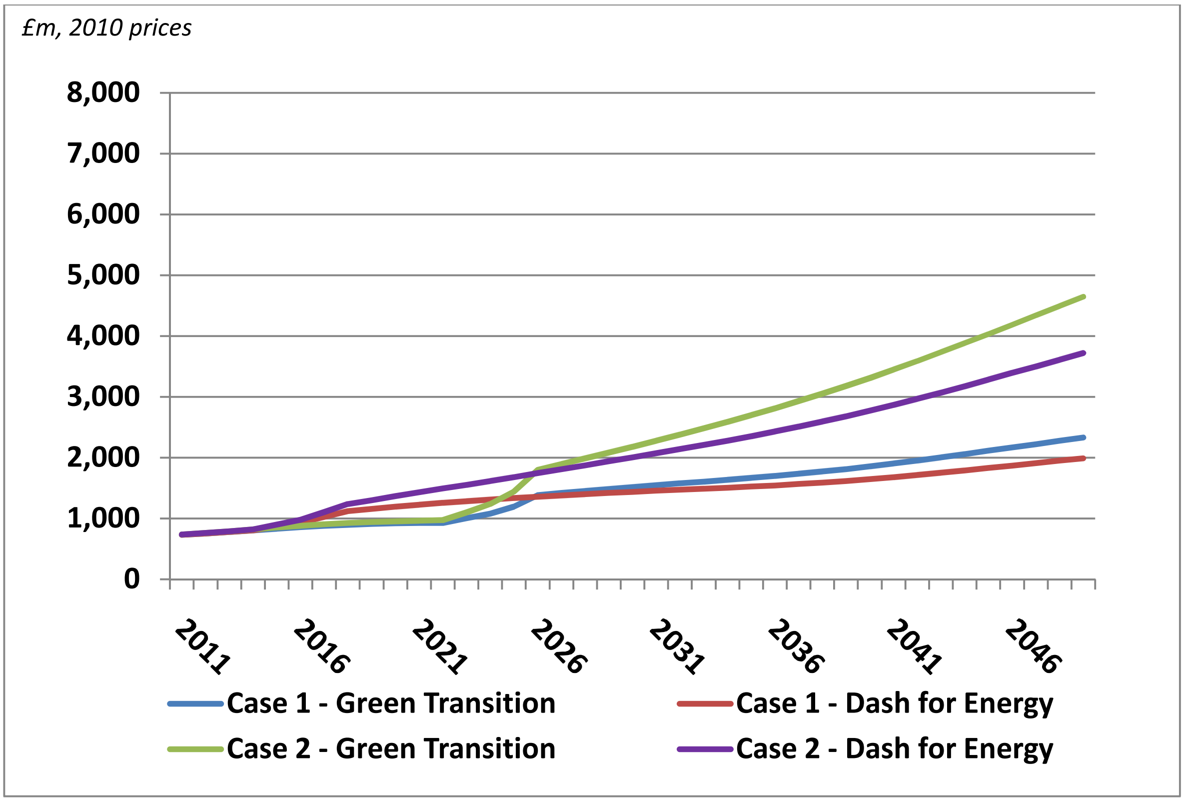
Figure F.1: Capital expenditure on electricity distribution, for "Green Transition" and "Dash for Energy" scenarios, under linear scaling (case 1) and modified (case 2) assumptions



[34] Our extensions of two of the Project Discovery Scenarios: Green Transition, and Dash for Energy.

[35] "base" (existing asset lives), "split" (existing lives for existing assets, new lives for new assets) and "full" (new lives for all assets).

Figure F.2: Capital expenditure on electricity transmission, for "Green Transition" and "Dash for Energy" scenarios, under linear scaling (case 1) and modified (case 2) assumptions



The tables below show cumulative figures for 2011 - 2050 inclusive (£m, 2010 prices), except for the gas distribution variant scenario which shows cumulative figures for 2011 - 2035.

Depreciation and Revenue figures are based on the 'base' option (keeping Ofgem's current asset lives for all assets), except:

- Electricity Distribution: Shows the 'split' option, using proposed lives of (i) 45 years, and (ii) 55 years.
- Gas Distribution variant scenario. Asset lives are set to 15 years for all assets, and declining each year such that all assets are fully depreciated by 2035.

Cases 1 and 2 refer to the electricity networks only, so the gas figures are identical. For the gas distribution variant scenario, figures shown are for 2011-35 only.

Table F.1: High level summary outputs, by network, for Green Transition Scenario, capex case 1

£m, 2011-50	Capex	Opex	Depreciation	Revenue
Electricity				
Distribution (base, 20 years)	166,492	115,364	116,104	346,975
Distribution (split, 45 years)			68,785	321,117
Distribution (split, 55 years)			59,499	315,116
Transmission	59,062	21,934	44,690	113,912
Gas				
Distribution (45 years)	35,338	47,920	30,031	132,851
Distribution (15 yrs in 2020)*	15,246	28,299	29,753	85,785
Transmission	2,929	2,517	4,766	14,607

Table F.2: High level summary outputs, by network, for Dash for Energy Scenario, capex case 1

£m, 2011-50	Capex	Opex	Depreciation	Revenue
Electricity				
Distribution (base, 20 years)	157,255	115,364	117,376	347,468
Distribution (split, 45 years)			71,059	326,263
Distribution (split, 55 years)			61,359	320,391
Transmission	56,704	21,934	45,109	114,189
Gas				
Distribution (45 years)	43,964	47,920	35,423	150,423
Distribution (15 yrs in 2020)*	22,984	28,299	37,491	99,141
Transmission	3,761	2,517	5,290	16,358

Table F.3: High level summary outputs, by network, for Green Transition Scenario, capex case 2

£m, 2011-50	Capex	Opex	Depreciation	Revenue
Electricity				
Distribution (base, 20 years)	128,471	115,364	96,867	306,579
Distribution (split, 45 years)			59,591	288,108
Distribution (split, 55 years)			51,977	283,390
Transmission	93,076	21,934	59,700	147,606
Gas				
Distribution (45 years)	35,338	47,920	30,031	132,851
Distribution (15 yrs in 2020)*	15,246	28,299	29,753	85,785
Transmission	2,929	2,517	4,766	14,607

Table F.4: High level summary outputs, by network, for Dash for Energy Scenario, capex case 2

£m, 2011-50	Capex	Opex	Depreciation	Revenue
Electricity				
Distribution (base, 20 years)	122,852	115,364	97,688	306,943
Distribution (split, 45 years)			61,048	291,431
Distribution (split, 55 years)			53,169	286,793
Transmission	84,583	21,934	58,542	143,872
Gas				
Distribution (45 years)	43,964	47,920	35,423	150,423
Distribution (15 yrs in 2020)*	22,984	28,299	37,491	99,141
Transmission	3,761	2,517	5,290	16,358

We start by looking at the electricity distribution network.

Electricity Distribution Network - Case 1 - Green Transition

The changes to depreciation profiles from changing the asset lives and the depreciation options are relatively intuitive, based on the principle that longer asset lives lead to lower depreciation in any given year.

Figure F.3: Annual asset depreciation, by year

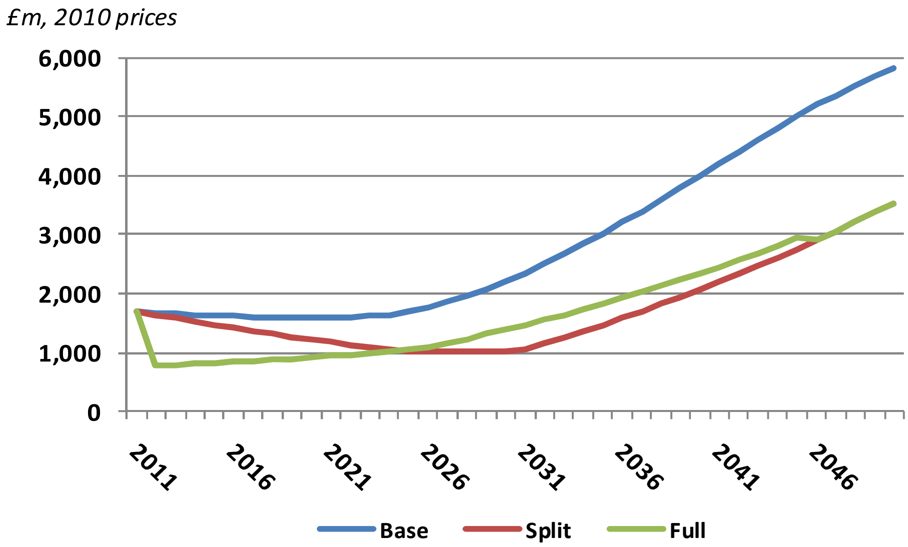


Figure F.4: Annual percentage difference (mark-up) in asset depreciation between scenarios, by year

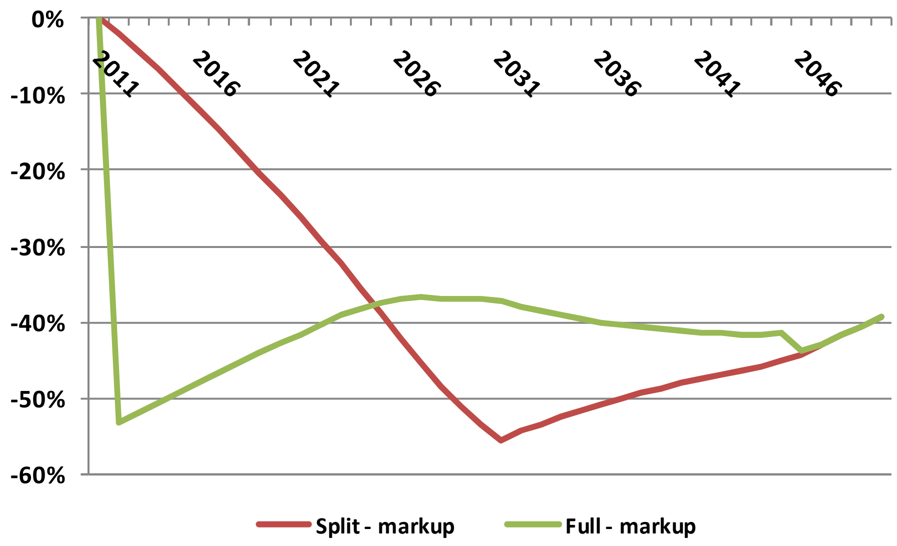


Figure F.5: Annual asset depreciation, by year, for each proposed asset life sensitivity

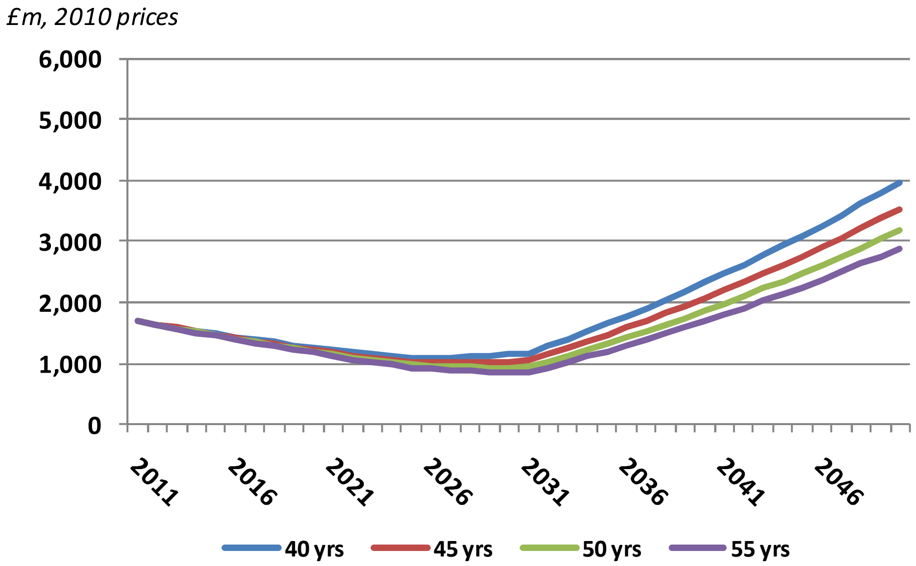
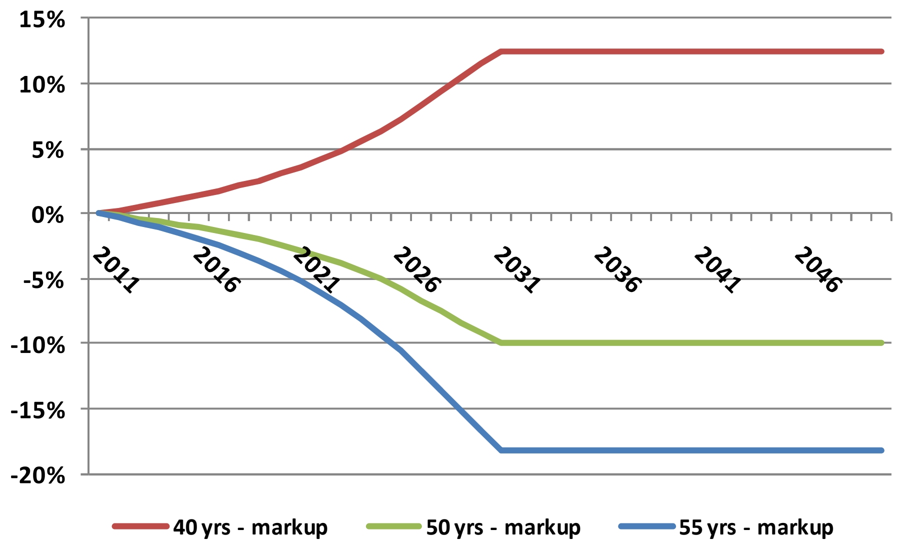


Figure F.6: Annual percentage difference (mark-up) in asset depreciation between sensitivities, by year



Revenue

Differences in revenue between the "base", "split" and "full" options are relatively small, as are those from varying the asset life between 40 and 55 years.

Figure F.7: Annual network revenue, by year, for each scenario

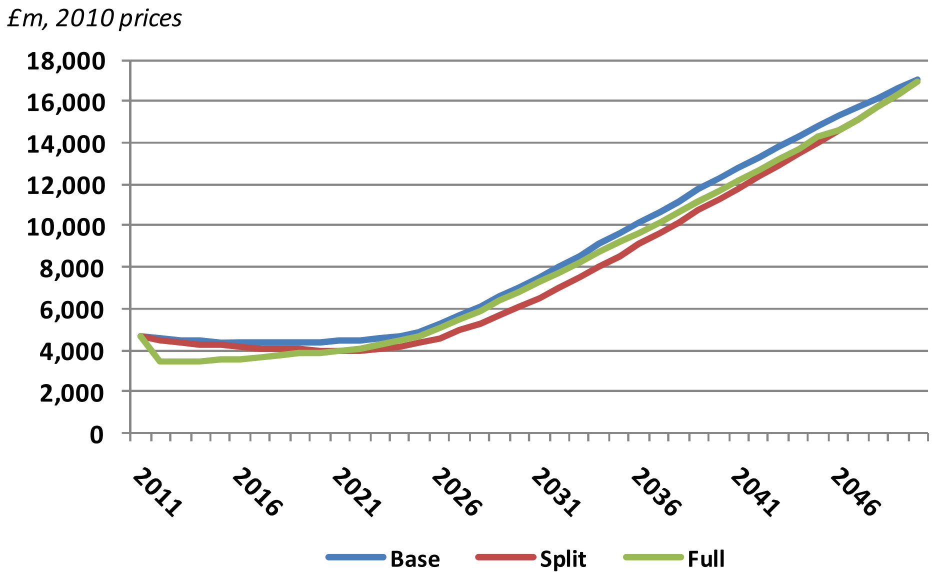


Figure F.8: Annual percentage difference (mark-up) in network revenue between scenarios, by year

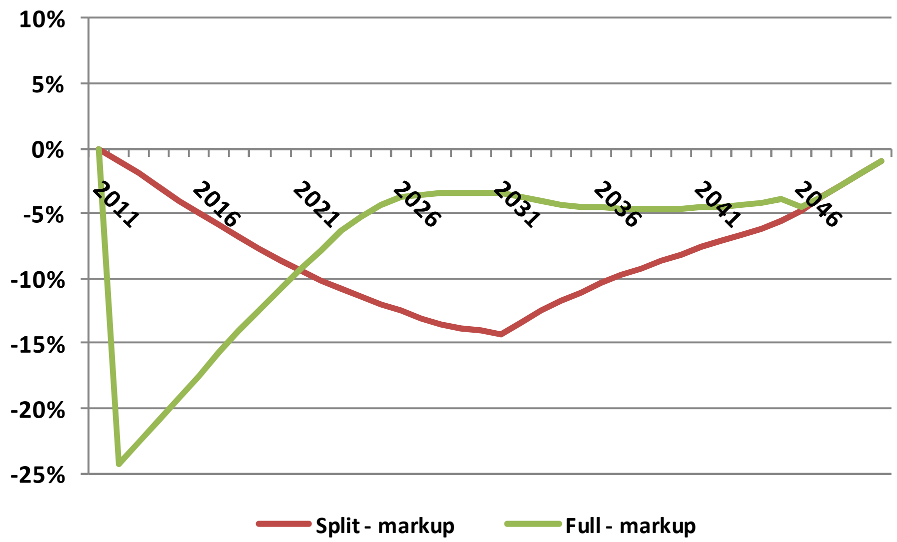


Figure F.9: Annual revenue, by year, for each proposed asset life sensitivity

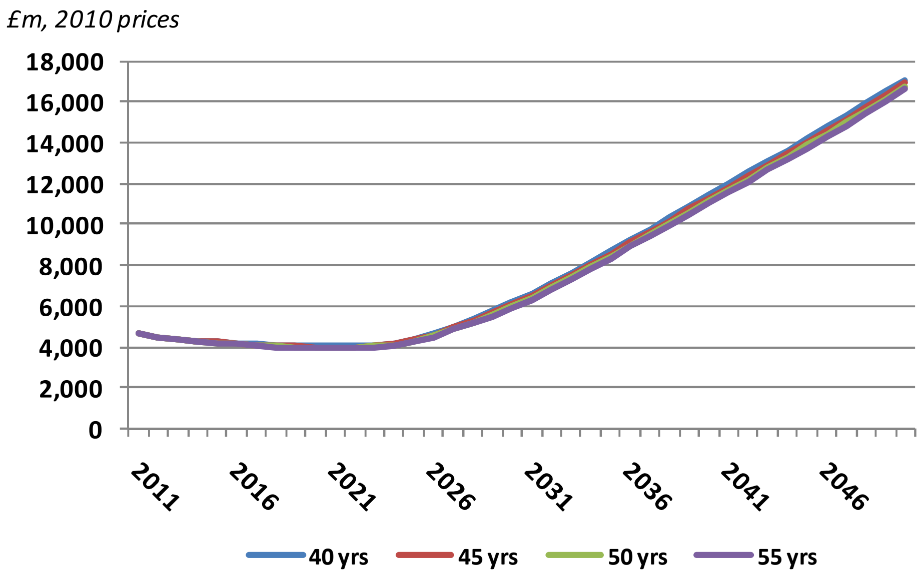
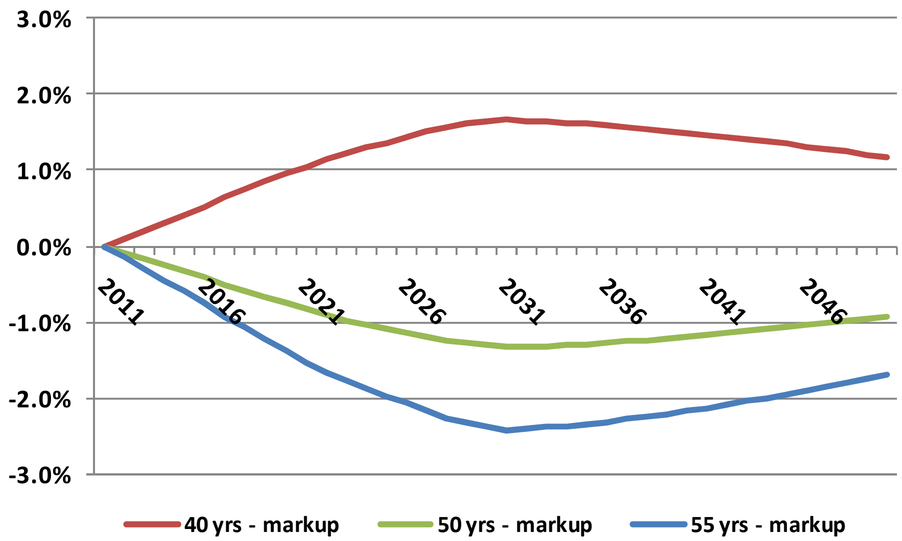


Figure F.10: Annual percentage difference (mark-up) in asset revenue between sensitivities, by year



Gearing

Gearing levels are, as expected, higher in the "full" option, since this shows a significant fall in depreciation and hence revenue compared to the other options, at least until 2020. Thereafter, gearing levels for all options converge, although gearing remains higher in the options where at least some asset lives are changed. In *all* cases for electricity distribution, gearing levels rise over time, while the levels in transmission are more constant.

Varying the asset life from 40 to 55 years makes little difference to the gearing.

Figure F.11: Annual network gearing, by year, for each option

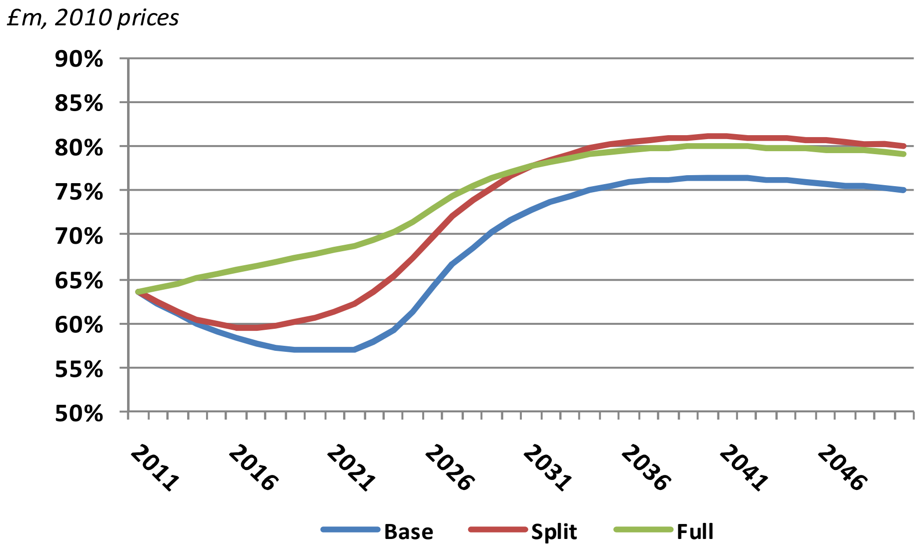


Figure F.12: Annual percentage difference (mark-up) in network gearing between options, by year

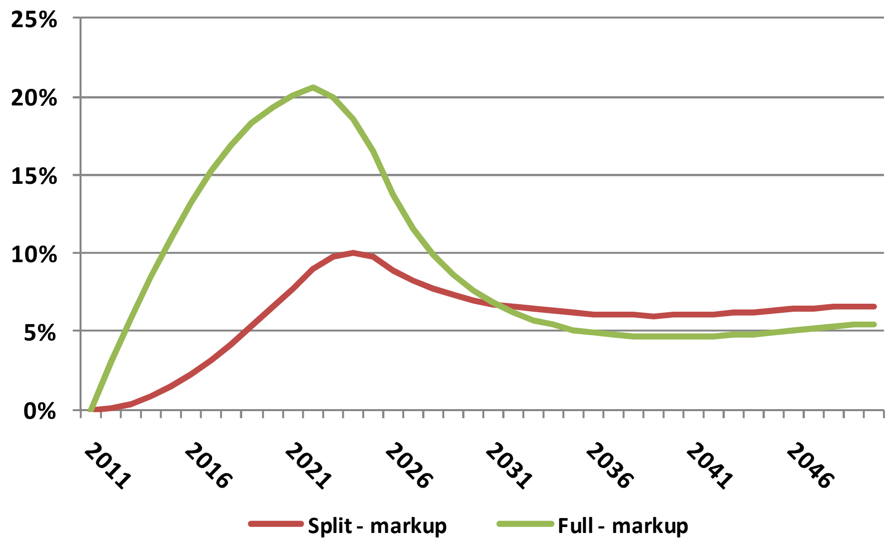


Figure F.13: Annual network gearing, by year, for each proposed asset life sensitivity

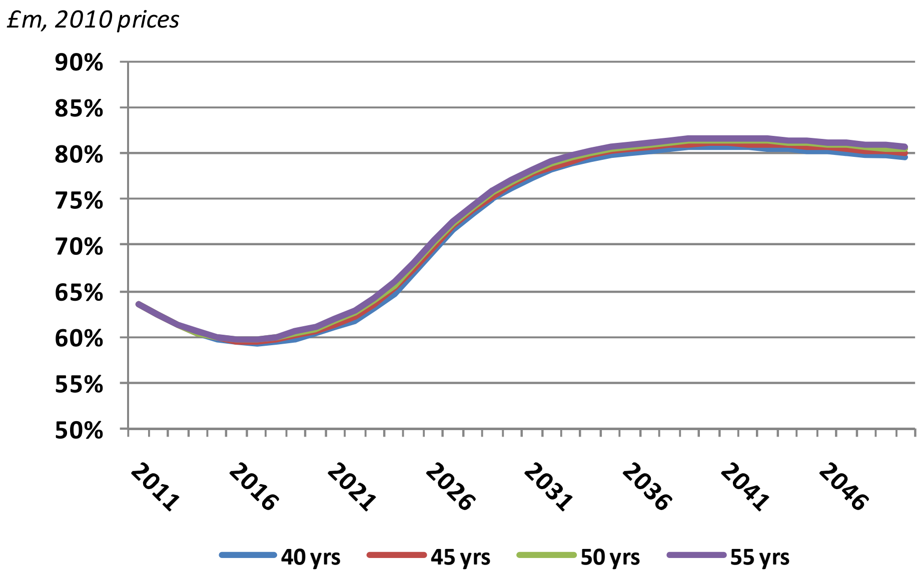
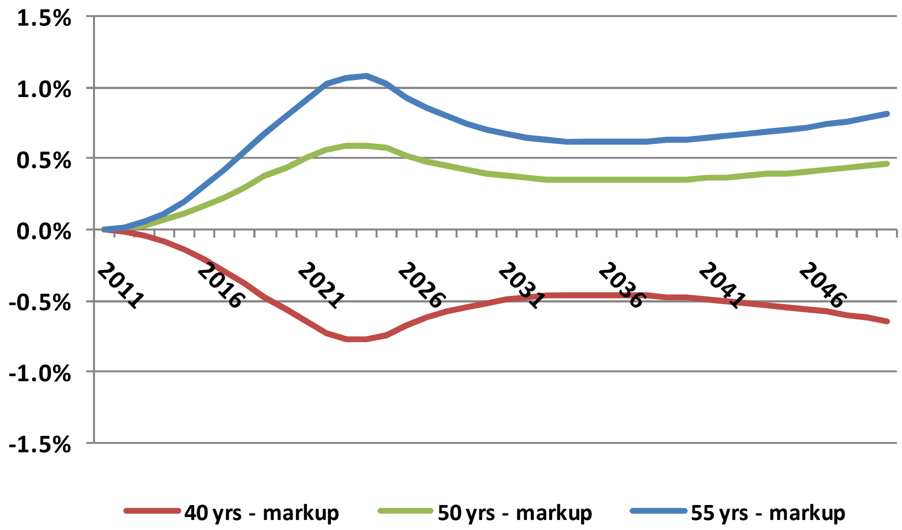


Figure F.14: Annual percentage difference (mark-up) in network gearing between sensitivities, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

We also show, for the "split" option, financial ratios for a 55 year asset life sensitivity, compared to the default 45 year asset life.

Table F.5 Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	5.6	4.6 - 7.1	3.8	2.6 - 6.4	3.2	2.7 - 6.3
Funds from operations / net debt	20%	16% - 25%	13%	9% - 23%	11%	9% - 23%
Gearing (net debt / closing RAV)	68%	57% - 76%	72%	60% - 81%	74%	64% - 80%
Post-maintenance interest cover ratio	2.0	1.7 - 2.3	1.9	1.6 - 2.2	1.8	1.7 - 2.1

Table F.6: Financial ratios over the whole modelling period (2011-50), for 55 year asset life sensitivity

Financial ratios (2011-50)	Split - 45 years		Split - 55 years	
	Average	Range	Average	Range
Funds from operations / interest	3.8	2.6 - 6.4	3.6	2.4 - 6.4
Funds from operations / net debt	13%	9% - 23%	12%	8% - 23%
Gearing (net debt / closing RAV)	72%	60% - 81%	73%	60% - 82%
Post-maintenance interest cover ratio	1.9	1.6 - 2.2	1.8	1.6 - 2.2

Electricity Distribution Network - Case 1 - Dash for Energy

Depreciation

We now consider the "Dash for Energy" scenario, which has lower environmental ambition than the "Green Transition" scenario.

As the graphs below show, the relative impacts of the different asset life options are more or less the same in both scenarios. The absolute level of depreciation and revenue is slightly lower in the "Dash for Energy" scenario, however. This reflects the greater electrification of heat and transport in the "Green Transition" scenario and so the greater need for investment in that scenario.

Figure F.15: Annual asset depreciation, by year, for each scenario

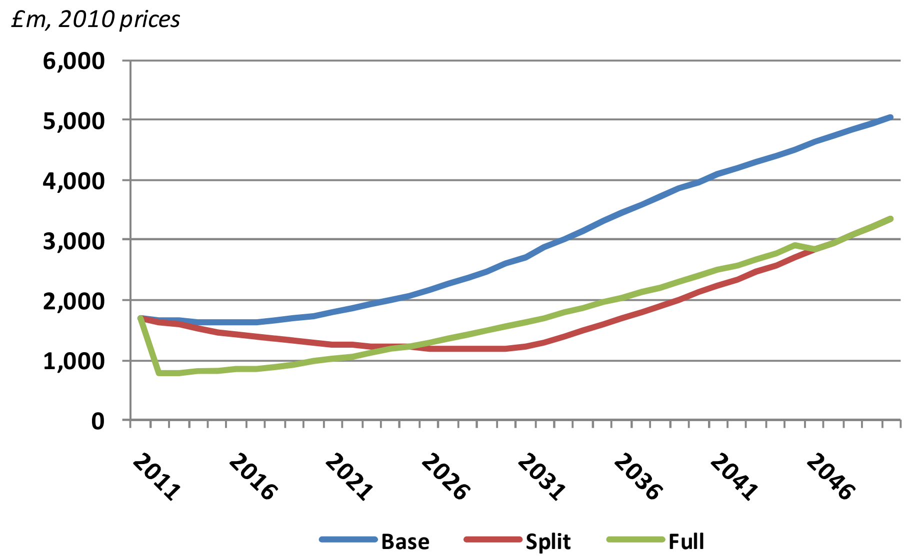


Figure F.16 Annual percentage difference (mark-up) in asset depreciation between options, by year

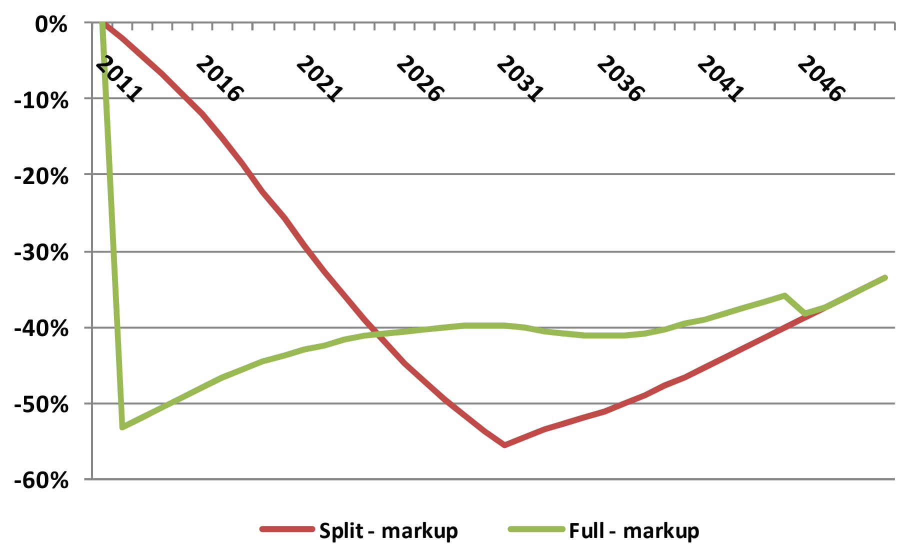


Figure F.17: Annual asset depreciation, by year, for each proposed asset life sensitivity

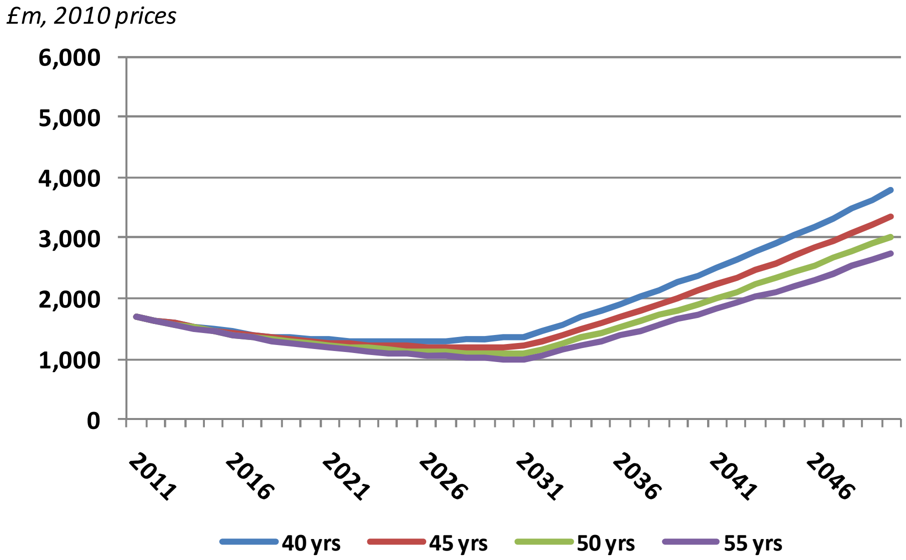


Figure F.18: Annual percentage difference (mark-up) in asset depreciation between sensitivities, by year

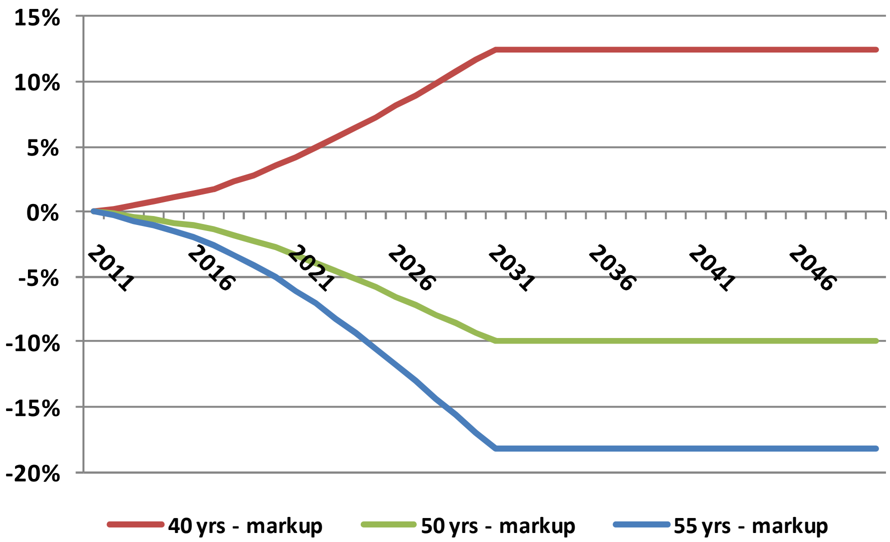


Figure F.19: Annual network revenue, by year, for each option

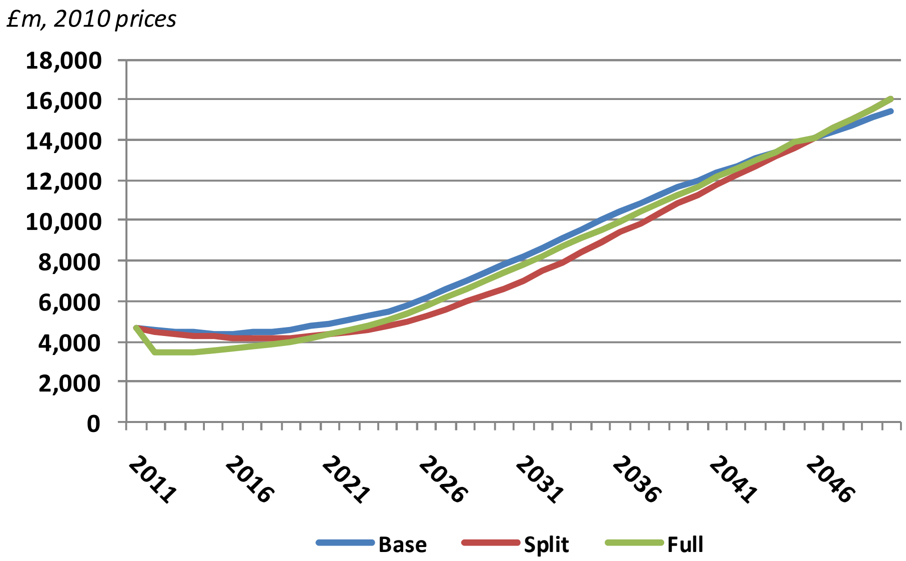


Figure F.20: Annual percentage difference (mark-up) in network revenue between options, by year

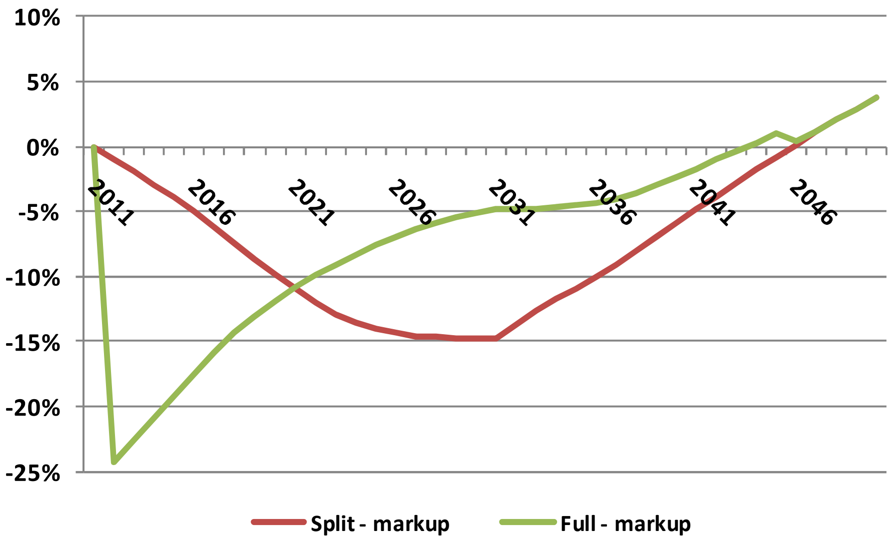


Figure F.21: Annual revenue, by year, for each proposed asset life sensitivity

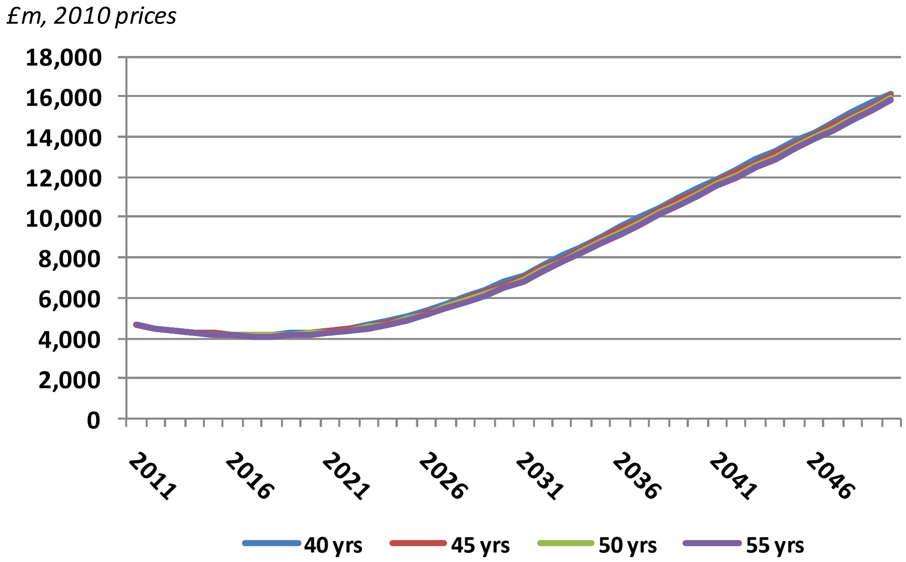


Figure F.22: Annual percentage difference (mark-up) in asset revenue between sensitivities, by year

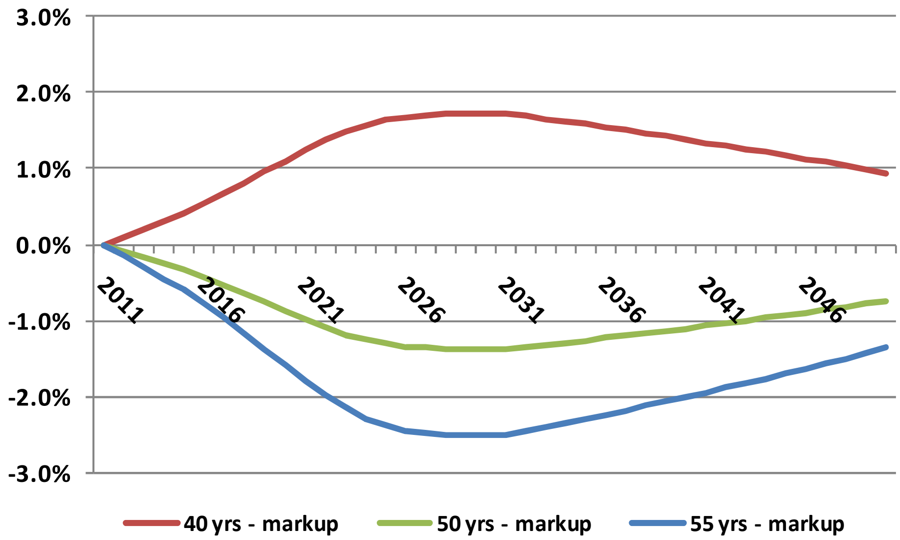


Figure F.23: Annual network gearing, by year, for each scenario

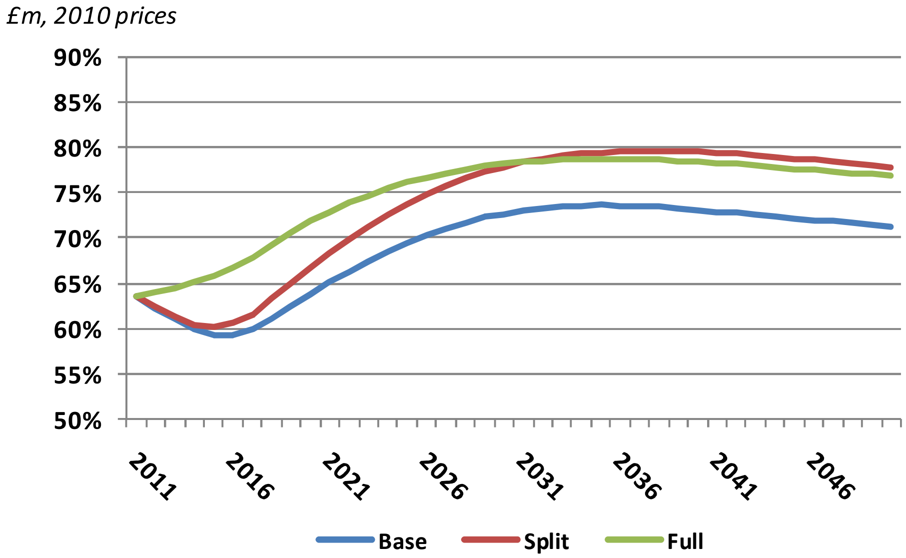


Figure F.24: Annual percentage difference (mark-up) in network gearing between scenarios, by year

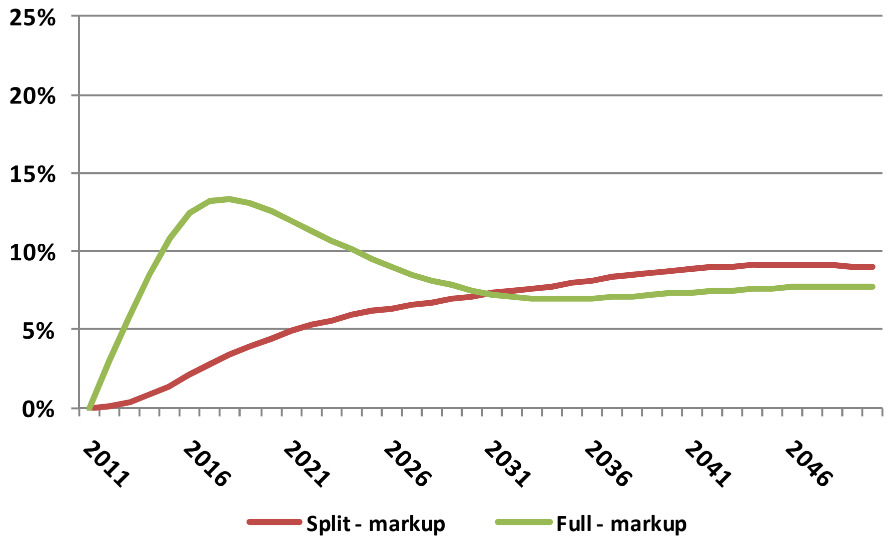


Figure F.25: Annual network gearing, by year, for each proposed asset life sensitivity

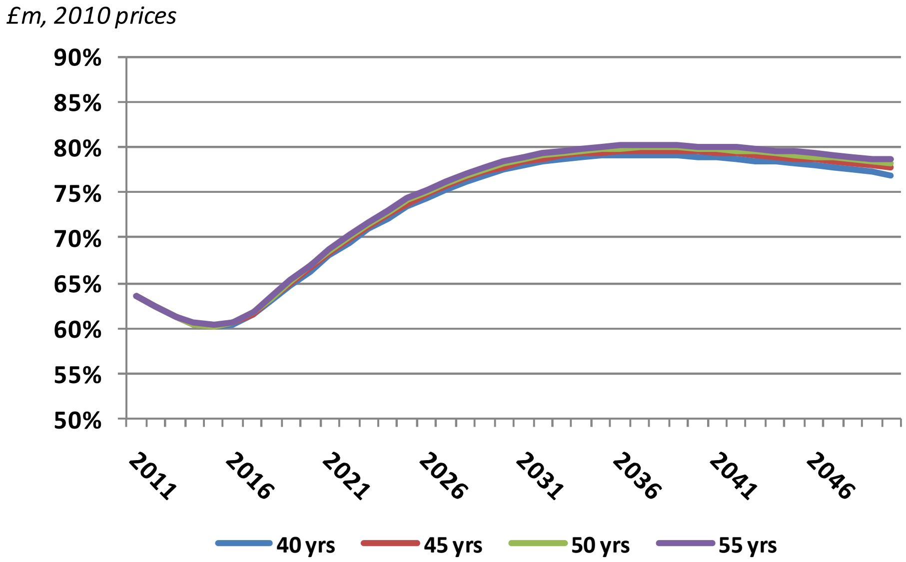
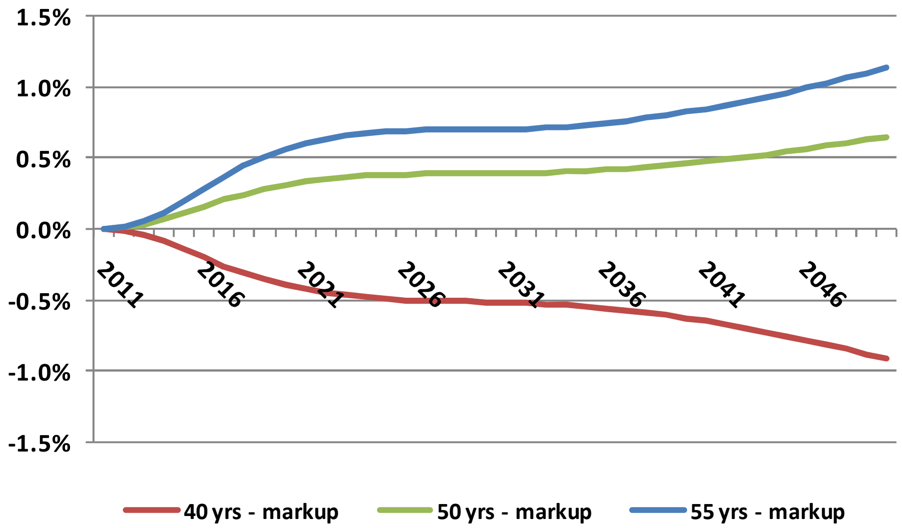


Figure F.26: Annual percentage difference (mark-up) in network gearing between sensitivities, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

We also show, for the "split" option, financial ratios for a 55 year asset life sensitivity, compared to the default 45 year asset life.

Table F.7: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	5.5	4.9 - 6.9	3.7	2.6 - 6.4	3.2	2.8 - 6.3
Funds from operations / net debt	19%	17% - 24%	13%	9% - 23%	11%	10% - 23%
Gearing (net debt / closing RAV)	69%	59% - 74%	74%	60% - 80%	75%	64% - 79%
Post-maintenance interest cover ratio	1.9	1.8 - 2.2	1.8	1.7 - 2.2	1.8	1.7 - 2.1

Table F.8: Financial ratios over the whole modelling period (2011-50), for 55 year asset life sensitivity

Financial ratios (2011-50)	Split - 45 years		Split - 55 years	
	Average	Range	Average	Range
Funds from operations / interest	3.7	2.6 - 6.4	3.5	2.4 - 6.4
Funds from operations / net debt	13%	9% - 23%	12%	8% - 23%
Gearing (net debt / closing RAV)	74%	60% - 80%	74%	60% - 80%
Post-maintenance interest cover ratio	1.8	1.7 - 2.2	1.8	1.7 - 2.2

Electricity Distribution Network - Case 2 - Green Transition

As distribution capex is lower in this case, depreciation and revenue is also lower. However the relative difference between the "base", "split" and "full" options is the same in either capex case.

Figure F.27: Annual asset depreciation, by year, for each option

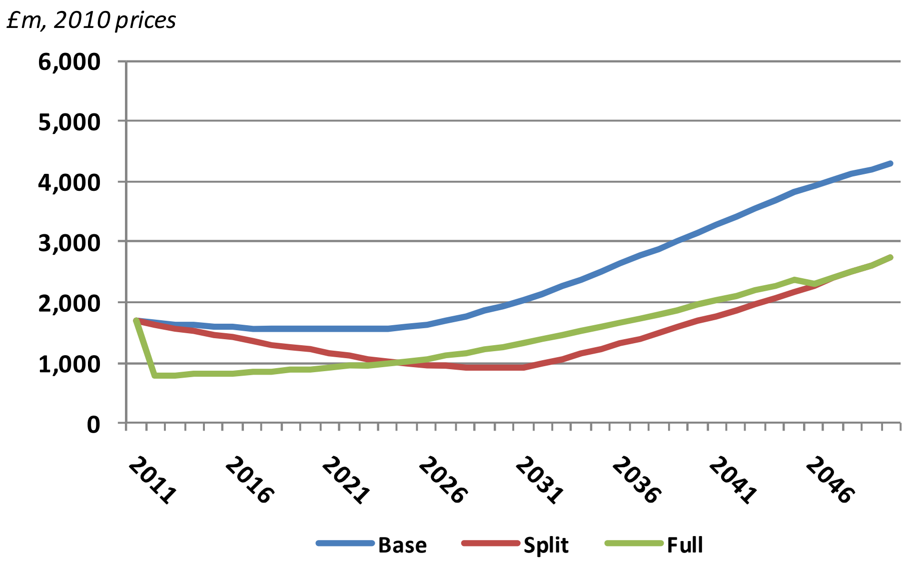


Figure F.28: Annual percentage difference (mark-up) in asset depreciation between options, by year

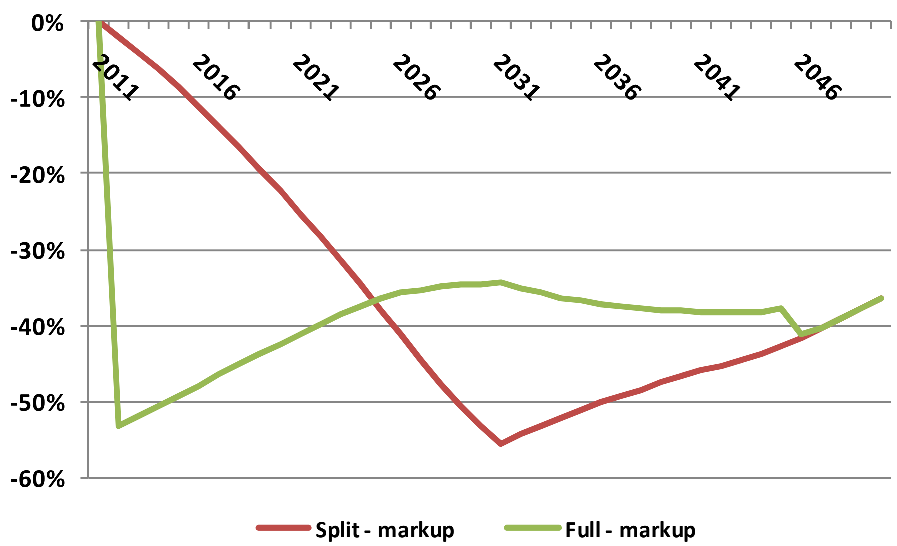


Figure F.29: Annual asset depreciation, by year, for each proposed asset life sensitivity

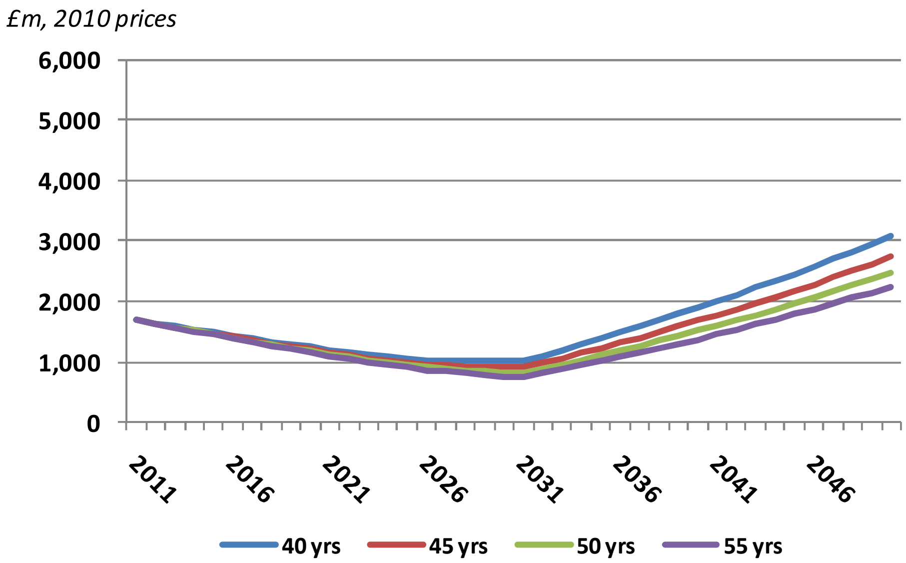


Figure F.30: Annual percentage difference (mark-up) in asset depreciation between sensitivities, by year

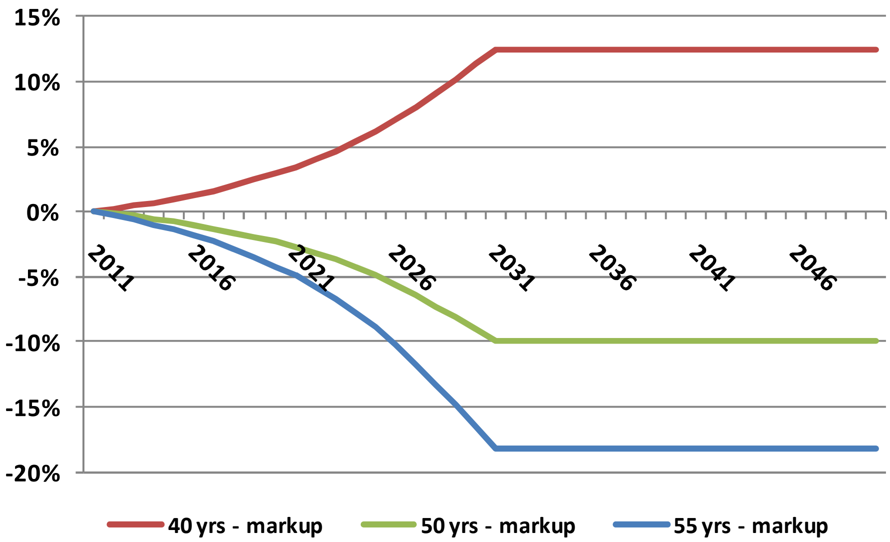


Figure F.31: Annual network revenue, by year, for each option

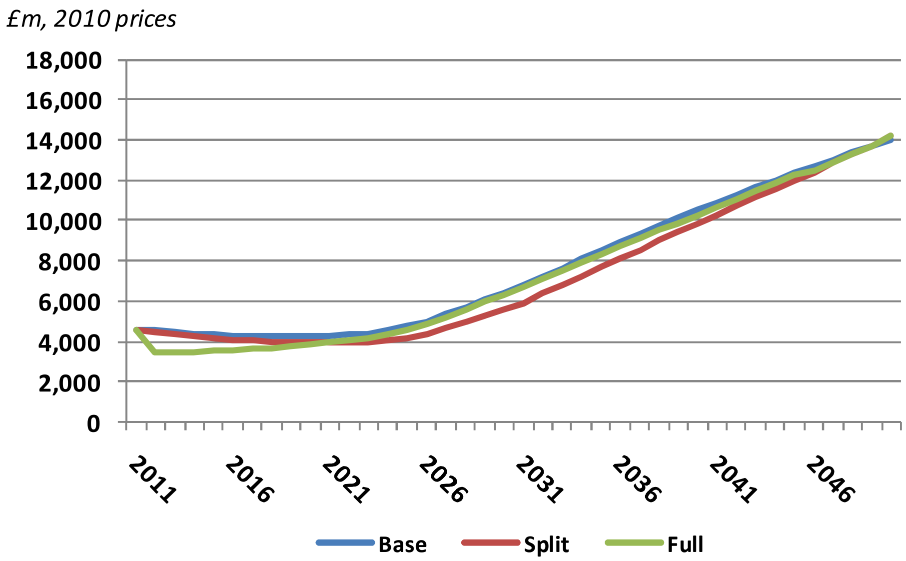


Figure F.32: Annual percentage difference (mark-up) in network revenue between options, by year

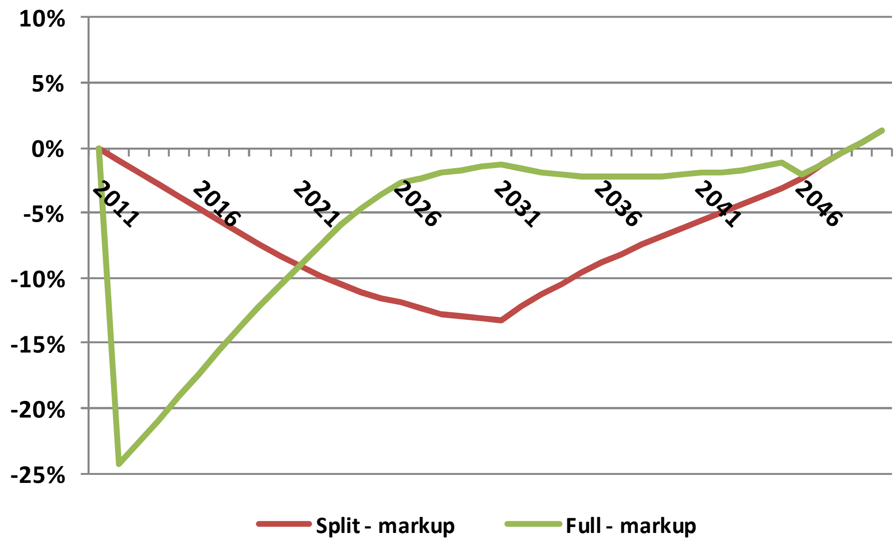


Figure F.33: Annual revenue, by year, for each proposed asset life sensitivity

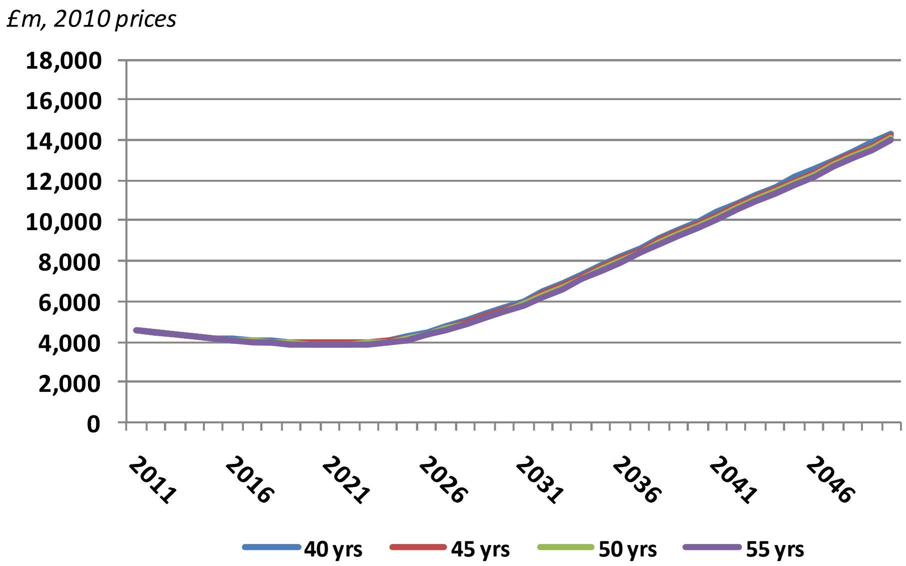


Figure F.34: Annual percentage difference (mark-up) in asset revenue between sensitivities, by year

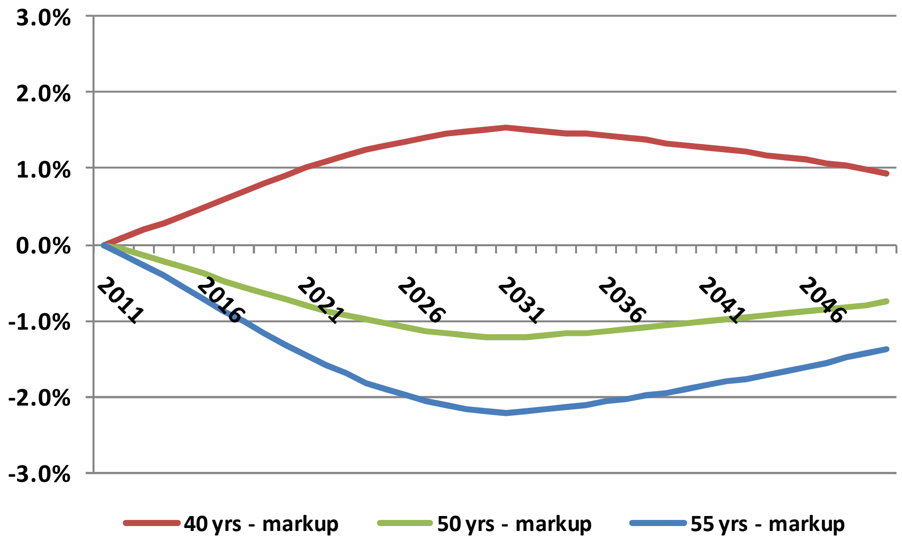


Figure F.35: Annual network gearing, by year, for each option

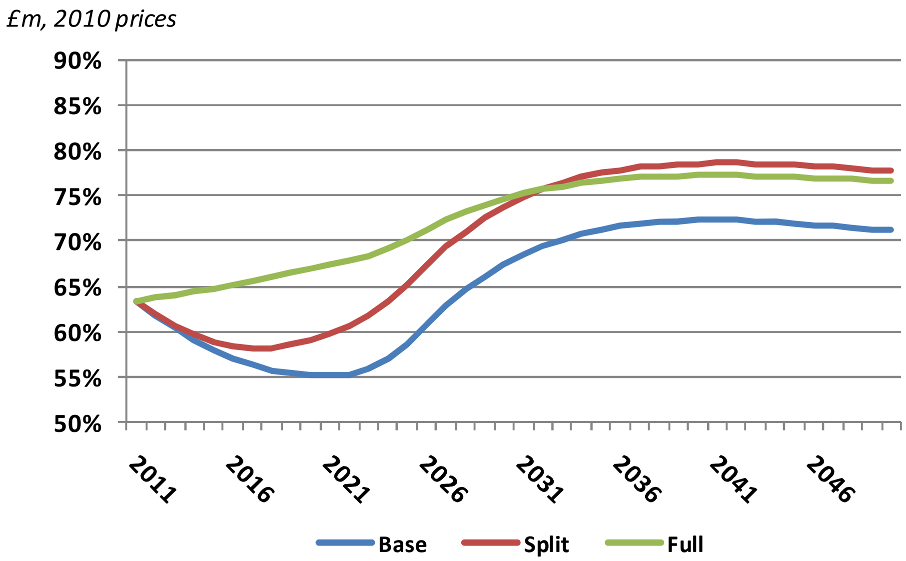


Figure F.36: Annual percentage difference (mark-up) in network gearing between options, by year

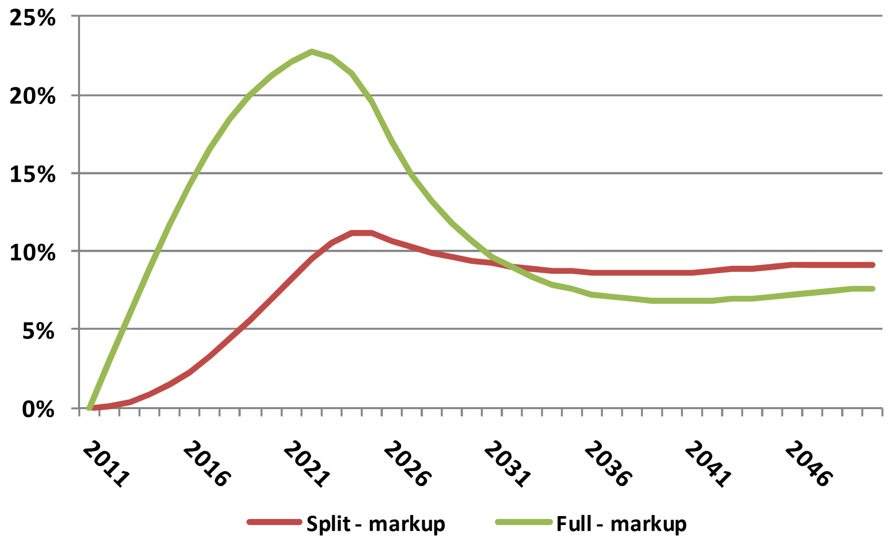


Figure F.37: Annual network gearing, by year, for each proposed asset life sensitivity, for "split" option

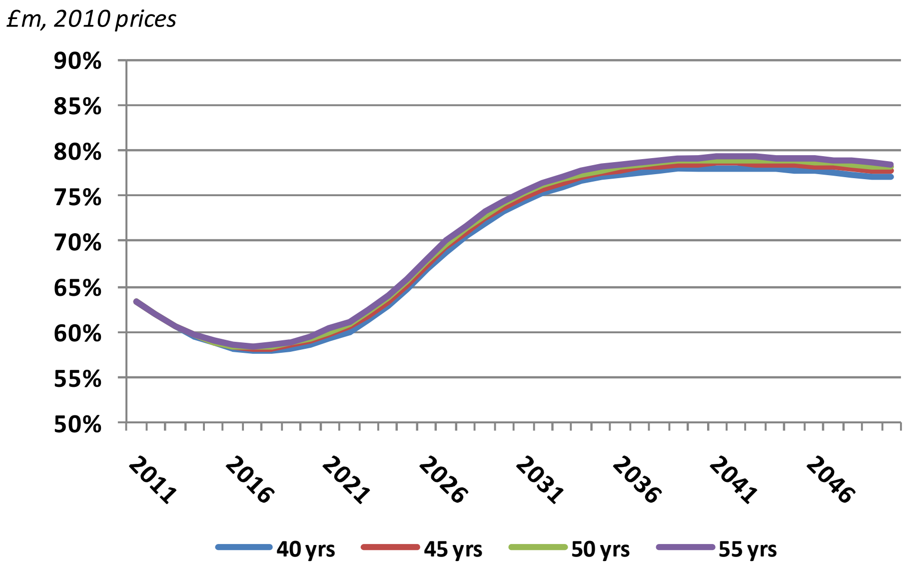
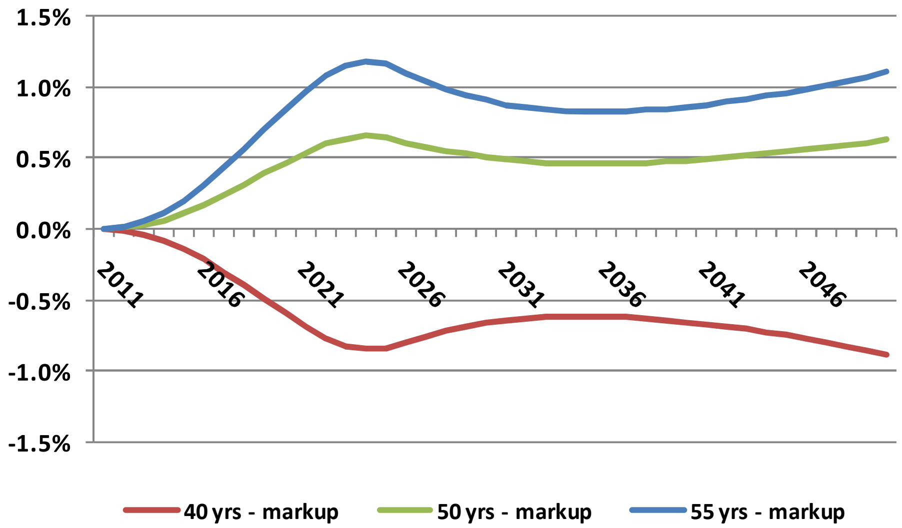


Figure F.38: Annual percentage difference (mark-up) in network gearing between sensitivities, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

We also show, for the "split" option, financial ratios for a 55 year asset life sensitivity, compared to the default 45 year asset life.

Table F.9: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	5.9	5 - 7.4	3.9	2.7 - 6.5	3.3	2.9 - 6.3
Funds from operations / net debt	21%	17% - 26%	14%	9% - 23%	12%	10% - 23%
Gearing (net debt / closing RAV)	65%	55% - 72%	70%	58% - 79%	72%	63% - 77%
Post-maintenance interest cover ratio	2.1	1.8 - 2.4	1.9	1.7 - 2.3	1.8	1.7 - 2.1

Table F.10: Financial ratios over the whole modelling period (2011-50), for 55 year asset life sensitivity

Financial ratios (2011-50)	Split - 45 years		Split - 55 years	
	Average	Range	Average	Range
Funds from operations / interest	3.9	2.7 - 6.5	3.7	2.5 - 6.5
Funds from operations / net debt	14%	9% - 23%	13%	8% - 23%
Gearing (net debt / closing RAV)	70%	58% - 79%	71%	58% - 79%
Post-maintenance interest cover ratio	1.9	1.7 - 2.3	1.9	1.7 - 2.3

Electricity Distribution Network - Case 2 - Dash for Energy

The figures below show the impact of "case 2" (lower) capex in the "Dash for Energy" scenario. As expected, compared to "case 1" capex, depreciation and revenue are lower. The relative differences between the "Base", "Split" and "Full" options are the same as for the "case 1" capex.

Figure F.39: Annual asset depreciation, by year, for each option

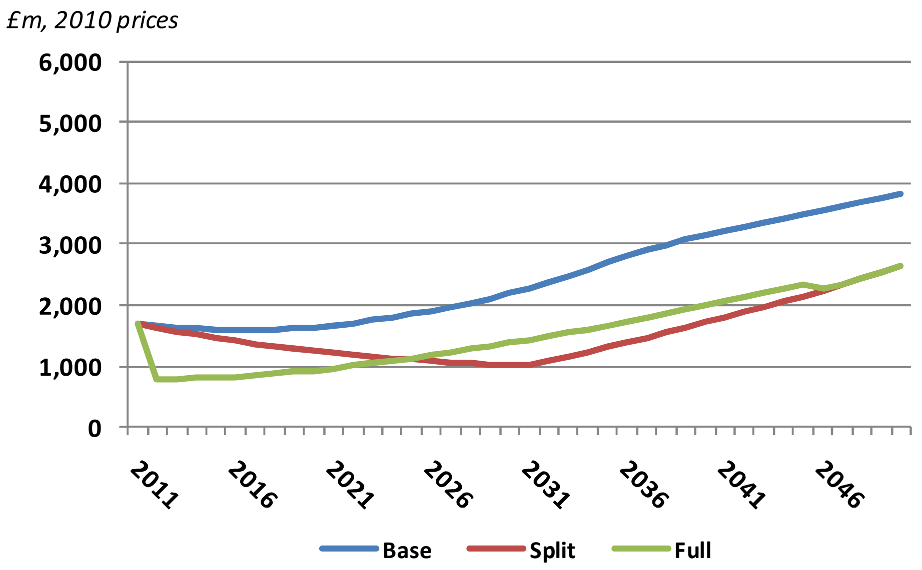
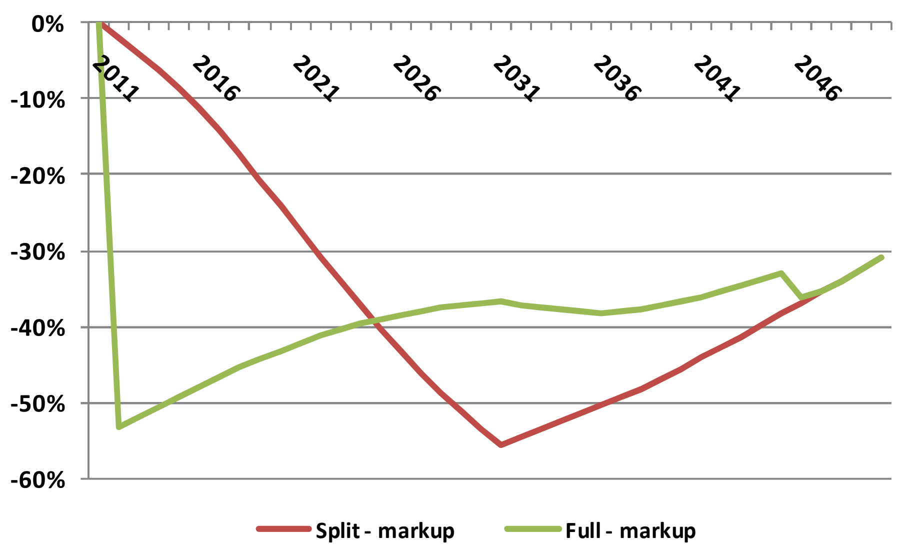


Figure F.40: Annual percentage difference (mark-up) in asset depreciation between options, by year



As for "case 1" capex, we performed a sensitivity analysis showing the impact of asset lives of 40, 45, 50 and 55 years.

Figure F.41: Annual asset depreciation, by year, for each proposed asset life sensitivity

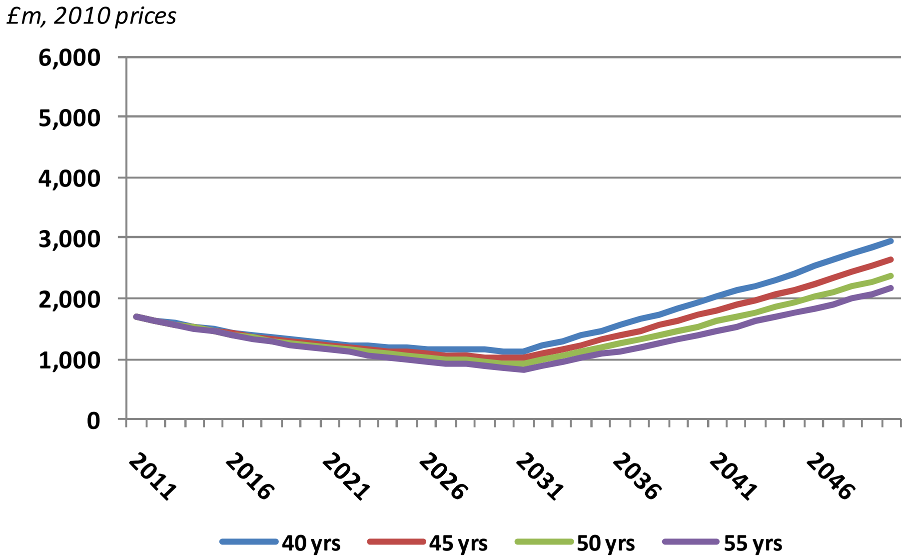


Figure F.42: Annual percentage difference (mark-up) in asset depreciation between sensitivities, by year

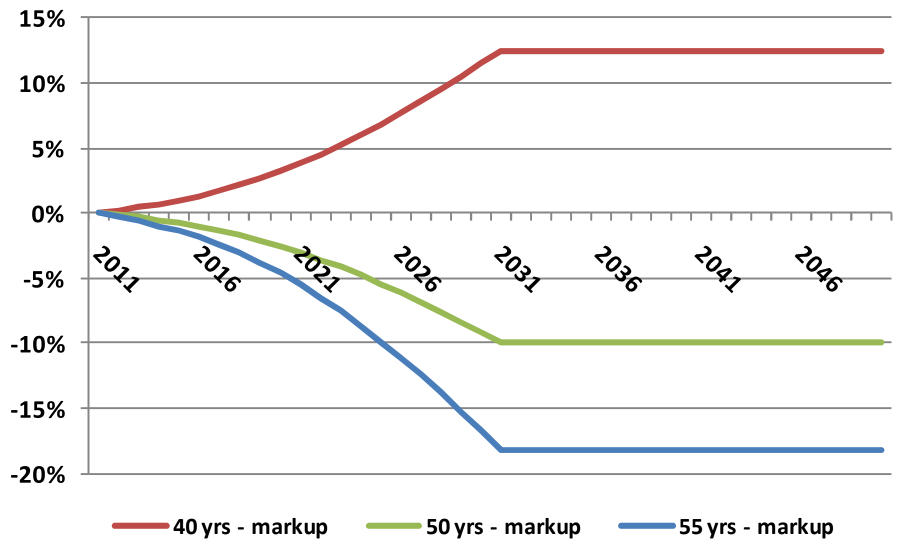


Figure F.43: Annual network revenue, by year, for each option

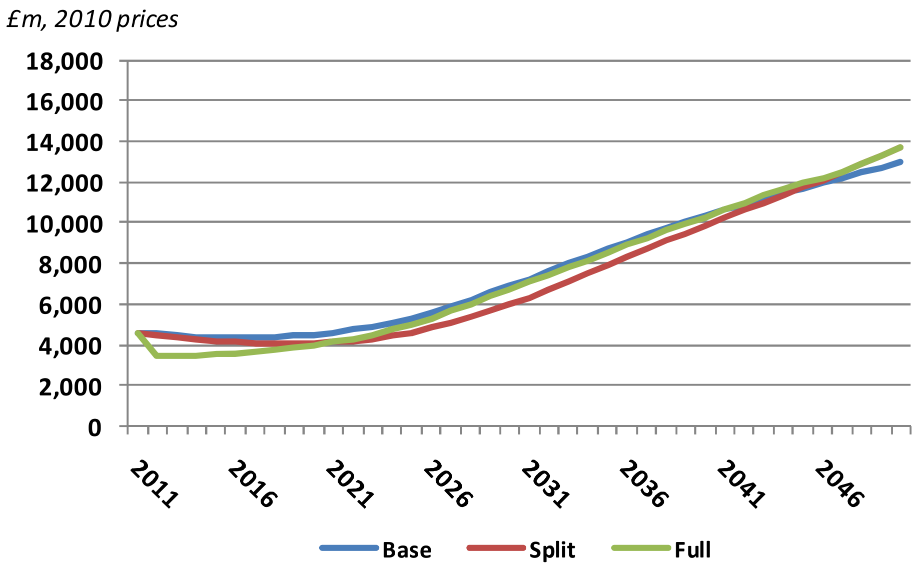


Figure F.44: Annual percentage difference (mark-up) in network revenue between options, by year

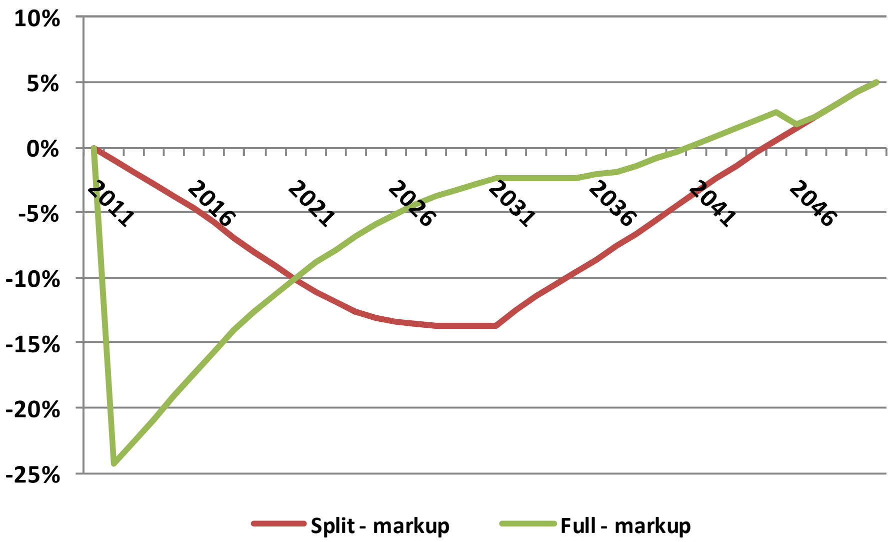


Figure F.45: Annual revenue, by year, for each proposed asset life sensitivity

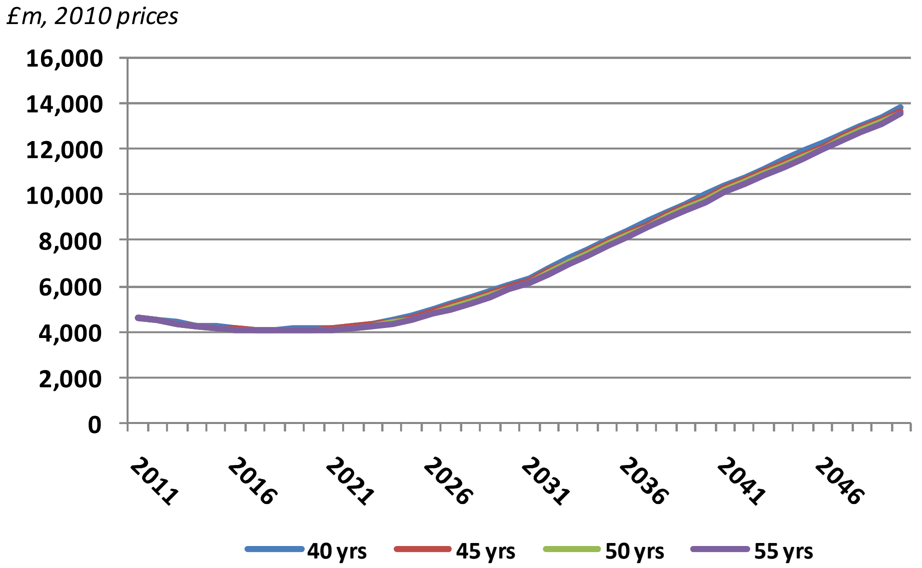


Figure F.46: Annual percentage difference (mark-up) in asset revenue between sensitivities, by year

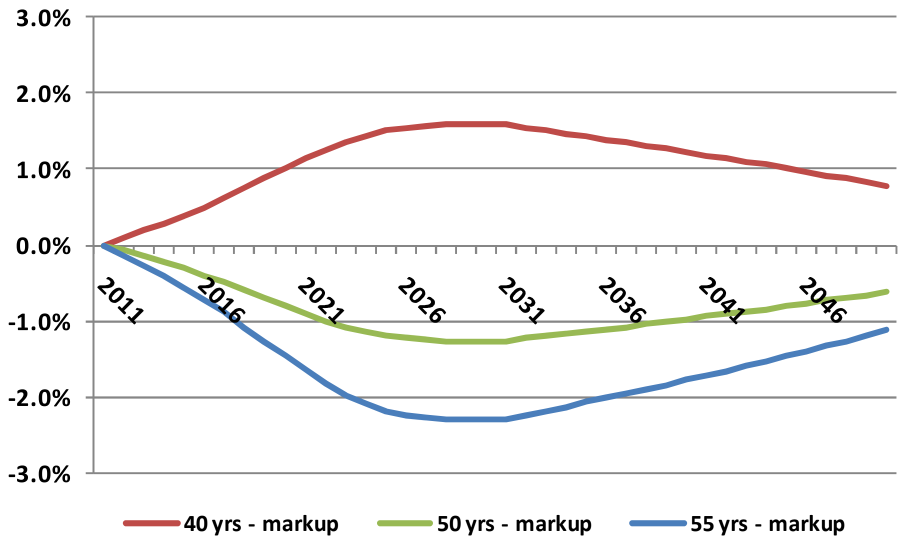


Figure F.47: Annual network gearing, by year, for each option

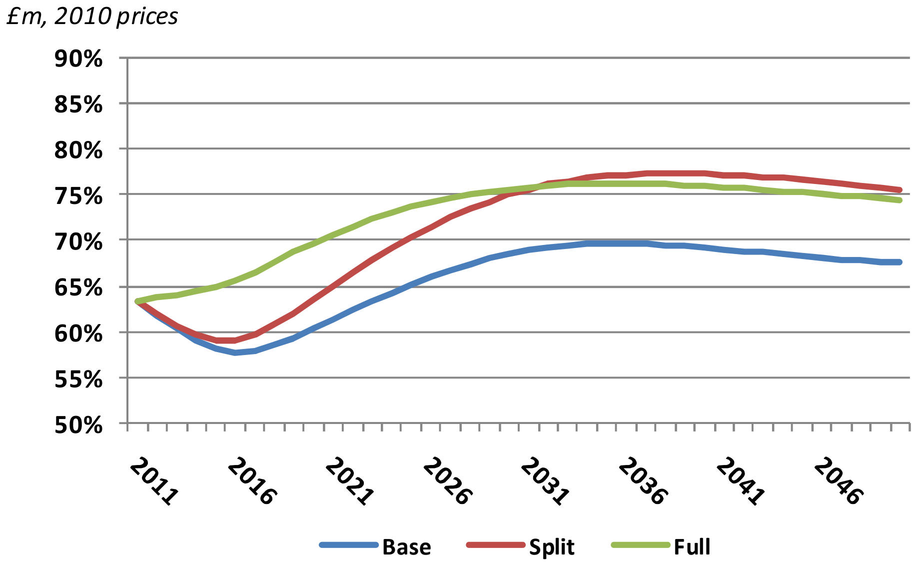


Figure F.48: Annual percentage difference (mark-up) in network gearing between scenarios, by year

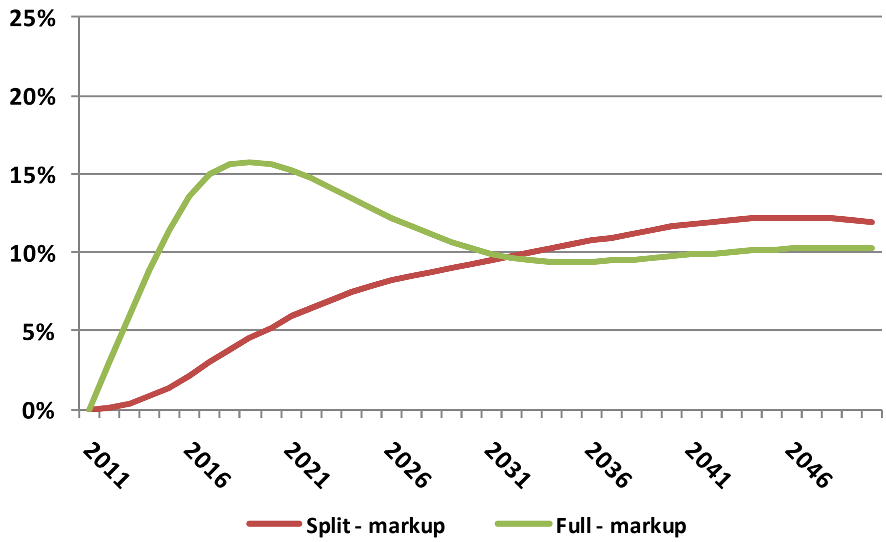


Figure F.49: Annual network gearing, by year, for each proposed asset life sensitivity

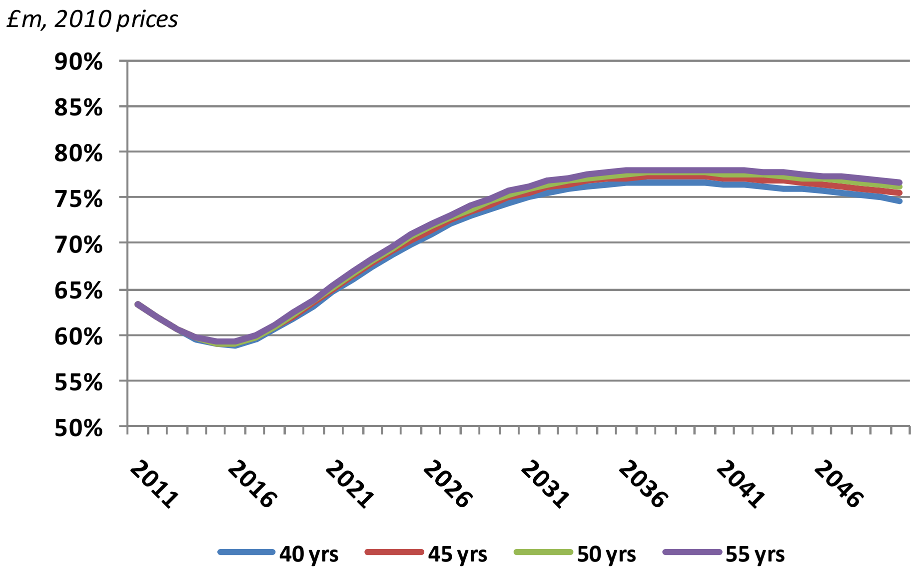
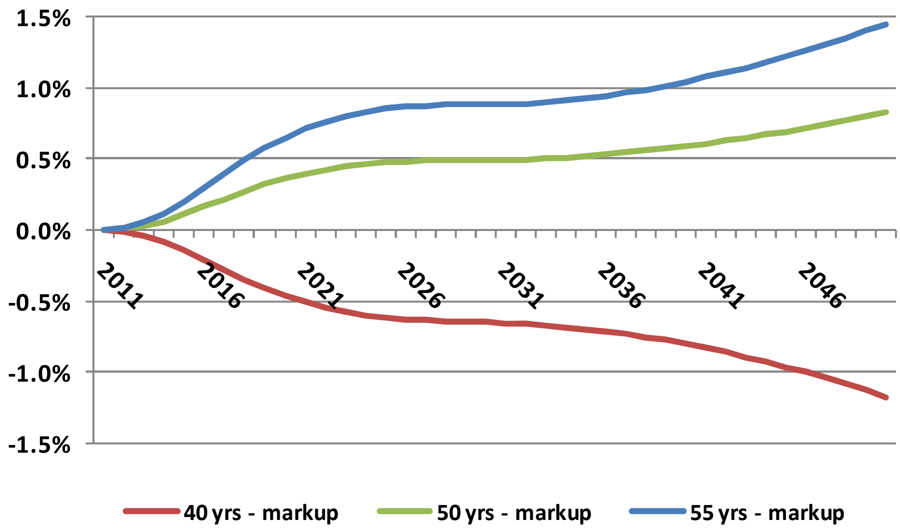


Figure F.50: Annual percentage difference (mark-up) in network gearing between sensitivities, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

We also show, for the "split" option, financial ratios for a 55 year asset life sensitivity, compared to the default 45 year asset life.

Table F.11: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	5.9	5.2 - 7.1	3.8	2.7 - 6.5	3.3	3 - 6.3
Funds from operations / net debt	21%	18% - 25%	13%	9% - 23%	11%	10% - 23%
Gearing (net debt / closing RAV)	66%	58% - 70%	71%	59% - 77%	73%	63% - 76%
Post-maintenance interest cover ratio	2.0	1.9 - 2.3	1.9	1.7 - 2.2	1.8	1.7 - 2.1

Table F.12: Financial ratios over the whole modelling period (2011-50), for 55 year asset life sensitivity

Financial ratios (2011-50)	Split - 45 years		Split - 55 years	
	Average	Range	Average	Range
Funds from operations / interest	3.8	2.7 - 6.5	3.6	2.5 - 6.5
Funds from operations / net debt	13%	9% - 23%	13%	9% - 23%
Gearing (net debt / closing RAV)	71%	59% - 77%	72%	59% - 78%
Post-maintenance interest cover ratio	1.9	1.7 - 2.2	1.9	1.7 - 2.2

Electricity Transmission Network - Case 1 - Green Transition

Depreciation

We now consider the implications of the different capex cases, treatment of new/ existing assets and asset life sensitivities for the electricity transmission network.

Total capex for this network is lower than for electricity distribution. While relative differences due to the "split" and "full" options are similar to those in case 1 in the short to medium term, the "full" option shows higher depreciation and revenue from around 2030 onwards than in "case 1".

Figure F.51: Annual asset depreciation, by year, for each option

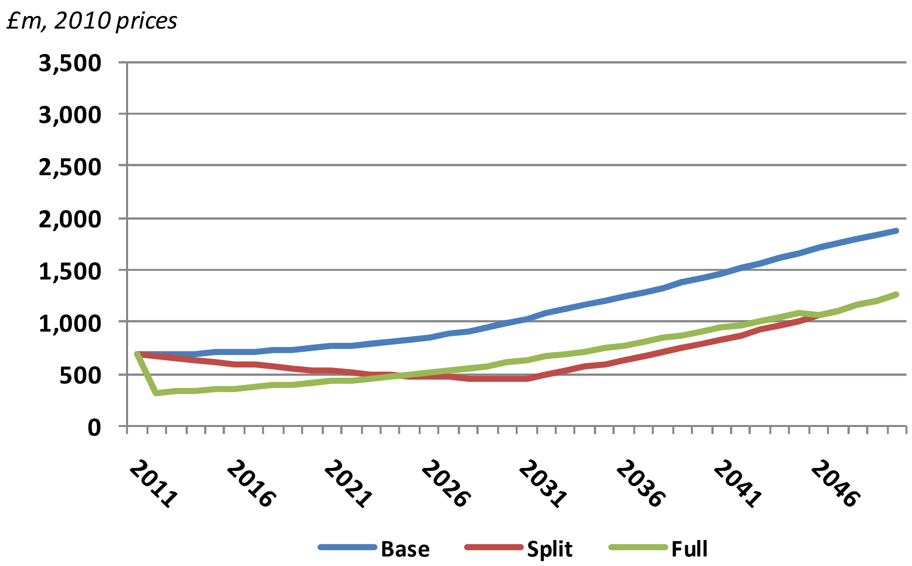


Figure F.52: Annual percentage difference (mark-up) in asset depreciation between scenarios, by year

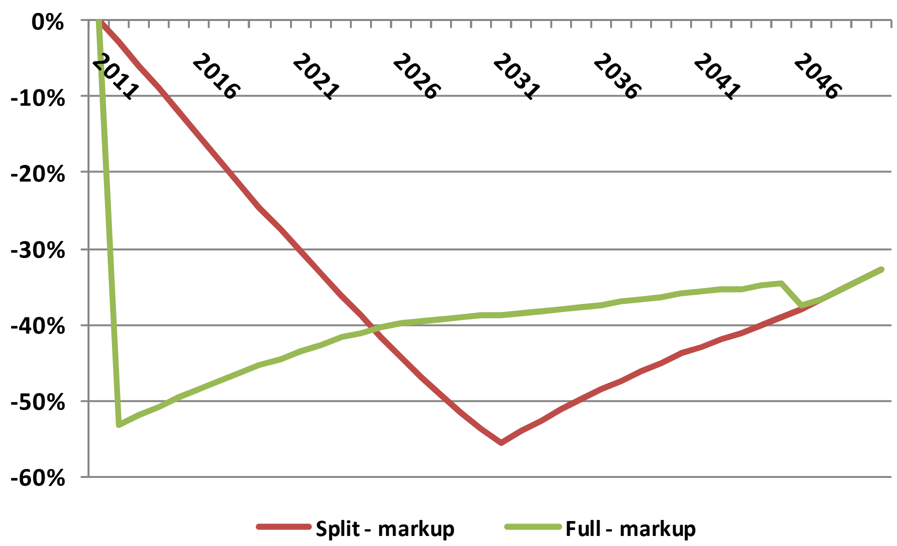


Figure F.53: Annual network revenue, by year, for each option

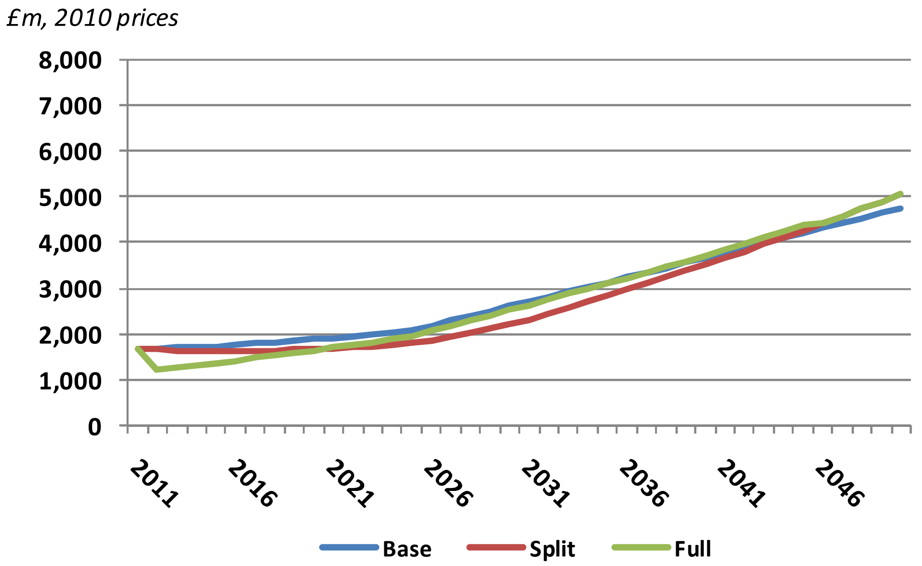


Figure F.54: Annual percentage difference (mark-up) in network revenue between options, by year

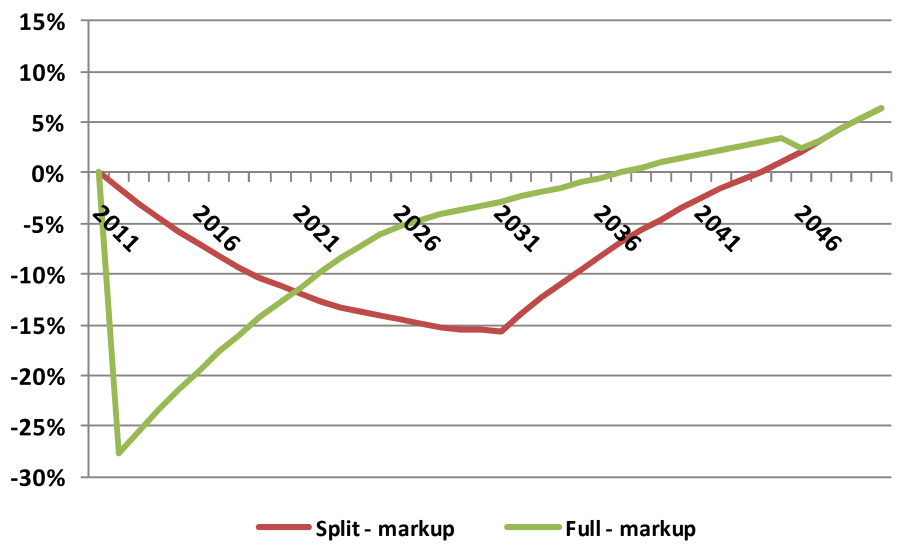


Figure F.55: Annual network gearing, by year, for each option

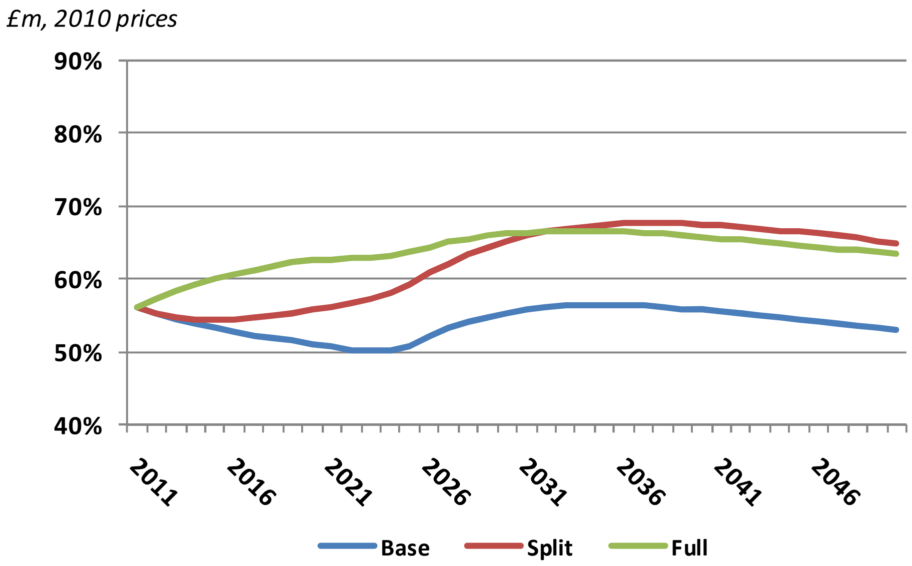
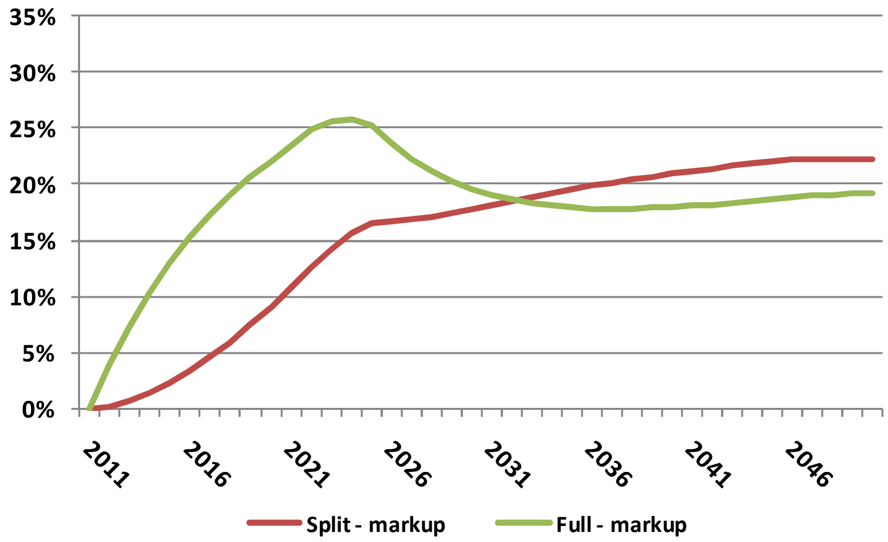


Figure F.56: Annual percentage difference (mark-up) in network gearing between options, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.13: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	6.9	6.4 - 7.5	4.2	3.2 - 7	3.7	3.4 - 7
Funds from operations / net debt	25%	23% - 28%	15%	11% - 26%	13%	12% - 26%
Gearing (net debt / closing RAV)	54%	50% - 56%	62%	54% - 68%	64%	56% - 67%
Post-maintenance interest cover ratio	2.5	2.4 - 2.7	2.2	2 - 2.5	2.2	2.1 - 2.4

Electricity Transmission Network - Case 1 - Dash for Energy

We now consider the "Dash for Energy" scenario, which has lower environmental ambition than the "Green Transition" scenario.

As the graphs below show, total capex is lower in this scenario, with corresponding impacts on depreciation, revenue and gearing compared to the "Green Transition" scenario. The relative impacts of the "split" and "full" options are the same for both capex cases.

Figure F.57: Annual asset depreciation, by year, for each option

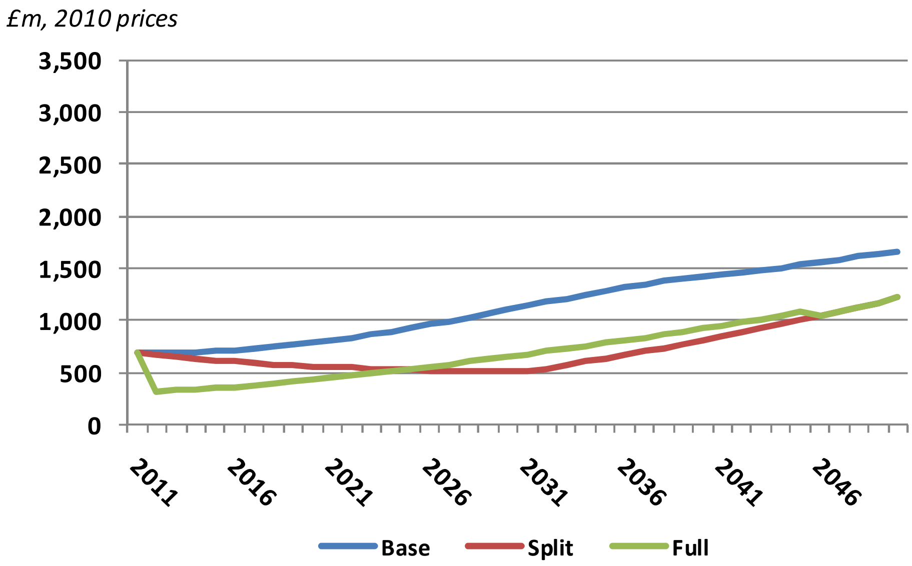


Figure F.58: Annual percentage difference (mark-up) in asset depreciation between options, by year

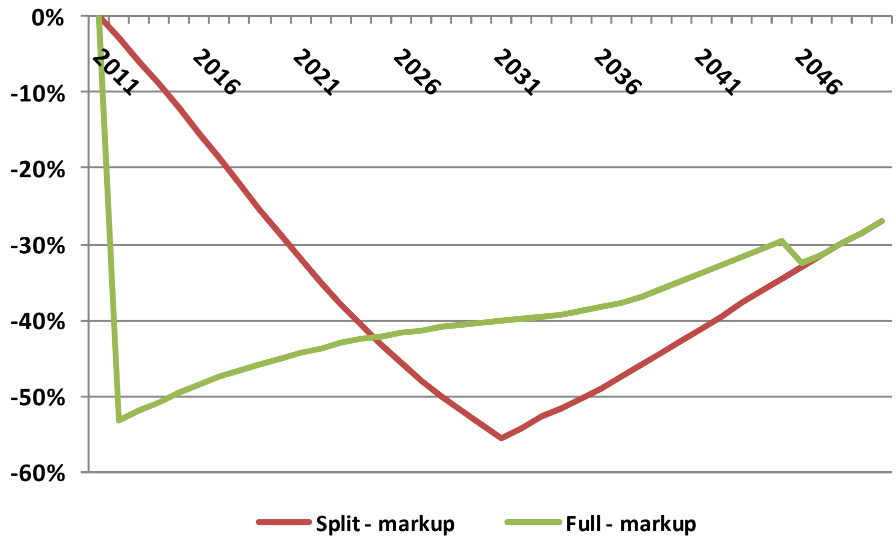


Figure F.59: Annual network revenue, by year, for each option

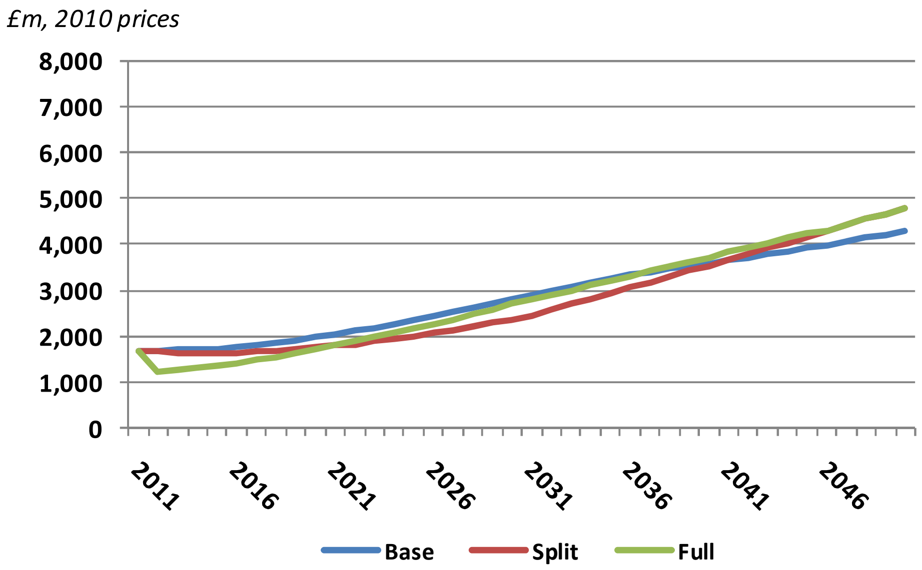


Figure F.60: Annual percentage difference (mark-up) in network revenue between options, by year

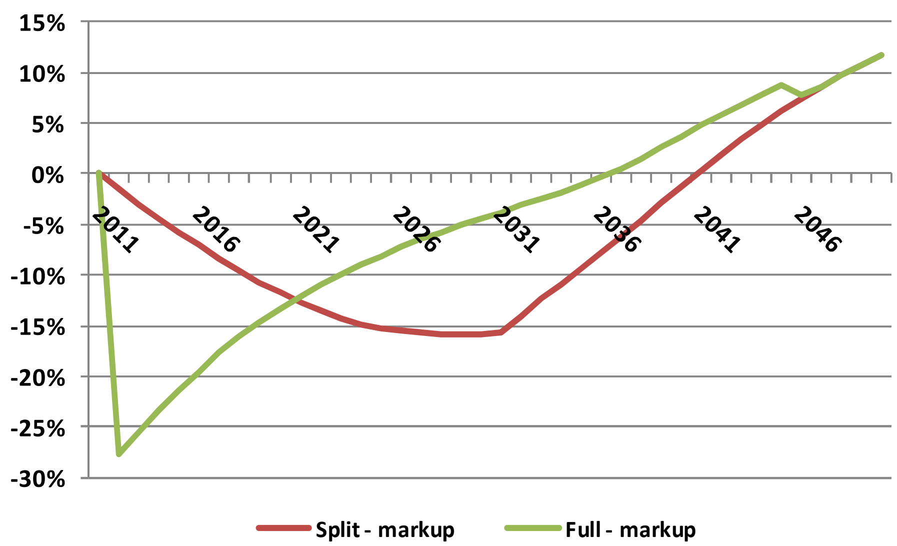


Figure F.61: Annual network gearing, by year, for each option

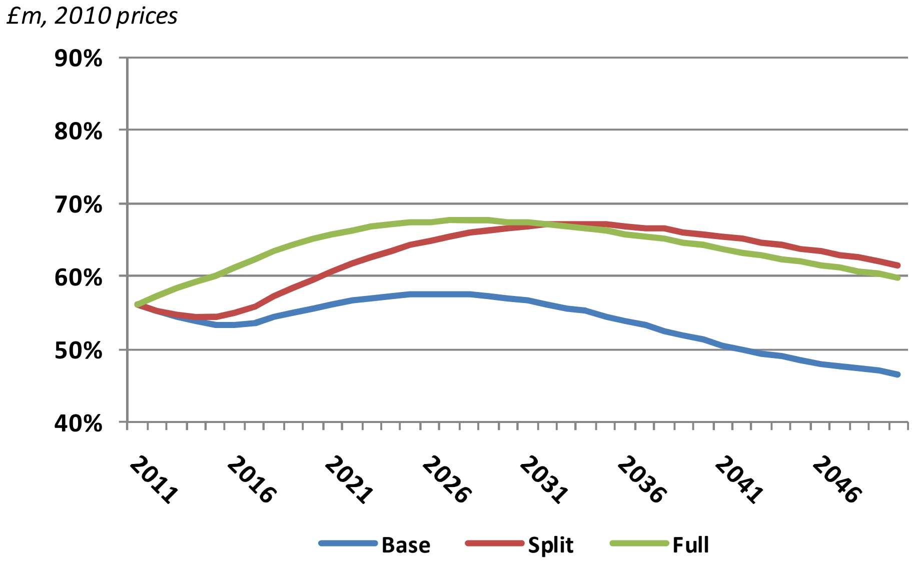
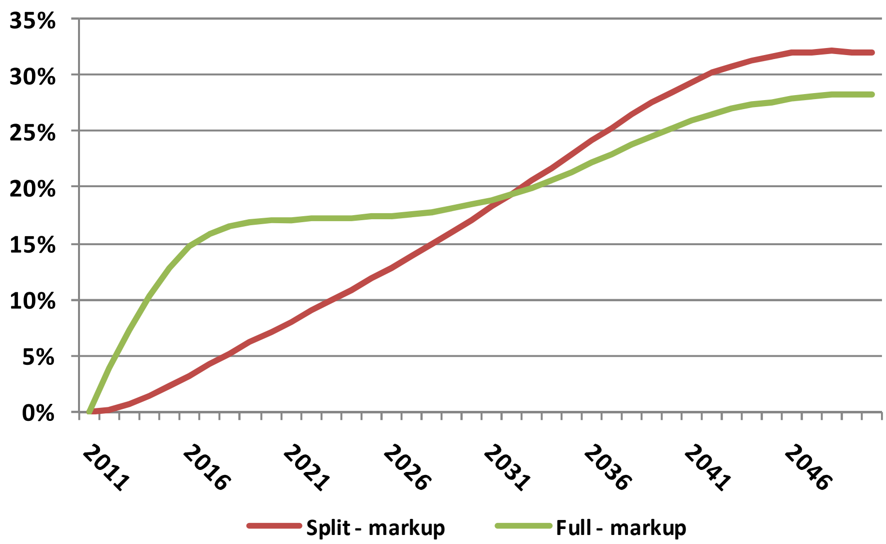


Figure F.62: Annual percentage difference (mark-up) in network gearing between options, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.14: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	7.1	6.3 - 8.1	4.2	3.1 - 7	3.7	3.3 - 7
Funds from operations / net debt	26%	23% - 30%	15%	11% - 26%	13%	12% - 26%
Gearing (net debt / closing RAV)	54%	47% - 57%	63%	54% - 67%	64%	56% - 68%
Post-maintenance interest cover ratio	2.6	2.4 - 2.9	2.2	2 - 2.5	2.2	2 - 2.4

Electricity Transmission Network - Case 2 - Green Transition

Depreciation

We now show the impact of revised capex assumptions. Capex is higher than in case 1, reflecting the restrictions assumed on overhead lines (OHL).

Figure F.63: Annual asset depreciation, by year, for each option

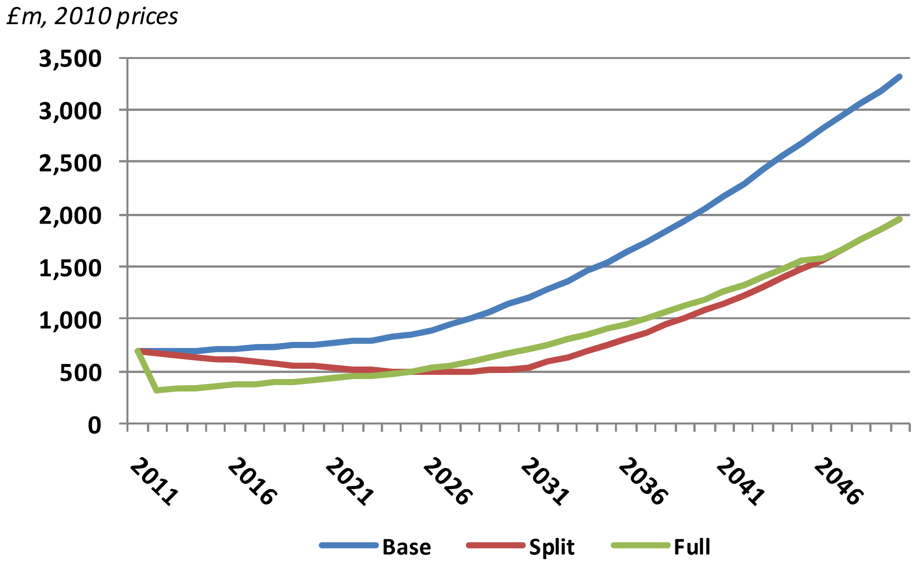


Figure F.64: Annual percentage difference (mark-up) in asset depreciation between options, by year

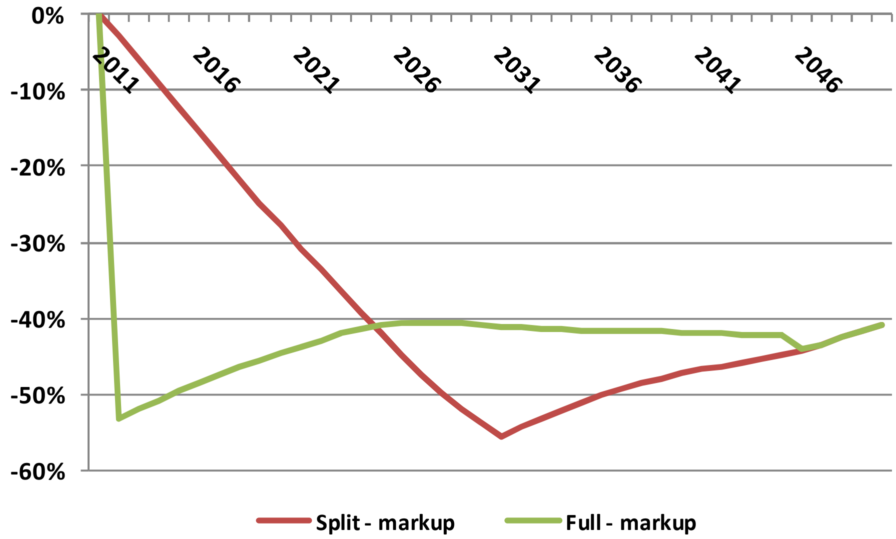


Figure F.65: Annual network revenue, by year, for each option

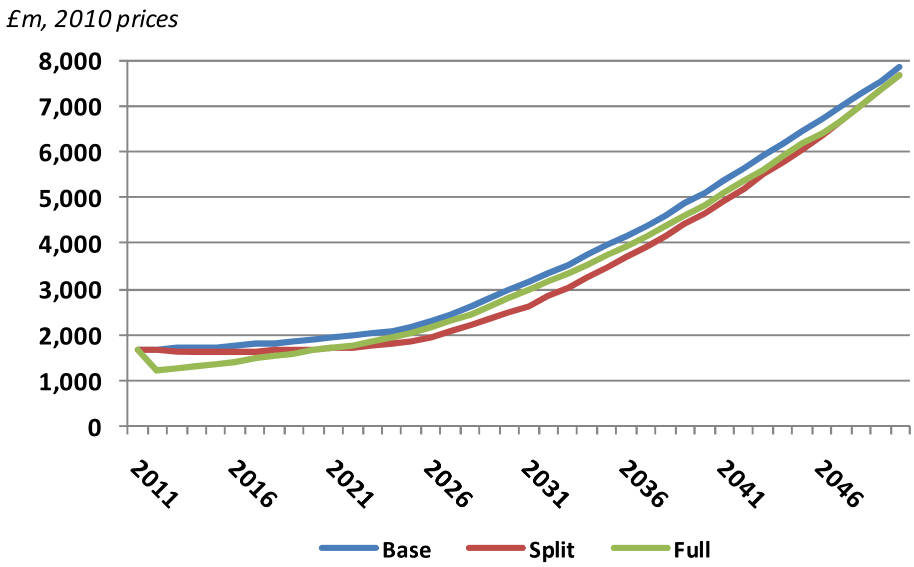


Figure F.66: Annual percentage difference (mark-up) in network revenue between options, by year

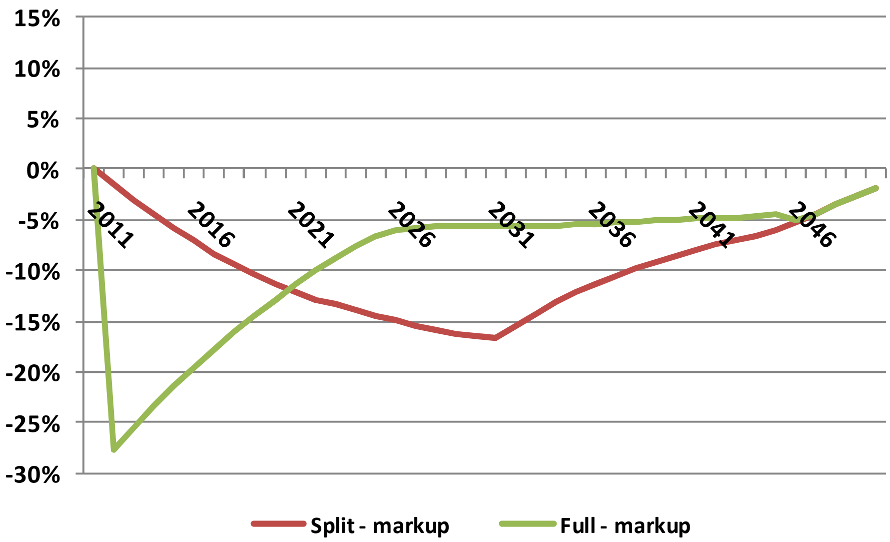


Figure F.67: Annual network gearing, by year, for each option

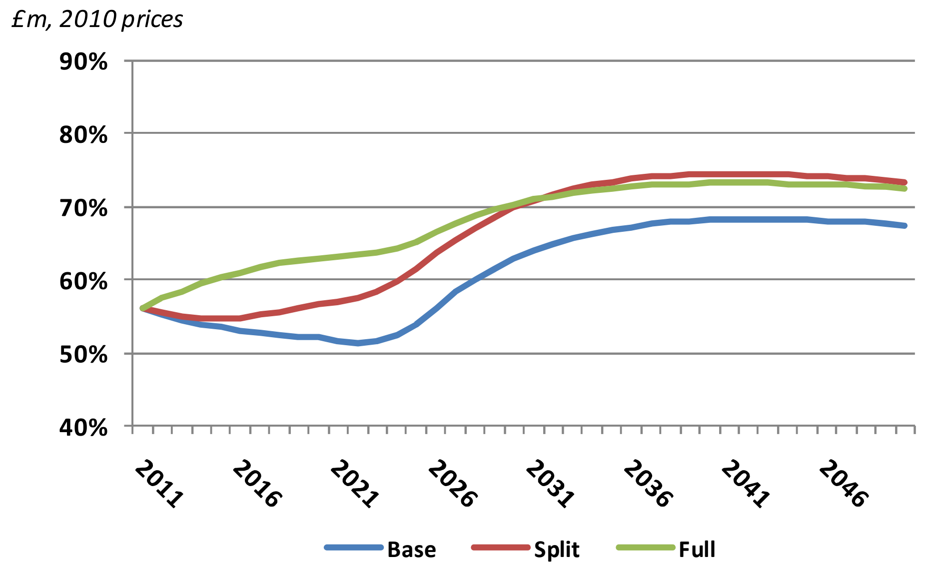
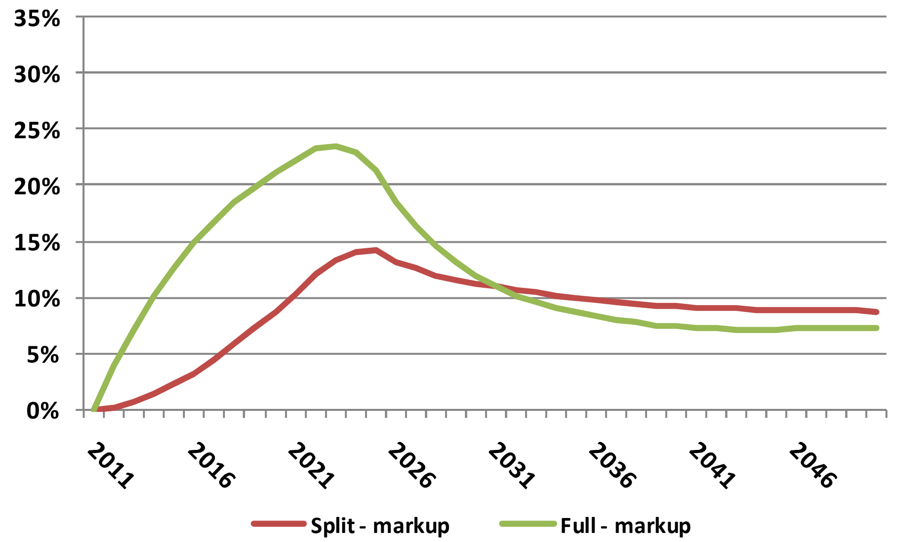


Figure F.68: Annual percentage difference (mark-up) in network gearing between options, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.15: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	6.1	5.1 - 7.3	4.0	2.9 - 7	3.5	3 - 7
Funds from operations / net debt	22%	18% - 27%	14%	10% - 26%	12%	11% - 26%
Gearing (net debt / closing RAV)	61%	51% - 68%	66%	55% - 74%	68%	56% - 73%
Post-maintenance interest cover ratio	2.3	2 - 2.7	2.1	1.8 - 2.5	2.0	1.9 - 2.4

Electricity Transmission Network - Case 2 - Dash for Energy

Depreciation

Capex in the “Dash for Energy” scenario is slightly lower than that for the “Green Transition” scenario; this is reflected in the impacts on depreciation, net revenue and gearing. The “full” option leads to, relatively, slightly higher depreciation with this capex case.

Figure F.69: Annual asset depreciation, by year, for each option

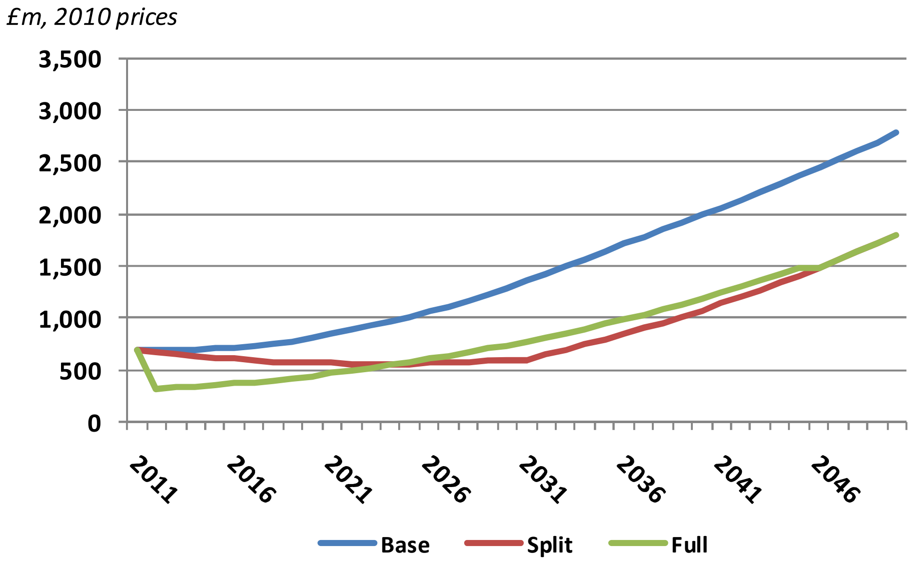


Figure F.70: Annual percentage difference (mark-up) in asset depreciation between options, by year

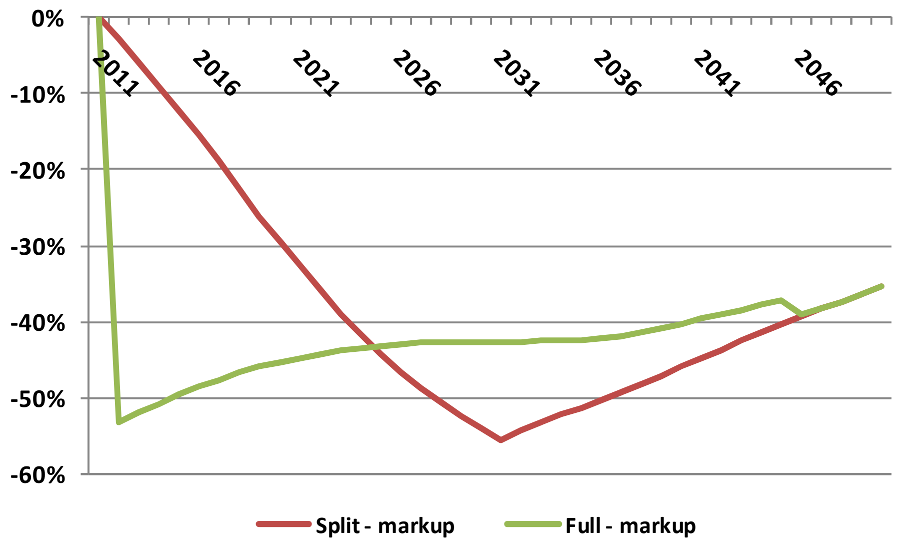


Figure F.71: Annual network revenue, by year, for each option

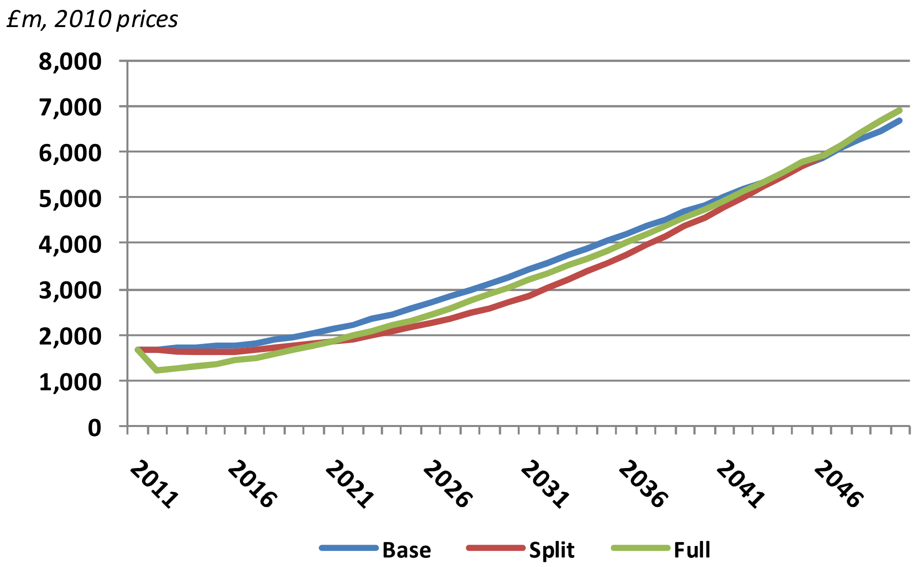


Figure F.72: Annual percentage difference (mark-up) in network revenue between options, by year

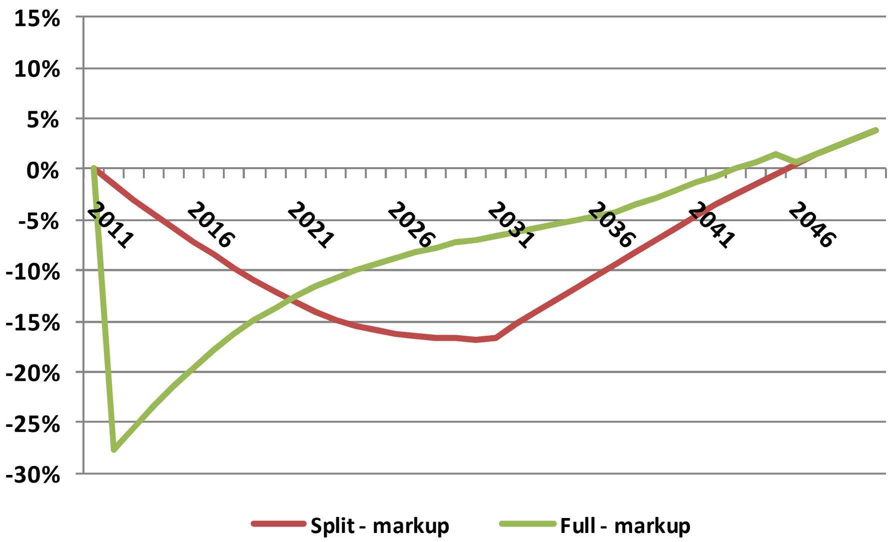


Figure F.73: Annual network gearing, by year, for each option

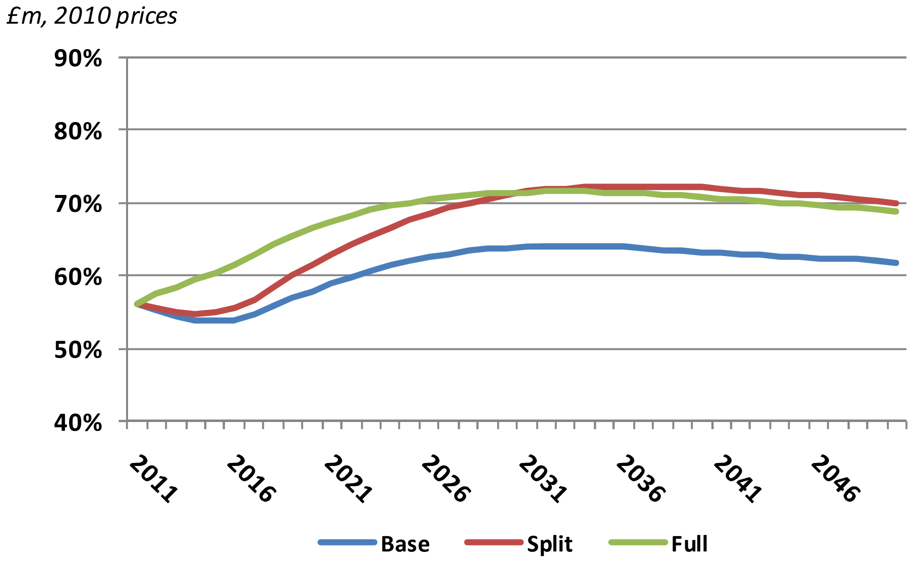
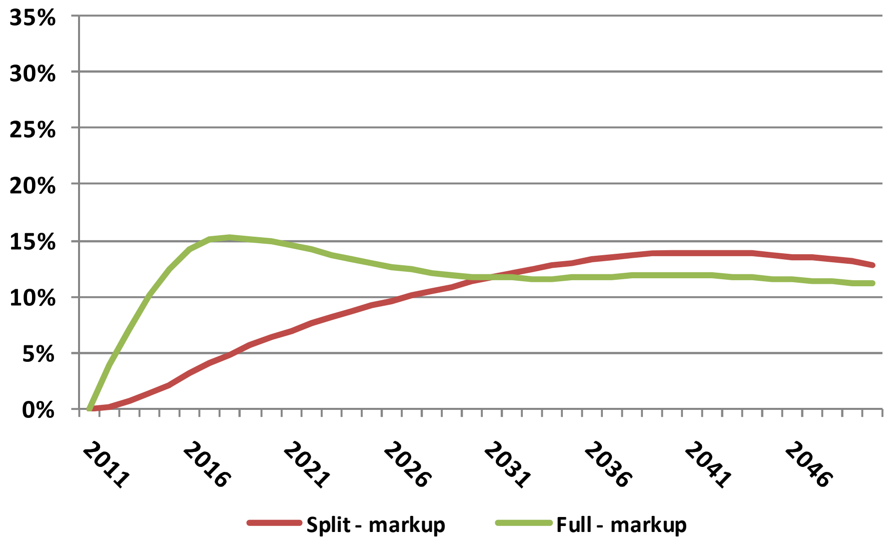


Figure F.74: Annual percentage difference (mark-up) in network gearing between options, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below, and for all three asset life options. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.16: Financial ratios over the whole modelling period (2011-50), by option

Financial ratios (2011-50)	Base		Split		Full	
	Average	Range	Average	Range	Average	Range
Funds from operations / interest	6.1	5.5 - 7.2	3.9	2.9 - 7	3.5	3.1 - 7
Funds from operations / net debt	22%	20% - 26%	14%	10% - 26%	12%	11% - 26%
Gearing (net debt / closing RAV)	61%	54% - 64%	67%	55% - 72%	68%	56% - 71%
Post-maintenance interest cover ratio	2.3	2.1 - 2.6	2.1	1.9 - 2.5	2.0	1.9 - 2.4

Gas Distribution Network - Green Transition

We now present the results of our analysis of the gas distribution network in the "Green Transition" scenario. When we conducted this analysis for the electricity networks, we considered three asset life options: "base", "split" and "full", which looked at the implications of different asset lives for new and existing assets. For the gas networks, both Ofgem's current asset lives and the proposed asset lives are 45 years, so there is no difference between the asset life options for the gas networks. The graphs below therefore only show a single line. We have also not looked at the impact of varying the asset life between 40 and 55 years (but we have considered an asset life sensitivity, which is covered in the next section).

Figure F.75: Annual asset depreciation, by year

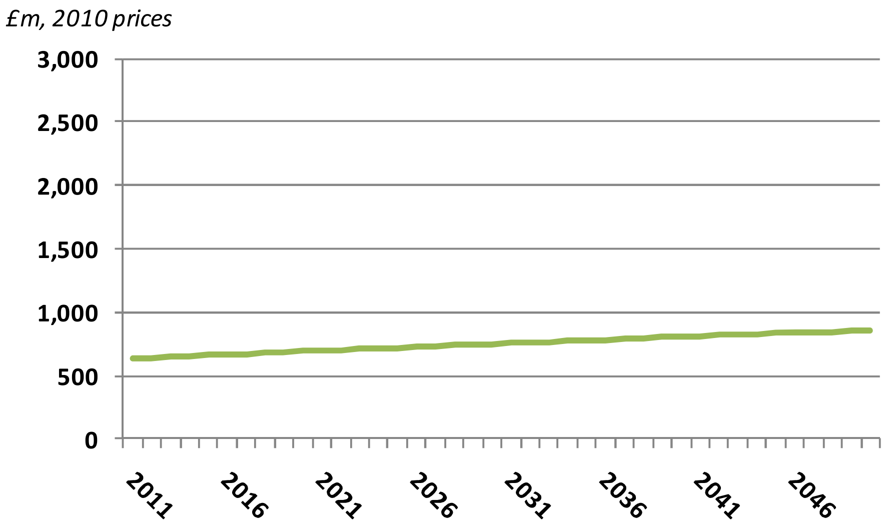


Figure F.76: Annual network revenue, by year

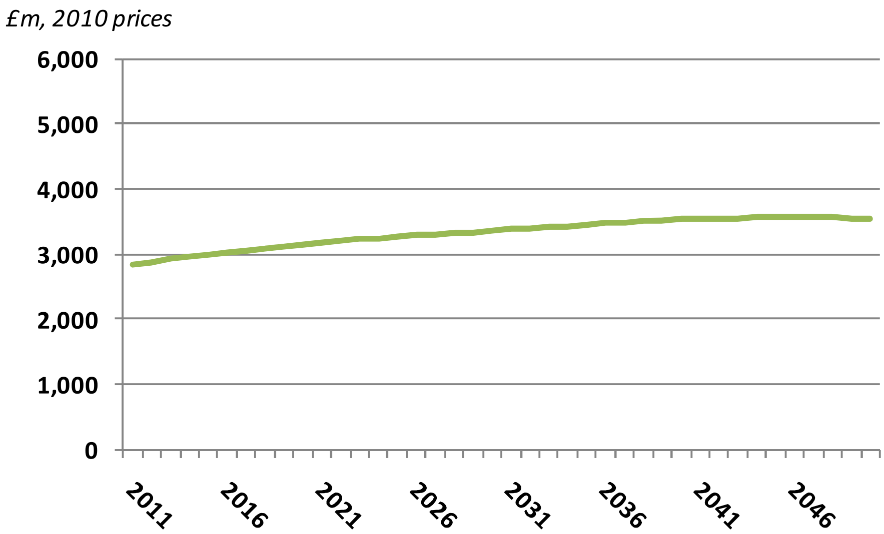
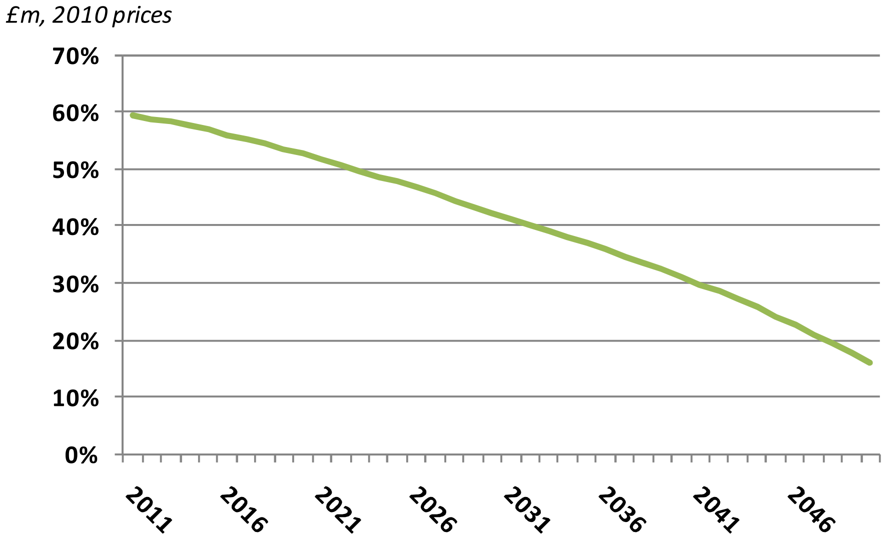


Figure F.77: Annual network gearing, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.17: Financial ratios over the whole modelling period (2011-50)

Financial ratios (2011-50)	Average	Range
Funds from operations / interest	7.1	4.4 - 15.7
Funds from operations / net debt	25%	15% - 58%
Gearing (net debt / closing RAV)	41%	16% - 59%
Post-maintenance interest cover ratio	3.9	2.4 - 8.4

Gas Distribution Network - Green Transition - 'Declining Network' variant

In this variant scenario, we assume that asset lives for all assets are set to 15 years in 2020, and that any assets built after that date are fully depreciated by 2035. The graphs below compare this 'variant' scenario to the figures from the previous section (based on 45 year asset lives); they expand on the summary graph used in section 7.

Figure F.78: Annual asset depreciation, by year, for 'variant' scenario versus '45 year' scenarios

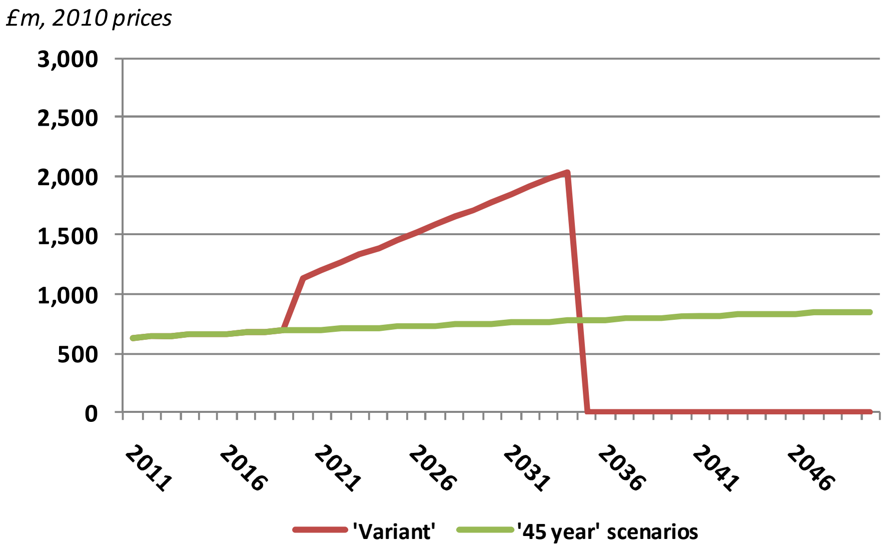


Figure F.79: Annual network revenue, by year, for 'variant' scenario versus '45 year' scenarios

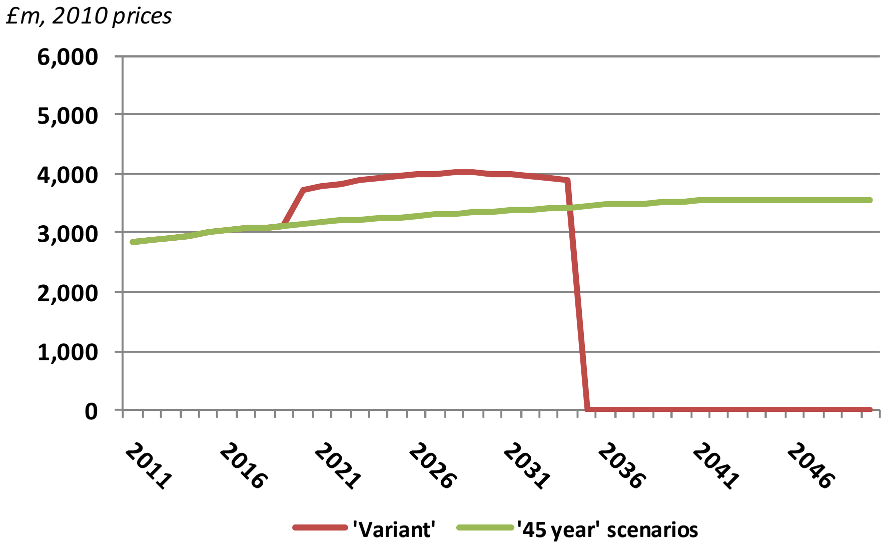
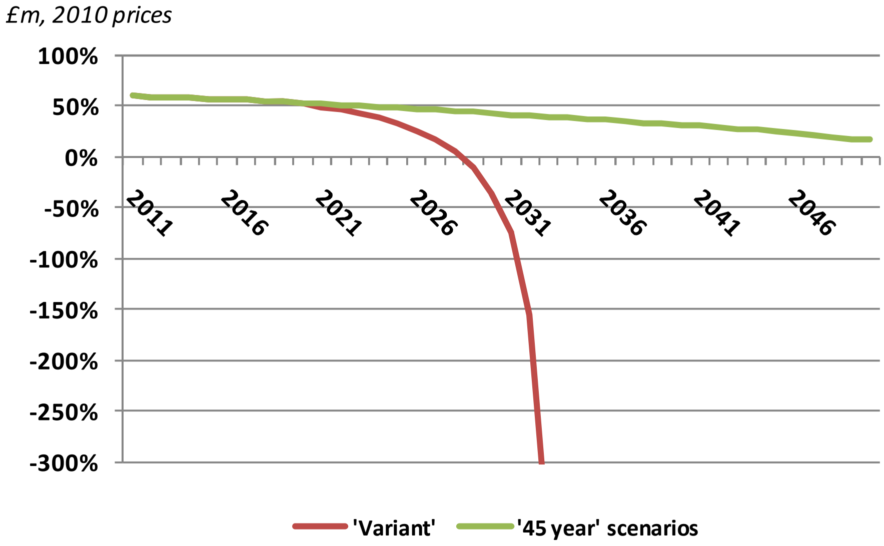


Figure F.80: Annual network gearing, by year, for 'variant' scenario versus '45 year' scenarios



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios. Both the (mean) average and the range are given below, with the 'variant' scenario and '45 year' scenario both shown. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

It should be noted that whist all other financial ratios in this collection of outputs are given for the period 2011-50, the ratios for the variant scenario are only shown for 2011-35 because the scenario assumes a zero value for the gas distribution network by 2035.

Table F.18: Financial ratios over the whole modelling period, for 'variant' scenario versus '45 year' scenarios

Financial ratios	'45 year' scenarios		'variant' scenario	
	Average	Range	Average	Range
Funds from operations / interest	7.1	4.4 - 15.7	-5.7	-249.9 - 51.9
Funds from operations / net debt	25%	15% - 58%	21%	-217% - 434%
Gearing (net debt / closing RAV)	41%	16% - 59%	n/a	n/a
Post-maintenance interest cover ratio	3.9	2.4 - 8.4	0.0	-54.1 - 12.8

Gas Distribution Network - Dash for Energy

Capex in the "Dash for Energy" scenario is slightly higher than in "Green Transition", reflecting the greater use of gas.

Figure F.81: Annual asset depreciation, by year

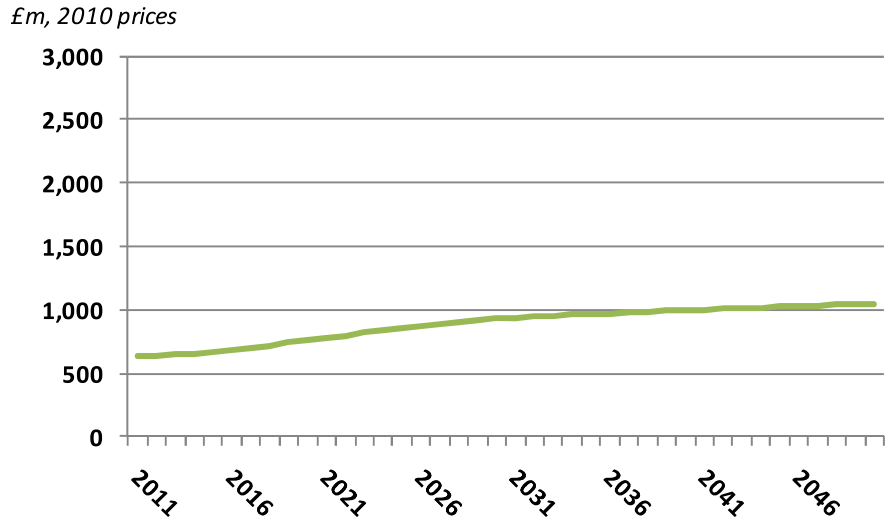


Figure F.82: Annual network revenue, by year

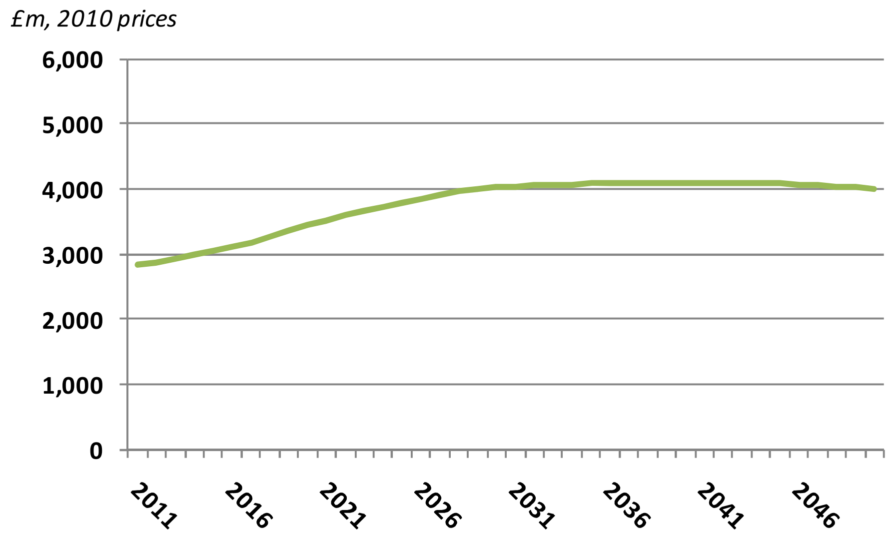
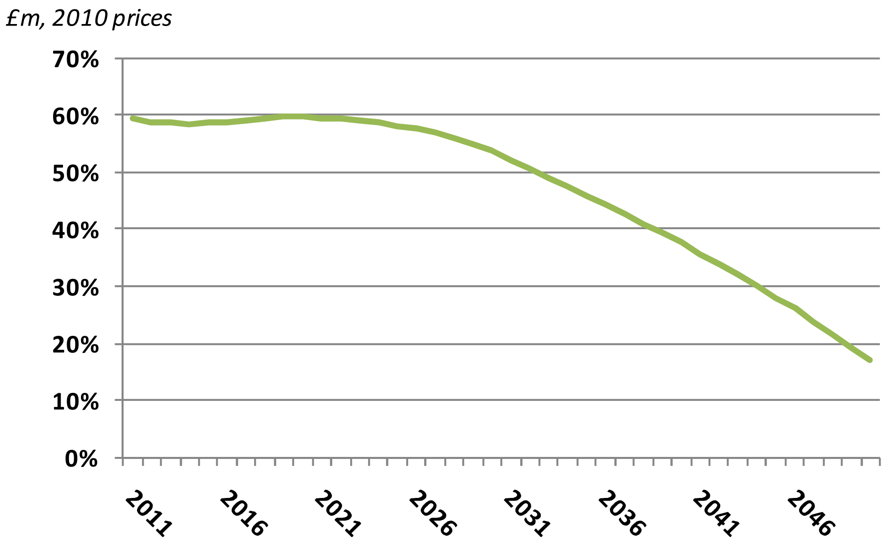


Figure F.83: Annual network gearing, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the period 2011-50. Both the (mean) average and the range are given below. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

Table F.19: Financial ratios over the whole modelling period (2011-50)

Financial ratios (2011-50)	Average	Range
Funds from operations / interest	6.0	4.2 - 14.9
Funds from operations / net debt	22%	14% - 56%
Gearing (net debt / closing RAV)	47%	17% - 60%
Post-maintenance interest cover ratio	3.3	2.4 - 7.8

Gas Distribution Network - Dash for Energy - 'Declining Network' variant

We re-run the variant scenario set out above (asset lives for all assets are set to 15 years in 2020, all assets fully depreciated by 2035) and compare this with a 45 year life for all assets.

As discussed in section 7, this variant could lead to significantly increased depreciation and hence costs to consumers, particularly when we consider that the number of consumers, and the consumption of each, is likely to be declining.

Figure F.84: Annual asset depreciation, by year, 'variant' scenario versus '45 year' scenarios

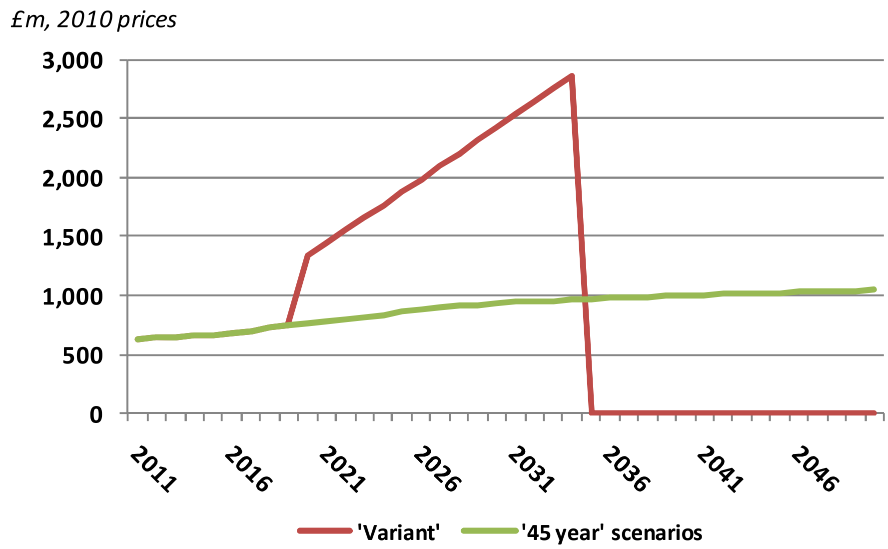


Figure F.85: Annual network revenue, by year, for 'variant' scenario versus '45 year' scenarios

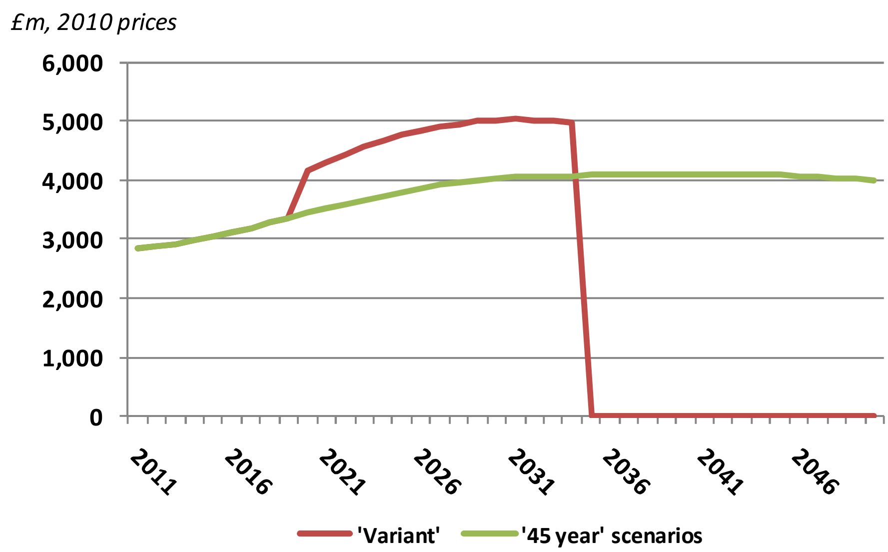
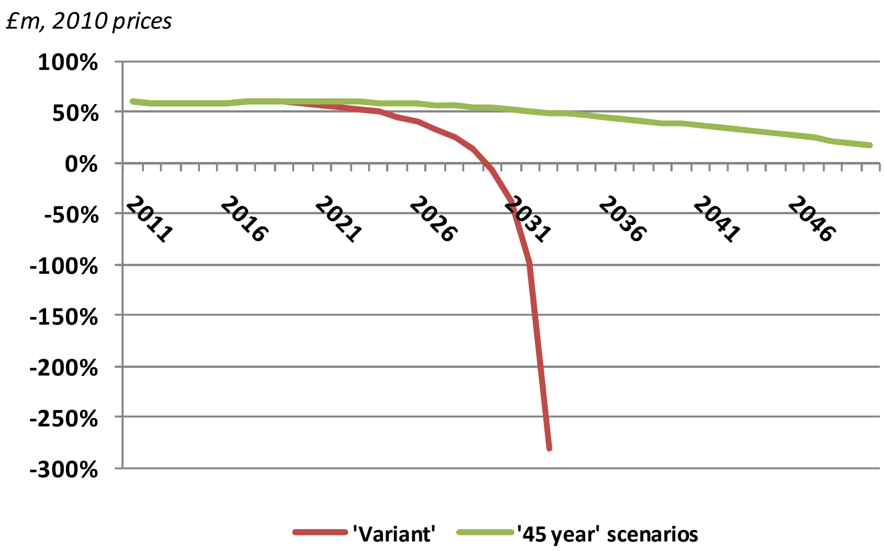


Figure F.86: Annual network gearing, by year, for 'variant' scenario versus '45 year' scenarios[36]



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios. Both the (mean) average and the range are given below, for both the 'variant' and '45 year' asset life scenarios. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

It should be noted that whist all other financial ratios in this collection of outputs are given for the period 2011-50, the ratios for the variant scenario are only shown for 2011-35 because the scenario assumes a total decline in the gas distribution network by 2035.

Table F.20: Financial ratios over the whole modelling period, for 'variant' scenario versus '45 year' scenario

Financial ratios	'45 year' scenarios		'variant' scenario	
	Average	Range	Average	Range
Funds from operations / interest	6.0	4.2 - 14.9	11.0	-47.7 - 203.1
Funds from operations / net debt	22%	14% - 56%	0%	-463% - 200%
Gearing (net debt / closing RAV)	47%	17% - 60%	n/a	n/a
Post-maintenance interest cover ratio	3.3	2.4 - 7.8	3.4	-7.1 - 37.5

[36] Under the variant scenario the RAV goes to zero in 2035, so gearing would become infinite. Therefore the 'variant' line in the graph below only goes up to 2034.

Gas Transmission Network - Green Transition

As for gas distribution, both existing and proposed asset lives are 45 years.

Levels of investment in this scenario are low.

Figure F.87: Annual asset depreciation, by year

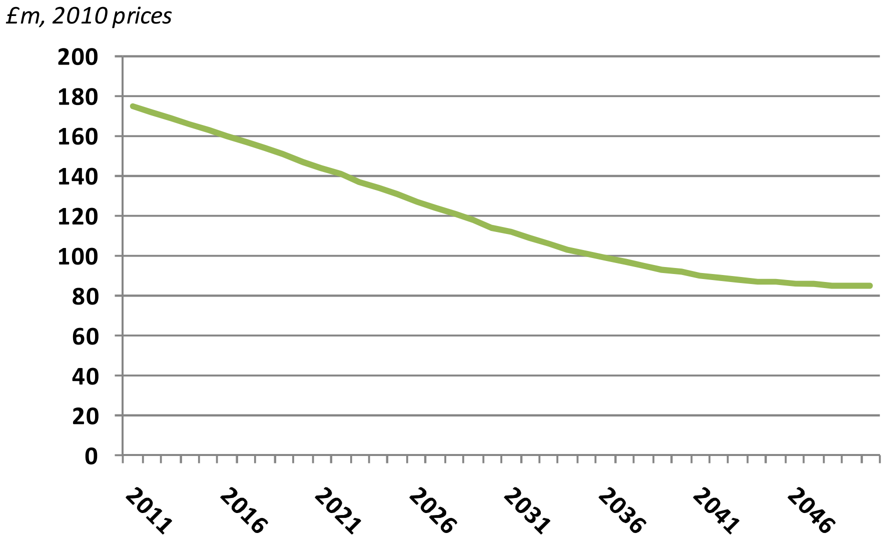


Figure F.88: Annual network revenue, by year

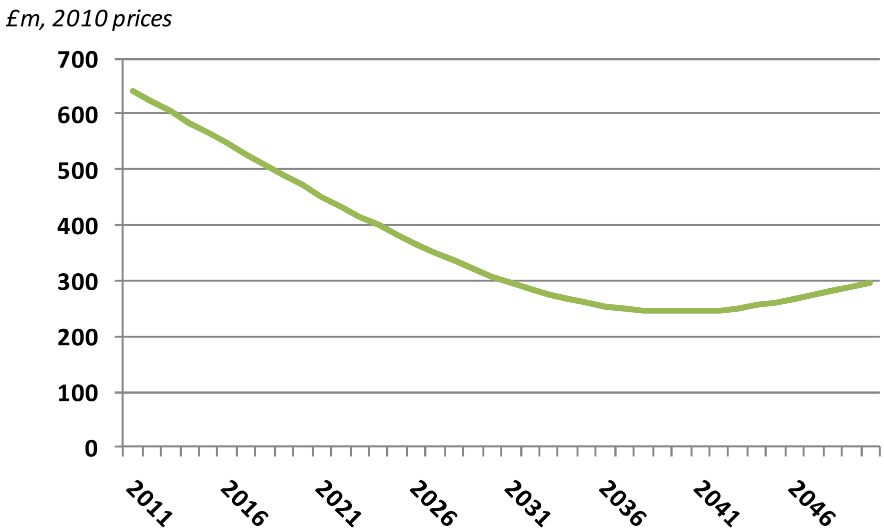
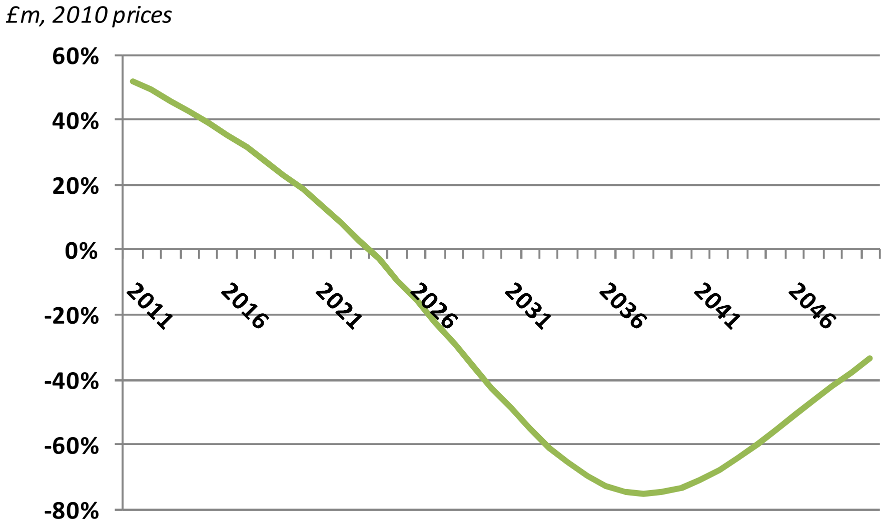


Figure F.89: Annual network gearing, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the modelling period. Both the (mean) average and the range are given below. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

In the figure below, gearing figures are shown for the entire modelling period. However, the other three financial ratios are not applicable from 2024 onwards because net debt (and therefore interest as well) becomes negative. So these ratios are shown for the period 2011-23 only.

Table F.21: Financial ratios over selected portions of the modelling period

Financial ratios	Average	Range
Funds from operations / interest	13.3	4.8 - 52
Funds from operations / net debt	71%	19% - 401%
Gearing (net debt / closing RAV)	-24%	-75% - 52%
Post-maintenance interest cover ratio	6.5	2.6 - 24.7

Gas Transmission Network - Dash for Energy

Capex is slightly higher in the "Dash for Energy" scenario, reflecting the increased use of gas in that scenario. However, gearing is still very low particularly post 2025.

Figure F.90: Annual asset depreciation, by year

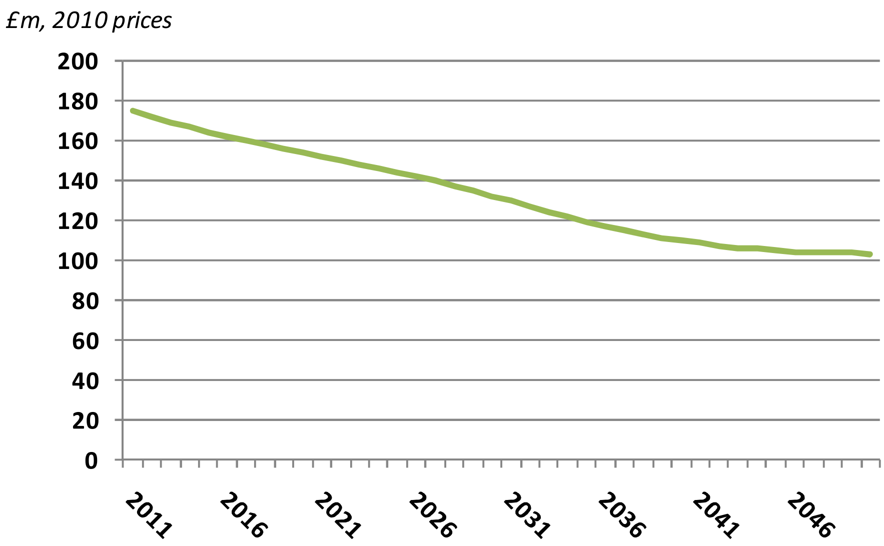


Figure F.91: Annual network revenue, by year

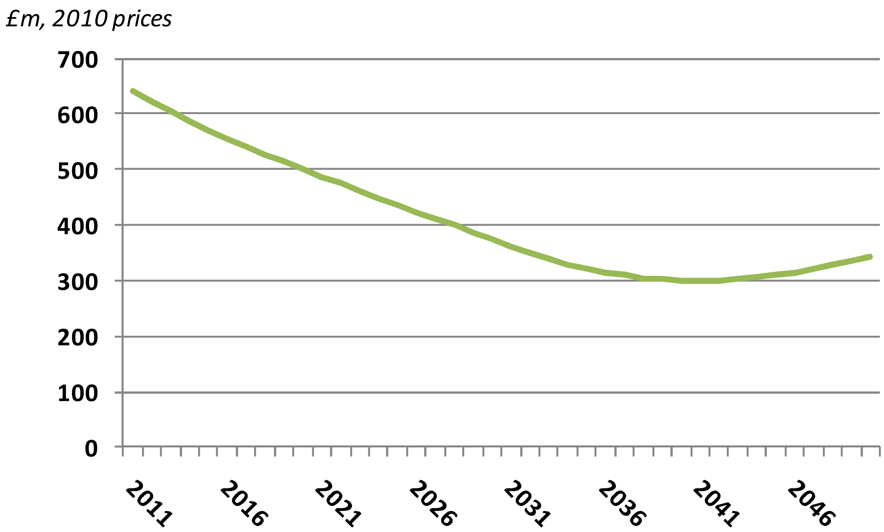
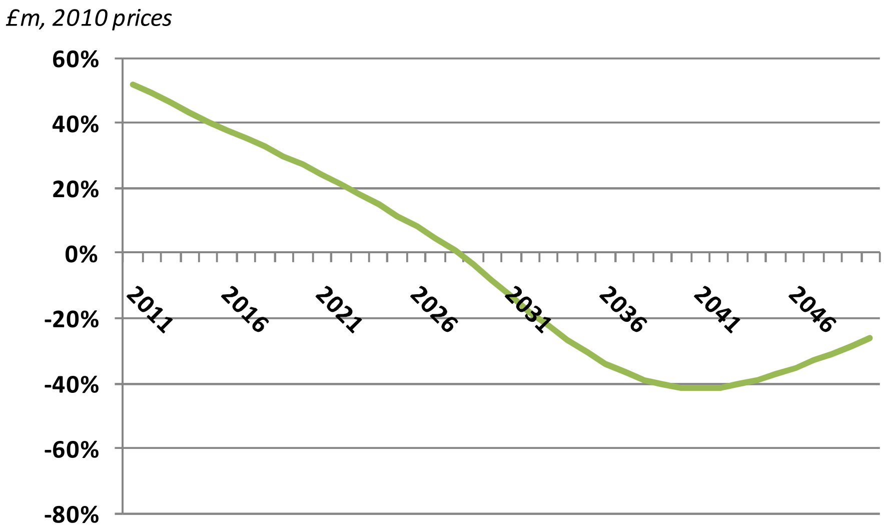


Figure F.92: Annual network gearing, by year



Financial Ratios

The model tests the financeability of the (sum of) network operators, by calculating certain financial ratios over the modelling period. Both the (mean) average and the range are given below. These averages and ranges can be compared against whatever benchmarks levels are deemed to be appropriate.

In the figure below, gearing figures are shown for the entire modelling period. However, the other three financial ratios are not applicable from 2029 onwards because net debt (and therefore interest as well) becomes negative. So these ratios are shown for the period 2011-28 only.

Table F.22: Financial ratios over selected portions of the modelling period

Financial ratios	Average	Range
Funds from operations / interest	18.1	4.8 - 110.7
Funds from operations / net debt	149%	19% - 1757%
Gearing (net debt / closing RAV)	-4%	-42% - 52%
Post-maintenance interest cover ratio	9.0	2.6 - 54.2

Impact on average household bill

This section shows the impact of changes in the average household energy bill over time, with changes over five year periods in the figures below. To calculate this, the model works out the increase in total network costs, and assumes this change will be passed through directly to consumers, increasing their total costs by that amount. This amount is divided between the number of UK households[37] to calculate the change in the average household bill[38]. We show:

- impact on electricity bill (based on changes in the total costs of electricity distribution and transmission networks)
- impact on gas bill (based on changes in the total costs of gas distribution and transmission networks)
- impact on combined bill (all four networks)

The impact of each asset life/ depreciation option is shown on a separate graph (a 45 year asset life is assumed unless otherwise noted). What can be seen is that the final 2050 impact is virtually identical for all options, but that the profile of impacts is slightly different, with "split" showing lower impacts in the short term, and "full" showing lower still impacts in the short term.

Since bill impacts can be positive or negative, the graphs show both increases and decreases to the bill. For each five-year period, decreases are shown in the left hand column (labelled with a 'down' arrow) while increases are shown in the right hand column (labelled with an 'up' arrow).

As the graphs below show, the increase in electricity bills is greater than the decrease in gas bills, so the combined bill rises under all options. The difference between impacts across all options is though of the order of 5%, so it is difficult to conclude that any one option is clearly more expensive than another[39].

The "Green Transition" scenario has a slightly higher impact than "Dash for Energy", reflecting the higher electricity network capex in that scenario.

In all cases, the impact of the electricity distribution network dominates.

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[37] 26.7m in 2010, source: ONS

[38] Source: 2010 average household energy bill £1,194 sourced from Uswitch press release (4th October 2010). The proportion of this total figure which relates to electricity versus gas was sourced from Ofgem's "*Updated household energy bills factsheet 81*" (6th August 2009).

[39] This analysis focuses on the relative bill impacts of future investment in the electricity and gas networks. To avoid complicating the picture, it does not consider the extent to which domestic gas demand shifts to electricity (because for example of an increase in electric heating). It also does not consider whether all those currently connected to the gas network will still be connected in future.

Electricity - Case 1 - Green Transition

Figure F.93: Change in the average household electricity bill - 'Base' option

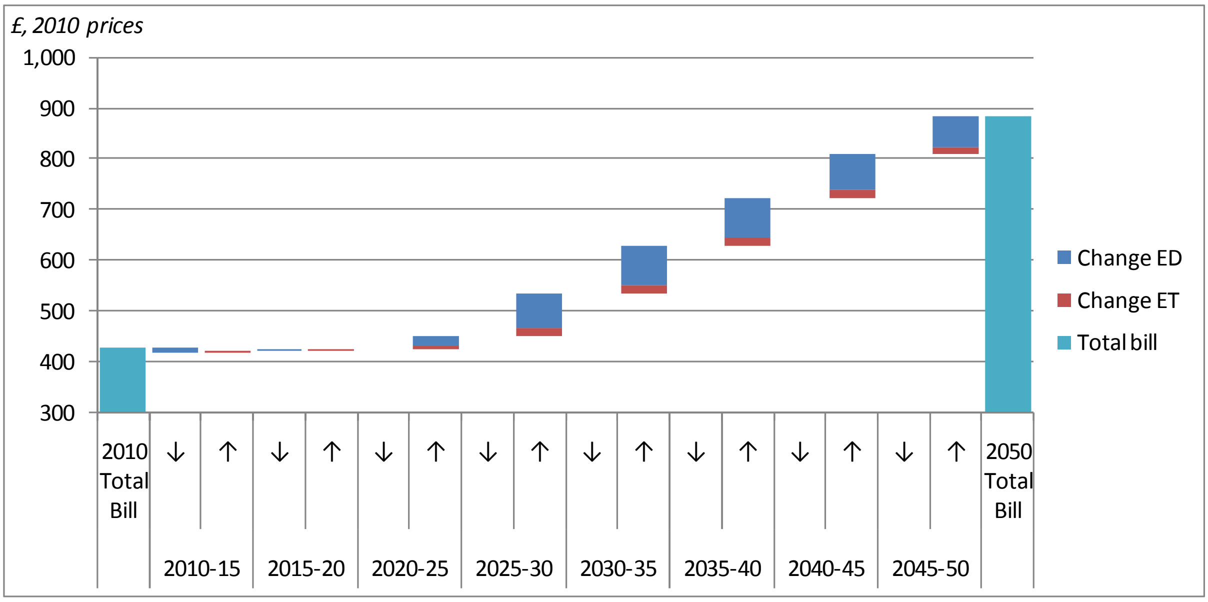


Figure F.94: Change in the average household electricity bill - 'Split' option

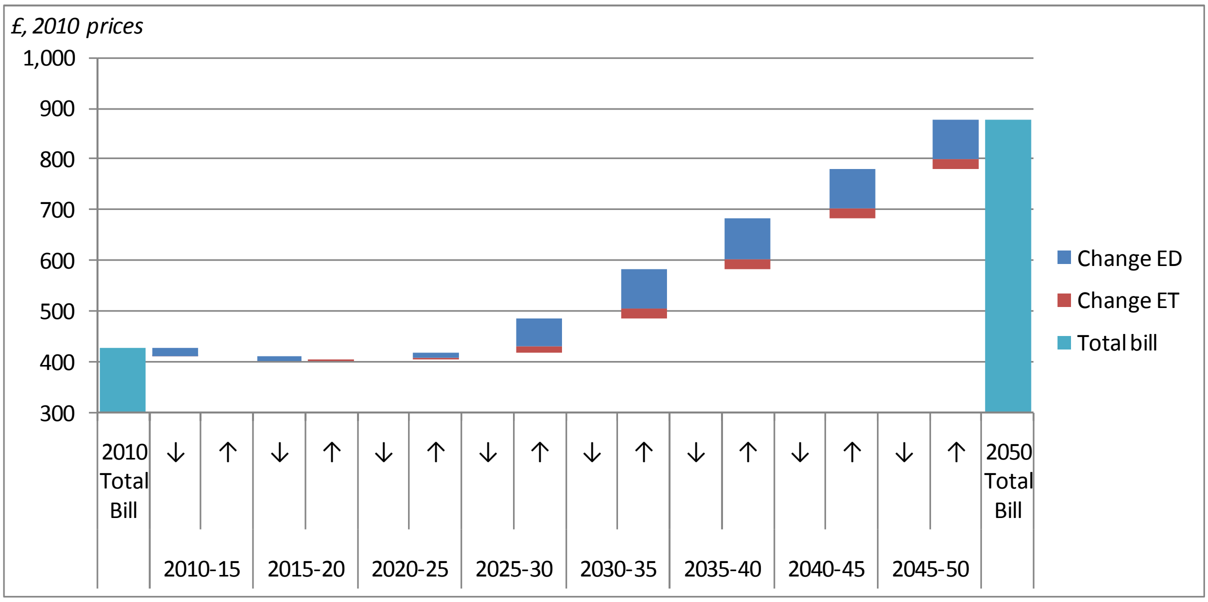
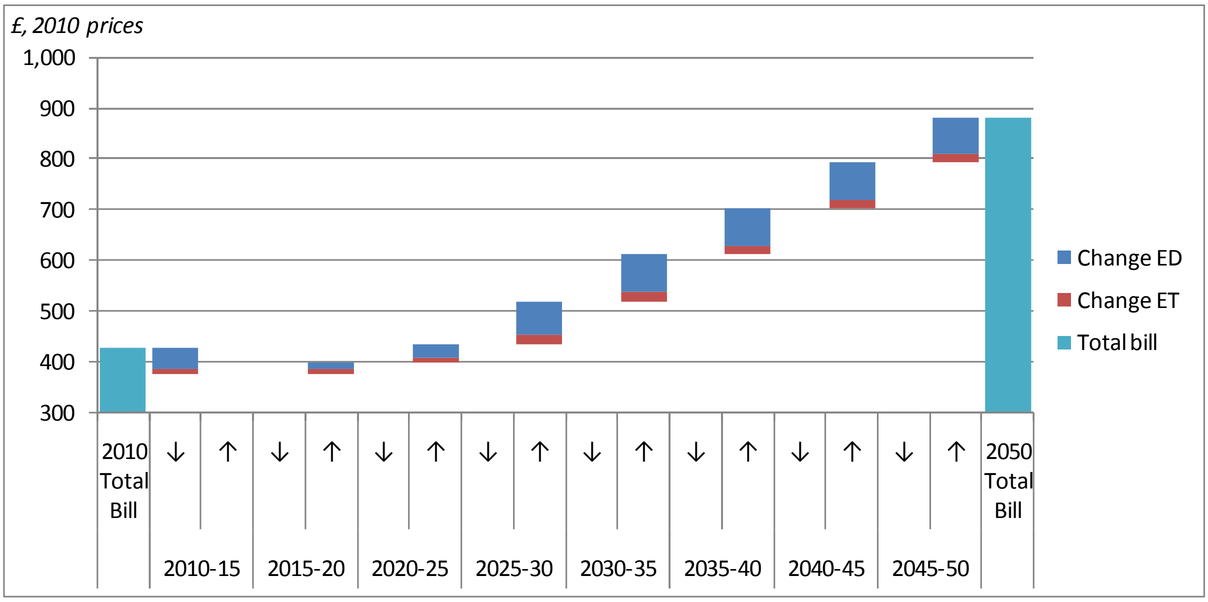


Figure F.95: Change in the average household electricity bill - 'Full' option



Electricity - Case 1 - Dash for Energy

This section shows the same charts as the previous one, but for the "Dash for Energy" scenario rather than "Green Transition". We also include a chart showing the impact of changing the asset life from 45 to 55 years for new assets only. As can be seen, the impact is negligible.

Figure F.96: Change in the average household electricity bill - 'Base' option

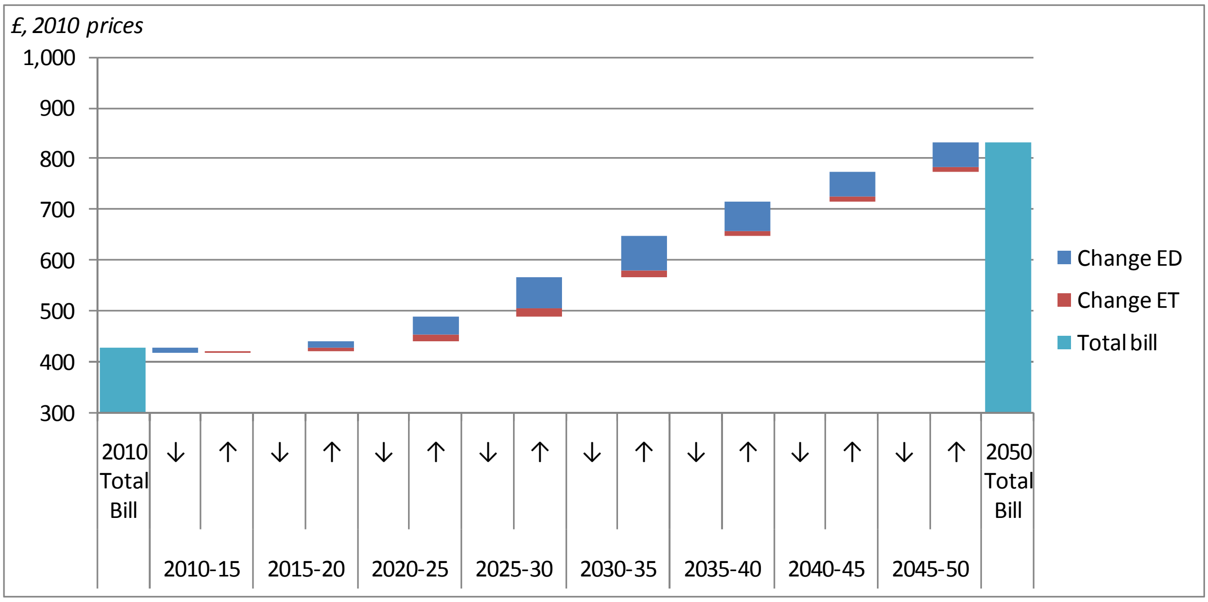


Figure F.97: Change in the average household electricity bill - 'Split' option

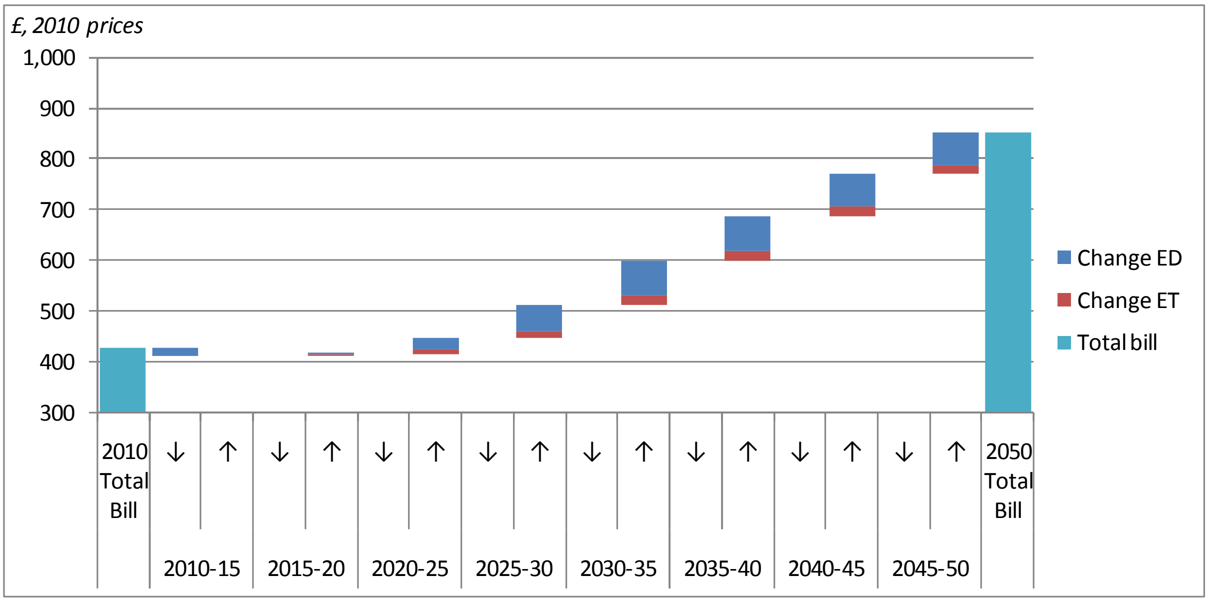


Figure F.98: Change in the average household electricity bill - 'Split' option, 55 year asset life for new assets

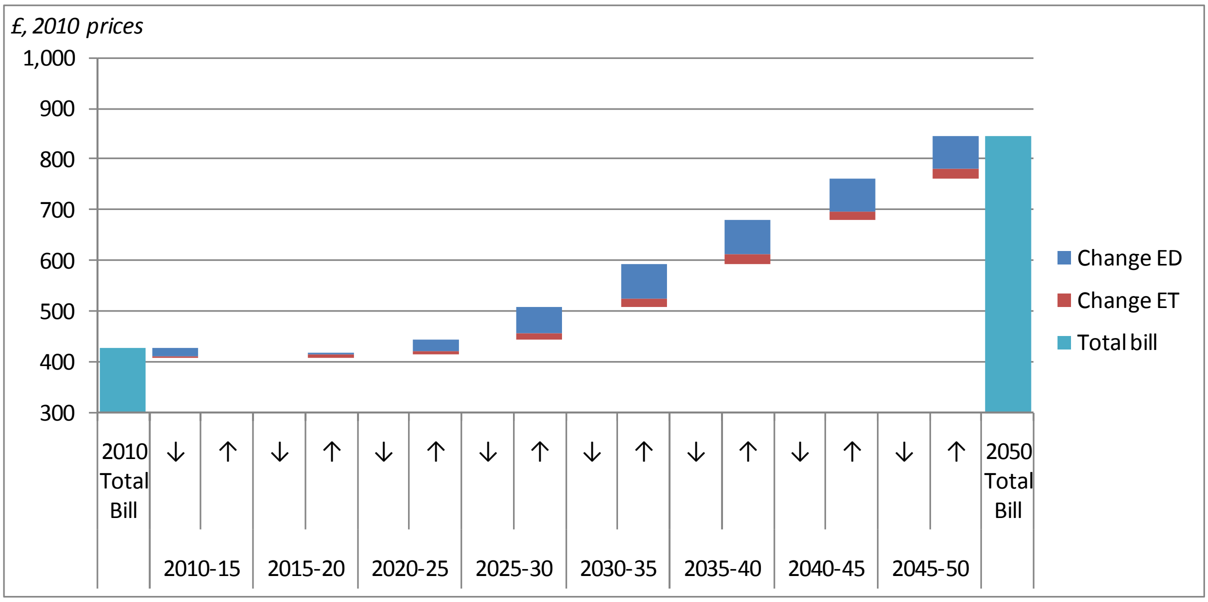
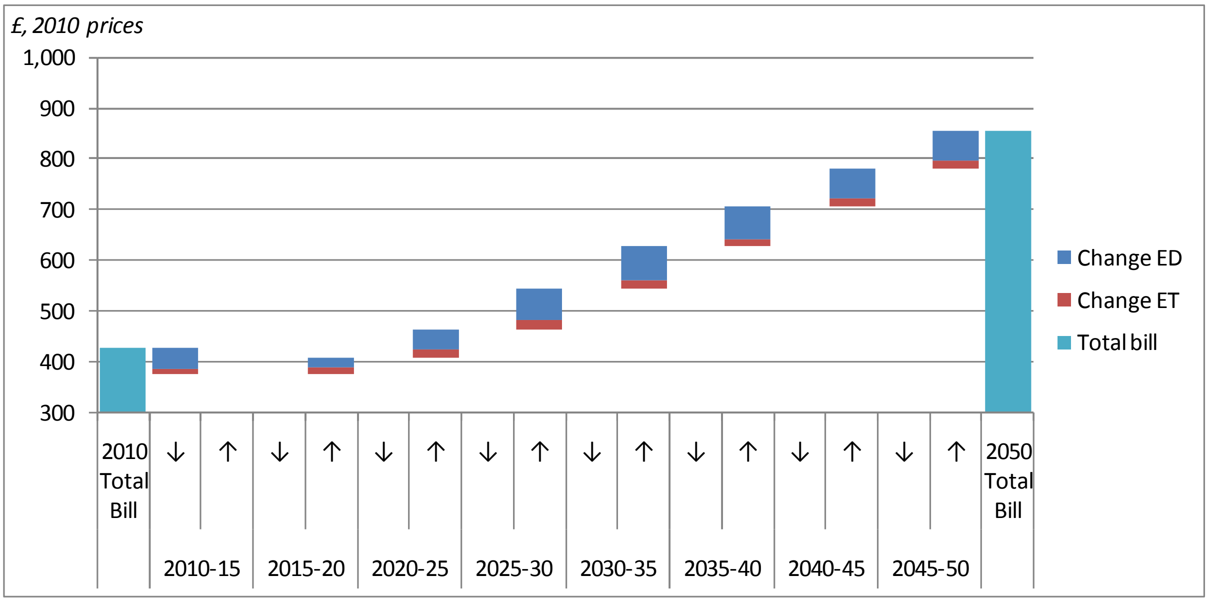


Figure F.99: Change in the average household electricity bill - 'Full' option



Electricity - Case 2 - Green Transition

We present here the impact on household bills of using "case 2" for electricity network investment. As described earlier, this case includes relatively lower capex for the distribution network, and relatively higher capex for the transmission network, to reflect a move away from overhead lines. The total bill impact is similar in both cases, but as expected the impact from the transmission network is higher in "case 2". We present the results for the three depreciation options ("base", "split" and "full"). Asset lives are as now in the "base" option, as now for existing and 45 years for new in the "split" option and 45 years for all assets in the "full" option. We also show a sensitivity for the "split" option where new assets have a life of 55 years.

The relative impacts are similar to those with "case 1" capex.

Figure F.100: Change in the average household electricity bill - 'Base' option

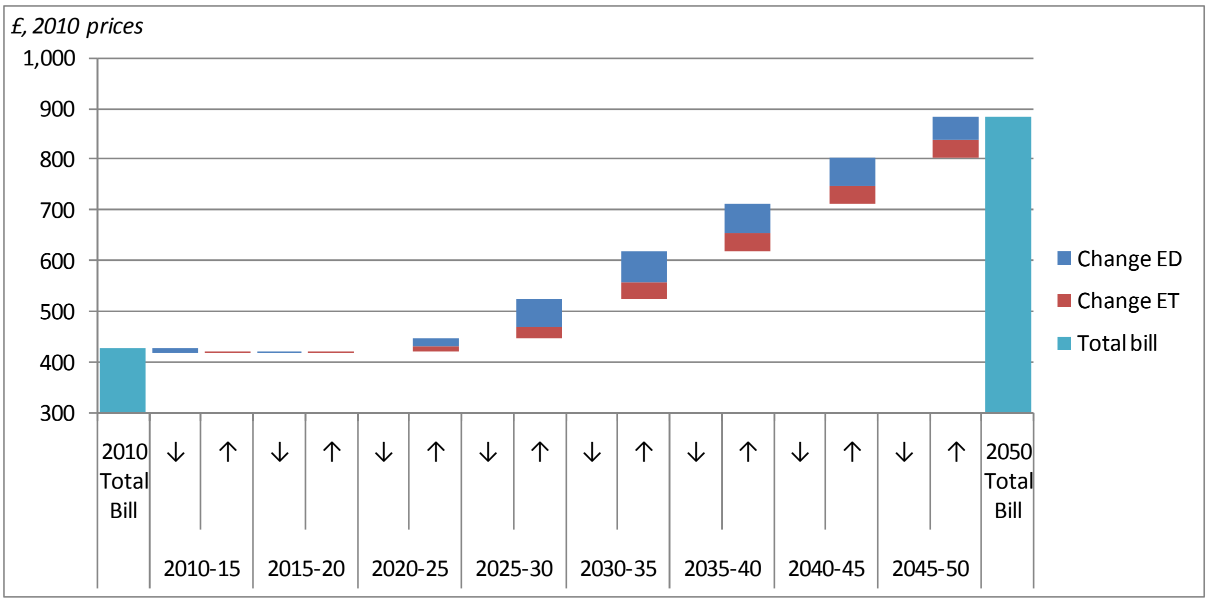


Figure F.101: Change in the average household electricity bill - 'Split' option

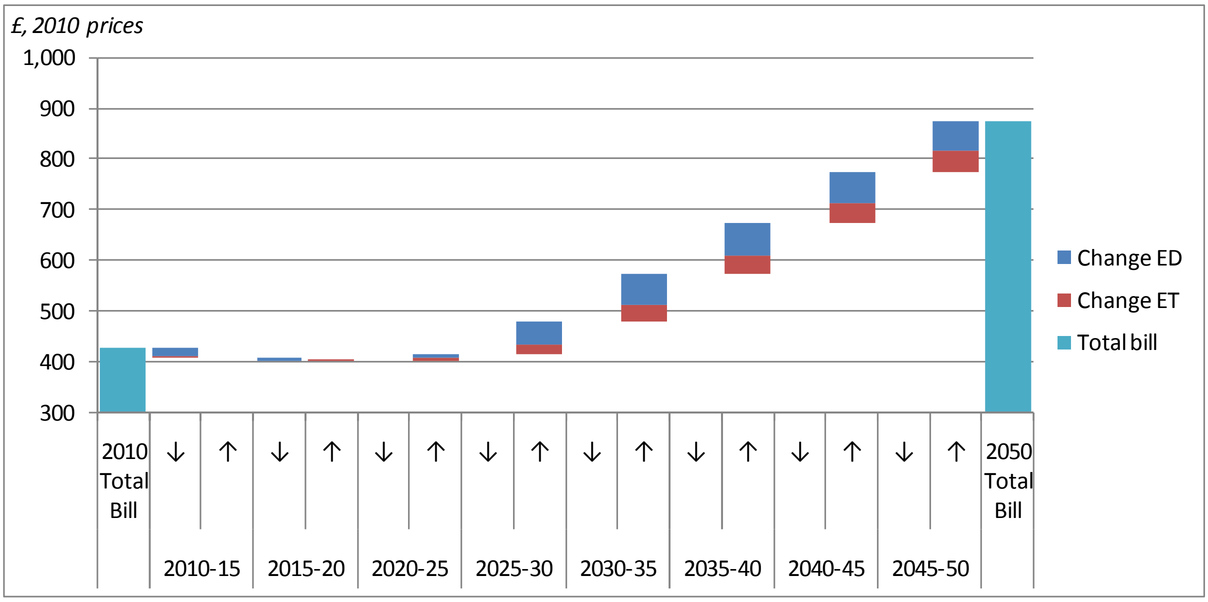


Figure F.102: Change in the average household electricity bill - 'Split' option, 55 year life for new assets

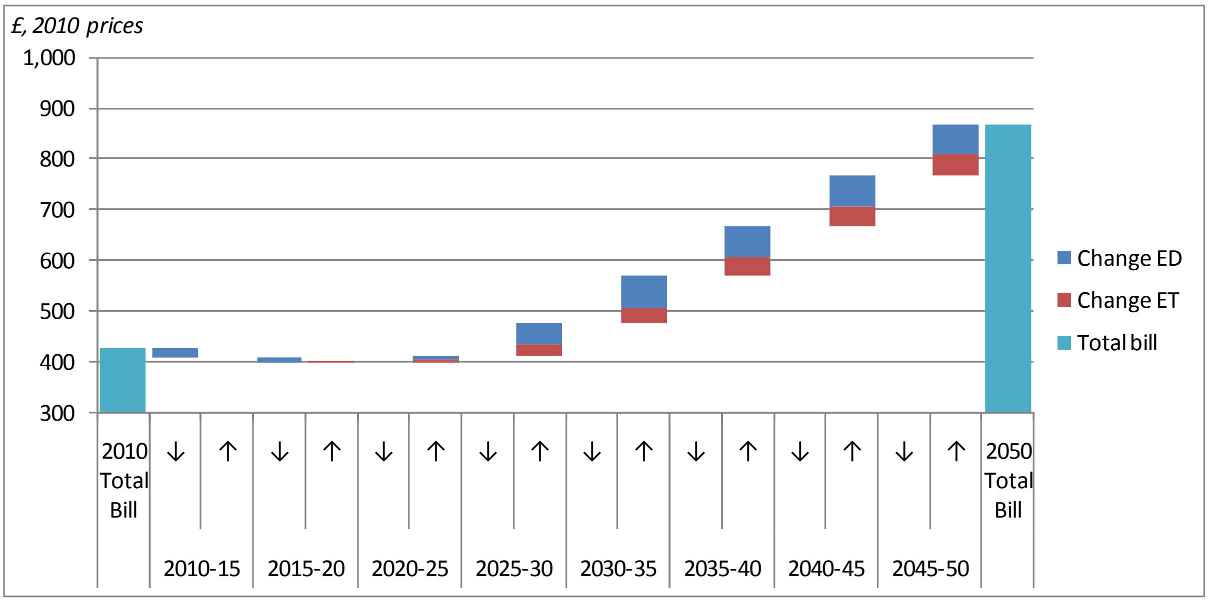
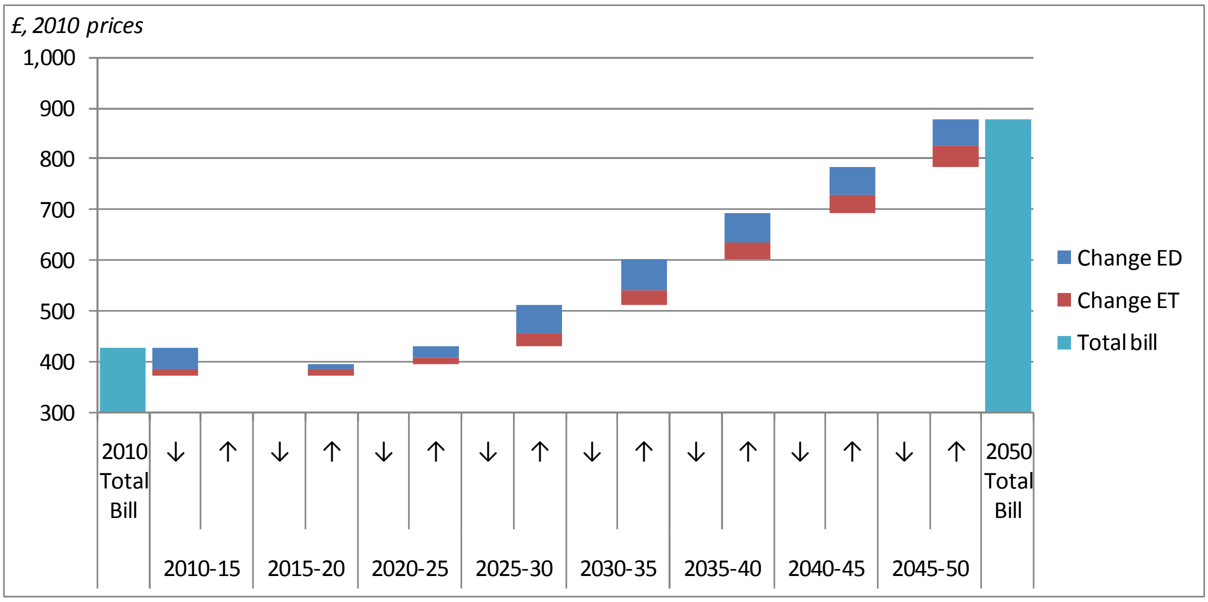


Figure F.103: Change in the average household electricity bill - 'Full' option



Electricity - Case 2 - Dash for Energy

This section shows the same results as for the previous section, but for the "Dash for Energy" scenario. Overall impacts are slightly lower; relative impacts of the different options remain the same.

Figure F.104: Change in the average household electricity bill - 'Base' option

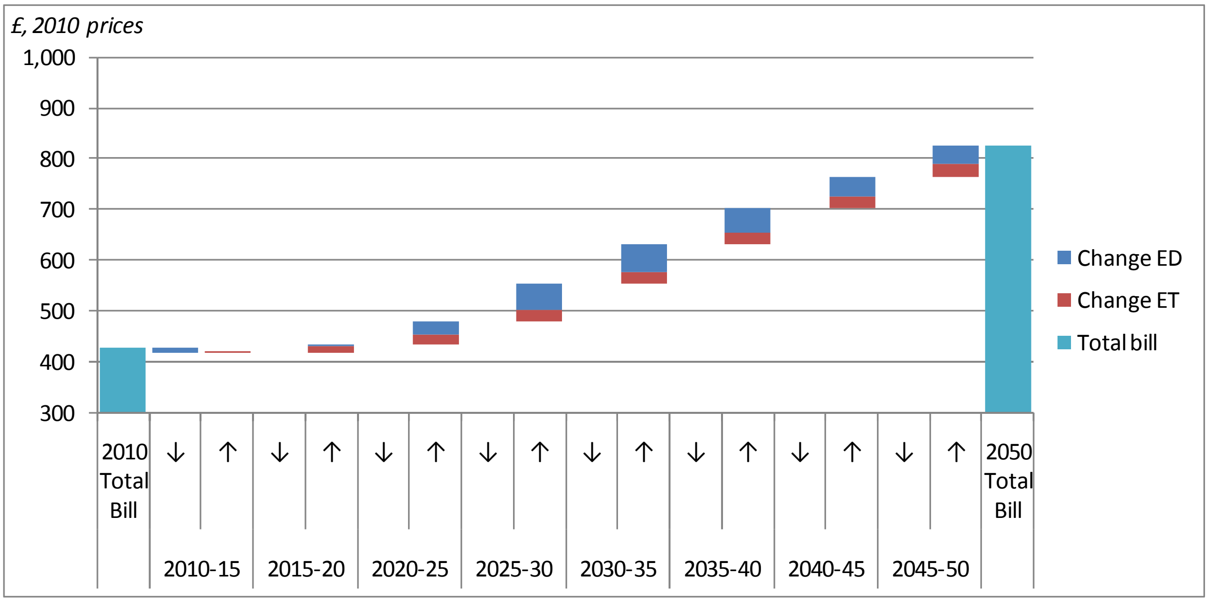


Figure F.105: Change in the average household electricity bill - 'Split' option

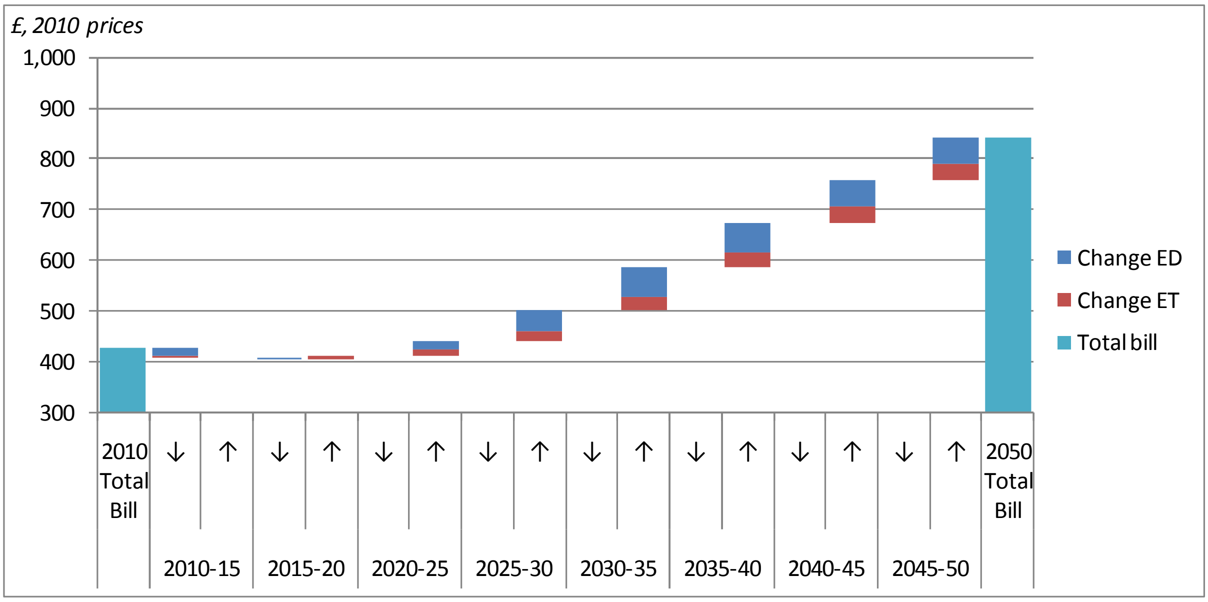


Figure F.106: Change in the average household electricity bill - 'Split' option, 55 year life for new assets

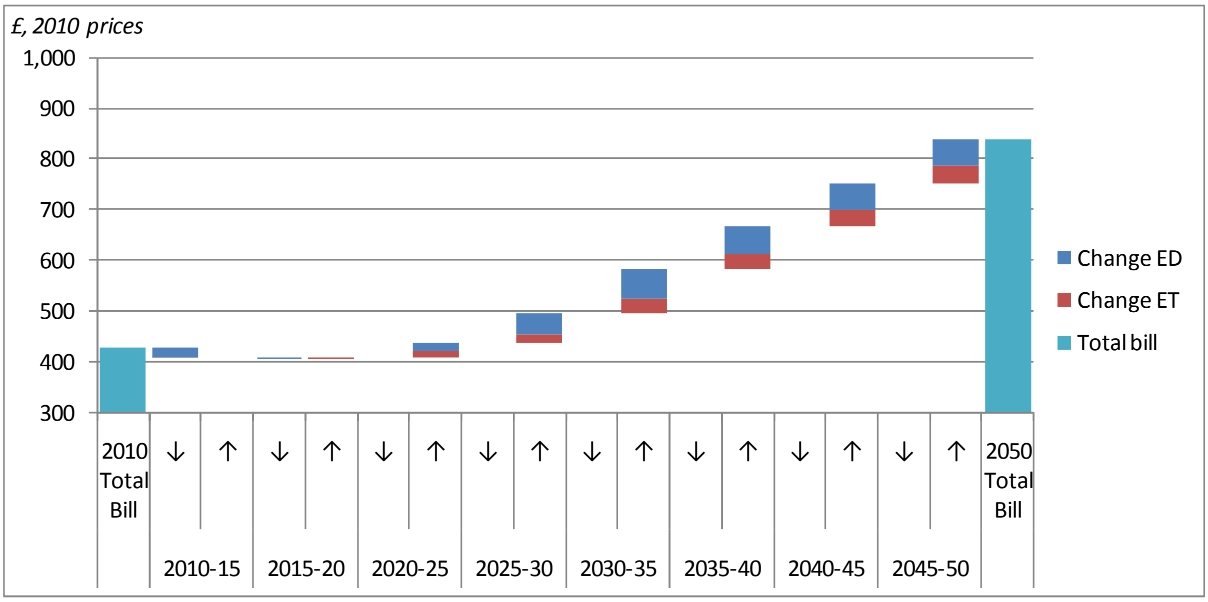
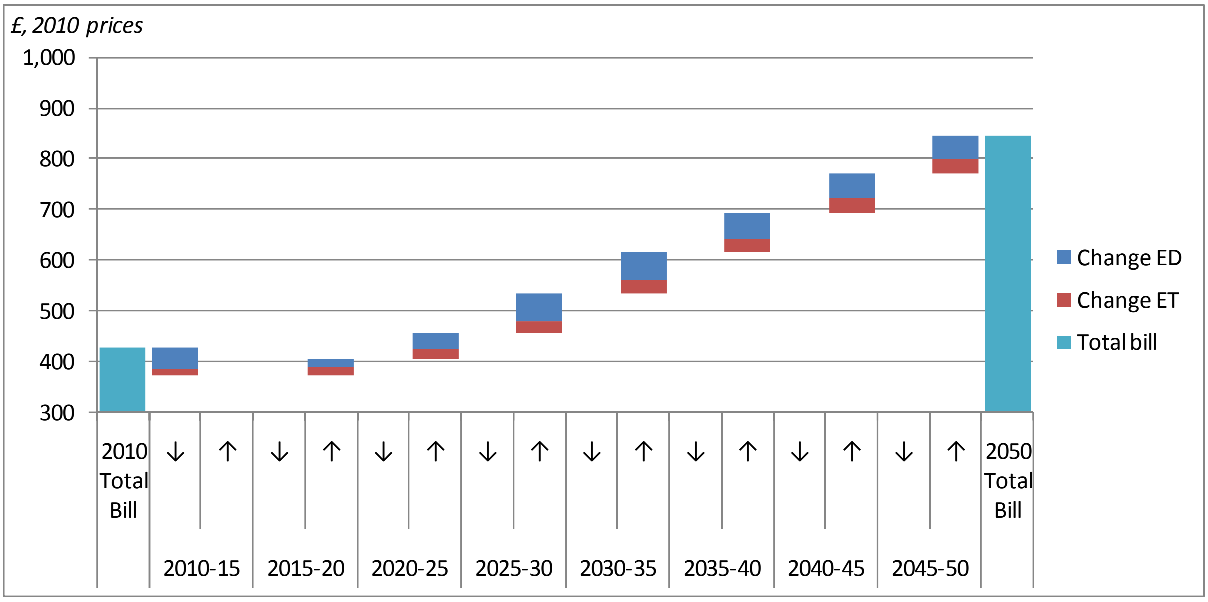


Figure F.107: Change in the average household electricity bill - 'Full' option



Gas - Green Transition

We show below the impact on consumer bills of changes in the gas networks, for both a 45 year life, and a "declining network" variant where the asset life changes to 15 years in 2020, and all assets are fully depreciated by 2035. The variant shows a larger bill impact, as depreciation which under the 45 year scenario would occur after 2050 is forced to occur by 2035. Impacts in both cases are though relatively small compared to impacts from electricity networks.

Figure F.108: Change in the average household gas bill

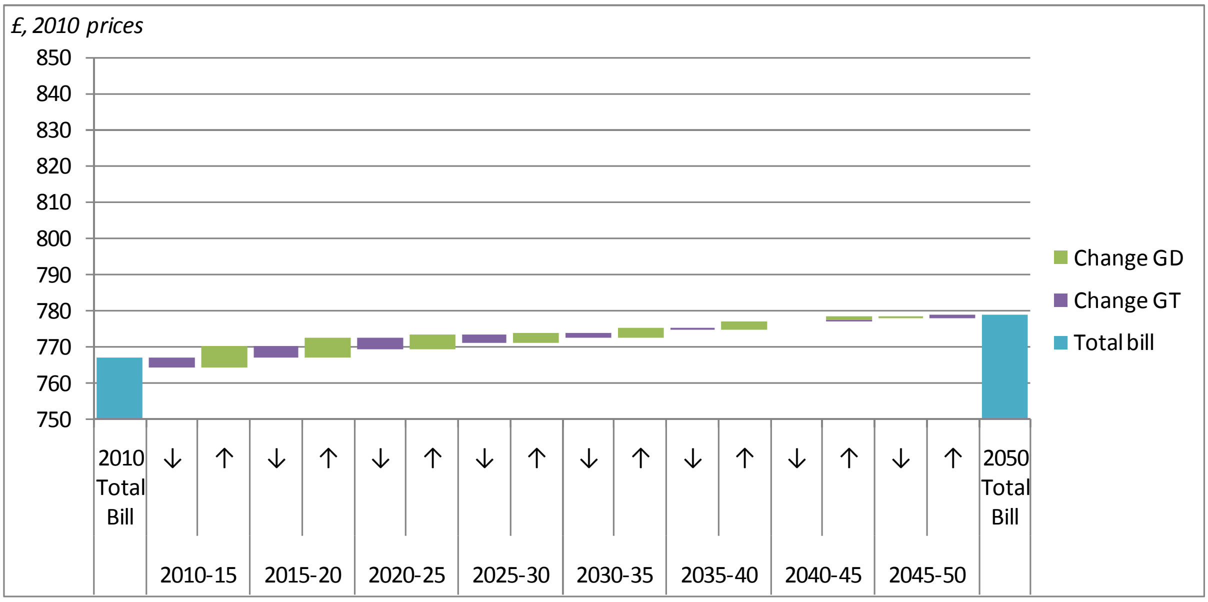
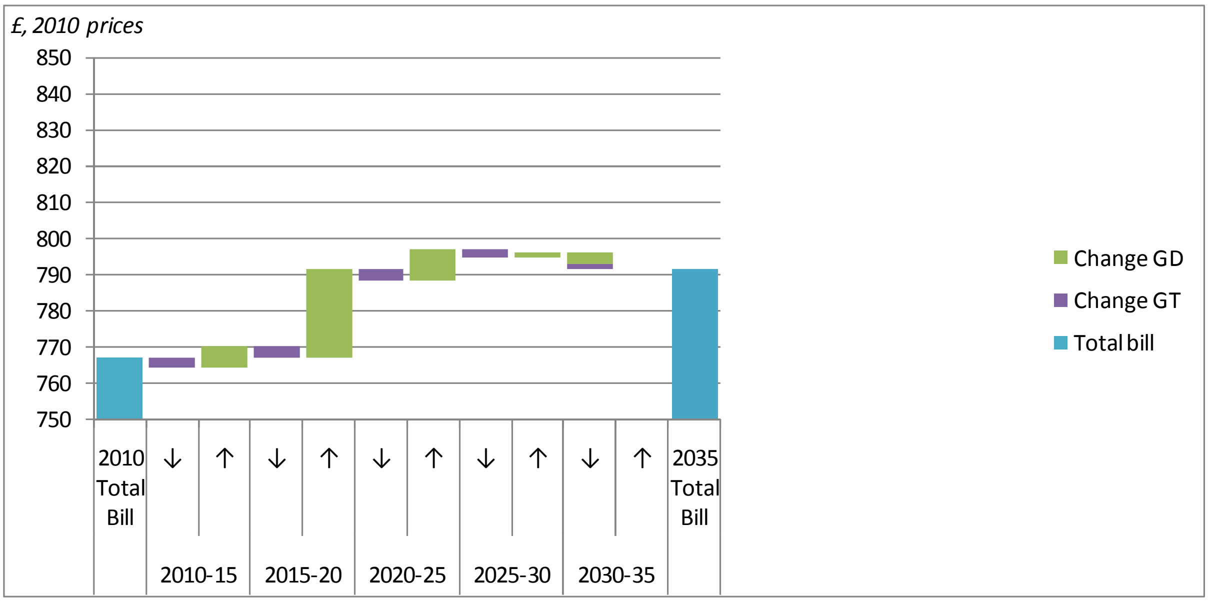


Figure F.109: Change in the average household gas bill - 'Declining Network' variant



Gas - Dash for Energy

This section shows the bill impacts from gas networks in the "Dash for Energy" scenario, where the use of the networks is higher than in "Green" scenarios. Bill impacts are higher in both cases, particularly "Declining Variant".

Figure F.110: Change in the average household gas bill

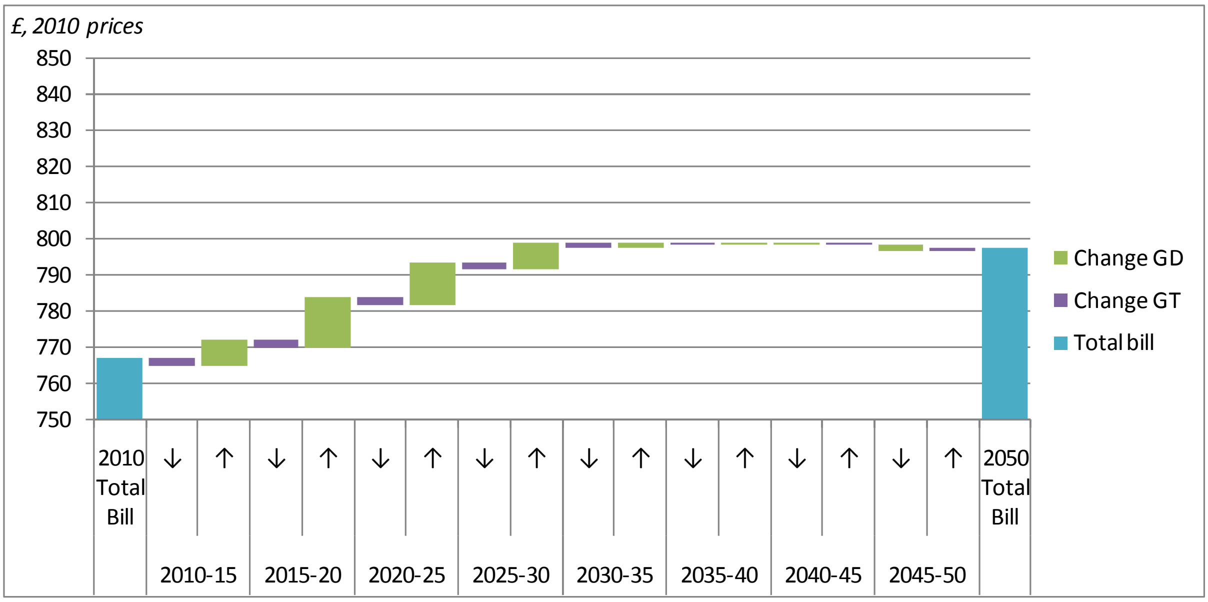
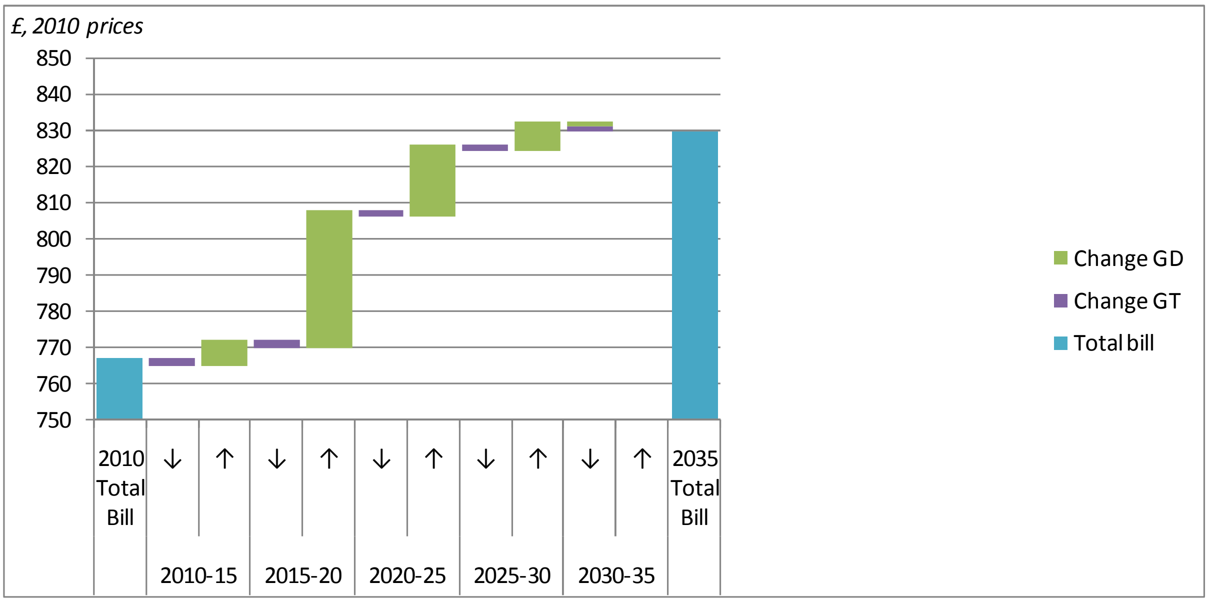


Figure F.111: Change in the average household gas bill - 'Declining Network' variant



Combined (Electricity & Gas)

This section shows the combined impact of the changes in gas and electricity networks on household energy bills. Since the impacts are assumed to be simply additive, the results here are the sum of the results for gas and electricity shown above.

Electricity distribution dominates in all cases (although electricity transmission impacts can be large particularly in the "Green Transition" scenario under an assumption about a move away from overhead lines).

Case 1 - Green Transition

Figure F.112: Change in the average household combined bill - 'Base' option

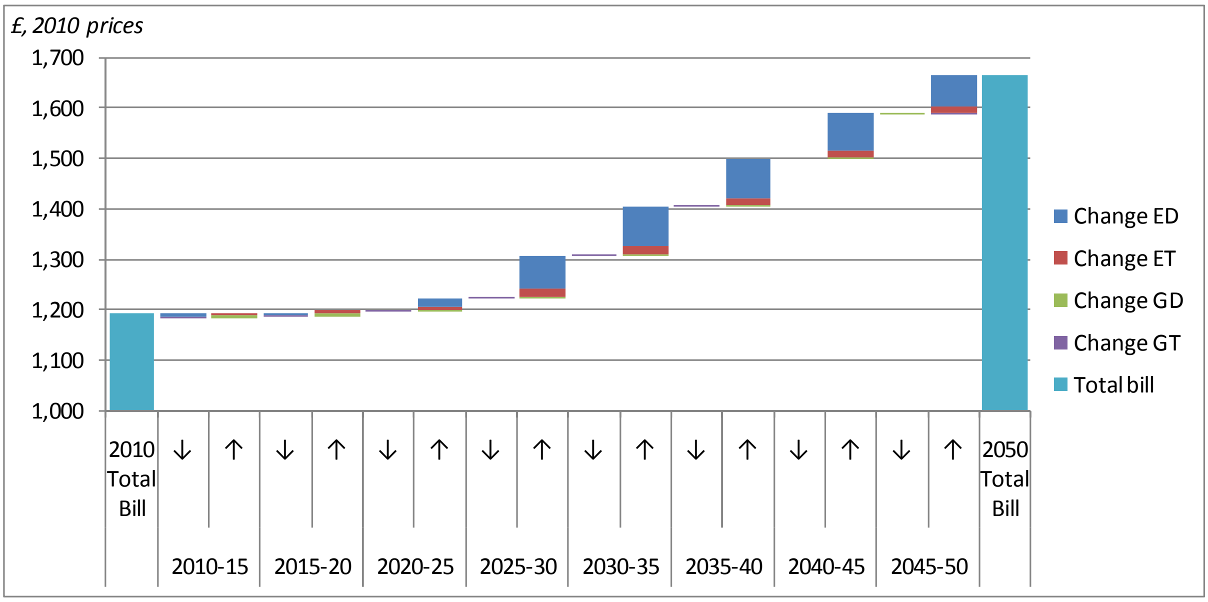


Figure F.113: Change in the average household combined bill - 'Split' option

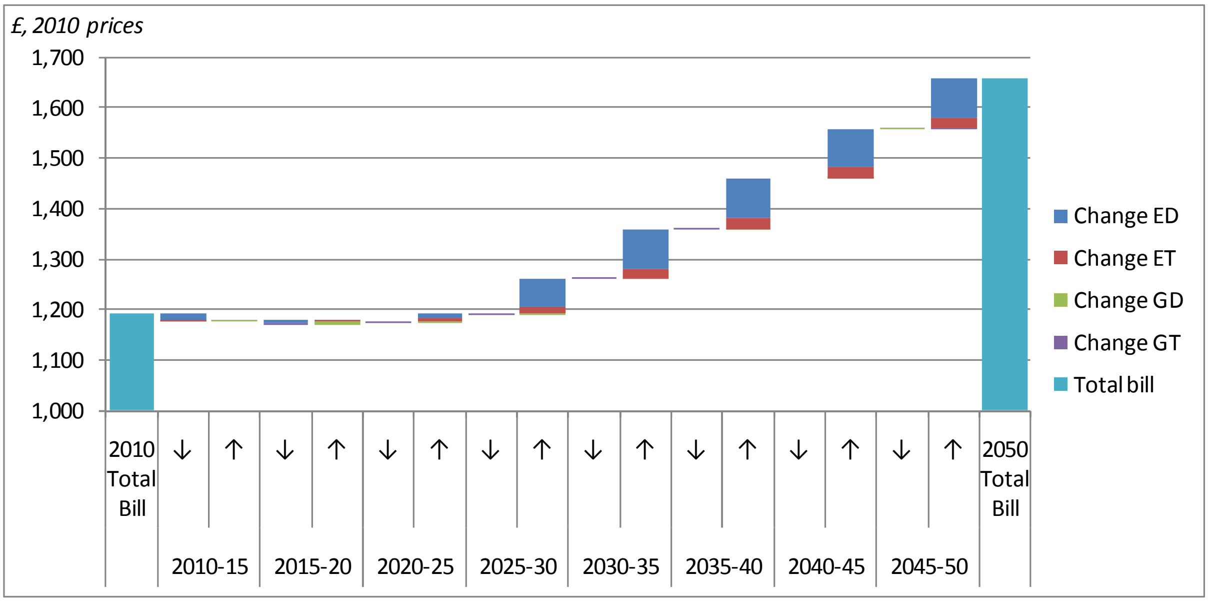


Figure F.114: Change in the average household combined bill - 'Split' option, 55 year life for new assets

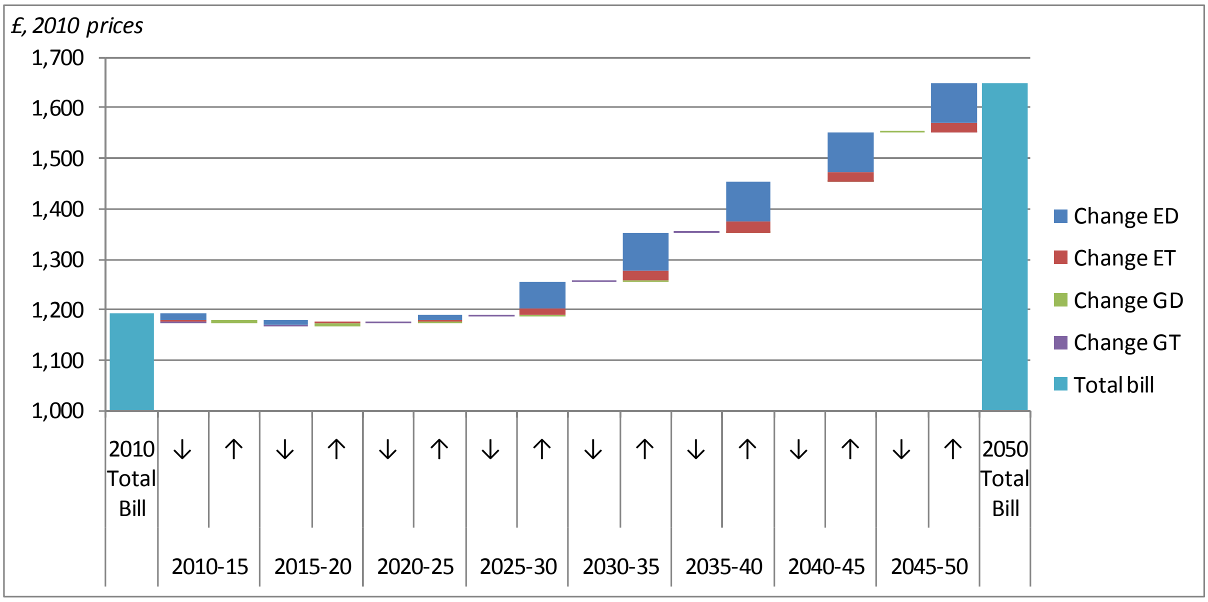


Figure F.115: Change in the average household combined bill - 'Full' option

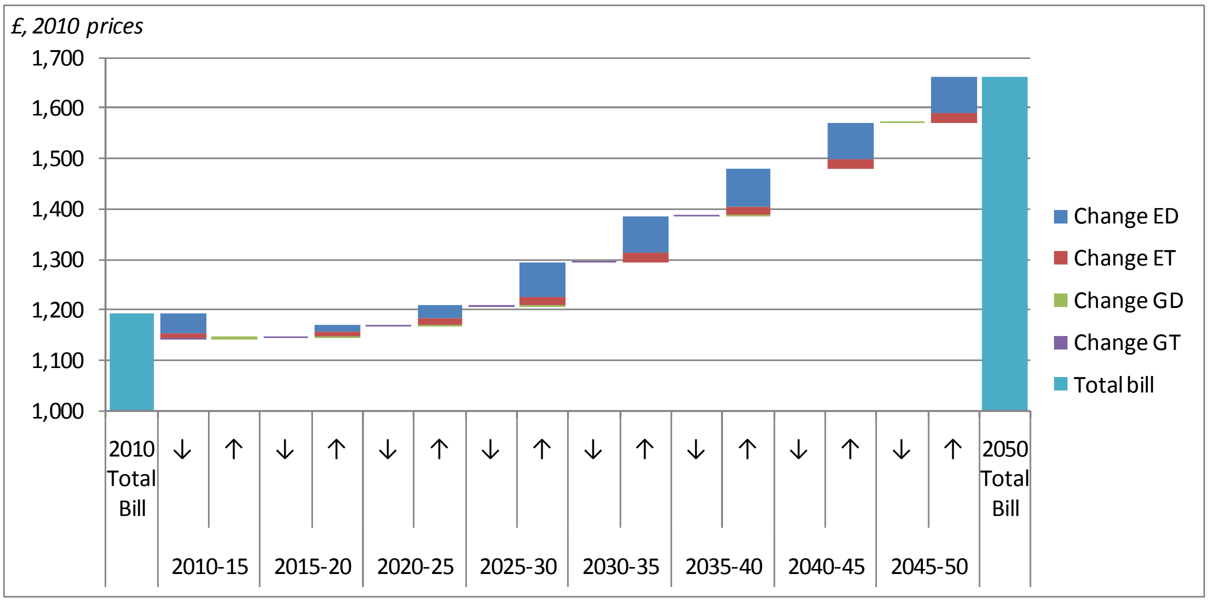
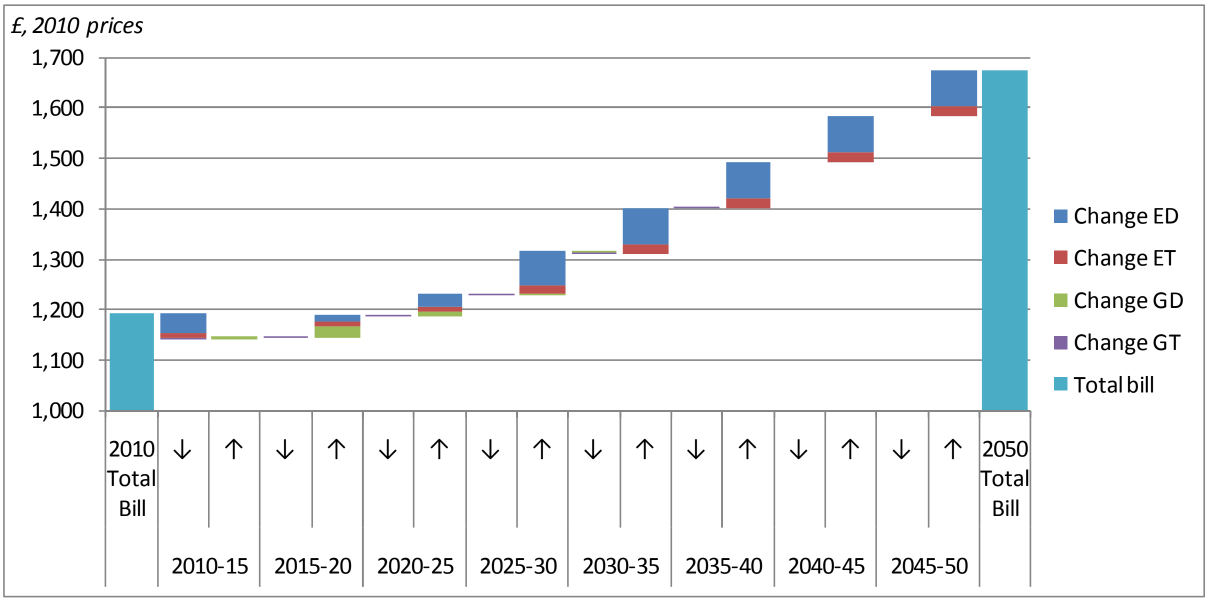


Figure F.116: Change in the average household combined bill - 'Full' option with 'Declining Network' variant



* NB This graph includes all changes from the gas distribution network up to 2035, and then assumes no change. However, were the gas distribution network to cease from 2035, the implications for the total household bill would be uncertain. Therefore this graph is purely illustrative and should not be used as a basis for strong conclusions.

Combined (Electricity & Gas) - Case 1 - Dash for Energy

Figure F.117: Change in the average household combined bill - 'Base' option

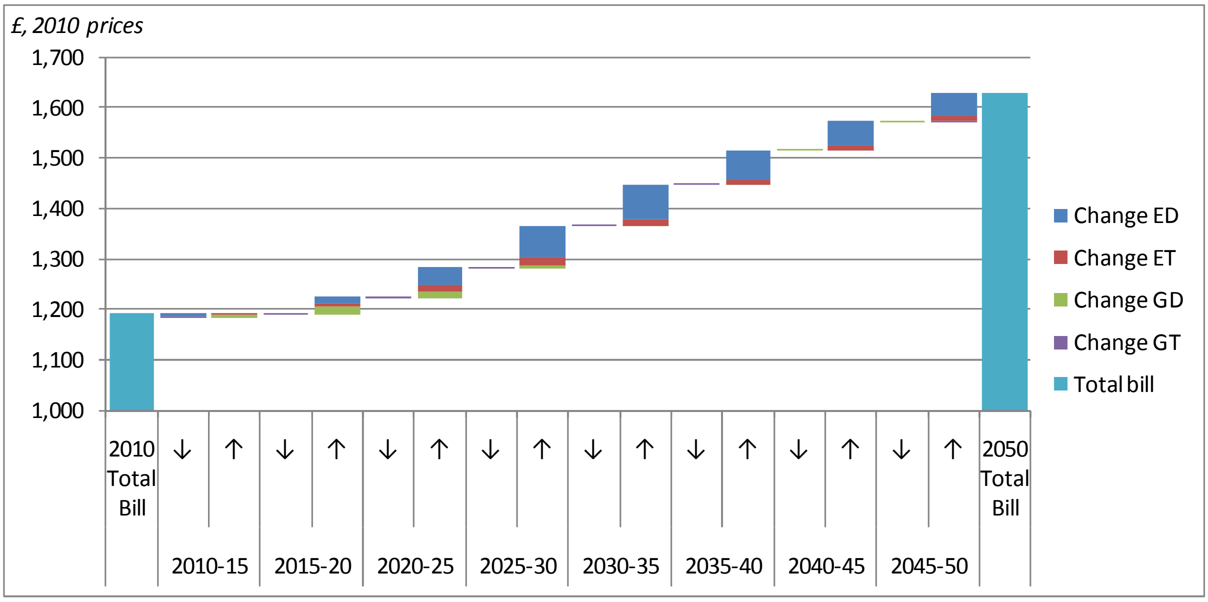


Figure F.118: Change in the average household combined bill - 'Split' option

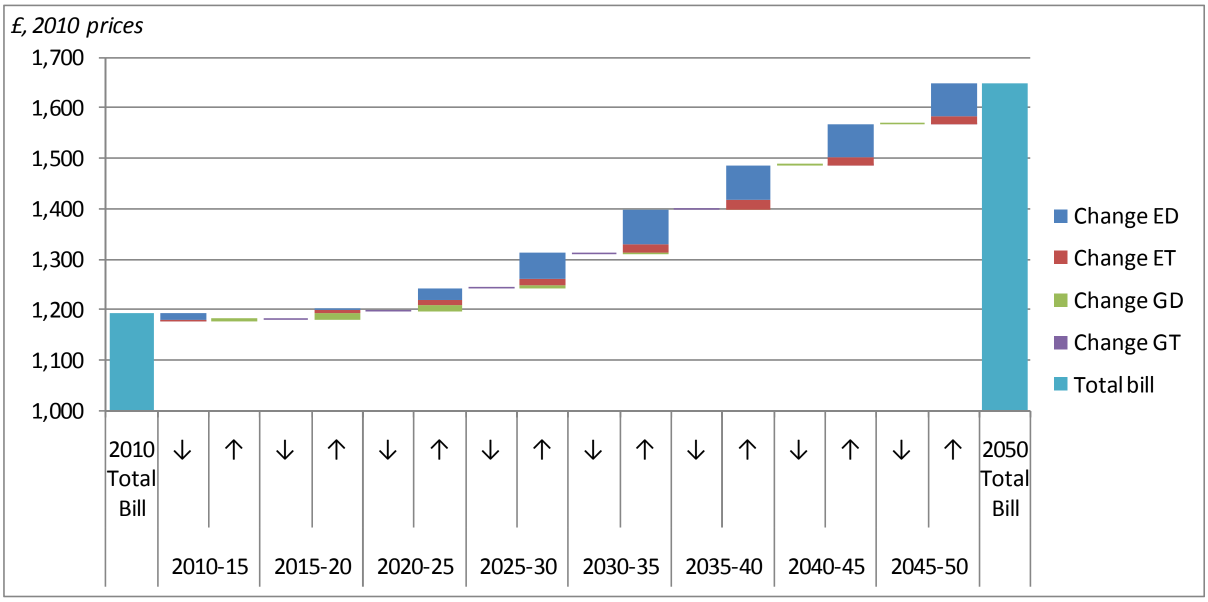


Figure F.119: Change in the average household combined bill - 'Split' option, 55 year life for new assets

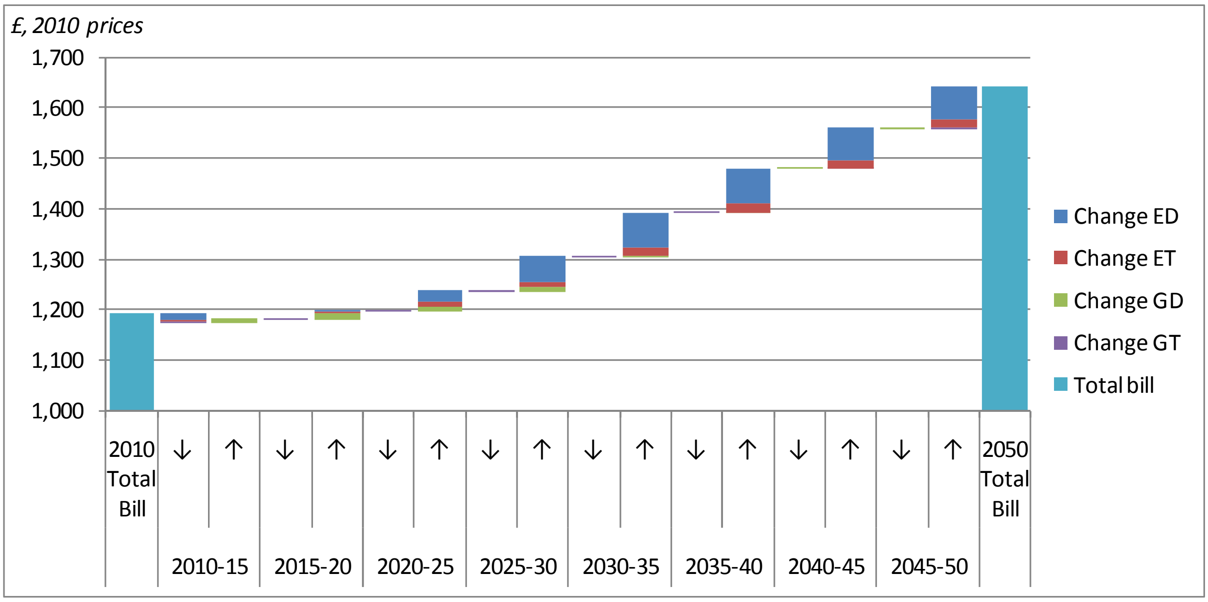


Figure F.120: Change in the average household combined bill - 'Full' Option

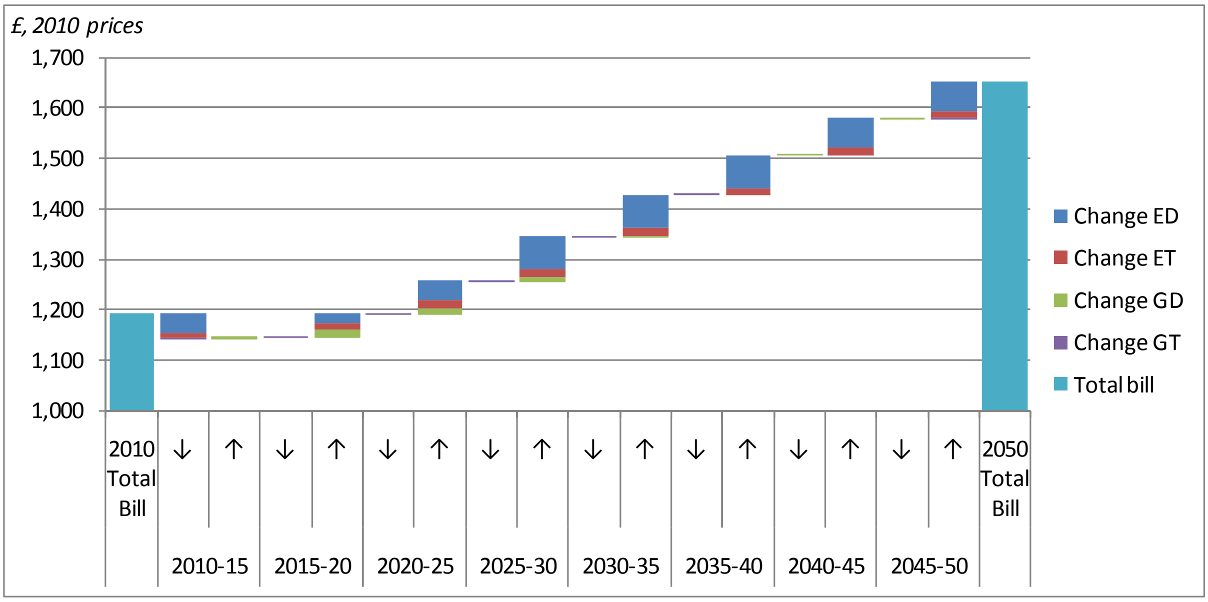
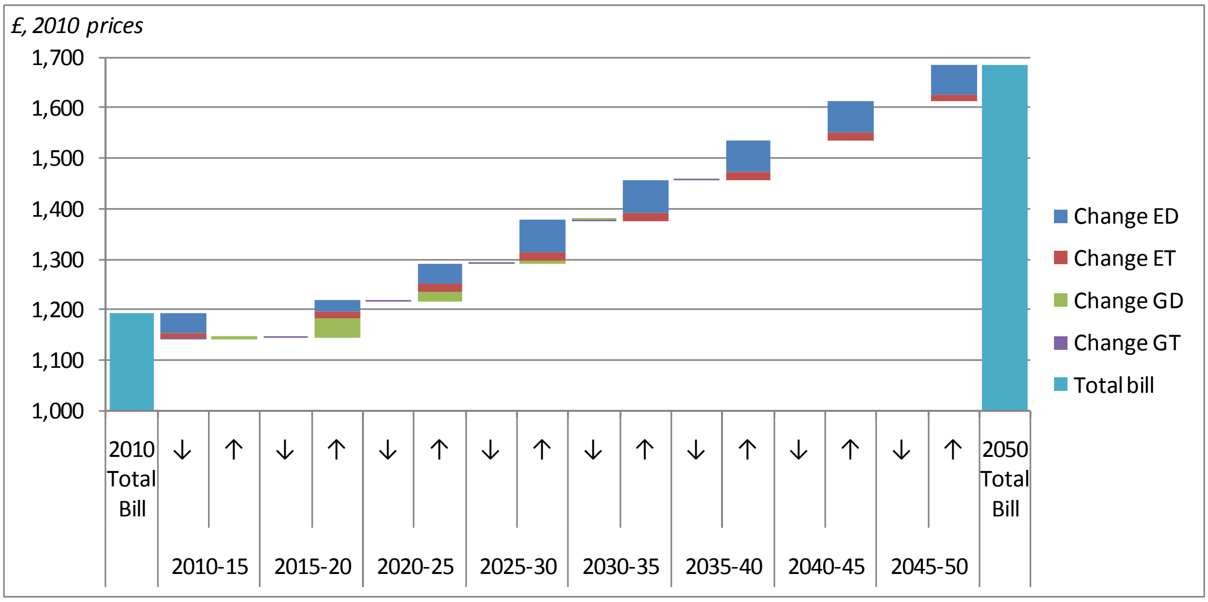


Figure F.121 Change in the average household combined bill - 'Full' option with 'Declining Network' variant



* NB This graph includes all changes from the gas distribution network up to 2035, and then assumes no change. However, were the gas distribution network to cease from 2035, the implications for the total household bill would be uncertain. Therefore this graph is purely illustrative and should not be used as a basis for strong conclusions.

Combined (Electricity & Gas) - Case 2 - Green Transition

Figure F.122: Change in the average household combined bill - 'Base' Option

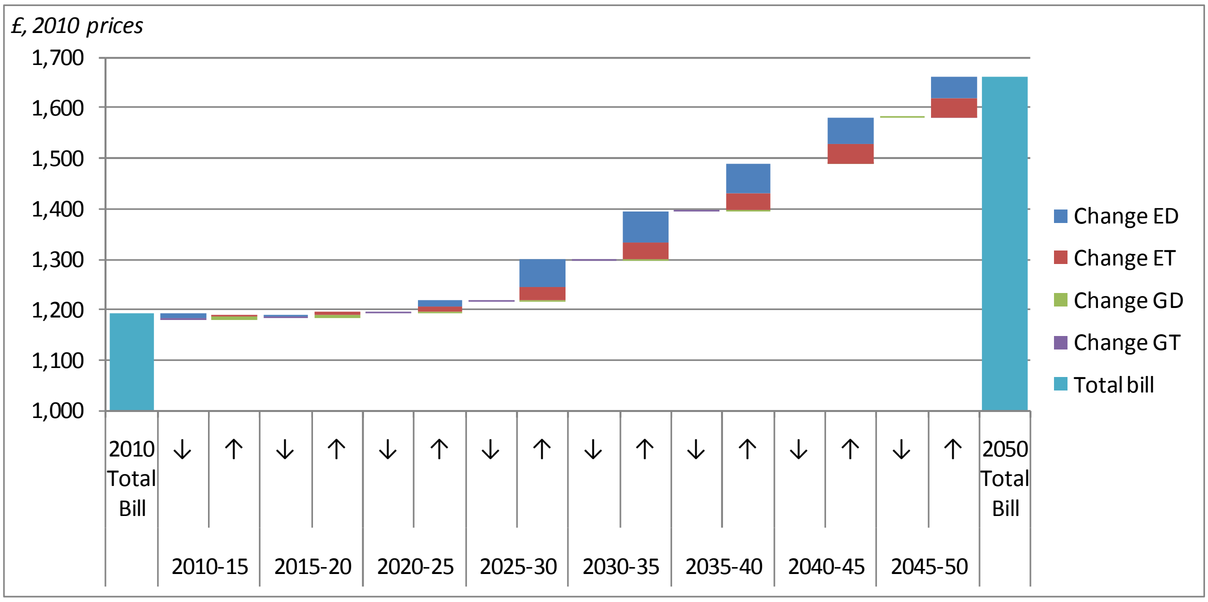


Figure F.123: Change in the average household combined bill - 'Split' Option

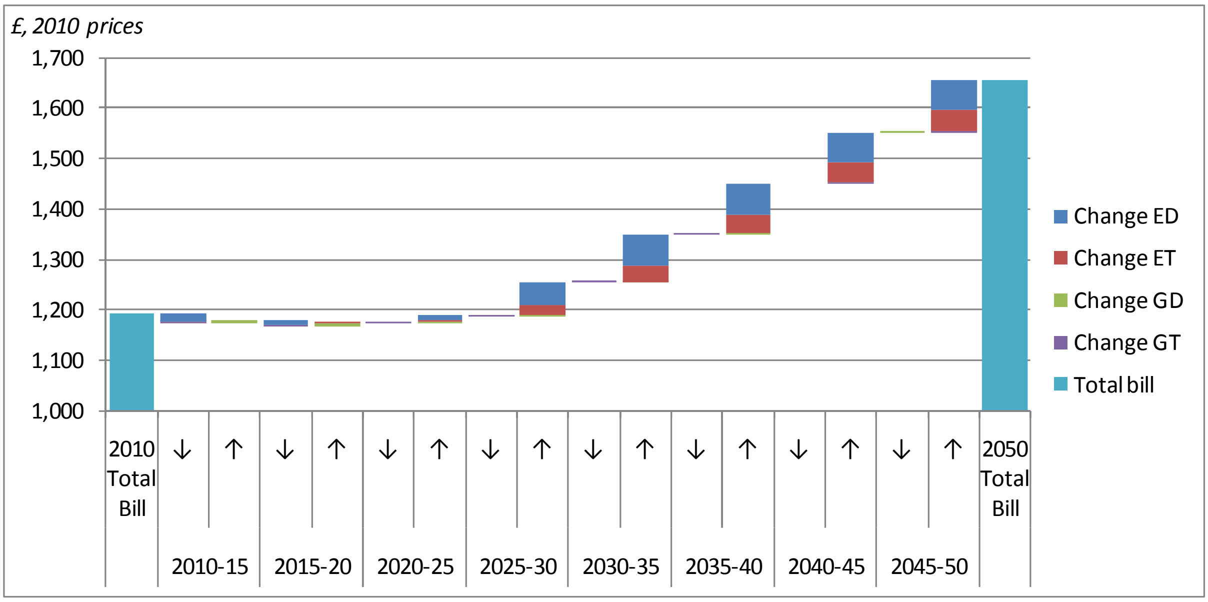


Figure F.124: Change in the average household combined bill - 'Split' Option, 55 year life for new assets

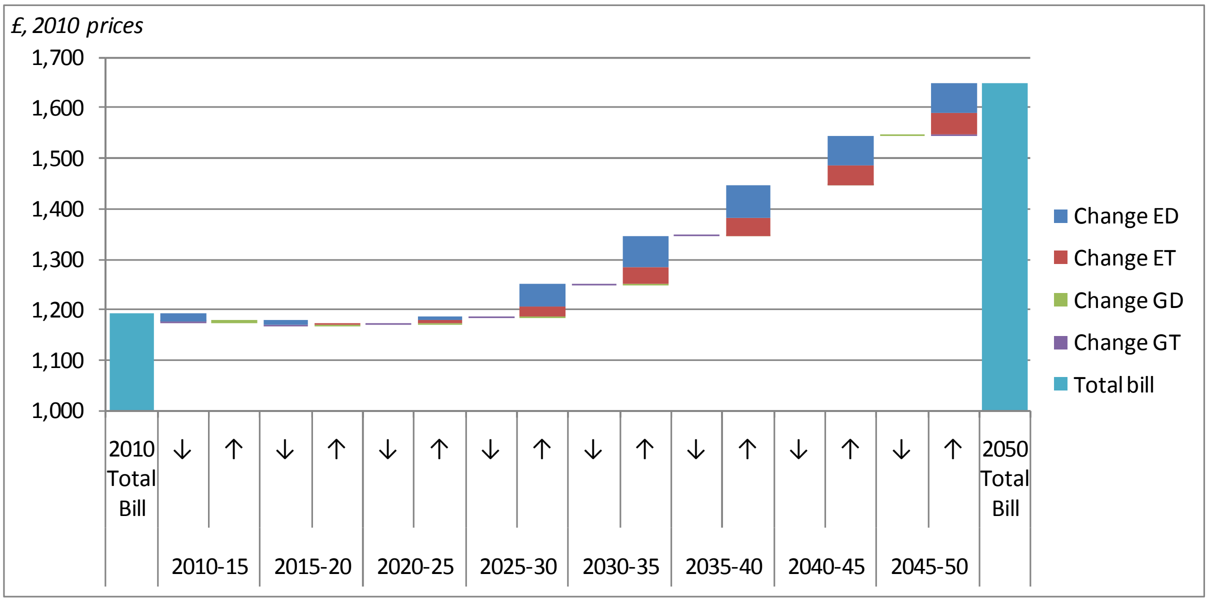


Figure F.125: Change in the average household combined bill - 'Full' option

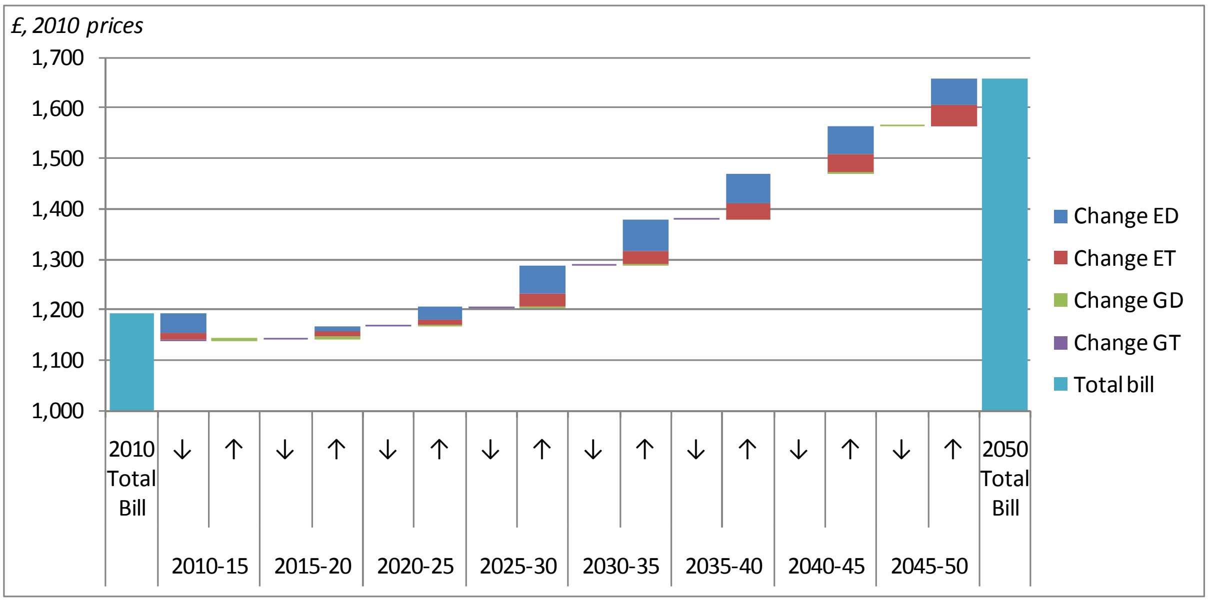
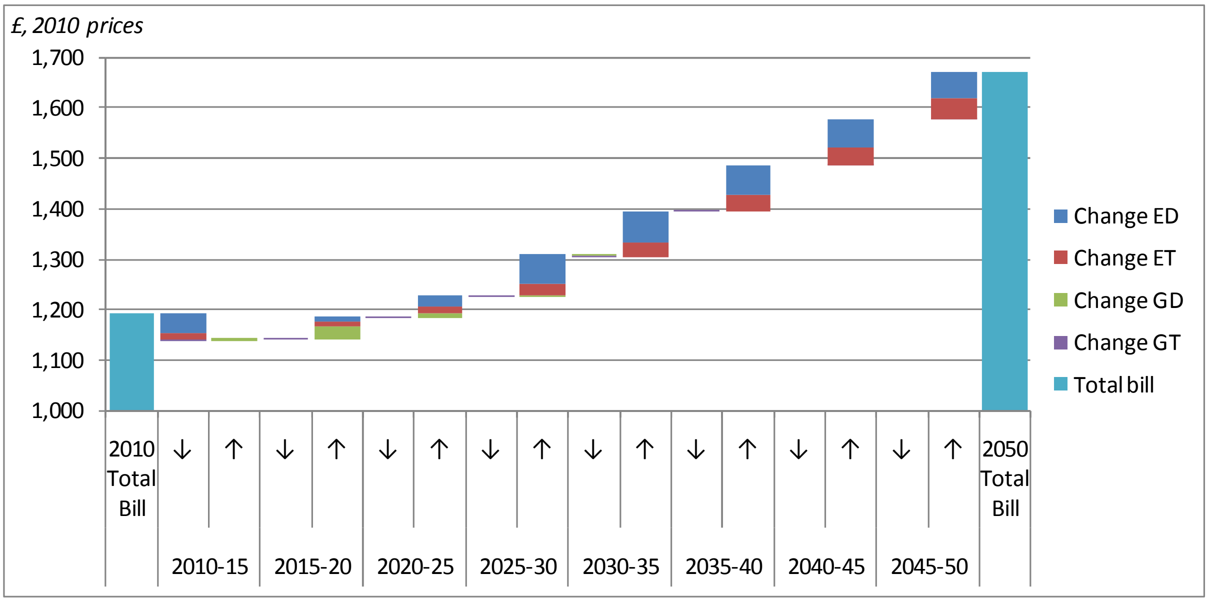


Figure F.126: Change in the average household combined bill - 'Full' option with 'Declining Network' variant



* NB This graph includes all changes from the gas distribution network up to 2035, and then assumes no change. However, were the gas distribution network to cease from 2035, the implications for the total household bill would be uncertain. Therefore this graph is purely illustrative and should not be used as a basis for strong conclusions.

Combined (Electricity & Gas) - Case 2 - Dash for Energy

Figure F.127: Change in the average household combined bill - 'Base' option

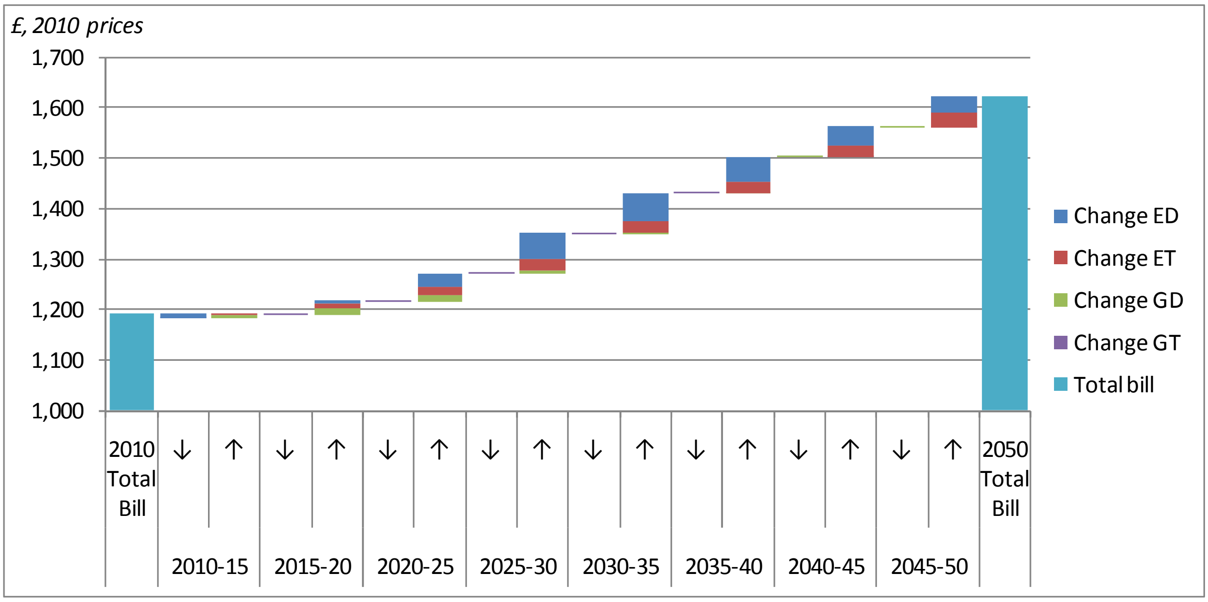


Figure F.128: Change in the average household combined bill - 'Split' option

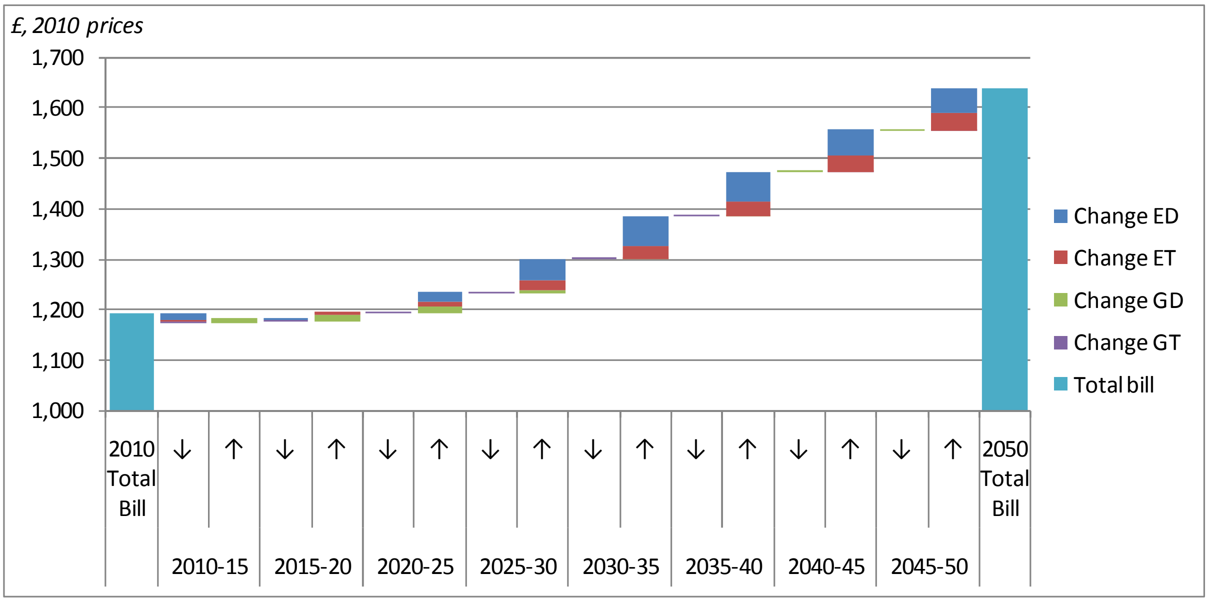


Figure F.129: Change in the average household combined bill - 'Split' option, 55 year life for new assets

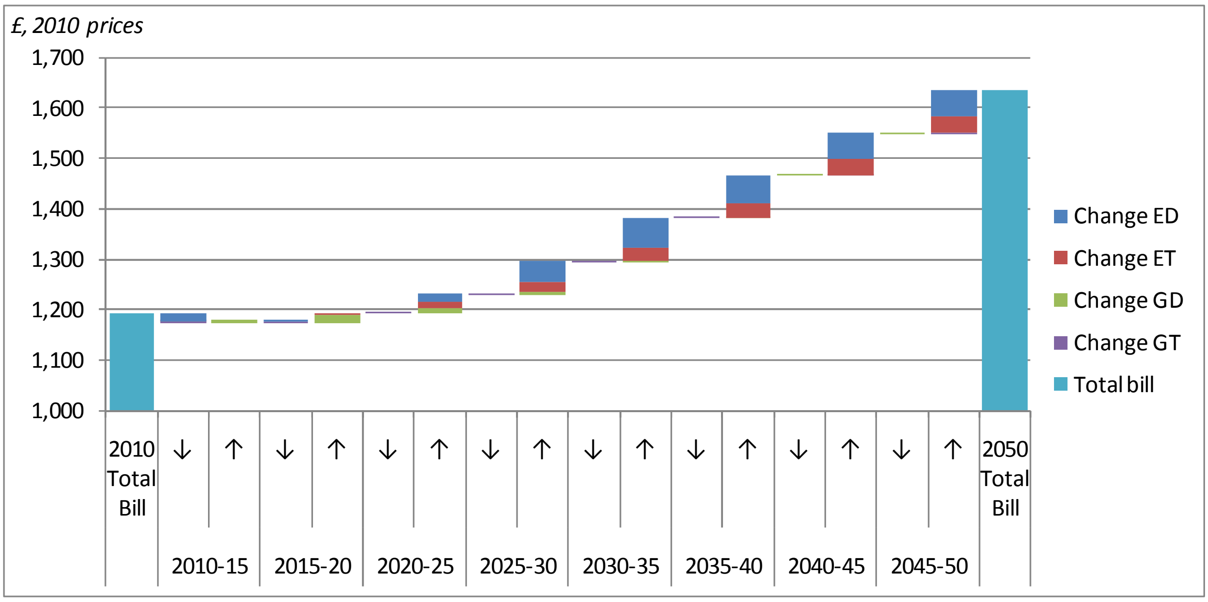


Figure F.130: Change in the average household combined bill - 'Full' option

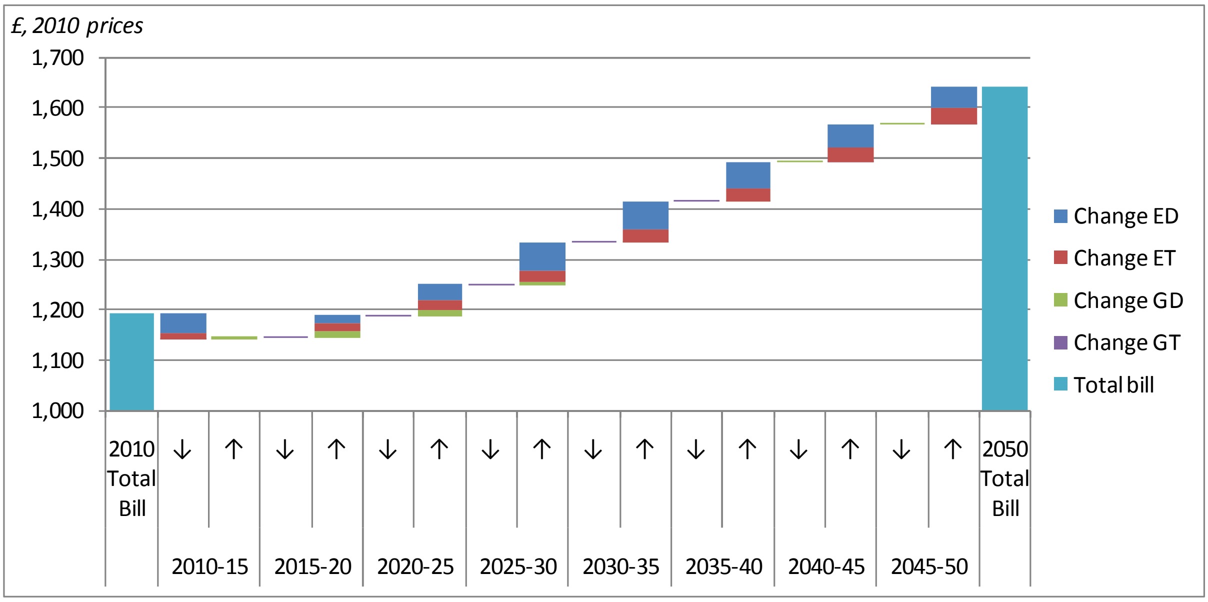
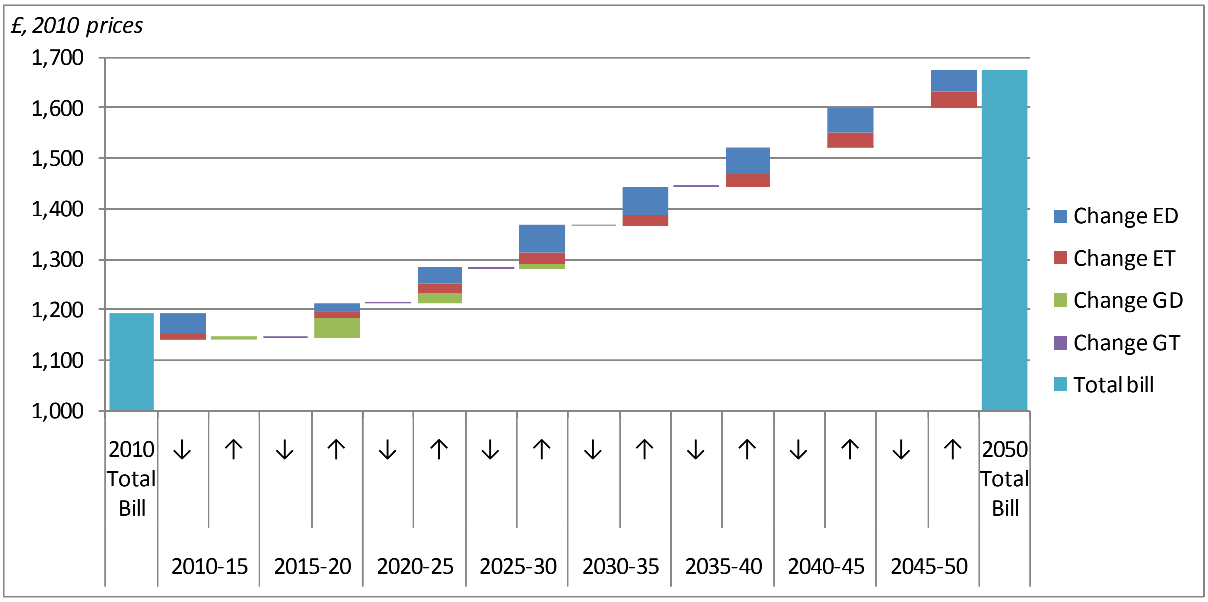


Figure F.131: Change in the average household combined bill - 'Full' option with 'Declining Network'



* NB This graph includes all changes from the gas distribution network up to 2035, and then assumes no change. However, were the gas distribution network to cease from 2035, the implications for the total household bill would be uncertain. Therefore this graph is purely illustrative and should not be used as a basis for strong conclusions.

Annex G: Network assets, by Modern Equivalent Asset Value

The graphs below show, for each of the four networks, the technical age profile of existing assets. The data is shown in terms of cumulative Modern Equivalent Asset (MEA) value; so for example for electricity distribution, around £80 billion of the assets have a technical life of 75 years or less.

Acronyms used are shown in table G.1 below.

Table G.1: Acronyms used in asset life distribution graphs

Acronym	Meaning
MEA	Modern Equivalent Asset
OHL	Overhead Line
SWG	Switchgear
TRF	Transformers
UGC	Underground cables
PRO	Protection
SUB	Other substation assets
LTS	Local Transmission System

Figure G.1: Cumulative MEA value vs. technical life for existing assets – Electricity Distribution

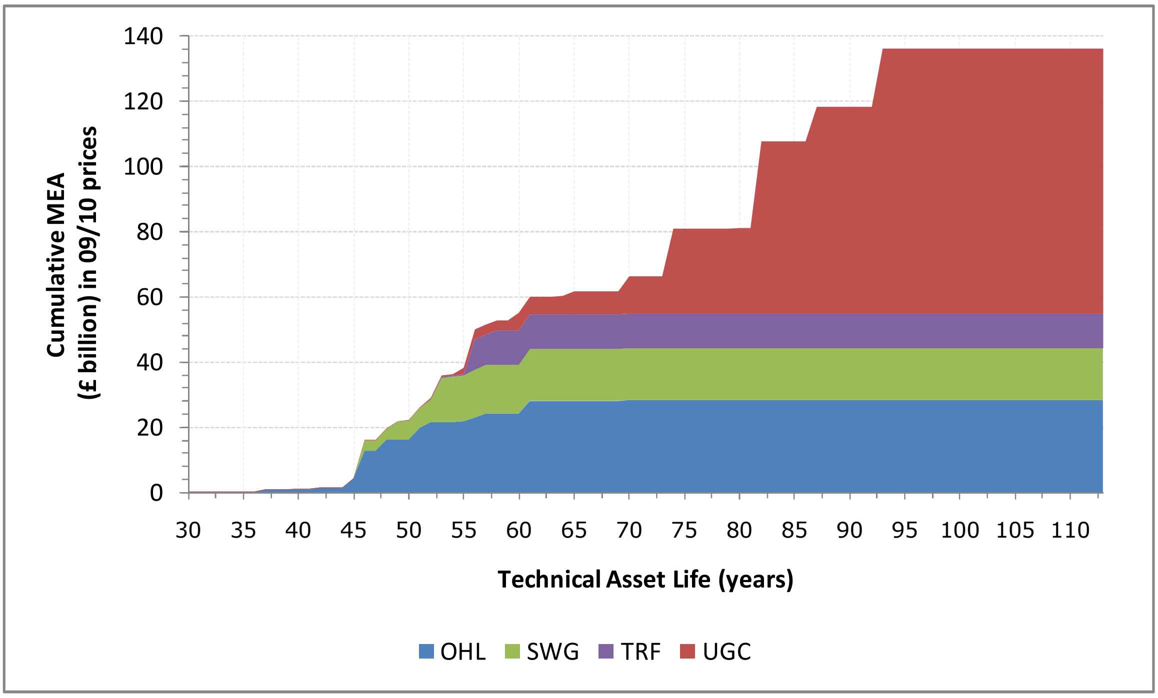


Figure G.2: Cumulative MEA value vs. technical life for existing assets – Electricity transmission

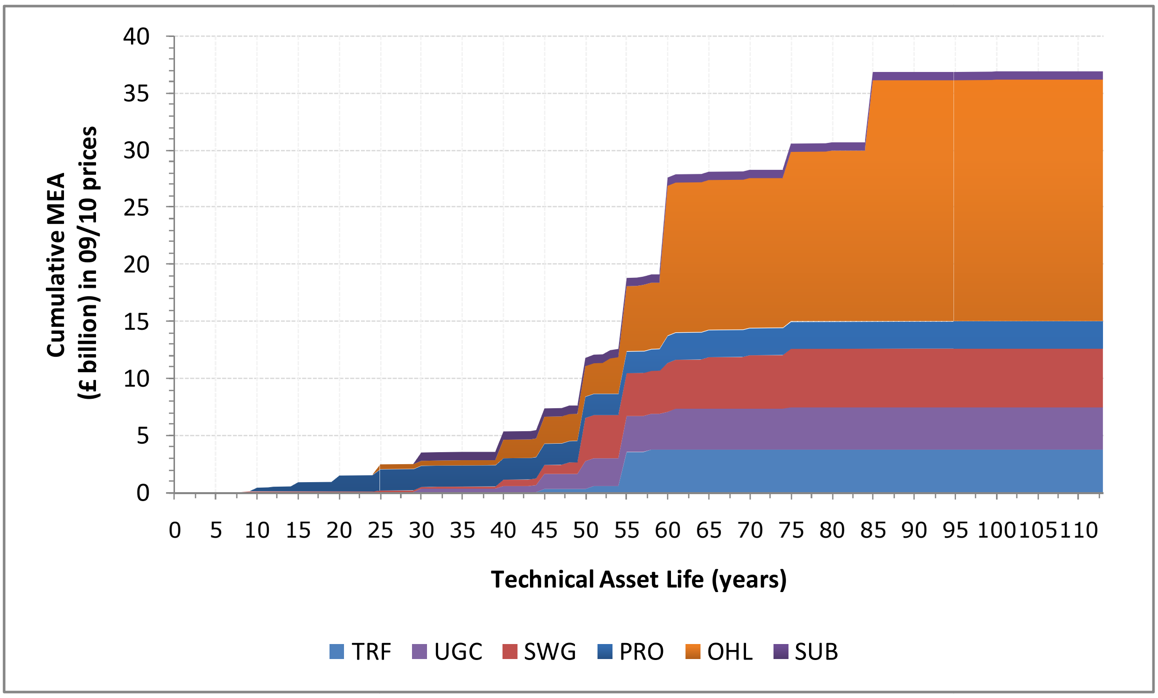


Figure G.3: Cumulative MEA value vs. technical life for existing assets – Gas Distribution

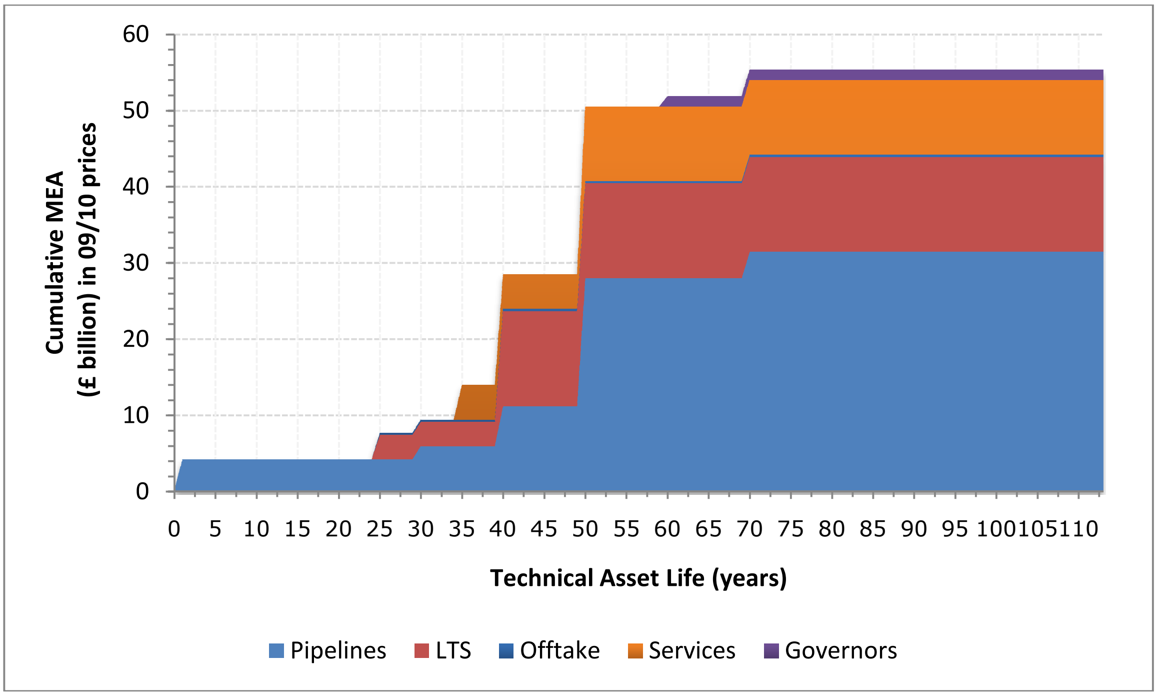


Figure G.4: Cumulative MEA value vs. technical life for existing assets – Gas Transmission