Scottish and Southern
Energy
Power Distribution

Technical Appendix 11.1

Efficiently managing risk and uncertainty

This Technical Appendix is part of the RIIO-ED1 Business Plan of Southern Electric Power Distribution plc ("SEPD") and Scottish Hydro Electric Power Distribution plc ("SHEPD"), together Scottish and Southern Energy Power Distribution ("SSEPD").

A map of the full Business Plan can be found at http://www.yourfutureenergynetwork.co.uk

Summary

Scottish and Southern Energy Power Distribution (SSEPD) is the owner of two electricity distribution networks: Southern Electric Power Distribution (SEPD) and Scottish Hydro Electric Power Distribution (SHEPD).

SSEPD has developed a robust Business Plan for the period 1 April 2015 to 31 March 2023 (the RIIO-ED1 period) following thorough engagement and consultation with our stakeholders. You can read more about our stakeholder feedback in What you said. This Business Plan will allow us to continue our proven track record in terms of efficiently managing and investing in our networks for both today's and future customers. However, given the current economic climate and the increase in length of the electricity distribution price control from five to eight years, it is very difficult for us to accurately forecast our activities and expenditure across all areas of our business. The uncertainties facing our business in the longer term, beyond the RIIO-ED1 period, are described in About electricity networks now and in the future.

The first part (**Approach to risk management**) of this document looks at our overall approach to risk management including SSEPD's internal policies and practices, and how we ensure that we identify, mitigate and manage risks and uncertainties across our business.

However, certain risks and uncertainties are outwith the control of SSEPD, for example the impact of the roll out of smart meter on our business. The second part of this document, **Managing external risk**, therefore looks at these exogenous risks for the RIIO-ED1 period and our proposals to mitigate these risks.

The final part of this document, **Improving the stability and predictability of our charges**, explains how we are ensuring that we minimise the impact that our proposed uncertainty mechanisms will have on the predictability of our customers' bills.

Overall, we consider that our proposals represent a balanced and proportionate means of dealing with uncertainty during the RIIO-ED1 period.

Regulatory policy

In March 2013, Ofgem published its **strategy decision** for the RIIO-ED1 period. This included a paper setting out regulatory policy on uncertainty mechanisms to deal with risks that are outside our control. The proposals set out in this paper are aligned with regulatory policy, with the following exceptions:

- We propose that the street works mechanism is extended to cover potential changes to street works legislation in Scotland (see Street works);
- We propose an additional mechanism to address the potential costs of diverting electrical lines and equipment to accommodate rail electrification projects (see Rail electrification).

A full list of the proposed uncertainty mechanisms is shown in **Table 1**. An explanation of how our proposals meet regulatory policy requirements is provided in the **Appendix - Regulatory policy.**

Generally the risks, and our proposals to efficiently manage them, represent little change from our current approach, which has worked well for both SSEPD and its customers.

Table 1 Summary of proposed uncertainty mechanisms for RIIO-ED1

Uncertainty	Ofgem March decision	SSEPD proposal
AUTOMATIC MECHANISMS		
Inflation	Continue to adjust allowed costs and revenue for actual RPI during each year.	Support Ofgem's decision.
Ofgem's fees	Continue to adjust allowed revenue each year to cover Ofgem's actual fees.	Support Ofgem's decision.
Business rates	Continue to adjust allowed revenue each year to cover actual business rates – subject to our making as much effort as possible during valuations.	Support Ofgem's decision.
Transmission Connection Point Charges	Retain DPCR5 pass through mechanism with a 2 year lag, for assets installed prior to RIIO-ED1, GSP refurbishment and any work not resulting from a DNO requirement.	Support Ofgem's decision.
Smart meters	Adjust allowed revenue each year to cover DCC fees until end of 2019/20 only. Note: this view was prior to Government decision to delay smart meter roll out.	Support Ofgem's decision.
Shetland balancing	Not stated.	Presume continuation of current mechanism until 2019/20, subject to further determination on Integrated Plan for Shetland.
VOLUME-DRIVEN MECHANISMS		

Smart meter installation	Upfront cost allowance based on 2% call out rate. Subsequent installations funded by a volume driver based on same unit cost with unit cost tapering as number increases.	Support Ofgem's decision.
Street works	Single reopener window in May 2019 where materiality threshold of 1% of average annual base revenue is met.	Support mechanism, but suggest it is extended to encompass proposed new legislation in Scotland.
Security of nationally important infrastructure	Single reopener window in May 2019 where materiality threshold of 1% of average annual base revenue is met.	Support Ofgem's decision.
Uncertainty about load related growth	Two reopener windows in May 2017 and May 2020 where materiality threshold of 1% of average annual base revenue is met.	Support Ofgem's decision.
High value projects reopener	A single reopener window in May 2019 for individual schemes of £25m or more that are not included in an ex ante allowance or that are included but costs have changed. Threshold 1% average annual base revenue.	Support Ofgem's decision.
Rail electrification	Not stated.	Single reopener window in May 2019 where materiality threshold of 1% of average annual base revenue is met.

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Introduction

Uncertainties and risks are issues that can impact our activities and costs over which we have little or no control.

SSEPD's Business Plan sets out our proposed service level targets and associated expenditure levels for our activities. Whilst some of these activities do have some uncertainties inherent within in them, such as when and where interruptions to supply will occur, the impact of these uncertainties is such that we can accommodate it within our day-to-day operations.

This paper considers the material risks to our business that are outside of our control and the measures we use to identify, mitigate and manage the impact of these uncertainties.

Uncertainties and risk can impact on the service that we are able to provide to our customers. An example of this is changes to legislation such as the introduction of the Feed-in Tariff (FiT), a scheme for small-scale generation, which was introduced on 1 April 2010. This resulted in a huge increase in the number of small generators wishing to connect to our system with a consequential impact on our connections workload and costs. There was an increase from approximately 1,000 quotations issued as a result of the FiT to just over 6,000 between 2010/11 and 2011/12. The number of acceptances increased from approximately 200 to over 1,800 over the same period. We had to quickly adapt and respond to the new requirements.

There is a lot that we can do to manage uncertainty on a day-to-day basis and prepare for unexpected events. The first part of this paper looks at our risk management processes. This is how we ensure that we have processes in place and appropriate senior management oversight to mitigate the impact of risks and uncertainties as far as possible. This is something that we take very seriously as the impacts of some uncertainties and risks on our business can be material.

However, when things happen and we have done as much as we can to manage the impact, then it is appropriate to consider how the costs are shared between us and our customers. One way of doing this is to identify uncertainties ("known unknown") and define how costs will be allocated if, or when, something happens. Another way is by setting thresholds so that we bear the risk up to a certain point and then share the risk with customers beyond this.

The second part of this paper talks about the specific uncertainties that we face in the RIIO-ED1 period and how we propose to manage these such that the impact on customers' bills is minimised.

By adopting pre-defined mechanisms that allocate uncertain costs when they happen, overall costs to customers have been kept down. The impact of uncertainty mechanisms on SSEPD allowed revenue over the three years from 2010/11 to 2012/13 is shown in **Table 2**.

The purpose of uncertainty mechanisms is to reduce the risk to SSEPD and customers of over- or under-forecasting costs associated with things that are outwith our control. Sharing risk between us and our customers ensures that the resulting impact on our customers' bills is low. We expect the proposals in this paper to have a similarly low impact on customers' bills during the RIIO-ED1 period.

The final part of this paper looks at the risk customers, or on their behalf electricity supply businesses, face if they are not able to accurately forecast our future charges. This uncertainty can be significantly reduced through a combination of managing year-on-year volatility and providing more information to assist accurate forecasting.

Table 2 Summary of DPCR5 uncertainty costs

Uncertain costs (£m) *Costs which are hard to predict, so automatically passed-through to customers*	**2010/11**	**2011/12**	**2012/13**
Licence fees	-0.14	-0.08	-0.11
Business rates	3.75	3.91	4.25
Transmission Connection Point Charges	-1.24	-3.30	-3.06
Shetland Balancing	11.09	12.51	13.42

Part 1

Approach to risk management

Managing risk and uncertainty in our business is critical to achieving strategic goals and maintaining effective operations. A structured risk management approaches ensures that risks are identified, evaluated and effectively managed to prepared for all circumstances and to ensure that we are able to continue to finance efficient delivery. You can read more about our efficient approach in Be efficient. The variety of risks and uncertainties that SSEPD faces ranges from legislative change to losing experienced staff with specialist skills.

SSEPD is part of a standardised approach to managing key business risks, issues and opportunities that is applied across the SSE group. This approach has direct involvement from our senior management to ensure that appropriate focus is directed and maintained.

This section details our approach and the processes and procedures we have in place to manage risk generally across our business.

Processes and procedures

The SSE group believes that any sustainable and successful business requires clear direction and guidance with regards risk management in all aspects of its activities. Accordingly, we believe that risk management is first and foremost an integral part of how managers run their activities every day. We therefore focus on looking at each activity area individually and putting in place a risk management framework that works effectively for that area. This is an ongoing process so that we can react to changes in the risk environment by constantly revising our internal processes. The need for good risk governance is critical to ensure that our overall business model is effective and value adding in practice. As such, the overall responsibility for risk management sits with our Board of Directors.

In practice, this approach uses a comprehensive suite of processes to ensure that the key risks and uncertainties across our activities are effectively identified, evaluated and economically managed. These processes encompass activities from SSE strategic level right down to the operational levels.

Our risk management process is summarised in **Figure 1** below.

Figure 1 Risk management approach

There are three principal categories of risk: strategic, operational, and project risk. Strategic risks are those which impact on SSE objectives and can be the most complex and dynamic. Operational risks are ongoing business risks which can be either generic across many business streams or specific to a particular business unit or operation Project risks are those arising from individual projects.

Strategic risk

Key strategic risks are those risks that if they were to occur would have an impact (either negative or positive) on SSE's goals or aspirations.

Group Risk Tolerance covers the SSE group (for more information on SSE group please see About electricity networks now and in the future.) Risk tolerance is influenced by overall generic risks which may impact on many different areas, and specific risks associated with an individual business unit. Both types of risk are considered where a bottom up, top down approach is used to ensure all risks are taken into account.

We have a formalised process for identifying, managing and monitoring risks. Our 'Business Risk and Internal Control Policy and Statement' and our 'Business Risk and Internal Control Work Instruction' are supporting documents to this paper. These two documents are used in conjunction with each other in order to ensure people understand and use the same processes.

Part of this process includes identifying risks both on a group level scale and business unit scale. The types of risk associated with the overall SSE group come under 20 headings. These 20 key areas are an output of the identification, management and monitoring of group level risk. These have been identified by considering areas of potential risk, and looking at a number of impact criteria including financial and regulatory impacts.

An example of one of the 20 key risk areas is Safety Management. The definition of this is: 'unsafe working practices, equipment and inadequate training may lead to accidents or incidents involving staff, contractors, members of the public or plant and equipment'. This key risk area has been identified both within our operations but also across all business activities. This demonstrates how wide reaching group level strategic risk can be as it can influence every task SSE undertake.

Each one of the 20 key risk areas has a dedicated risk owner/ champion, who is a member of our Management Board. The Management Board sits under the Board of Directors, where the Board of Directors has overall responsibility for risk management. The champions are required to provide 6-monthly updates to the Management Board on the level of risk in that area and what is being done to mitigate this. At each Management Board a number of the risk areas are discussed in greater detail; we call this a 'deep dive'. This is an opportunity to further discuss key risk areas and is a chance for Board members to fully explore the key risks in that key risk area.

As part of our process for managing risk, each part of our business has its own risk register which is maintained and reviewed in accordance with our internal work instruction. The risk register is a document which includes a standardised uniform scoring matrix that ensures all risks across SSE are evaluated in the same manner. . Using the same process and methodology for each risk register means risks are comparable, understandable and addressed in an effective/ clear manner. The outcome of managing risk in this way can be seen throughout everything we do because all key decisions must be informed by a full understanding of the risks involved.

Operational risk

Operational level risks are those which influence the way we do things on a day to day and process by process basis. This is at a lower level than strategic risk, yet these risks can be just as influential. Implicit within the defined risk process are that individual business units (or individuals) are responsible for actively managing their risks. This approach promotes that individuals are responsible for risk within their area and that they can cascade any required management action as required.

All business unit risk registers are centrally collated and analysed by the SSE Group Risk Manager on a six monthly basis

The risk matrices, as described above, are owned by the relevant business unit with the purpose of the risk matrices are to identify and evaluate risks in the business unit area-. Business units are responsible for awareness of exposures which fall into their area and interaction between other business units. They are required to evaluate risks as part of the management of the risk registers through methods such as key performance/ risk indicators. In addition, business units are also required to produce systemic and prompt reports on any perceived new uncertainties or risks, which will then inform decision making.

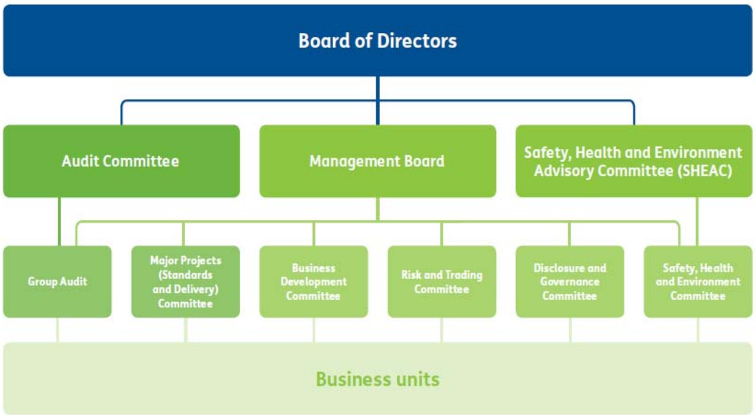
The management of operational risk is vital to our risk management process and is an integral part of our approach to risk. By ensuring we are risk aware and understand current, past and potential risk areas through the management of risk registers at an operational level, ensures that risks identified. Evaluated, managed and monitored with an ‘eyes open approach’.

Project risk

Project risk refers specifically to an individual project. This is more specific than operational risk, although the information is collated to inform operational level risk which in turn can influence strategic level risk. Business units are responsible for project risk. They manage project risk in accordance with our internal risk management process, as described above, where the methods used to fulfil requirements of our process include working with experienced advisers and undertaking assurance reviews.

Maintaining oversight

The structure of our internal control assurance process can be seen in the figure below.



The SSE Board of Directors are ultimately responsible for risk management. They do this through approving policies, procedures, and the frameworks for the maintenance of a sound and effective system of internal control. The Board determines the nature and extent of the significant risks it is willing to take in achieving its strategic objectives, and approves, regularly reviews, and updates SSE's strategy and business development.

The Management Board[1] monitors operational and financial performance while developing and implementing strategy, plans, policies, procedures and budgets for assessing and controlling all key strategic risks. They do this through receiving and reviewing regular presentations and reports from business units.

The Audit Committee and the Safety, Health and Environmental Advisory Committee (SHEAC) support the risk management responsibilities of the business units by reviewing and proposing changes to policy statements and strategy. They work alongside Group Audit to develop tools and processes which can be used within the business units.

All of the above demonstrates our commitment to ensuring that the risks and uncertainties for our business are mitigated and minimised. The direct senior management oversight ensures that appropriate focus is maintained, as well as ensuring the appropriate checks and balances are in place. This in turn ensures the risk to our customers in terms of any impact on their bills is reduced.

[1] Replaced in January 2014 with the Executive Committee.

Part 2

Managing external risk

Despite the comprehensive process framework and senior management focus that we have on identifying, mitigating and managing business risks, there are inevitably a number of external risks of potentially material impact that we cannot quantify and therefore cannot fully manage until they materialise.

These are issues that we have little or no control over. The source of these types of risk could be natural or political changes or significant economic shifts. It is therefore important that appropriate uncertainty mechanisms are in place to ensure we are not inappropriately exposed to consequential levels of costs which could impact on our ability to finance efficient delivery. That is, we need something in place to make sure we can provide the things we plan to, even though there are a lot of factors which can influence how we operate. Without some mechanism in place, we could be exposed to significant risks which could impact on our ability to efficiently run our business and continue to 'keep the lights on'.

In addition, we need to ensure that the risk is appropriately shared between us and our customers and that the impact on customers' bills is minimised. This type of risk must be shared between us and our customers because it spreads the risk and is in itself a way to mitigate the impact of changes in external factors. We can't solely be exposed to all external risk as this would at a minimum result in an increase in volatility of prices, and at the maximum could impact on our ability to run our business. When this risk is shared it means the level of volatility is smoothed and the impact of the change is mitigated.

This section details the uncontrollable risks and uncertainties that we expect to face during the RIIO-ED1 period and the regulatory mechanisms we believe should be put in place to manage them. In general, we propose a continuation of mechanisms already in place. Our views are broadly aligned with the proposals put forward by Ofgem. We support this approach and consider the proposals to be a well-balanced and proportionate package of uncertainty mechanisms.

What are regulatory uncertainty mechanisms?

During the price control reviews we agree our revenue with Ofgem for a period of time (DPCR5 was 5 years; RIIO-ED1 is 8 years). As we need to tell Ofgem what we think we will spend money on, we need to make sure we take account of everything which can influence our costs.

There are some costs which are certain, that is, we can accurately forecast what we think they will be. There are other costs which are uncertain. We still need to make sure we account for the uncertain costs and find a way to include them in our revenue, even though we might not be certain what they will be over the price control period.

We could use the same approach as we do for certain costs, that is, forecasting what we think these costs will be based on current knowledge. However, because they are uncertain, there's a high chance we'll get it wrong.

On the other hand, we could recover the money we've spent on these costs after they've happened, so we get back exactly what we spend. This means as we spend the money, it's taken from customers, that is, costs are passed on to our customers when they are incurred. This mechanism isn't always suitable for uncertain costs as there is little incentive to manage the impact, as they are always passed on to customers regardless of the impact. This also poses a cash-flow risk because it means we need to find the money to pay for these uncertain costs upfront, where there isn't a provision in place to get the money when we need it.

Regulatory mechanisms strike the balance between these options as they provide a mitigation of risk while also ensuring there are no perverse effects.

There are three different types of regulatory uncertainty mechanism:

- **Automatic** uncertainty mechanisms are those which are triggered automatically when our actual costs are different from our forecast costs in certain categories, such as Retail Price Indexation and Business Rates.
- **Volume driven** uncertainty mechanisms are those where there is uncertainty around the volume of certain activities that we will carry out during the period; the uncertainty mechanism is triggered when we meet a certain threshold of costs above the figure which we have forecast.
- **Exceptional** uncertainty mechanisms are those that may be triggered in very exceptional circumstances when certain criteria are met.

The following sections consider each type in turn.

Automatic uncertainty mechanisms

Automatic uncertainty mechanisms are those where a change in our revenue is triggered automatically where our costs are different from forecast for certain cost categories.

We describe five automatic uncertainty mechanisms in this section:

- Inflation – automatic application of the Retail Price Index (RPI).
- Automatic increase to cover Ofgem's fees.
- Automatic adjustment for changes to Local Authority business rates.
- Automatic adjustment for changes to charges for being connected to the electricity transmission system.
- Smart meter costs – automatic increase to cover the Data Communication Company's fees.

This section also includes a summary of the Shetland balancing mechanism for SHEPD, with reference to likely developments on Shetland during the RIIO-ED1 period.

A further two automatic uncertainty mechanisms – cost of debt indexation and changes to corporate tax rates – are described in Efficiently financing our plans.

Inflation

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
Allowed revenues are adjusted for actual RPI each year.	To continue current mechanism.	We support this approach.

Inflation is a change in prices where there is a change in the value of how much money can buy. For example, when there is an increase in inflation, the value of money goes down so people get less for the same amount. A change in price affects our business because a lot of what we do is influenced by prices. For example, procurement of goods and services required to install a new connection or our overhead costs such as offices, are all affected by a change in price. When something costs more, we need to be able to pay more, even though the thing we are buying hasn't changed.

Inflation is measured by the Retail Price Index (RPI) which is a set formula commonly used in the UK as a measure of how much prices have changed. The Retail Price Index is made up of a 'basket' of goods that is intended to reflect the consumption of the population as a whole. Some of our costs, for example the price of materials, vary in a different way to RPI. We describe this inflationary effect in Our expenditure forecast and the impact on our costs forecasts.

Our Business Plan has been prepared using prices from 2012/13. We expect that these prices will go up every year. Rather than try to forecast how we think that prices will change each year, we propose RPI is automatically applied to our forecast costs and allowed revenue each year. This approach protects SSEPD and our customers from an inaccurate, pre-determined forecast of inflation, while maintaining an incentive on us to keep our own cost base below inflation.

In addition, our Regulatory Asset Value, including forecast additions, will continue to be adjusted in line with the full year RPI each year.

This is a long-standing regulatory approach. The practical application of this means we are always in line with current prices. Every year our allowed revenue formula which includes RPI, will take into account changing prices. This is beneficial to all parties, as other options would mean an inaccurate price base. We need to make sure we have the right amount of money available at the right time.

Our current forecast of RPI for the RIIO-ED1 period is shown in **Table 3**.

Table 3 RPI forecast for RIIO-ED1 period

Year	RPI-measured inflation
2014/15	3.0%
2015/16	3.4%
2016/17	3.6%
2017/18	3.8%
2018/19 and thereafter	4.0%
2019/29 and thereafter	3.4

Source: First Economics

Ofgem’s fees

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
Ofgem licence fees are recovered in full from customers each year.	To continue current mechanism.	We support this approach.

Licence fees are payments to the Authority. They take account of the following costs:

- Ofgem’s own costs
- Ofgem’s income
- Proportion of the expenses of the National Consumer Council (NCC)
- Proportion of the expenses of the Secretary of State
- Proportion of the expenses of the Citizens Advice or Citizens Advice Scotland
- Any adjustment as calculated under Ofgem’s price control regime.

The amount payable by each DNO licensee is determined by the proportion of the number of electricity customers which are directly connected to any licensed electricity distribution network of that electricity distribution licence holder, to the total number of electricity customers.

The bill is received in 2 tranches. The first bill covers 75% of the overall cost of the licence fee, where the second bill covers the remaining 25%.

We cannot accurately forecast future licence fees as we do not control any of the components which make up the costs within the bill or the split of costs between network licensees. Thus it is appropriate that we are allowed to adjust our revenue each year to recover Ofgem’s fees in full.

We support Ofgem’s decision to continue to use the current mechanism, which has historically been used.

Our forecast of future licence fees for the RIIO-ED1 period is based on these fees increasing in line with RPI each year (**Figure 2** and **Figure 3**). The uncertainty is how far our estimate of licence fees increasing in line with RPI is wrong. Our revenue is set based on this forecast of Ofgem’s fees; the uncertainty mechanism then allows us to recover the difference between our allowance and the amount Ofgem actually charge.

Figure 2: Historic licence fees

£m	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Ofgem licence fees	62	46	46	47	47	45	46	56	42	41	52
SHEPD	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4
SEPD	1.5	1.3	1.3	1.3	1.3	1.3	1.3	1.6	1.2	1.2	1.5

Figure 3: Forecasted levels of licence fees

£m	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
SHEPD	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
SEPD	1.5	1.5	1.5	1.6	1.7	1.7	1.8	1.9	1.9	1.9	2.0

We have forecasted SHEPD and SEPD based on changes in RPI where 12/13 is still a forecast as the second tranche of the licence fees has not yet been received. In summary, we estimate the total cost over the RIIO-ED1 period to be £18.5 million (including inflation), which equates to around £5 per customer over the period.

Local Authority business rates

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
Business rates are recovered in full from customers each year.	To continue current mechanism.	We support this approach.

Business rates are taxes that we are required to pay on our distribution networks and associated properties. The annual charge is calculated by multiplying the rateable value (RV) of the network by the unified business rate (UBR).

The RV of the network is calculated on a periodic basis by the Valuation Office Agency in England (VOA) and the Scottish Assessors Association in Scotland (SAA) respectively. The last valuation took place in 2010. The Scottish and UK Governments set the UBR on an annual basis.

Normally, each revaluation of the RV for a period of 5 years and the 2010 valuation was due to end in March 2015. However, in late 2012 both Governments announced their plans to postpone the planned 2015 valuation until April 2017. Therefore the RV set in 2010 will continue through until 2017.

During the course of previous valuation processes SSEPD has actively engaged with the VOA and SAA with the objective of minimising the rates liability and ensuring the rates charges passed to consumers are minimised. This engagement was done both collectively with other DNO's via the Energy Networks Association and also on an individual DNO basis. We have utilised the services of a firm of Chartered Surveyors with many years of ratings and electricity industry experience to assist us in the negotiations as this is a specialist area with some complex legislation and valuation concepts. This robust engagement and use of specialist support has successfully allowed us to minimise the rates liability. SSEPD will engage in the same robust process during the 2017 valuation.

As it is difficult to accurately forecast future business rates, there has historically been an automatic adjustment mechanism to allow the full cost of rates to be passed-through and recovered from customers – as long as DNO's ensure every effort is made to minimise the rates liability. We propose a continuation of this approach for the RIIO-ED1 period, with an allowance provided based on our forecast business rates and an automatic mechanism to adjust this each year to the actual costs incurred.

There is a significant element of uncertainty about both the valuation process and whether VOA/SAA will utilise the same methodology as in 2010. In order to forecast our business rates for the RIIO-ED1 period, we have made the following assumptions:

- Rates charges will remain broadly at 2012/13 levels through until 2016/17 pending the outcome of the 2017 valuation.

- The rates revaluation calculation is based on an income and expenditure methodology. One of the key components of the RV is the level of RAV. An increased RAV in real terms will result in increased revenue. Between 2007/08 and 2012/13 there has been an increase in RAV of 6% in SEPD and 1% in SHEPD. There are a number of other smaller contributing factors associated with the valuation methodology that may be assessed differently in 2017 for SEPD and will give rise to an increased RV in SEPD. We do not expect similar methodology factors to impact SHEPD. Following the 2017 valuation we would expect the SEPD RV to increase by approximately 5% to 10% and the SHEPD RV to remain broadly in line with 2010 RV.
- Offsetting the increased RV we would expect a small reduction in the level of the UBR. We would expect the overall UK RV to increase from 2010 as economic conditions improve. The government would not increase the total rates collected as the rates collected in theory should remain the same. In order to do this the UBR would be reduced accordingly.

Based on the above assumptions we estimate that SEPD rates will increase by approximately 3% on 2010 valuation levels and the SHEPD rates charge will remain at 2010 valuation levels (**Figure 4** and **Figure 5**).

In summary, we estimate the total cost over the RIIO-ED1 period to be around £200m in our SHEPD area around £320m in our SEPD area. This equates to around £140 per customer over the period.

Figure 4: DPCR5 Business rates

	2010-11	2011-12	2012-13	2013-14	2014-15
	£M	£M	£M	£M	£M
SHEPD	24.18	24.23	24.85	24.85	24.85
SEPD	42.59	39.88	39.31	39.31	39.31

Figure 5: Forecast business rates for RIIO-ED1

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
	£M	£M	£M	£M	£M	£M	£M	£M
SHEPD	24.85	24.85	24.85	24.85	24.85	24.85	24.85	24.85
SEPD	39.31	39.31	40.49	40.49	40.49	40.49	40.49	40.49

Figure 6: SEPD Business rates - DPCR5 and forecast for RIIO-ED1

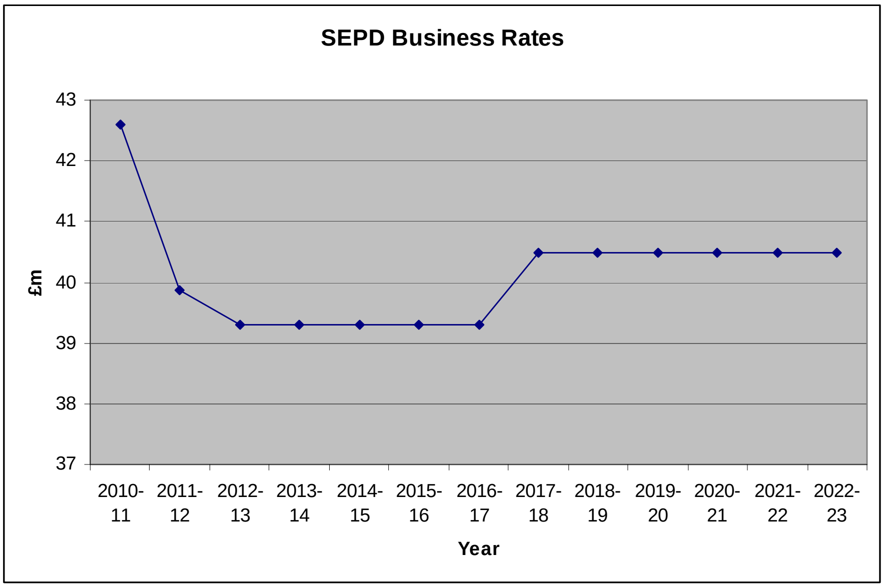
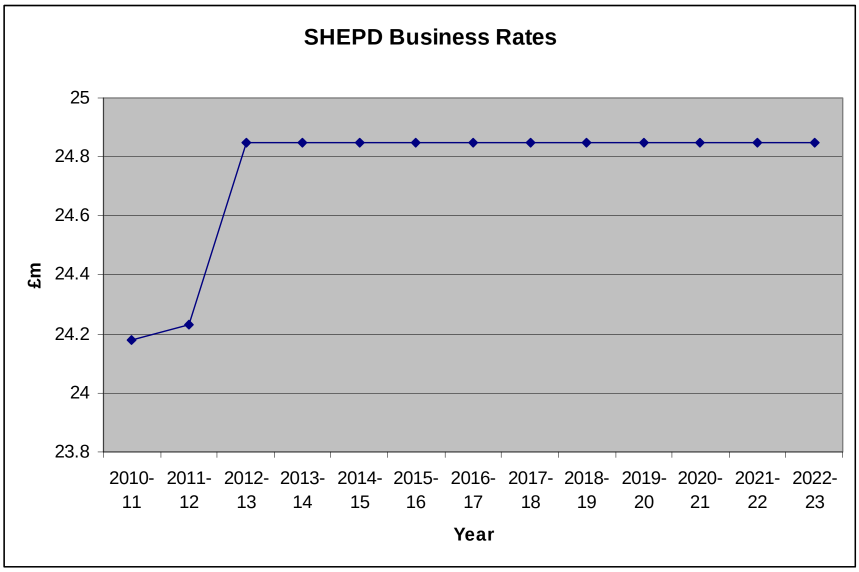


Figure 7: SHEPD Business rates - DPCR5 and forecast for RIIO-ED1



Transmission connection point charges

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
Charges for DNO connections made to the electricity transmission system prior to 1 April 2010 are recovered in full from customers each year.		We support this approach.
Charges for DNO connections made to the electricity transmission system after 1 April 2010 are split into two elements: 100% pass through on charges outside the DNO's control and an incentivised element for areas that the DNO can influence.	To retain the 100% pass through element and replace the incentive element with an ex ante adjustment.	We support this approach.

Transmission connection point charges are DNO connection charges that we are required to pay to the system operator, under the Connection and Use of System Code (CUSC). These charges are to cover the cost of equipment that we use at Grid Supply Points (GSPs) and are calculated under National Grid's connection charging methodology.

The current mechanism consists of two separate elements: 100% pass through of charges that are outside of our control; and an incentivised element for the element of these charges that we are able to influence. For RIIO-ED1, the 100% pass through element is retained, and the DPCR5 incentive element will be replaced with an ex ante allowance that will be subject to adjustment.

In our SHEPD area we expect to see a very significant increase in the level of TCPCs, both in the pass through and in the ex ante elements. The main driver of the increase is the growth in renewable generation connecting to the transmission and distribution systems. There are also a number of other contributors to the expected increase:

- Increase in the price control period from five to eight years
- The significant increase in the capacity at the GSPs where replacement works are required
- The increases in SHE Transmission plc's 'Illustrative Connection Asset Charges'

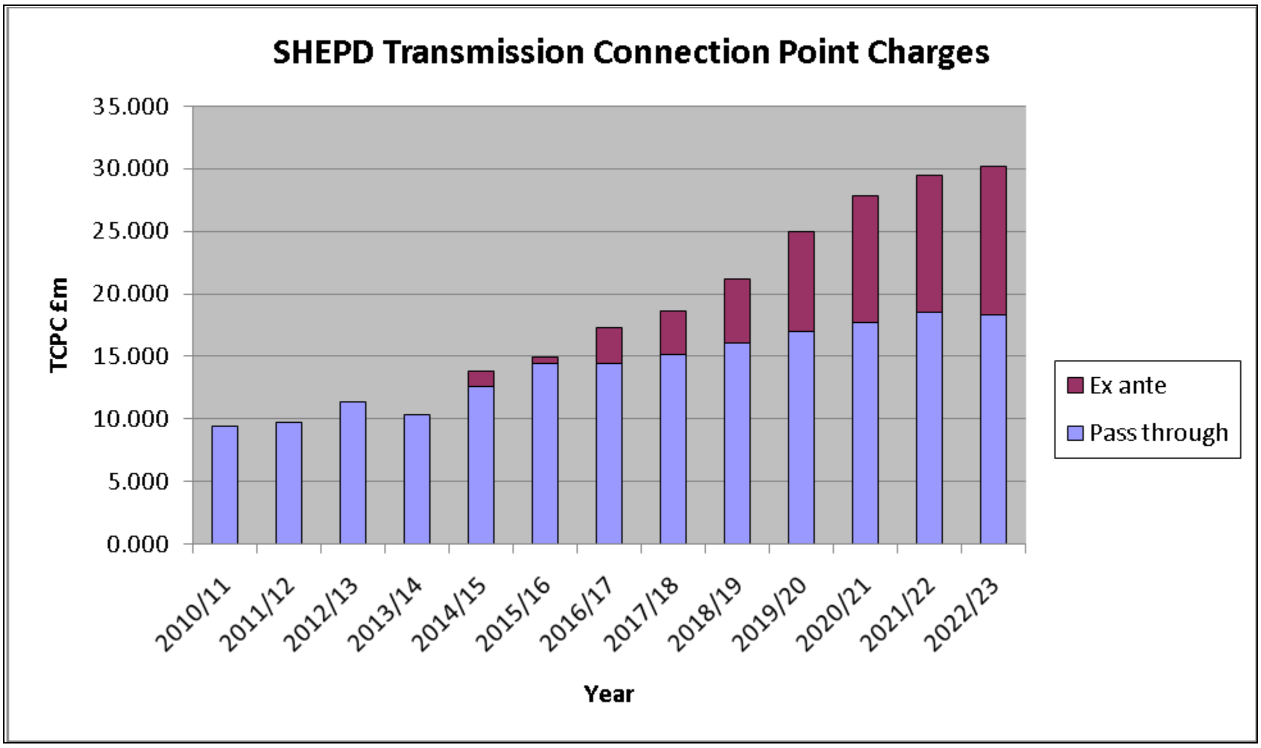
Of 16 projects that are forecast to be completed in RIIO-ED1, 12 of these are expected to be completed within the first three years of RIIO-ED1, meaning that we will see the increased charges for the full period of the price control.

Our forecast TCPCs for RIIO-ED1 for SHEPD are set out in Figure 8 below. The increase in TCPCs since 2010 is illustrated in Figure 9.

Figure 8: SHEPD forecast TCPCs for RIIO-ED1

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
SHEPD	£M	£M	£M	£M	£M	£M	£M	£M
Pass through	14.39	14.45	15.15	16.11	16.99	17.71	18.5	18.30
Ex ante	0.50	2.89	3.49	5.07	7.98	10.12	11.02	11.91
Total	14.89	17.34	18.64	21.18	24.97	27.83	29.52	30.21

Figure 9: Chart showing TCPCs for SHEPD – DPCR5 and forecast for RIIO-ED1



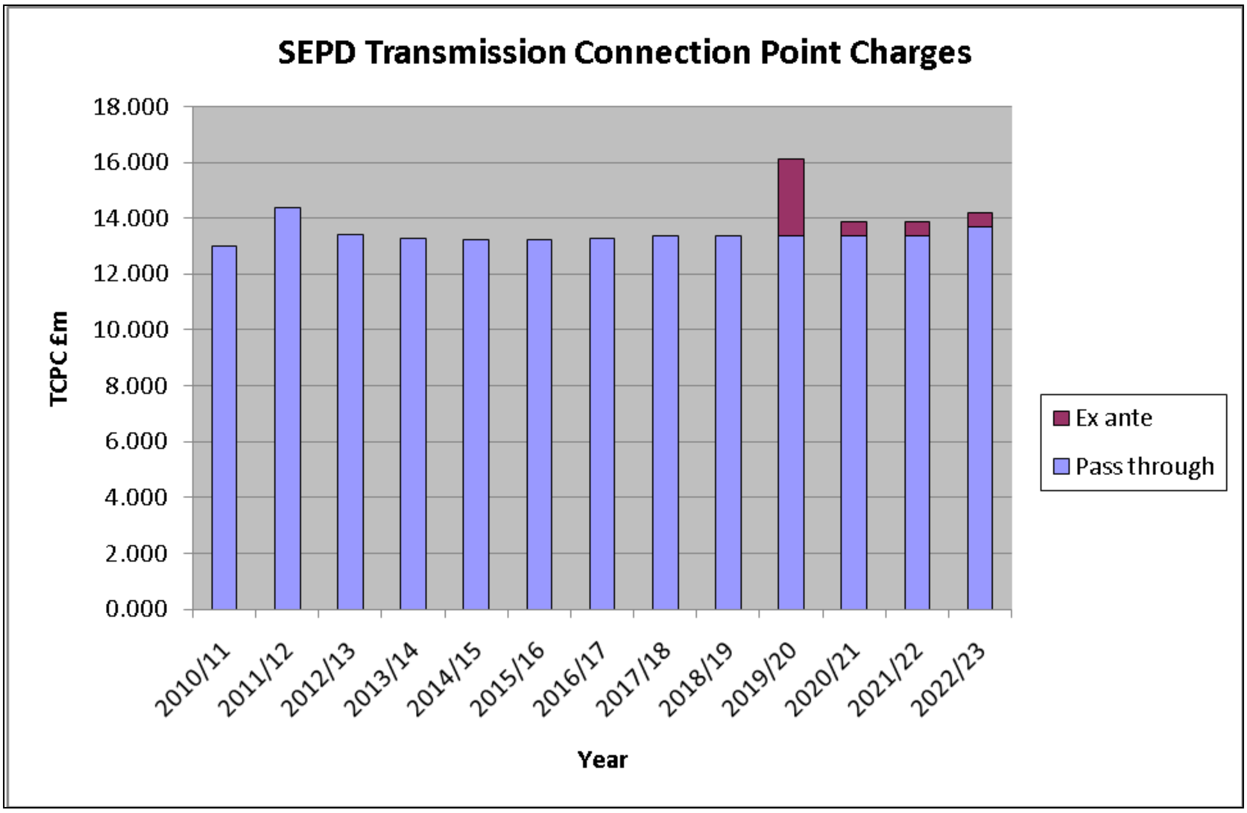
In SEPD we do not expect to see any significant change from DPCR5 charges. The slight increases that we do expect to see is as a result of the lengthening of the price control period from 5 to 8 years, and one project forecast to complete in 2020, increasing costs for the last 4 years of the price control.

Figure 10 below sets out our expected charges for the RIIO-ED1; these are flat over the period. Figure 11 demonstrates the relative stability of TCPCs that we have seen since 2010.

Figure 10: SEPD forecast TCPCs for RIIO-ED1

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
SEPD	£M	£M	£M	£M	£M	£M	£M	£M
Pass through	13.22	13.29	13.36	13.36	13.36	13.35	13.35	13.70
Ex ante	0	0	0	0	2.75	0.51	0.51	0.50
Total	13.22	13.29	13.36	13.36	16.11	13.86	13.86	14.20

Figure 11: Chart showing TCPCs for SEPD - DPCR5 and forecast for RIIO-ED1.



In summary, we estimate the total cost over the RIIO-ED1 period to be £295m, which equates to around £127 per customer over the period.

Smart meters – DCC fees

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
None.	DCC fees should be recovered from customers until the end of 2019, after which DNOs should pick up these costs. Note this view was expressed prior to the delay to the smart meter roll-out programme.	We support this approach.

Smart meters are intelligent meters which tell customers how much energy they are using at any point in time, as well as the cost of the energy they are using. Information is displayed on a device in the home or customer's property so it is easy to access and read. The meters can also communicate with energy suppliers and other parties who are authorised to access it, including DNOs like us. We can then use this information to help us manage our networks.

A key benefit of smart meters is the help with the transition to a low carbon economy and help GB meet the future challenges of ensuring an affordable, secure and sustainable energy supply. For more information on Government objectives, please see the About electricity networks now and in the future; for more information on smart meters, please see our paper on smart meters.

The Government's vision is for every home and small business in Great Britain to have a smart metering system installed by the end of December 2020. This means the industry will need to replace around 54 million meters and visit over 29 million properties. We have 3.7 million meters in our network areas in the north of Scotland and south of England that will need to be replaced (SEPD - 2,940,000, SHEPD - 743,000).

The Data and Communications Company (DCC) is a key element of the Government's approach to rolling out smart meters in Great Britain. The DCC will offer the means by which network operators, suppliers and other energy services companies can communicate remotely with smart meters. The DCC activity will be licensed, and regulated by Ofgem. Under a new Smart Energy Code (SEC) that is currently being consulted on by the Government, DNOs will be obliged to use the DCC services. The SEC will govern the relationship between the DCC and users of its services including network operators and suppliers. It will also set out a charging methodology under which charges for DCC services will be calculated.

These are costs that are unavoidable and outside of our control. Ofgem has suggested that after smart meter roll-out is complete, we should be able to make use of smart meter data to reduce the costs of our business. Hence Ofgem has proposed that after 2019/20, we would not be allowed to recover these costs from customers. We support this approach.

Shetland balancing

Existing regulatory mechanism	Ofgem March decision	Our view for RIIO-ED1 period
Pass through mechanism whereby Shetland balancing costs are recovered in full from customers in the north of Scotland each year.	None	Presume continuation of current mechanism until 2019/20, subject to further determination on Integrated Plan for Shetland.

These costs impact SHEPD only.

The Shetland Isles are not connected to the mainland meaning that for generation purposes they must be self sufficient and ensure that there is enough generation to meet demand at all times. From the introduction of British Electricity Trading and Transmission Arrangements (BETTA) in 2005, SHEPD has assumed the role of System Balancer (SO) to ensure that generation and demand is managed to maintain security of supply at all times. The costs associated with performing this role, and which are not recovered from power purchase agreements with suppliers, are currently recovered from SHEPD customers through DUoS charges and include the incremental cost of generation on Shetland (including the costs associated with the diesel fired Lerwick Power Station). Since the incremental cost of generation varies on an annual basis and is out with the control of SHEPD, the uncertainty is currently managed by way of a pass through cost recovery mechanism set out in our licence. In summary, where the costs of performing this role differ from the combined sum of income received from suppliers in respect of generation on Shetland and the annual upfront allowance included in the current price control, a corresponding adjustment is automatically made to SHEPD's allowed revenue. For the first three years of DPCR5, the annual average differential charge recovered through SHEPD's DUoS charges has been in the region of £26m.

However, when the current price control was set, Ofgem recognised that Shetland faces a number of future challenges. Accordingly, SHEPD was tasked with devising a renewed energy system for Shetland, an Integrated Plan, for submission to Ofgem by 31 July 2013. Ofgem is currently considering the Integrated Plan. As a consequence, where Ofgem's determination on the Integrated Plan has cost and revenue implications for SHEPD during the transition period within ED1, it is necessary to ensure that they are appropriately reflected.

For the purposes of this update, we propose that the existing pass through mechanism continues up to, and including 2018/19 and thereafter we have set the mechanism to zero. This is an assumption for modelling purposes and we expect the regulatory provisions in Ofgem's determination on the Integrated Plan will be incorporated at that point.

Figure 12: Forecast costs for Shetland balancing

2015/16	2016/17	2017/18	2018/19	2019/20 and beyond
£26.5m	£26.5m	£13.25m	£13.25m	Zero

Since any future arrangements for Shetland will need to be agreed by Ofgem, the proposed ED1 uncertainty mechanism outlined above may need to change depending upon the final outcome.

Volume-driven uncertainty mechanisms

Volume-driven uncertainty mechanisms are there to provide for areas of our business where there is a high degree of uncertainty as to the level of activity that we will see.

We describe six volume-driven uncertainty mechanisms in this section:

- Smart meters – the number of times we will need to assist in the installation of smart meters.
- Dealing with the costs of changes to street works legislation.
- Government requirements to improve the security of nationally important infrastructure sites.
- Uncertainty about the growth in either demand or generation connected to the network.
- Dealing with the roll-out of new innovations.
- The potential requirement for electrical lines and equipment to be moved to allow for rail electrification.

A further volume-drive uncertainty mechanism – the cost of pension deficit repair – is described in Efficiently financing our plans.

Each of the proposed volume-driven uncertainty mechanisms has a trigger level that we must hit before the mechanism initiates; below this level we will bear the costs. This trigger level is high: 1% of allowed revenue for the RIIO-ED1 period, and we can therefore still be exposed to very significant costs before an adjustment is made. This ensures that there is an appropriate balance of risk between us and our customers and that our customers are not impacted unless the costs reach a significantly high level.

However, there is a risk that we see costs across several of the uncertainty areas which do not individually reach the materiality trigger of 1% of allowed revenue, but which when looked at together are material costs. This cumulative effect is an important issue that should not be overlooked. However, we will implement risk mitigation actions to manage any cumulative effects which may occur.

Smart meter installation

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
None.	Upfront allowance based on 2% call out rate. Volume driver with tapering mechanism.	We support this approach.

The section above regarding Smart Meter DCC costs is also related to this section as they both relate to the roll out of Smart meters. We recognise the importance of our role in helping to facilitate the roll-out of smart meters in RIIO-ED1 to every home and small business in Great Britain. Across the industry we will need to replace around 54 million meters and visit over 29 million properties by the end of December 2020. We have 3.7 million meters in our network areas in the north of Scotland and south of England that will need to be replaced (SEPD - 2,940,000, SHEPD - 743,000).Whilst energy suppliers are leading this roll out, there will be significant challenges faced by all industry parties. In particular, it is recognised by suppliers and DNOs that during the installation of smart meters, technical issues will arise that will require us to be called out to customers' premises to assist.

To understand how this will affect us, and the number of call outs we can expect to see, we have carried out various types of research including a survey of more than 4000 customers from the end of 2010 to the start of 2011. We have developed a good understanding of costs and what is likely to be involved. Further information can be seen in our paper on smart meter.

Throughout the Smart Meter roll out, we are committed to working with all of our stakeholders to ensure that the impact of network issues reported during the smart meter roll-out is minimised.

None-the-less, given the scale of the project, the number of call-outs and hence the level of costs to us are likely to be significant. There will be a large increase in workload in the RIIO-ED1 period but the cost per unit won't change. This is because we would have to visit these properties anyway, it's just we're doing all our visits one after the other in a short period of time. That is, the amount of time has condensed but the number of properties remains the same. The tapering mechanism Ofgem proposes implies economies of scale, that is, the more visits undertaken, the lower the unit cost. Our findings have not been consistent with this view, and there is a risk that unit costs do not decrease as forecast. Nonetheless, we support Ofgem's proposal in this area and will monitor the realisation of any economies of scale.

There are a number of different activities that we could be required to carry out when called out to premises for an issue with the installation of a smart meter. We have categorised these activities as follows: cut out; service inspection; service alteration; and other miscellaneous activities. We may also have abortive call outs where, on inspection, no service is required. The work we will need to carry out will be varied in terms of urgency, cost and skills required. This will mean a significant increase in workload and costs for our business over the next 7 years. Dedicated resources will be needed to ensure we are able to respond in timescales that will minimise disruption for our customers. However we will also need to plan our work and respond efficiently to maintain safety and keep costs down.

Having carried out surveys on our network, we have found that 6% of smart metering installations on the SHEPD network and 7% on the SEPD network will require some input from us. 3.5% of all installations on SHEPD network and 4% on the SEPD network will require work to be carried out by us on our network either immediately to maintain safety or in the short term to allow the smart metering system to be installed. The majority of the remaining jobs can be carried out at a later date as part of 'business as usual' where there is no immediate safety or reliability concern and there is no impact on the smart metering programme.

We have also been able to determine unit costs from our survey data (**Figure 13**). The current unit cost rates, as further detailed in our Smart Metering Justification Paper and the associated CV109 spreadsheets, we believe provide a sound basis for setting future allowances.

Figure 13: Unit Costs

Item Description	SHEPD		SEPD	
	DPCR5	RIIO-ED1	DPCR5	RIIO-ED1
Cut out change	£248	£249	£242	£247
Service Inspection	n/a	n/a	n/a	n/a
Service Alteration	£1,063	£1,225	£1,227	£1,281
Abortive calls	£59	£52	£51	£50
Miscellaneous repairs/ safety reports	£145	£145	£140	£140

Based on our findings, which we have shared with many parties including DECC and Ofgem, we support Ofgem's proposals of an upfront allowance of 2% call out rate plus a volume driver. We believe this is proportionate and will help facilitate the smooth roll out of smart meters. Additionally, and despite our concerns regarding whether economies of scale will materialise for call out unit costs, we support Ofgem's proposals regarding the tapering mechanism.

Street works

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
Opportunity to apply for costs midway at a pre-determined window.	To continue current mechanism, with an application window in May 2019.	We support this approach, but suggest that the scope is extended to encompass proposed legislation in Scotland.

We have the potential to incur significant costs as a result of working in areas that are operating permit schemes established through the Traffic Management Act 2004[2] or the Transport (Scotland) Act 2005[3] respectively, as well as other areas of street works legislation including the New Roads and Street Works Act 1991[4].

These are costs which we need to pay in order to carry out our operations, from laying new cables to repairing underground cables for example. We incur these costs from working on the public roads, as we need to have a permit to allow us to work for a period of time and make sure we do certain things like reinstate the road back to the same high standard as we found it. There are also things like lane rentals we need to pay for, as well as fines if we don't complete the work within a certain period.

In general, cost incurred in relation to streetworks can be broken down into the following categories:

- Permits: costs are incurred by a DNO when works are undertaken within the control of a local authority which has the authority to issue permits
- Permitting penalties: costs incurred by a DNO when non-compliance with the permitting process occurs. This could be anything from a typo on the permit request to changing required start dates for works to not completing works by the required deadline.
- Notification Penalties: this is similar to permitting penalties but with reference to road opening notices. Streetworks notifications incur no cost to a DNO at the moment.
- Sample and Investigatory Inspections: DNOs are required to complete a percentage of sample and investigatory inspections dictated by the Local Authority
- Inspections Penalties: These are penalties incurred following inspection where non-compliance with the TMA has been confirmed.

As a DNO we recover costs for Permits from connectee's, and also from Contractors where overstay fines are received due their lapse in works.

[2] http://www.legislation.gov.uk/ukpga/2004/18/contents
[3] http://www.legislation.gov.uk/asp/2005/12/contents
[4] http://www.legislation.gov.uk/ukpga/1991/22/contents

The amount of these costs we incur is influenced by lots of different factors including the number of faults we have, and the number of connections we make. The forecasts for these two factors can be seen in our papers entitled A reliable supply of electricity and Get connected, respectively. We also are becoming more efficient at what we do, which has an effect on our costs as it drives the cost down.

Overall, we are expecting costs to be consistent across both our licence areas. Although we are expecting an increase in economic activity, and an increase in the number of connections (see our Get connected), we are also forecasting a decrease in the number of faults (see out A reliable supply of electricity) and increase in efficiency. This means our forecasted costs are broadly flat for both SEPD and SHEPD, as seen in our forecast of direct and indirect costs in **Figure 14** below.

Figure 14 Forecast street works costs for RIIO-ED1

£ (m)	2016	2017	2018	2019	2020	2021	2022	2023	RIIO-ED1
SEPD	0.924	0.924	0.924	0.924	0.924	0.924	0.924	0.924	7.396
SHEPD	0.184	0.184	0.184	0.184	0.184	0.184	0.184	0.184	1.473

However, there are some uncertainties which could significantly impact on our forecast. In Scotland, there is the potential of legislative change which could result in an increase in costs. In SEPD, there is the potential of more local authorities automatically enforcing the Traffic Management Act 2004 which could result in an increase in our costs.

In SHEPD, there is the potential of a change in legislation specific to Scotland. As a result of a recent Road Maintenance Review[5], the Scottish Government has now issued a Strategic Consultation on Works on Scottish Roads[6]. This sets out a number of proposals, the most significant of which discusses required contributions from utility companies for the costs of making good long term damage to Scottish roads. This is on the basis of the reduction in service life of a road that is considered to occur due to utility company reinstatements, even when such reinstatements fully comply with the specification. If this proposal was to be implemented, we estimate the cost to us to be £3-4 million per annum. This is a significant increase from the proposed level of spend of £184K per annum in our SHEPD area over the RIIO-ED1 period. Therefore, we propose this uncertainty should be brought within the scope of the street works reopener. The benefits of being included means the risk can be managed.

[5] www.transportscotland.gov.uk/road/maintenance/road-maintenance-review

[6] www.transportscotland.gov.uk/strategy-and-research/publications-and-consultations/j266615-00.htm

In SEPD, there is the potential of many local authorities increasing enforcement of the Traffic Management Act 2004. To date, we have seen the level be broadly flat; however there is the potential of an increase in costs should more local authorities more strictly enforce the Act.

In order to address the uncertainty around street works legislation and implementation, there is an existing regulatory uncertainty mechanism that allows for an application for efficient cost recovery at a pre-defined time window. Ofgem has proposed that this mechanism is extended into the RIIO-ED1 period, with a single application window in May 2019. At that date, subject to meeting the cost trigger of 1% of allowed revenue, we would have the opportunity to apply for costs. We agree with and support this approach. However, we believe it should be extended to cover the proposed changes in Scottish legislation.

Security of nationally important infrastructure

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
A single application window in which DNOs can apply for a reopener for the costs associated with carrying out security works as required by the Centre for the Protection of National Infrastructure (CPNI). The materiality trigger is 1% of base demand revenue.	An application window in May 2019 in which DNOs can apply for a reopener for the costs associated with carrying out security works as required by the CPNI. There will be a materiality trigger of 1% of average annual RIIO-ED1 base revenue. Costs that do not reach the materiality trigger will be logged up for recovery at RIIO-ED2.	We support this approach.

The Centre for the Protection of National Infrastructure (CPNI) can designate works that are required to be carried out to improve the security of certain DNO sites. We can incur significant costs in order to comply with a requirement, as notified by a relevant authority, to enhance the security of particular sites on our network. These requirements can be notified by relevant authorities at any time and we do not have any influence over the scope or timing of the works. The requirements are very specific and often to a higher specification that we would typically provide. We cannot therefore accurately forecast these costs.

The existing mechanism is a single re-opener window in which we can apply for costs that meet a certain materiality threshold. For RIIO-ED1, an allowance will be provided where we are able to provide 12 months of cost data relating to security requirements. In addition to this, there will be a single re-opener, with a re-opener window in May 2019, and a materiality threshold of 1% of annual base revenue.

In addition, any efficiently incurred costs that do not meet the materiality threshold be logged up for consideration at RIIO-ED2. These are works that we are required to carry out and whilst we will always ensure that any work is carried out efficiently, we do not have any control over the extent of the works. It is therefore important that we are able to recover all of these costs. This must include the costs associated with maintaining the enhanced security to the required level.

We do not currently have any CPNI designated sites and have therefore not included any costs for an ex ante allowance. We agree with the proposed approach and if we are required to carry out works for CPNI over the course of RIIO-ED1 then we will require the use of the reopener window or logging up of costs mechanism.

Uncertainty about load related growth

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
A single application window to recover costs of general reinforcement and low-volume high-cost connections. And A volume driver for high volume, low cost connections.	A single LRE reopener to cover low volume high-cost connections, high-volume low-cost connections and general reinforcement. Two reopener windows (May 2017 and May 2020) to apply where costs are over or under our ex ante allowance by >20% and the amount over or under meets or exceeds 1% of annual average base ED1 revenue.	We support this approach.

Our network can grow through many different ways, one of which is related to the load on our network. Load, the amount of energy going through our network, changes as a consequence of the number of connections made to our network, or by the way our customers use their electricity. For example, connecting new properties onto our network results in load related growth of our network.

Load related expenditure (LRE) means money which we need to spend on our network as a result of lots of customers using energy from our network, and is related to the capacity of the components making up our network. LRE covers all of the investment that we are required to make in our system to ensure that it is able to meet the requirements of changes in the level and patterns of load on our network.. The expenditure that we intend to make in order to continue to provide a reliable supply to our customers over the RIIO-ED1 period is provided in further detail in A reliable supply of electricity. Some relevant information is also included in Get connected, which covers the investment that we will be required to make to connect Distributed Generation customers during RIIO-ED1. Distributed Generation is generation assets which produce electricity and are connected straight to the distribution system.

LRE covers a huge proportion of our total expenditure and encompasses a large number of activities. Whilst we have made every effort to forecast our expenditure as accurately as possible, there inevitably remains a certain degree of uncertainty, particularly around the level of Distributed Generation and Solar PV (solar panels often seen on roofs of houses) that will connect to our system.

The introduction of the Feed-in Tariff Scheme in DPCR5 led to a huge increase in the number of connections to our network, demonstrating the uncertainties that exist in this area. We have given a conservative estimate of the level of DG and Solar PV that we expect to connect to our network as we do not wish to expose our customers to costs that may not be necessary. However there is a concern that the level of DG and Solar PV connecting to our network could be far larger than we expect.

The current DPCR5 mechanism provides for a single reopener window in which efficient costs the connection of low-volume high-cost connections involving shared assets and for general reinforcement of our system. The materiality threshold for these costs is 1% of base demand revenue. There is a separate volume driver for high-volume low-cost connections involving shared assets.

For RIIO-ED1 we propose combining all load related expenditure into one reopener, including high-volume low-cost connections. Where we over or under-spend by >20% of our relevant ex ante allowance and the amount over or under-spent meets or exceeds 1% of our allowed revenue. Given the degree of uncertainty and the significant level of expenditure involved, we propose two reopener windows: May 2017 and May 2020.

High value projects reopener

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
A single reopener window for individual schemes of £15m or more that are not included in an ex ante allowance. Threshold 1% average annual base revenue.	To continue the current approach with a single window in May 2019, but increase the scheme value to £25m.	We support this approach.

High value projects (HVPs) have historically been individual schemes of £15m or more that are not already accounted for in our allowance but that we will be required to complete during the price control period. In RIIO-ED1 schemes will be considered as HVPs if they exceed £25m. There may be HVPs that we are aware of but do not yet have accurate forecast costs for or have not yet developed a needs case for. This could be because of concerns over delays with planning consents or resource constraints. There is also a possibility that there may be schemes that we have not yet planned but which may become necessary during the course of the RIIO-ED1 period. These are not typical projects that we carry out, but only those that are in excess of £25m.

The existing mechanism is a single reopener window that applies to the totality of high value projects (rather than individual projects) where the net efficient expenditure over the price control period is greater than 20% of the baseline. Currently, HVPs are defined as those costing over £15m.

Ofgem has proposed continuing with a single reopener approach (in May 2019), with a change to the definition of HVPs to those costing over £25m. This mechanism will include both projects that are already in the pipeline but have not been included in our allowance, and any new projects that arise during RIIO-ED1. The materiality threshold will be 1% of average annual base ED1 revenue.   We support this approach.

Innovation roll-out

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
None.	Two reopener windows (May 2017 and May 2019) in which we will be able to apply for innovation roll-out costs that meet the trigger level of 1% of annual average base E1 revenue. This will be for costs not yet incurred.	We support this approach.

The innovation roll-out mechanism is being introduced to provide us with funds to roll-out proven innovations that we indentify during the price control period that reduce our carbon or environmental impact and provide long term value for money for customers.

We are supportive of the approach proposed by Ofgem to introduce an Innovation Roll-out Mechanism for funding for the roll-out of proven low carbon or environmental innovations. There will be two windows in which to apply for a reopener in this area which is appropriate given how quickly innovation projects can progress and change. Costs which exceed the trigger level will be 1% of annual average base ED1 revenue will be considered for funding, if the following criteria are met: the project provides long term value for money for customers; there are low carbon or environmental benefits; and the roll-out will not facilitate commercial or financial returns within the remainder of the price control period that would effectively cover the cost of the roll-out.

Innovation is hugely important to us as a business and we are currently working on number of innovation projects with the aim of ensuring that we continue to operate as efficiently as possible. We also have a significant number of other ideas that are currently in the research phase and that we plan to progress. It is therefore useful to have this mechanism to allow us fund the roll out of some of these innovations in the RIIO-ED1 period. Further detail on this is provided in our Innovation Strategy.

Rail electrification

Existing regulatory mechanism	Ofgem March decision	Our view for the RIIO-ED1 period
None.	Unknown.	A single reopener window where we are able to recover costs that exceed 1% of average annual base revenue.

Network Rail is carrying out a project of rail electrification across the country. Rail electrification allows railway trains to be supplied with electricity such that they can operate without the use of a diesel engine, which may be more efficient. To allow this project to progress, DNOs will be required to carry out a significant number of diversions throughout the RIIO-ED1 period. There is an ongoing issue in relation to an Master Wayleave Agreement whereby Network Rail consider that the costs of these diversion works should by picked up by the DNO and hence by electricity customers. Whilst until now these costs have been fairly low given the limited development of the national railway network, the electrification project is likely to require significant expenditure.

It is intended that all rail electrification projects across the country will be completed by 2019. The Great Western Main Line is the first major project of this strategy and we forecast that the associated diversion work of this project alone will cost around £35m.

We consider it inappropriate for electricity customers to fund the costs of carrying out works that are necessary only for the improvement of the railway network and we continue to engage with Network Rail, DECC and Ofgem to solve this issue. However, there is still significant uncertainty in this area and in the event that the legalities are such that we are required to fund these works, we require a mechanism to allow us to ensure that we are not exposed to this high level of costs. **Table 4** summarises our proposed uncertainty mechanism for rail electrification.

Table 4 Justification for rail electrification mechanism

Issue	Our response
What is the issue / risk that the proposed mechanism addresses?	The risk is the significant costs (>£35m) that we could be exposed to if we are required to fund the move of distribution assets on our network as a result of the Network Rail electrification project.
What is the proposed mechanism?	We propose that an additional reopener is introduced in RIIO-ED1 to account for this risk. Similar to the other reopeners, we propose that there is one reopener window in May 2019 with a threshold of one percent of average annual RIIO-ED1 base revenue. We propose that any other costs efficiently incurred as a result of the rail project be logged up for consideration in RIIO-ED2.
What are the justifications for the mechanism?	The justification is that this is a similar mechanism to that proposed for enhanced physical site security and TMA costs. Effectively, the principle of this issue is the same: we could be exposed to significant costs to carry out works that we had not intended to and do not believe we would otherwise require to. It is not appropriate for us to be exposed to this high level of costs that is not within our control.
What are the drawbacks from the proposed mechanism?	We are not aware of any drawbacks. The best solution for us and for our customers would be for the wayleave issue to be resolved such that we are not accountable for these costs. Whilst we will continue to progress this and to engage with Network Rail, DECC and Ofgem to do so, we do require a reopener in the event that this resolution does not happen.
Can the drawbacks be reduced?	n/a
On balance, does the mechanism deliver value for money while protecting the ability to finance efficient delivery?	Yes. A reopener would ensure that we are not exposed to these uncontrollable costs whilst ensuring that we would only recover the efficiently incurred costs.

Dealing with exceptional events

Exceptional events are unexpected circumstances with a material impact on our business. These range from regional events such as storms, to national issues such as changes to legislation or Scottish Independence. There are appropriate provisions for dealing with exceptional events, and these vary depending on how extreme the circumstance is.

For exceptional events such as storms, there is a Statutory Instrument in place that grants us an extension to some of the standards that we would normally be required to meet. Specifically, Regulation 5 of The Electricity (Standards of Performance) Regulations 2010 sets out supply restoration targets that we are required to meet; in normal circumstances this is 18 hours and if we do not meet this standard we are required to make a payment to the customer. For severe weather events, Regulation 7 sets out extended targets of 24 hours and 48 hours depending on the extent of the effects of the weather on our network.

For more extreme circumstances, there is a provision under our licence (Charge Restriction Condition 19: Duration of the Charge Restriction Conditions) that allows us to reopen or disapply any or all of the Charge Restriction Conditions (CRCs) of our licence. In practice, if we were experiencing an exceptional event such that we consider that we require to disapply any or all of the CRCs, we would submit a disapplication request to the Authority. This is an extreme measure, and not one we would normally intend to use. Nevertheless, it is appropriate that this provision is retained and we support Ofgem's intention to continue with the existing disapplication policy for RIIO-ED1, albeit with an updated licence condition to reflect recent legislative changes brought about by the Third Package.

Part 3

Improving the stability and predictability of our charges

Whilst uncertainties do inevitably have an impact on our customers' bills, once our risk management practices and regulatory uncertainty mechanisms are taken into account, the actual impact historically has been relatively low.

However, we recognise the importance of keeping our charges as stable and predictable as possible. This section describes how we propose to minimise the impact of uncertain costs on the predictability of our customers' bills. In addition it sets out the process we go through to set our charges each year so that we provide as much information as possible to help energy supply companies forecast our future charges.

In terms of the impact on our customers' bills, it is important to note that the higher distribution costs in the North of Scotland (due to the unique geography and set up of the network) have historically been shared between all GB customers via the Hydro Benefit. We expect this to continue through RIIO-ED1.

Minimising the impact of uncertainty mechanisms

Network charging volatility results from changes in the allowed revenue that we are able to recover through charges to our customers. Suppliers use the allowed revenues that are set for us at the start of a price control to set their tariffs. Any changes to this allowed revenue, for example through the use of an uncertainty mechanism, could result in an unexpected change for suppliers, particularly where fixed price contracts have already been set. Suppliers have told us that when offering fixed price contracts to customers they include a risk premium to compensate them for the risk associated with unexpected changes in network charges. It is therefore important that we reduce the impact of uncertainty mechanisms on network charging volatility to ensure that we minimise the cost to our customers.

If and when we will need to use an uncertainty mechanisms is, by the very nature of the subject, unpredictable. As has been explained in this paper, there are several different types of uncertainty mechanism: automatic and volume-driven.

Automatic uncertainty mechanisms are there for costs that we incur that we little or no control over, for example licence fees and business rates. Whilst we will make a forecast of these costs, it is possible that the actual costs that we see will differ from this, and that is when the uncertainty mechanism comes into play.

Volume-driven uncertainty mechanisms are there to allow us to recover costs where we see an unexpectedly high volume of works in certain categories. An example is connections, where the introduction of a new Government scheme or legislation could lead to unexpected changes in the number of connections to our network.

We therefore cannot tell you now which of the uncertainty mechanisms we will use over RIIO-ED1 as this will only become clear during the RIIO-ED1 period. Because of this, if we do need to use an uncertainty mechanism during RIIO-ED1, it is important that supply companies are given as much notice and information as possible as to what the costs will be and when they can expect to see these extra costs.

There are two main ways that we will ensure that we minimise the impact of these uncertainty mechanisms on the predictability of our customers' bills:

- A delay in uncertainty mechanisms; and
- The Mid Period Review.

These are discussed in more detail below.

Delay in uncertainty mechanisms

A two year lag is being introduced in RIIO-ED1 for all of the **Automatic uncertainty mechanisms** detailed in this paper. This means that the costs we incur in one year will effectively be recovered two years later. In practice, we will therefore be able to include the change to our allowed revenue for these uncertainty mechanisms in our forecasts at then end of the year in which the costs are incurred although we will not be recovering the costs from customers until two years later. This gives suppliers greater predictability in the charges that they will see and therefore ensures that the costs to customers associated with charging volatility are minimised.

It is important to note that introducing this two year lag does inevitably mean that we are taking on an additional cash-flow risk, as we are effectively required to fund these sometimes significant costs for two years until we are able to recover them from our customers.

Mid-Period Review

During an eight year price control, such as RIIO-ED1, RIIO-GD1 and RIIO-T1, there is the potential for greater uncertainty than the previous five year control period. In line with the other RIIO models, and in addition to other uncertainty mechanisms discussed in this section, Ofgem have decided to carry out a mid-period review of output requirements.

This mid period review, which will being with an open letter consultation in January 2018, will cover two factors. These are any material changes to outputs which can be justified by changes in government policy, and introducing new outputs which might be required in order to meet the needs of consumers and other network users.

If the mid period review results in a requirement to change an existing output, the amendments won't be retrospective. That is, any changes will be applied to future outputs and not back dated.

Should Ofgem decide a change to output requirement is needed, they will then review if the revenue in the price control will need to be changed in order to reflect the impact of the change. Changes to allowed revenues will be limited to reflect the change to outputs. In addition to any other major issues that may arise prior to January 2018, one of the most important issues to be considered at the Mid Period Review will be the Scottish Independence Referendum.

Supporting predictability of tariffs

In addition to the mechanisms detailed in the **Minimising the impact of uncertainty mechanisms** section, there are a number of other ways that we ensure that we improve the predictability of our charges for our customers. This includes provision of information to suppliers and penalties where we over or under-recover the level of costs that we are allowed to recover in a year. These measures are explained in more detail below.

Information provision

We work hard to ensure that supply companies are given as much information as possible throughout the year to enable them to understand the different elements that are making up their charges and any changes to these that there might be.

Our process for updating our tariffs each year is 2-step. Firstly we submit our indicative forecast tariffs to Ofgem in December each year for implementation from 1 April the following year. These indicative tariffs are also made available to supply companies. We then hold a teleconference with supply companies in January to discuss our forecast tariffs and allow us to answer any questions that suppliers may have.

We then provide suppliers with our final tariffs no less than 40 days before 1 April each year. As part of the indicative and final tariff packs that we provide, we include a 5 year forecast of our tariffs.

In addition to this process, we provide suppliers with quarterly updates throughout the year. We issue quarterly tables setting out our final collected revenue forecast (and all of the different elements that make this up) and illustrative tariffs. We also hold a teleconference after issuing each of these tables to discuss our figures with supply companies and allow them to ask any questions that they may have.

K-Factor

We are required to make our annual tariff forecast by 30 January of the preceding year. Whilst we have previously been able to adjust our tariffs twice during a year (although we only did this in exceptional circumstances), this will be limited to once a year in RIIO-ED1. This means that not all of the information necessary to make an accurate forecast of the tariff is known. Currently, a retrospective adjustment to account for inaccurate forecasting is made through the k-factor term. We intend to continue to use the k-factor term through the RIIO-ED1 period. The k-factor currently incorporates a mechanism to penalise us if we forecast our tariff too high and, hence, over-recover. For SHEPD and SEPD this mechanism currently applies when we over-recover by more than 3%. To account for the increased risk associated with only being able to update our tariffs once per year, in ED1 the penalty mechanism will apply when we over-recover by more than 6% (double what it was before). A lag to the adjustment for over or under recovery will be applied in ED1 such that the impact of any over or under recovery on charges will be seen two years after the over or under recovery occurs. This should allow improved predictability in our charges for suppliers and customers.

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Appendix

Regulatory policy

Process: Has the DNO followed a robust process?

This paper is set out in three main sections – **Approach to risk management; Managing external risk;** and **Supporting predictability of tariffs.**

In preparing our plans, we have engaged extensively with stakeholders. You can read more about what stakeholders said in What you said and What our Stakeholders Think.

All of our forecast uncertainty costs are set out in the relevant table and consistent with those presented in this paper. Where relevant these have been included in the Price Control Financial Model.

Outputs: Does the plan deliver the required outputs?

This paper sets out how we intend to manage risk during RIIO-ED1. It sets our all of the things we are doing to mitigate risks. Overall where possible we plan to avoid the use of uncertainty mechanisms and have ensured that our forecasts are as accurate as possible. However there are some areas, such as rail electrification, where it is impossible to say at this stage what, if any, the costs will be. We believe that our plans strike an appropriate balance of risk between our customers and us. The 1% materiality threshold is sufficiently high to ensure that we bear an appropriate level of risk. Where we have proposed additional uncertainty mechanisms we have justified why, including an assessment of the impact on our customers.

Resources (efficient expenditure): Are the costs of delivering the outputs efficient?

Any expenditure we undertake is need-based and delivers maximum value for our customers. We have always had a close focus on efficiency – it's the way we do things. Our paper entitled "Be efficient" sets out how we compare with other DNOs in efficient performance and how we intend to stay at the forefront of efficiency throughout RIIO-ED1.

Resources (efficient financing): Are the proposed financing arrangements efficient?

Our paper entitled Efficiently financing our plans sets out how we plan to finance our plans for RIIO-ED1.

Uncertainty & Risk: How well does the plan deal with uncertainty and risk?

Our paper assesses the risks that we face during the RIIO-ED1 period and looks at each in turn when determining how this risk will be dealt with. Where possible, we have sought include costs associated with these risks in our allowances. For each uncertainty mechanism we have set out clear justification as to the need for the mechanism, as well as the benefits to our customers and the balance of risk between us and our customers. Our proposals are broadly in line the **Ofgem strategy document.** However where there are any differences we have justified these in the format suggested by Ofgem.

We have also set out how we will ensure that we minimise the impact of uncertainty on the predictability of our customers' bills.