Developing Network Monopoly Price Controls: Workstream A

Regulatory mechanisms for dealing with uncertainty

A final report prepared for Ofgem

March 2003

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Context

In setting price controls for all network monopoly companies - the DNOs, NGC and Transco – it is necessary to consider how the regulatory framework should deal with uncertainty.

We have been asked by Ofgem to help develop a framework to enable it to ask the right questions to determine the best regulatory response to uncertainty. This framework does not represent a simple procedure to be followed to arrive at a unique correct answer. Instead, it indicates what that range of solutions (or policy options) is likely to be.

The problem of uncertainty

Uncertainty is at the heart of the economics of regulation. Regulators and regulated utilities face uncertainty and the fact that they do so, and their attitudes to that uncertainty, is one of the key factors determining the overall shape of the regulatory contract.

The regulator faces two general informational problems. It may be uncertain about the prevailing cost level, and it may be uncertain about whether that prevailing cost level is the efficient one. In addition, both the regulator and the firm are affected by a shared uncertainty about the impact of exogenous events on the cost level. This uncertainty creates a risk for the firm that profits may be less than expected for given price levels, because of the effects of unanticipated events or shocks. If prices adjust instead, the risk is passed to consumers – but in addition, incentives for the firm to reduce its controllable costs will almost certainly be weaker, as the regulator will not perfectly be able to distinguish increases in controllable costs from the effects of uncontrollable events.

The superior information that the firm possesses has a value to the firm that it will not want to reveal unless there is a profit incentive to do so. The risk that it faces because of uncertainty creates a need for some regulatory insurance, compared to the strongest possible incentive regime. At the heart of regulation, therefore, is a tension between offering the firm incentives to reveal its efficient cost level, and offering it insurance against unforeseen events. Too much insurance (cost-pass through) weakens incentives, whilst high-powered incentives may leave the firm vulnerable to financial distress.

Executive Summary

A decision making framework

The decision-making framework identifies the questions that a regulator needs answered when deciding upon the appropriate response to uncertainty and the factors that should influence the answer. We divide the problem according to the characteristics by which uncertainty can be classified and develop separate questions for each of these:

- Materiality
- Predictability
- Separability
- Controllability
- Diversifiability
- Predictability of impact
- Correlation across companies
- Correlation over time

The results of each decision-making process can be taken together to provide guidelines to the appropriate regulatory response.

Applications

We have applied the decision-making framework to a number of real examples faced by Ofgem. The purpose of this exercise is to test the framework. As noted, the range of appropriate regimes emerges from this exercise, but the precise specification of the regime clearly requires more detailed analysis than can reasonably be handled in a generic framework. We have applied the framework to the following cases:

- Distributed generation
- Licence fees
- DNO's recovery of NGC exit charges
- One-off IT costs
- Overstay fines and lane rentals
- Severe weather exemptions for guaranteed payments

We have focused particularly on distributed generation as this represents the largest source of uncertainty of any of these, in terms of its impact on costs, for the DNOs.

Distributed generation

Background

There are two main sources of uncertainty in relation to distributed generation:

- The volume of DG to be connected, both nationally and for any given DNO.

- The costs of reinforcement and effect on service quality will be specific to, among other things, the connection point, the type of DG connecting and the presence of any existing DG.

This uncertainty can have different effects in the short and long terms. In the short-term, connecting DG is an activity that is additional to the DNOs' core business. Furthermore, an initial reconfiguration of networks to accommodate DG for the first time may lead to particularly high expenditure. At some point in the future (the long-term), if the use of DG expands in line with Government targets, this may change. Accommodation of DG will no longer be an additional activity for distributors, but a core function, and it becomes less meaningful to identify costs on a project-by-project basis as being DG-related or load-related.

These short and long term situations seem to us to be so clearly different as to require different analysis using the framework. However, ideally the short-term regulatory framework should be capable of evolving to a framework suited to the long-term problem.

The regulatory problem associated with DG is that even though the costs and volumes of DG are uncertain *ex ante*, at the time connection decisions are made, the DNOs are likely to have some control over both the volume of DG to be connected, and the cost of connection (including reinforcement). If Ofgem seeks to impose a high powered regime to incentivise cost reduction it might reduce incentives to connect. On the other hand, if it adopts a cost pass through approach there is a risk that the absence of incentives will lead to inefficient behaviour. Ofgem's dilemma between risks to costs and risks to volumes requires a value judgement to be made on the basis of broad public policy.

Executive Summary

Regulatory options in the short term

We recommend an approach involving each of the following elements in the short term:

- Incorporate all DG-related expenditure in the overall RPI-X framework, to provide reasonably balanced incentives to reduce DG costs.

- Assessment of DG-related capital expenditure plans is likely to be difficult. Companies can be expected to make excess returns in the early years, but by doing so they reveal information. Increasingly, Ofgem should be able to incorporate benchmarking, or other tests for efficiency, into its assessment of capital expenditure plans.

- Incorporate a volume driver into the price control formula (i.e. regulate the average allowed unit costs, not overall allowed revenue), or alternatively audit volumes built (and penalise under-delivery) after the event, to prevent companies simply not delivering the programme. This volume driver could be simple (kW connected) or a more complex commitment by DNOs to deliver specific programmes. The latter is more administratively costly but potentially less risky for firms than the former.

- Consider increased flexibility through more formal logging up and interim review arrangements than now, or through a sliding scale.

All of the above provide Ofgem with options for trading off:

- risks of cost inefficiency against risks of non-delivery of volumes;

- risks to DNOs against incentives on DNOs to improve efficiency.

The choice between them, in the absence of good information, is largely a value judgement. We have outlined a scheme that emphasises incentives for efficiency over guarantees for delivery and insurance for the companies, although it does not ignore such issues. The options for introducing flexibility would allow this emphasis to shift; they are designed to promote objectives other than cost efficiency, at some expense of a reduction in incentives for such efficiency.

If the risk of non-delivery of DG were judged to be more significant than that of cost over-runs and gaming, the preferred solution might look very different. If this were the case, the flexibility mechanisms described above would need to be strengthened in order that the regime more closely approximated to a cost-pass through arrangement. If this were to occur, then the main scope for efficiency improvement lies in Ofgem having sufficiently robust information to be able to resist cost increases by applying a type of used and useful test. This would be likely to increase the degree of scrutiny of the DNOs costs on an ongoing basis.

Regulatory options in the longer term

In the long term, DG is likely to become a more "normal" part of what DNOs do. It becomes less of a separate problem and simply a part of the general price control regime and incentives provided to companies. In effect, once DG connection cost drivers are as well understood as cost drivers for load, it should be possible to use benchmarking, incentives for accurate capital expenditure forecasts and consultant estimates of efficiency in much the same way as the main price control is set at the moment. Equally, of course, if the main price control system were to change (for example, to make more formal use of benchmarking), it should be possible to bring DG costs into that new framework as well. The main actions that could be appropriate in evolving to the longer-term regime include:

- Considering whether DG-related costs can be separately reflected in setting price controls. The identification of some costs as generation-related and others as load-related would become increasingly arbitrary, as the network develops towards a transmission role, in which its function is to connect generation to load.

- Using the data acquired over time to establish a cost function for distribution businesses, incorporating (possibly detailed) cost drivers relating to distributed generation as well as to load. Collect data on these cost drivers for each review to use benchmarking to provide incentives for efficient network expansion and management.

1. Introduction

In forthcoming price reviews for the DNOs, NGC and Transco, new sources of uncertainty will arise that require a regulatory response. More generally, Ofgem will want to monitor its regulatory responses to existing sources of uncertainty to ensure that they are appropriate.

We have been asked by Ofgem to construct a framework to enable it to ask the right questions to determine the best regulatory response to uncertainty. This framework does not represent a simple procedure to be followed to arrive at a unique correct answer. Instead, it indicates what that range of solutions (or policy options) is likely to be.

In this report we describe the decision making framework in detail in section 2. Then in section 3 we apply it to a number of real examples to test that the framework produces regulatory options in line with established economic principles. Finally, in section 4 we apply the framework tree to the problem of uncertainty associated with distributed generation.

2. The decision making framework

2.1 Uncertainty and regulation

Uncertainty is at the heart of the economics of regulation. Regulators and regulated utilities face uncertainty and the fact that they do so, and their attitudes to that uncertainty, is a key factor in determining the overall shape of the regulatory contract.

If Ofgem could precisely predict the future efficient cost and output levels of a regulated business, then its task would be straightforward: it would simply set a price equal to the expected efficient cost of providing the output. This would simultaneously maximise productive efficiency and allocative efficiency. However, regulators and regulated companies are faced with many different types of uncertainty, and this makes regulation a more complex problem.

The regulator faces two general informational problems. It may be uncertain about the prevailing cost level, and it may be uncertain about whether that prevailing cost level is the efficient one. These are examples of the well-known problem of information asymmetry, where the firm possesses superior information to the regulator about both of these facts. In addition, both the regulator and the firm are affected by a shared uncertainty about the impact of exogenous events on the cost level. This uncertainty creates a risk for the firm that profits may be less than expected for given price levels, because of the effects of unanticipated events or shocks. If prices adjust instead, the risk is passed to consumers – but in addition, incentives for the firm to reduce its controllable costs will almost certainly be weaker, as the regulator will not perfectly be able to distinguish increases in controllable costs from the effects of uncontrollable events.

It is useful, even at this early stage, to illustrate the implications of these different types of risk. The superior information that the firm possesses has a value to the firm that it will not want to reveal unless there is a profit incentive to do so. The risk that it faces because of uncertainty creates a need for regulatory insurance, compared to the strongest possible incentive regime. At the heart of regulation, therefore, is a tension between offering the firm incentives to reveal its efficient cost level, and offering it insurance against unforeseen events.

If the insurance effect dominates, low-powered regulation (providing weak, or no incentives) is appropriate; if the incentive effect dominates, high-powered regulation is appropriate. The regulator's decision is driven by the degree of uncertainty and the firm's managers' risk-aversion:

- If there is a great deal of uncertainty, and managers are risk averse, then the insurance effect dominates the incentive effect.
- If there is uncertainty but no risk aversion, the managers have no need for insurance, and the incentive effect dominates.
- If there is no uncertainty, the incentive effect dominates.
- Between the extremes, there is a balance to be struck between risk and incentives.

This suggests that there are two questions to ask about any new potential source of uncertainty:

- Will it diminish managers' incentives to innovate, in the absence of any countervailing incentives or risk-reduction measures by the regulator; and
- Will it increase the cost of capital, in the absence of countervailing actions by the regulator?

The answers to the two questions may differ. For example, financially diversifiable risks have no effect on the cost of capital but can impose uncertainty on managers and can therefore be expected to affect incentives. Consequently, a key regulatory issue is whether the new source of uncertainty is diversifiable or not.

2.2 Developing a framework to analyse uncertainty

We have been asked by Ofgem to develop a framework that should enable a regulator to ask the right questions to determine the best regulatory response to uncertainty. In particular, this should be applied as new uncertainties arise. Although it could be used to update the rationale for existing regulatory arrangements, this is not the primary reason for its development. To develop the framework, we need to define the following:

- The regulatory options available.

❒ The "no specific response" option – what is the base regulatory framework within which the uncertainty will be accommodated if the regulator takes no specific action?

❒ The characteristics by which uncertainty can be described.

2.2.1 The regulatory options

Every regulatory framework comprises a number of components, including:

- an incentive mechanism;
- a treatment of capital costs (including the choice of regulated rate of return);
- the length of the control period;
- provisions for undertaking an interim review; and
- revenue drivers (such as volume terms in the price control formula).

Furthermore, the regulator can decide whether a given activity should fall within a broad price control or whether it should be separately regulated.

2.2.2 The "no specific response" option

We have characterised the default option in the following way:

❒ The regulator sets RPI-X price controls every five years, using its own forecasts of operating expenditure and capital expenditure, derived partly from firm-specific data but also from formal and informal benchmarking. Incentives for cost reduction derive from this fixed price path. There are also incentives within the price control system for enhanced quality.

❒ The forecast capital costs used in setting the price control are based on annual depreciation of the regulatory asset base and a return on that asset base, set so that expected returns equal the company's cost of capital. The RAB is increased according to actual capital expenditure at each review, although the regulator has discretion over whether or not to include items of historical capital expenditure when doing so.

❒ Price controls can be re-opened within the price control period, but there are no automatic triggers for this to occur.

- The main revenue drivers are simple volume measures, but quality incentive payments depend on other drivers.

This set-up should be recognisable as a simple characterisation of the regime applying to electricity distribution, but the gas pipelines and transmission businesses regulated by Ofgem are also governed by a similar framework.

2.2.3 Characteristics by which uncertainty can be described

In the decision tree framework that follows, we describe uncertainty using the following eight headings:

- Materiality
- Predictability
- Separability
- Controllability
- Diversifiability
- Predictability of impact
- Correlation between areas
- Correlation over time

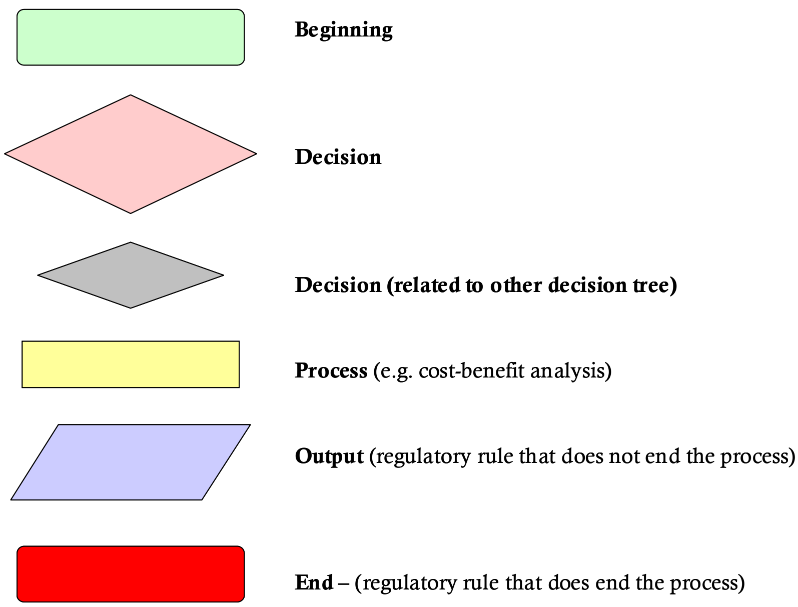
We define and discuss each in more detail when dealing with the way in which the regulator's decision depends on each of these characteristics.

2.3 A decision making process

We now set out a decision making process, listing the questions that a regulator needs answered when deciding upon the appropriate response to uncertainty, and the factors that should influence the answer. We divide the problem according to the characteristics by which uncertainty can be classified, listed above, providing a separate process for each topic. The results of each decision-making process can be taken together to provide guidelines to the appropriate regulatory response (and we provide examples of using the framework in this way in subsequent chapters). At the end of this section, we provide an overview of how the different decision processes are linked.

For each topic, we discuss the relevant issues, then provide a flow diagram to illustrate the decision tree.

Figure 1: Symbols used in the decision tree



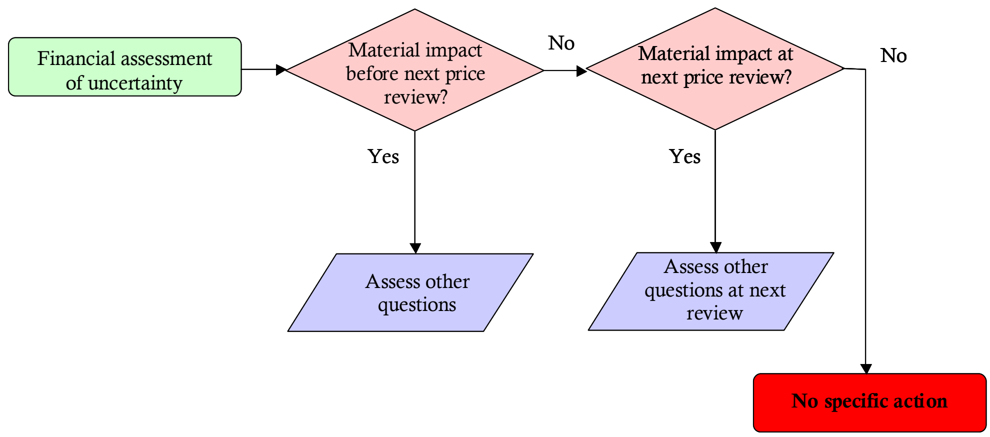
2.3.1 Materiality

The regulator must have regard for the potential effect that any given source of uncertainty could have on the costs of a regulated firm. Some sources of uncertainty may only cause costs to vary by a small proportion. It is possible that some sources of uncertainty might give rise to a significant increase in costs that may have an impact on the financial position of the company.

The consequences of the materiality question are obvious. This is a pass/fail question and if the answer is no, the regulator should take no particular action.

The important question is what constitutes a material impact. This could be measured in a number of ways, including the impact on the financial position of a company (i.e. consideration of key financial ratios), as a proportion of turnover or price control revenue. It may not be possible to define in advance one specific measure – although it is likely that the regulator and companies will want to consider a range of measures to help ensure that the appropriate regulatory response is taken forward.

Figure 2: Is the uncertainty material?



2.3.2 Separability

Uncertainty might affect the total costs of the firm or only one component of costs. Sometimes this will be obvious (either *ex ante* or *ex post*). For example, the cost of taxes is obviously and (more important) verifiably separable from any other activities. Other events will be harder to separate from cost changes that result from the firm's own choices and behaviour or other events. For example, when investments are made to accommodate a new distributed generation connection, it may be difficult to decide whether all the cost is specific to that connection, or whether some would have been incurred as part of general network enhancement.

In some cases, separating costs will be inherently difficult. In others, there may be scope for deliberate gaming to blur the distinction still further. For example, a regulatory regime that allows the pass-through of one category of costs provides an incentive for the firm to reclassify or otherwise substitute additional costs into that category. When the regulator assesses whether or not an event is separable, this must be taken into account. "Technical" separability is not enough.

If the effects of uncertainty (on costs or on other matters of concern such as quality outputs) are separable, it will typically be better to create a separate regulatory regime, or at least transparently to treat the costs and revenues of the activity within the general regulatory framework. For any particular item of regulatory interest, there will be an appropriate regulatory regime (in terms of incentives, risk properties and so on). Consequently, it is extremely unlikely that a single regulatory regime will be appropriate for simultaneously responding to two or more different conditions (although, of course, independent assessment of the two conditions could arrive at the same answer for both). Against this benefit, of course, Ofgem will need to set any additional implementation and compliance costs that it and the regulated companies would face. These costs may not be trivial[1].

If the effects of the uncertainty cannot be separated from the general cost base (or other targets of incentive regulation) on a robust enough basis then a separate regime should not be applied. By definition, a separate regime must have different rules for establishing how revenues relate to the company's costs from the "main" regime (otherwise there is no point in establishing it).

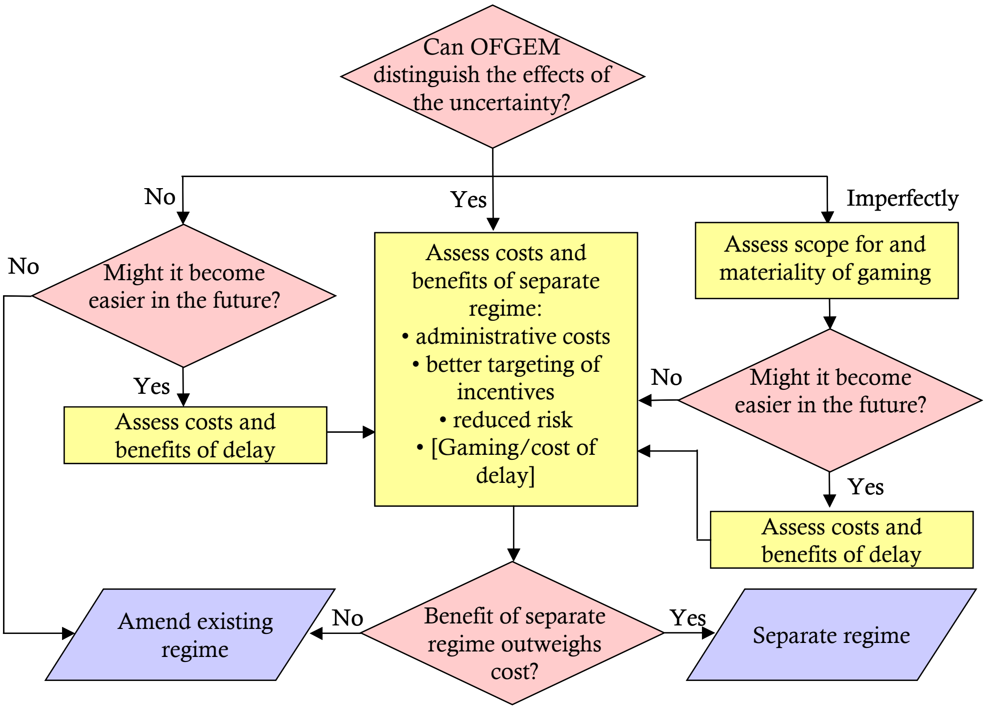
The difficult case, of course, is when costs are imperfectly separable. In order to establish a separate regime for such cost items Ofgem would need to satisfy itself that one of the conditions below holds.

- The possibility of substitution into a newly-defined cost category is very limited.
- The costs will become separately identifiable in the future. This process could be helped through an audit.

Note also that the answers to some of the later questions in the framework help to determine whether the uncertainty's effects are separable. In particular, if the uncertainty is correlated across firms, then benchmarking can provide an estimate of the separated costs of the effects of that uncertainty (since companies' costs will all move in the same way as the uncertainty appears).

[1] We note, however, that Ofgem has in recent years greatly expanded the number of different regimes applying to NGC and Transco's operations, which was generally welcomed.

Figure 3: Is the uncertainty separable?



2.3.3 Controllability

Controllability relates to the ability of the firm to mange risk by either opting out of the uncertainty in the first place, or by adopting risk mitigation strategies as part of its planning procedures.

Optionality

Firms may be able to decide whether to take a risk on a new type of business activity, where the outcome is uncertain. Since managers are risk averse, they may avoid risky options that could be in the public interest for them to take on. In such situations managers might need to be provided with an incentive to participate, perhaps through the opportunity to earn additional returns if performance is good.

Risk mitigation strategies

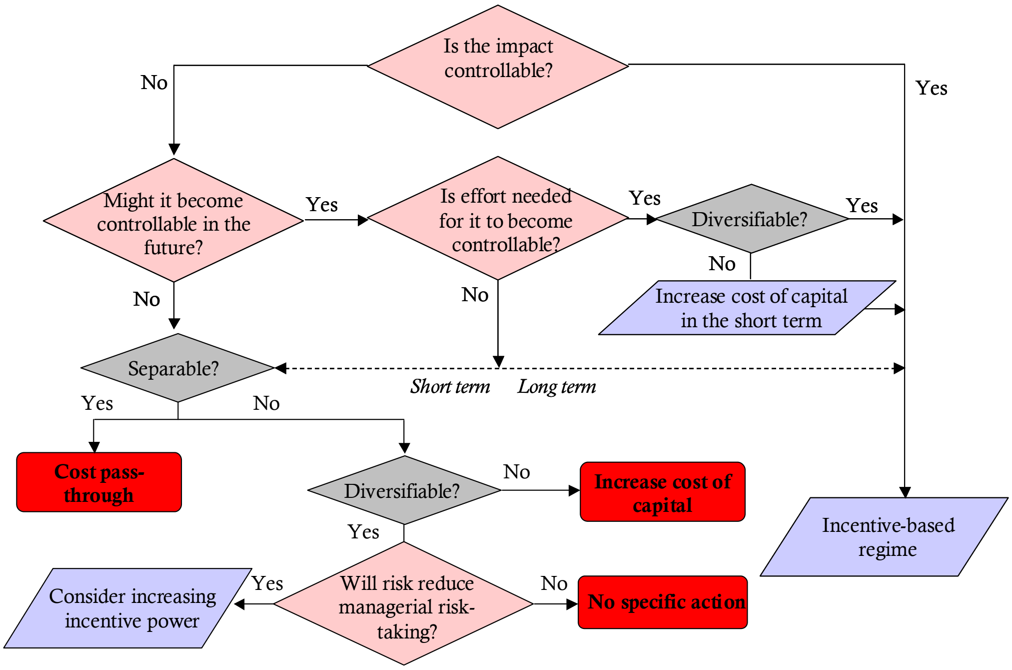
If there is nothing the firm can do to control costs driven by uncertainty, there is nothing to be gained from introducing an incentive to manage costs based on the actual outcomes.

If, however, the firm can manage risk then incentive design is important. For example, a firm could have a choice of investment options – one is expected to be a low cost project but requires more managerial time and effort to implement, and there is a risk that costs could be very high. The other is expected to be a higher cost project, but the cost is more stable in the face of changing circumstances, and managerial time and effort is lower. The first project could therefore be described as an innovation, whilst the second is the use of a more established technology. A low-powered regime would tend to encourage the adoption of the second option, whilst a higher-powered regime would encourage the innovative choice.

Incentive mechanisms

The extent of controllability clearly impacts upon the choice of regulatory mechanism. If the impact of the uncertainty is controllable by the firm, the regulator can implement an incentive-based regime. However, if the uncertainty is not controllable, then the regulator must consider whether it is separable. If it is, he can use a cost pass through regime. If not, diversifiability must be assessed. If the uncertainty is not diversifiable then the allowed cost of capital may have to be increased or an equal (compensating) adjustment be made to allowed revenue to cover the cost impact. If it is diversifiable, the regulator must consider whether the increased risk will reduce managerial risk taking. If it does, the regulator might consider increasing the incentive power of the regime.

Figure 4: Is the uncertainty controllable?



2.3.4 Diversifiability

Uncontrollable risks are reflected in the allowed return, based on Ofgem's assessment of the cost of capital (as applied to the expected regulatory asset base) in the traditional RPI-X framework. However, it is important to recognise that the riskiness of a financial asset is not the same concept as the risk faced by a firm. Investors seek to assemble portfolios of financial assets to spread risks. What matters is whether the riskiness of an individual asset – such as shares in a specific firm – add to or detract from the riskiness of that portfolio. In the Capital Asset Pricing Model, this tendency to add to or detract from the riskiness of a diversified portfolio is referred to as beta. Given an established source of uncertainty, the estimation of beta therefore provides an established, empirical route by which any financial risks are incorporated into the determination of price control revenue.

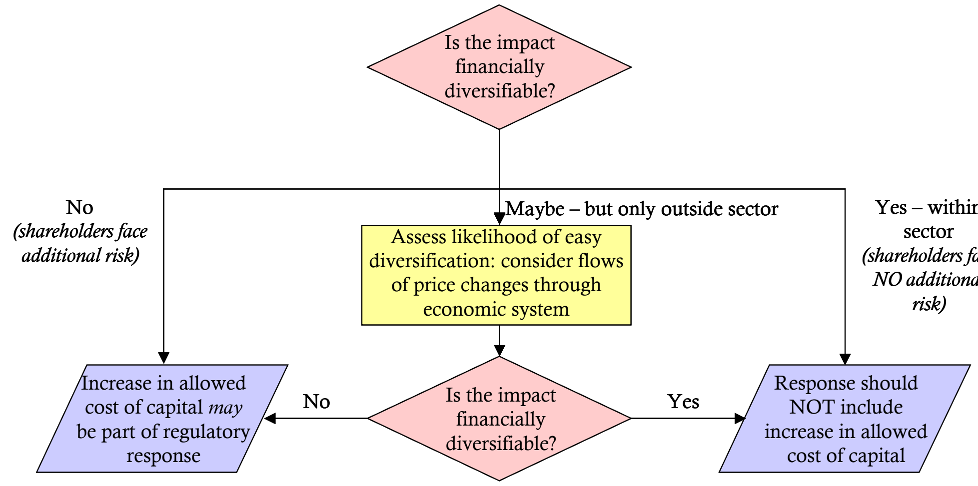
The difficulty therefore arises for a new source of uncertainty, for which no data exist for empirical determination. In these circumstances a regulator could instead attempt to forecast the impact on beta. In practice, such an exercise is likely to be reduced to a set of rules of thumb, based on whether the additional variance appears likely to be positively, negatively or not correlated with the variance of another easily-identified asset.

When risks are uncorrelated or negatively-correlated across the industry, the revenues of each individual company might well have become more variable and hence more risky. However a rational investor could purchase a portfolio: a bundle of shares in all the firms operating in the industry. Since the impact of the uncertainty, at the industry level, is offsetting, the revenues of the whole industry are more certain than the revenues of any given firm. As such the market rate of return for investments in the industry would be commensurate with the more certain industry revenues. This is based on the familiar result from finance that investments embodying a diversifiable risk do not attract a higher rate of return.

We can in principle make similar arguments with regard to risks that can be diversified since they are uncorrelated, or negatively-correlated with uncertainties *outside* the sector being regulated. For example, reductions in TNUoS or NTS charges could benefit energy-intensive industries (gains to generators or shippers are likely to be competed away in lower retail prices). In principle, an investor could again construct a portfolio that limits the risk: buying shares in NGC/Transco and in energy-intensive industries. Since such risks could be diversified away, the market rate of return for such investments would also be consistent with only the non-diversifiable risk. Whilst in practice it may be difficult to construct a balanced portfolio across all relevant financial assets, the following risks could all be regarded as diversifiable:

- short-term purely random events that are uncorrelated across companies;
- regulatory risks arising from a yardstick regime in which prices are based on average costs; and
- rewarding companies on the basis of the generating capacity they attract.

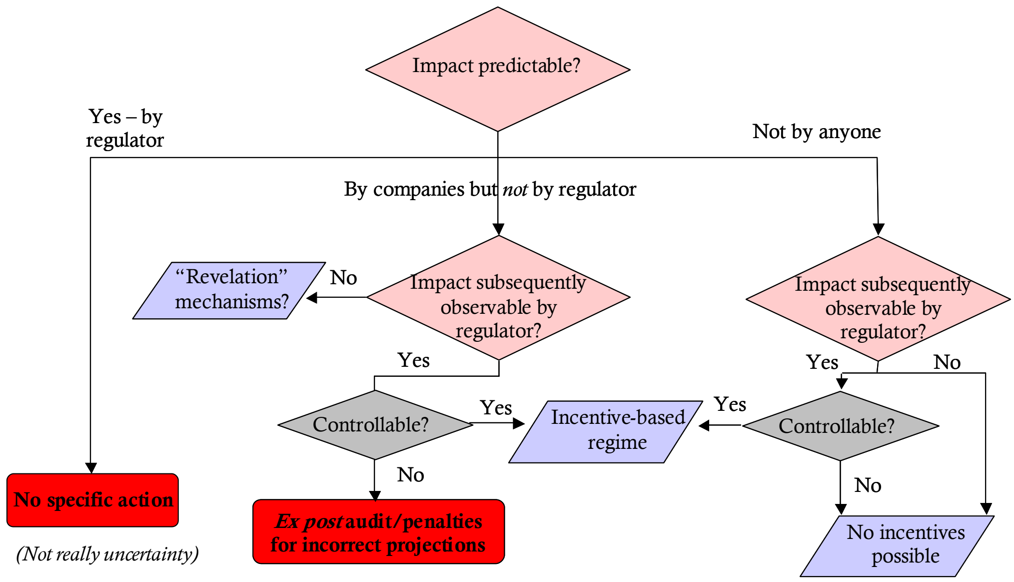
Figure 5: Is the uncertainty diversifiable?



2.3.5 *Predictability*

The degree of predictability by each party also has a bearing on the regulatory regime, as Figure 6 illustrates.

Figure 6: Is the impact of the uncertainty predictable?



The figure illustrates the implications of predictability for the applicability of incentive-based regimes, and the feasibility of audit procedures compared to incentives for information revelation.

Incentive-based regimes

The degree of predictability can therefore help to determine the kinds of arrangements that the regulator might consider putting in place. For example, in situations where the regulator feels comfortable making a forward looking spot estimate (i.e. when variance is small) it might be able to employ mechanisms such as RPI-X. If the variance is larger, the regulator might want to retain the option of modifying this estimate, for example through some form of error correction mechanism at the next review.

In other cases (when future values are more unpredictable still) the regulator might feel uncomfortable using a point estimate. In such situations it might still be possible to place reasonable upper and lower bounds on expected outcomes. Sliding scale regulation, in which *ex-post* adjustments to reflect extreme outcomes (as applied, for example, to National Grid's system operator activities) may then be the appropriate regulatory response.

Uncertainty could affect measurable variables other than the costs of the firm. If the regulator can observe such measures with more accuracy than he can observe the firm's costs and if he can determine a cost function (the effect of the physical variable on efficient costs or quality), then they can be used as a revenue driver. Revenue drivers allow the regulator in effect to specify efficient costs, insuring companies against uncontrollable costs while rewarding them only for efficient responses. However, they are only as good as the data on the physical variables used, and the understanding of the cost function.

In other cases uncertainty might give rise to an output that is not currently accounted for in the existing regulatory arrangements. Arguably, this is the case with distributed generation. By recognising an appropriate output measure, e.g. the capacity of distributed generation connected, the regulator might be able to implement more flexible and responsive regulatory mechanisms than by considering costs alone.

Information revelation and audit procedures

The impact of the uncertainty might be predictable by the companies but not by the regulator. If this is so, then the mechanism the regulator should employ depends on whether the impact of the uncertainty will become observable over time. If so, the regulator could implement an ex-post audit or penalties for incorrect projections. If not, then the regulator could consider using 'revelation mechanisms': offering a "menu" of options to regulated companies. Such menus can enable the regulator to obtain information from the companies, by offering different combinations of incentives and risks[2].

2.3.6 Correlation

Correlation of uncertainty across companies will determine the practicality of benchmarking. Correlation over time will affect the choice of price control period, or the regulatory regime more generally.

Benchmarking

Uncertainty could be positively correlated, negatively correlated or uncorrelated across firms. **Positive correlation** is likely to be quite common. For example, increased costs of supplies or construction contractors are likely to affect all network businesses to some extent. **Negative correlation** will be rare but it is not unimaginable. Of course, there are also types of uncertainty that will often be **uncorrelated** across firms.

If the uncertainty is correlated across companies (and affects them at the same time) then benchmarking should solve many of the informational problems discussed under the other headings above. Benchmarking provides an external measure of controllable, efficient costs, in that common uncontrollable shocks are included in the benchmark but inefficiency specific to the firm is not.

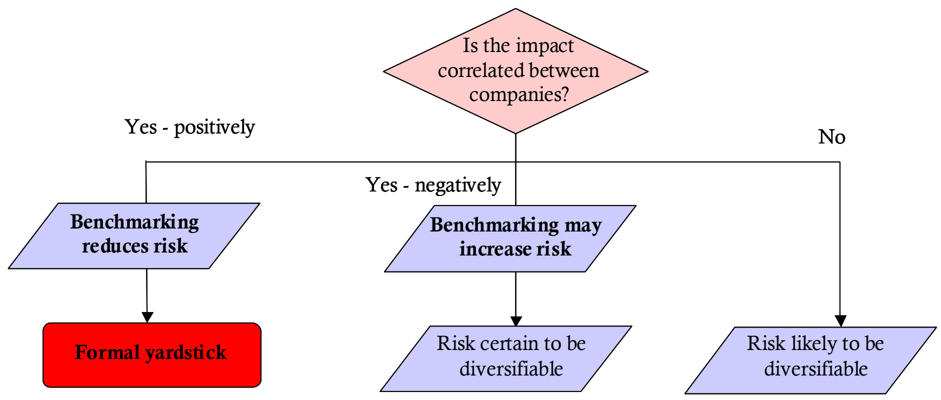
If the uncertainty is uncorrelated across companies, or negatively correlated, then benchmarking may lead to increased risk for the companies (as comparisons of costs between firms cannot distinguish the effect of the shock from the effects of inefficiency. Note that even this risk is likely to be diversifiable across firms as long as the benchmarking is applied symmetrically (winners gain as much as losers lose), so there should be no effect on the cost of capital. However, the additional firm-specific risk may affect *managers'* incentives to reduce costs, because they will seek to compensate by avoiding risk (or be compensated by shareholders with less incentivised contracts). However, benchmarking

2 To take an extreme example, suppose companies were offered a choice between a cost-plus regime (with no incentive power) and RPI-3. Companies choosing the latter are effectively telling the regulator that they expect to be able to reduce costs by more than 3% annually, companies choosing the former are signalling that they cannot.

can provide very powerful incentives for cost reductions. A yardstick regime would represent a significant increase in incentive power over RPI-X, and it is unlikely that managers' reaction to the additional risk would outweigh this direct effect.

Figure 7 shows that a formal yardstick is the appropriate mechanism if the impact of uncertainty is positively correlated between companies. If the impact is negatively correlated, then benchmarking cost and other factors affected by the uncertainty is likely to become less accurate and may increase risk, but still retains its incentive properties. As a consequence, the efficiency benefit of yardstick competition needs to be greater than the insurance that would need to be offered to the firm to compensate for the higher firm-specific risk.

Figure 7: Is the impact of the uncertainty correlated between companies?



Benchmarking possible and effective: Yardstick competition strongly indicated

Benchmarking needs to be supported with more insurance

Benchmarking/yardstick case unaffected. Benchmarking possible – may be essential component of desire to reduce the price control period

Correlation over time

The impact of uncertainty can be positively or negatively correlated *over time* (or, uncorrelated). Positive correlation occurs when high values for some measure of the uncertainty's impact in one year imply high values in the next year, while low values imply lower values still in future. Negative correlation implies some sort of self-correcting behaviour. Many aspects of the regulator's decision, particularly as to details of benchmarking and the price control period, will depend on whether the impact builds up over time or is cyclical.

If the uncertainty results in short-term changes in costs and outputs, then any benchmarking should be applied to costs over a reasonably long period (such as five years – the aim being to average out the effects of uncertainty). If, on the other hand, the uncertainty results in cost changes building up gradually, more frequent comparisons are appropriate. For example, storms might fall into the first category and connection of distributed generation into the latter.

The same distinction – between short term movements around a fairly constant average and long-term persistently increasing effects also affects the overall incentive power of the price control regime chosen, through the choice of price control period and the potential for the use of sliding-scale mechanisms.

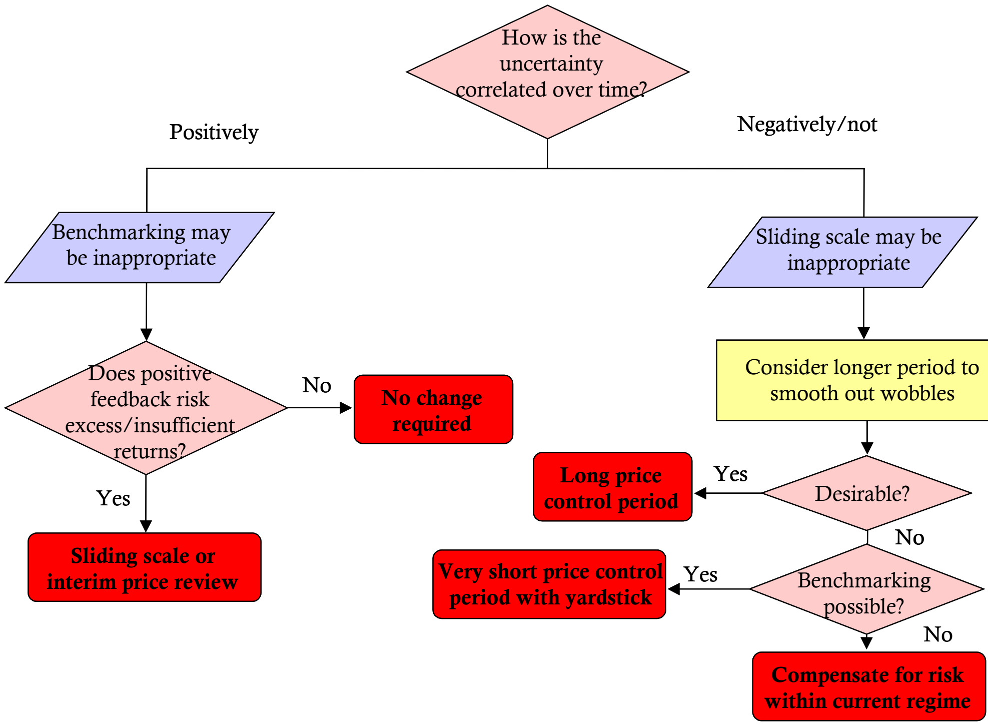
❒ Uncertainty resulting in short-term movements in costs or outputs implies that the price control period should be long and that sliding-scale regulation should be avoided. The long period allows cost variations to average out, shorter periods (including annual sliding-scale controls) are more likely to result in inappropriate regulatory decisions as a result of confusing random cost changes with efficiency changes.

❒ Uncertainty resulting in long-term, persistently increasing changes in costs and outputs implies that the price control period should be short. The longer the regulatory period the more likely it is that regulated prices will be significantly "wrong". Of course, shorter periods under RPI-X provide lower incentives. However:

  - sliding scale regimes can provide adequate incentives with annual price adjustments; and
  - yardstick competition with annual price-setting can provide even stronger incentives than does an RPI-X regime based on long periods between price controls.

Figure 8 shows that if the uncertainty is positively correlated over time and if positive feedback leads to a risk of insufficient or excessive returns, a sliding scale mechanism or a provision for an interim review would be appropriate. If the uncertainty is negatively or uncorrelated over time a change to the price control period might be desirable.

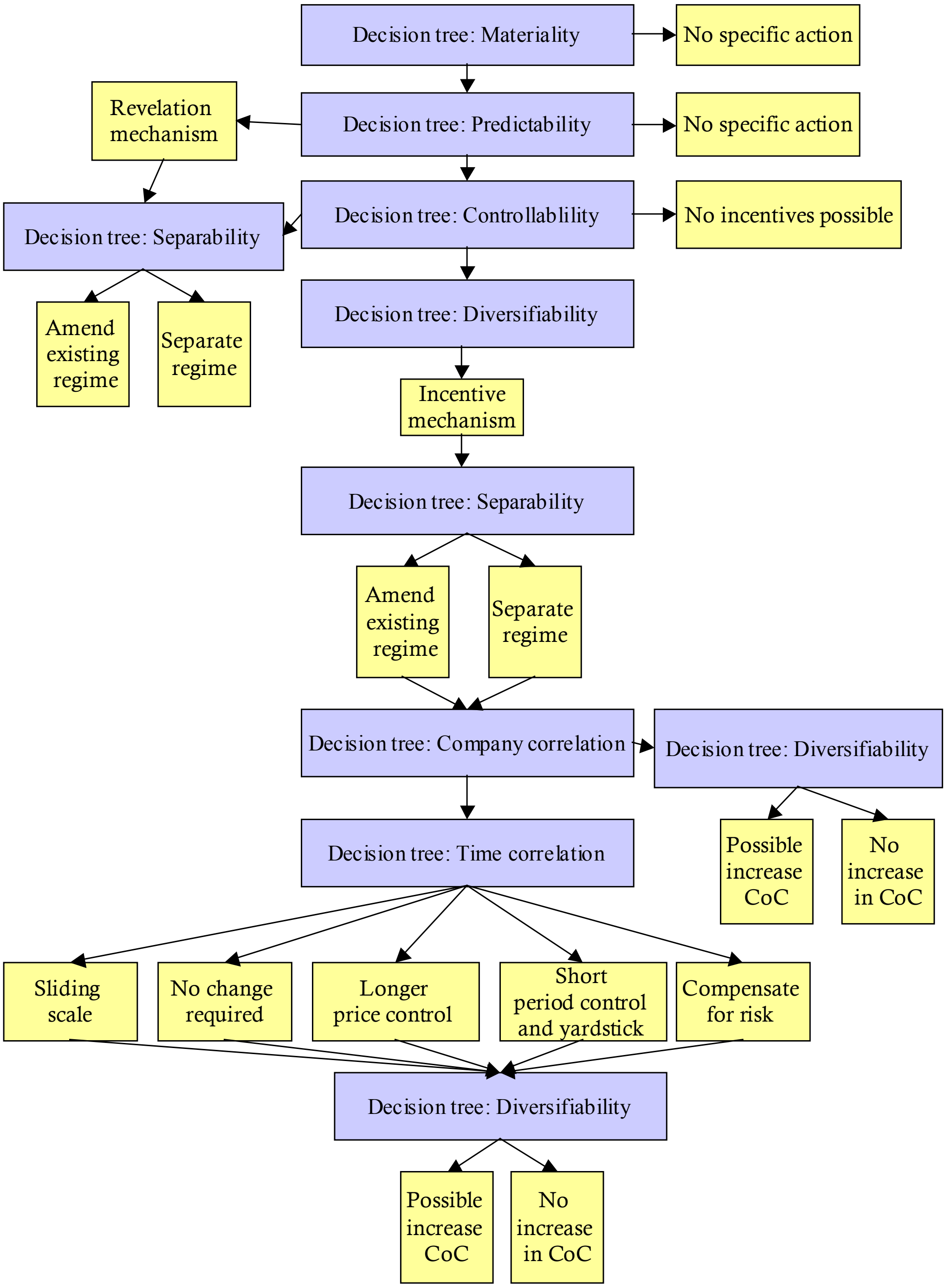
Figure 8: Is the impact of the uncertainty correlated over time?



2.3.7 Developing the overall decision making framework

Figure 9 links the individual decision trees presented above.

Figure 9: Combining the decision trees



3. Using the decision making framework

3.1 Introduction

Ofgem has asked us to apply this decision framework to some real examples of uncertainty that may require (or have in the past required) a regulatory response. The purpose is principally to test the framework to establish whether it can assist the regulator in devising appropriate incentive and risk-sharing mechanisms. As a secondary purpose, of course, the process also provides a starting point for a discussion about the regulatory response to particular issues.

Therefore, the principal conclusions of this section are about the usefulness of the framework, not the appropriate regulatory responses to the issues. This, however, is the obvious next step – to confirm the broad regulatory regime that emerges from the framework, and then to parameterise it in more detail as part of the regulatory process itself.

We have applied the framework to a number of real examples, which we analyse in turn:

- Licence fees
- DNO recovery of NGC exit charges
- One-off IT costs
- Overstay fines and lane rentals
- Severe weather exemptions for guaranteed payments

The first four of these we deal with in tabular form, and severe weather exemptions are discussed in a separate part of this section.

Finally, in section 4 we discuss the application of the framework to distributed generation.

3.2 Application to some simple examples

Table 1: Applying the decision making framework: licence fees

Background	Energy network businesses pay licence fees to contribute to the running costs of Ofgem, energywatch and other regulatory/Government activities. There is a cost pass-through, with under/over recovery corrected through the K-factor. Historically, costs were stable but the introduction of NETA substantially raised Ofgem's costs temporarily and energywatch costs have increased since privatisation.
Materiality	Typically, licence fee variations do not appear to be so material as to require a change to the regulatory regime between price controls.
Separability	Clearly separable – easy to audit, with no possibility of gaming.
Controllability	Effectively uncontrollable (relative to almost any other cost) – suggesting a cost pass-through.
Financial diversifiability	None - No diversified portfolio exists that would enable companies to offset the risk of variations in licence fees. It is therefore possible that additional risks arising from this source would raise the cost of capital, in response to which Ofgem could raise allowed returns. However, the two questions above point to a separate cost pass-through mechanism, which imposes no risk.
Predictability	In this case, the regulator is likely to have better information than do the companies about likely future costs. This possibility was not included in our decision tree, nor should it be because it is very rare. However, taking "Not by anyone" as the answer to whether the uncertainty is predictable leads to the conclusion that no incentive regime is possible.
Correlation over time	Perhaps positively correlated – higher regulatory expenses in one year are more likely to signal higher expenses in the future than to signal lower expenses. However, because a separate cost pass-through is indicated by the answers to earlier questions, there is no danger of insufficient returns, so no account need be taken of correlation over time.
Correlation between companies	Perfect. In principle, benchmarking is indicated. However, unless costs are controllable there is no point.

Table 1: Applying the decision making framework: licence fees	
Conclusions: optimal regulation	The answers to the questions in the decision tree clearly point to: • Allowing a separate cost pass-through if the uncertainty is material and unpredictable; or • Ignoring the issue and including the costs in general price control costs if not. This fits well with Ofgem's approach – initially the latter, moving to the former in response to more cost variability resulting from NETA.
Notes on application of decision tree	*In some cases, this example does not fit the framework well, not least because any predictability, controllability and so on for this cost item rests with the regulator, reversing the usual information asymmetry. However, all of the answers to questions posed in the decision tree point to an answer which common sense suggests is obviously correct.*

	Table 2: Applying the decision making framework: DNOs' recovery of NGC exit charges
Background	DNOs pay exit charges to NGC to cover the cost of their connection to the system, mainly the capital costs of the Grid Supply Point. Asset-specific charges are set annually by NGC with reference to the peak load volumes of the DNO concerned and are published in January of each year. Recovery of NGC exit charges is netted off DNOs' revenue before their performance is compared against targets. The majority of exit charges relate to existing DNO connections to the National Grid. The costs of these connections are regulated in NGC's price control formula. However, the costs of new or reinforced connections are not regulated in this way, being a matter for negotiation between the DNO and NGC (whose licence requires it to make no more than a reasonable rate of return for such activities).
Materiality	Uncertainty about NGC exit charges appears not to be large and is arguably therefore not material.
Separability	The costs of existing connections are fully separable. However, we understand that in principle there is a possible substitution between transmission and distribution investment when a new connection is required. If these substitution possibilities are significant, and if the volume of new connection is expected to be significant, then in principle a separate regime is not desirable (because of the gaming possibilities). However, we understand that the significance of either is low.
Controllability	No control over costs of existing connections. The cost of new connections is in principle controllable by the DNOs, in that they can choose the location of the GSP (which may affect the balance of distribution and transmission assets required). However, we understand that requirements for new connection capacity are driven principally by uncontrollable security standards, and the design of the new connection by engineering principles. In practice, therefore, even new connection costs are relatively uncontrollable, except in the very long term: DNOs could in principle reconfigure their networks to control these charges. However, there is a possibility of control if NGC's profit margins on new connections are flexible. If DNOs can achieve cost savings purely through negotiation with NGC, these costs are partially controllable. If this is significant, DNOs should be incentivised to negotiate. If it is trivial compared to the larger uncontrollable costs, then a cost pass-through is indicated.
Financial diversifiability	Again, it is worth distinguishing between true engineering costs and any NGC profit margins in the cost to a DNO. Variations in the former are not easily diversifiable. Variations in the latter could be diversifiable by buying NGC shares. If, therefore, DNO's were incentivised to negotiate harder with NGC over the cost of new connections, there is no case for higher cost of capital to reflect the risk.

	Table 2: Applying the decision making framework: DNOs' recovery of NGC exit charges
Predictability	Charges relating to pre-Vesting connection assets should be fully predictable, charges relating to post-Vesting somewhat less so. Some unpredictability arises for DNO replacement costs, if NGC's own investment plans effectively drive the timing of DNO investment. However, NGC's investment plans are typically well-known to DNOs in advance.
Correlation over time	Unlikely to be significant correlation of variations in costs over time.
Correlation between companies	Costs of existing connections will be highly specific but costs of new connections could be benchmarked.
Conclusions: optimal regulation	It would appear that little risk is associated with existing (especially pre-Vesting) connections but there may be a small element of risk and controllability associated with new investment. The key is the significance of the controllability of new investment costs. These costs are not formally regulated (because the activity is assumed to be reasonably competitive and negotiable) but – *unlike generators* – DNOs have no incentive to negotiate to minimise the costs. However, there is the possibility of a *perverse* incentive to minimise costs by deferring capital expenditure if such incentives were introduced. Whether such a perverse incentive would be a serious concern is a matter beyond the scope of this paper. However, it makes clear that throughout the decision tree, "incentive regimes" should be understood to imply balanced regimes that do not provide perverse incentives as a by-product of the incentive to minimise cost. Dual incentives on capital expenditure and network quality represent such a balance (and are treated in detail in our report on the Incentive Framework for Network Regulation). We understand that the scale of such new investment, and the scope for inefficiency, are small. The cost pass-through regime may therefore be an appropriate regulatory response, although Ofgem will obviously want to monitor the costs incurred in any new investment to guard against inefficiency or gaming.
Notes on application of decision tree	*The decision tree points to an incentive regime, if the costs of new connection are material, unpredictable and controllable. Arguably, they are none of these. However, as noted above, any such regime to provide incentives to minimise cost would also need to be balanced by network quality incentives to ensure that any cost savings do not arise at the expense of quality. Determining the appropriate balance is outside the scope of the assessment of uncertainty. However, if a new scheme were required (in addition to the IIP and other quality incentives), for balancing an incentive regime for NGC connection charges, the administrative costs of introducing incentives would be high and the "threshold" at which the materiality, unpredictability and controllability of costs demand a separate incentive regime consequently lower.*

Table 3: Applying the decision making framework – one-off IT costs	
Background	In the late 1990s, DNOs had to incur additional IT costs as a result of policy-driven and other uncontrollable events. The introduction of domestic competition, business separation and the Millennium Bug created a need for renewal of IT systems. Many of the costs declared by the DNOs as being related to these purposes fell in the 1995-2000 price control period but at the last distribution price control review, there was an expectation of some continuing costs. Both in 1995, and also in 2000, there was therefore uncertainty about these costs. This case study was suggested by Ofgem because of the extreme difficulties in separating such expenditure from general price control expenditure. Firstly, simply in accounting terms there was much variation across DNOs about the treatment of such IT costs (some counted them as non-operational capital expenditure, some as operating expenditure). More fundamentally, there is scope for synergy between the three "additional" drivers of IT expenditure listed above, and between those three drivers and general needs to renew IT infrastructure. In particular, a completely new IT system could solve all three problems, while also providing a DNO with state of the art IT going forward, reducing general price control costs after 2000. If Ofgem had simply allowed whatever expenditure companies declared to be "for" these items, as a separate pass-through, DNOs would have had an incentive to game by investing in IT wherever practical (possibly thereby saving operating and capital costs) and declaring the expenditure to relate to these one-off uncontrollable events.
Materiality	It is hard to tell whether the cost variation was material. Total annual "non-operational capital expenditure" across 14 DNOs was £269m 1995-2000, compared to £169m 1991-1995 (falling back to £150m annually in business plans for 2000-05). This could, however, be an inaccurate measure of the costs for uncontrollable events. We note that Ofgem did not re-open the price control between 1995-2000. However, this was against a backdrop of general out-performance of the price control targets (so companies' returns were high). Conceivably, a similar rise in costs in a period in which achieved returns were at or below the cost of capital could be treated differently, at least to the extent of considering the historical costs in a price review.
Separability	This is the key issue. These costs are separable from general IT costs, but imperfectly so. Indeed, substitution possibilities extend more widely than to IT alone. High-technology IT solutions could allow reductions in general operating costs (e.g. customer service). If this is the cheapest overall option, it should be adopted but if it is not, the regulatory regime should not encourage it. We suspect that a separate regime with weaker incentives (more cost pass-through) for these costs than general costs would provide strong incentives for gaming, while monitoring to prevent gaming would be administratively costly. We conclude that there should not be a separate regime, with lower incentives for cost efficiency.

Table 3: Applying the decision making framework – one-off IT costs	
Controllability	It seems reasonable to assume that most components of these costs are controllable. Certainly, companies' declared costs varied greatly. The requirements for IT changes are (by assumption, in this example) uncontrollable, but companies have great freedom in choosing how to respond, and can affect the efficiency with which they do so. This points to an incentive-based regime.
Financial diversifiability	Probably not. Increased IT requirements were generally common across at least the 12 DNOs in England & Wales. Arguably, some risk could be diversified by buying shares in IT companies, but this is too complex to be costless. It could therefore be legitimate to raise the allowed rate of return to reflect an increase in the cost of capital in response to this uncertainty, if the risk cannot be removed or the additional costs not reimbursed through other means.
Predictability	The existence of Millennium Bug and domestic competition costs should have been reasonably predictable to the regulator and companies at the 1995 review, although the companies would have significantly better information about the cost level. All items, however, were quite unpredictable to all parties – IT costs change rapidly and precise regulatory requirements for business separation will have been unpredictable for the companies, for example. However, the regulator should be able to observe the impact after the event (companies are either compliant with regulatory requirements and secure against the Millennium Bug or not) and we have previously assumed that costs are controllable – so the decision tree indicates an incentive-based regime.
Correlation over time	Low. If anything, this question is almost irrelevant in this case. These were truly one-off events, without implications for continuing expenditure, unlike all of the other case studies we consider.
Correlation between companies	This should be high – companies faced substantially the same regulatory requirements and all have similar business models within which general IT expenditure provides benefits. This points towards benchmarking.
Conclusions: optimal regulation	Answers to the questions posed in the decision tree suggest that Ofgem should have adopted an incentive-based regime, using benchmarking. There is a case for an increase in the allowed cost of capital in 1995, if other risk-reducing measures were not adopted. We are not aware that the problem was considered at length in Ofgem's (Offer's) reviews of 1994 and 1995. However, in principle the right solution would be to allow companies a benchmarked cost for additional IT expenditure (based upon average, or lower-quartile declared expenditure). This could have been "allowed" retrospectively in the 1999 review (but we suspect that the large gap that had emerged between costs and prices – reflected in the P0 cuts in 2000 – prevented the companies arguing vigorously for such an adjustment). For 2000-05, a benchmarked fixed allowance could be added to the price control revenue (and therefore

Table 3: Applying the decision making framework – one-off IT costs	
	subject to the same incentives as normal price control revenue – not a separate regime). How this differed across companies would have depended on the drivers of IT expenditure. We understand that Ofgem allowed all companies £1m annually for 2000-05 in relation to these cost items (definitions differ slightly – this relates to the ongoing costs for business separation). This implies a judgement that there are no drivers resulting in differing costs for different companies, not even customer numbers. Given the "lumpy" nature of large IT investments, this is plausible.
Notes on application of decision tree	*The decision tree points clearly to incentives and benchmarking. Note that the decision tree on "predictability" could be held to point to the "no incentives possible" outcome if the impact is not observable by the regulator. This would contradict the conclusions elsewhere in the tree. However, the appropriate "impact" to be observed is compliance with regulatory and other criteria (i.e. the performance of the IT system), avoiding this outcome.*

Table 4: Applying the decision tree - Overstay fines and lane rentals	
Background	Section 74 of the New Roads Act has introduced a trial of overstay fines. Since the trial began in June 2001, 25 local authorities have taken part. The trial is due to be completed at the end of 2003 (but DETR will then need time to consider the results, before introducing any formal system). Under the trial, utility companies must notify the local authority in which they need to carry out work stating how long that piece of work should take (and local authorities have guidelines on likely duration). If the work should take longer than the specified length of time they will be fined by the local authority. The fines that can be levied are the same across all local authorities, although the New Roads Act does allow the local authorities to propose their own fines. The fines vary for several reasons including the type of road, size of disruption e.g. number of lanes used and type of work. Section 74A of the New Roads Act also introduced a separate trial of lane rentals. Two authorities, Camden and Middlesborough have so far signed up for the trial. Under the trial, the utility company is charged as soon as they start their work digging up the road. The charges that are levied are set by the local authority and again may vary according to the type of road, size of disruption etc. Should the utility suggest a method of minimising disruption then the local authority can offer a reduced charge. The question is therefore what, if any, account Ofgem should take of this in setting regulated charges to network businesses.
Materiality	The scale of possible costs and cost variations is very unclear at present, and will still be highly uncertain even when DETR proposes a definite scheme. Some companies have suggested very high annual expected costs for lane rentals. The uncertainty relating to lane rentals is clearly material, and may even be sufficiently material to require Ofgem to act outside regular price control reviews, if DETR introduces such a system during the next price control period. Overstay fines are less likely to result in material increases in uncertainty, if the targets for completion of work are reasonable.
Separability	Clearly, any costs payable to local authorities can be identified separately from other costs. However, there are substitution possibilities. By increasing operational costs, companies should be able to reduce lane rental/overstay charges (for example by working more intensively when the road is up or by pre-positioning workers ready to begin the next stage of work). Gaming is therefore possible if a separate regime has a different incentive power from the main price control regime. With cost pass-through of lane rental costs, companies can be expected to attempt to minimise operational costs with no regard for minimising lane rental costs. This is, in effect, identical to the current position (since currently no lane rental costs are incurred). We conclude that there should be no significant difference in the incentive power of the lane rental cost regulatory regime and that of the general price control – implying that there should not be a separate regime.

Table 4: Applying the decision tree - Overstay fines and lane rentals	
Controllability	The drivers of the volume of work (faults, new connections) that could close lanes are relatively uncontrollable by companies. However, the speed with which the work is completed and the degree to which it disrupts road traffic is controllable (indeed, this is the rationale for the schemes).
Financial diversifiability	Probably not, as the financial beneficiaries of high lane rental/overstay charges are local councils. If risks are not mitigated in other ways, and if the regulator does not compensate shareholders in other ways, there could be an argument for increased allowed returns to cover an increase in the cost of capital.
Predictability	We understand that both lane rental charges and overstay fines relate to relatively unpredictable drivers (faults, new connections). Companies will have better information than the regulator, but the latter can observe the drivers after the event. Since these costs are partially controllable, this suggests an incentive-based regime.
Correlation over time	From the current position of high uncertainty to the "mature" phase when companies are accustomed to the charge, correlation of uncertainty is likely to be very strong. At present, no one knows how much the system will cost the companies. The scale of costs in the first year is probably a good guide to the scale in the second year and so on. The decision tree implies that an interim price control review is appropriate if the costs greatly differ from those expected at the previous regular price control review.
Correlation between companies	The physical element of lane rental/overstay charges (the length of time and number of lanes closed for a particular activity) are likely to be similar across companies and could be benchmarked, as long as proper allowance can be made for regional differences. We understand that local councils are expected to be free to set the level of fines, however, so unit costs cannot be benchmarked.
Conclusions: optimal regulation	The answers to most questions point to an incentive regime, in which companies are exposed at least to some of any costs above expected costs. *In the long run*, this suggests that lane rental/overstay costs should be brought into the general price control. As are other operational costs, they could be forecast five years ahead and any under/overspend is retained/incurred by the companies. Benchmarking of expected lane closures across companies should be used in assessing company forecasts. *Before* the scheme is introduced by DLTR, there is large uncertainty about its possible impact. If the long term regime described above is used when the scheme is untried, the increase in risks will be larger, particularly if local authorities are free to set the level of charges. Consequently, in the first period of operation of any new scheme there is a case for:

Table 4: Applying the decision tree - Overstay fines and lane rentals	
	• an interim price control review to amend the price control solely to reflect lane rentals, once the scheme is introduced; and • reduced incentives (for example through a flexible mechanism) during the first price control period of the scheme. This represents a separate regime (in the short term), with a lower incentive power than the general price control. The risk-reducing benefits of a sliding-scale must, of course, be set against the reduced incentives and possibilities of gaming created by such a separate regime. However, we note that these perverse incentives cannot result in worse outcomes than the present system, under which lane rental/overstay costs are zero and there is no financial incentive whatever to minimise disruption.
Notes on application of decision tree	*One difficulty encountered in applying the decision tree to this problem is that no scheme currently exists. It is natural to compare the results to the CURRENT arrangements, in which the "cost" of these activities is zero. However, the default option of no specific action is actually defined in the decision tree as being the existing main price control. Thus, when considering whether "action" should be taken, the question is not whether Ofgem should respond at all to a new scheme of this sort, but whether it should take any action other than making appropriate operating and capital cost allowances in the five-yearly price review, providing incentives for companies to beat the cost projections in the same manner as for other items in the cost base. It seems reasonable to conclude that it should not, in the long term, but that the first price control period may require special treatment.*

3.3 Severe weather exemptions for guaranteed payments

Customers experiencing supply failures can claim compensation payments from distribution companies. Payments begin at £50 (for domestic customers) 18 hours after supply fails, with further payments of £25 for every subsequent 12 hours until restoration.

In a typical year the sums involved are not large in comparison to total price control revenue –tens to hundreds of thousands of pounds (price control revenue is typically £100-200 million per year). However, following severe storms such as those of late 2002, payments could in principle rise dramatically, to the point where a DNO could face claims for several million pounds.

However, companies can claim an exemption from making compensation payments to customers if severe weather prevented them from restoring supplies in the relevant timescales, provided that they designed and maintained their networks in a reasonable way and they made reasonable efforts to reconnect customers. In the past, some companies have made payments even when they could have claimed exemption (for example, following the Boxing Day storms of 1998 companies made substantial levels of ex-gratia payments to customers). More recently, companies' willingness to forego the option of claiming an exemption appears to have fallen. In particular, most affected DNOs claimed exemption following the storms of late 2002. It is up to the company to consider the provisions of the regulations and decide whether to claim the severe weather exemption (or other exemptions – see below). Customers may challenge the application of the exemptions and refer the issue to Ofgem. In such cases Ofgem decides whether or not the DNO has acted consistently with its legal obligations and whether the customers are due compensation. Approximately 3,000 customers have made such a referral to Ofgem in respect of the October 2002 storms.

The decision is not simply a straightforward one of whether the weather was severe. The exemptions system appears to be intended to capture *uncontrollable* causes of customers being cut off. For example, no payments are required if work to reconnect a customer within the specified timescales would have resulted in a breach of health and safety guidelines (which could prevent repair crews being sent out in very bad weather). Most importantly, in order to claim a severe weather exemption, a company must demonstrate that it took all reasonable steps to minimise the disruption. This could cover both the actions taken after the supply failure and any earlier actions that could affect the probability of a failure.

Companies that are deemed to have undertaken inadequate maintenance may face payments even if the weather was "severe".

There has been a suggestion that the severe weather exemption could be reduced in scope. This is because it is not clear that companies have appropriate incentives under the existing scheme to manage the impact of severe weather on an efficient basis. We assume for simplicity that the proposal to be assessed is that:

- companies are fully exposed to payment claims, without recourse to the severe weather exemption; and
- Ofgem allows companies additional revenue in the price control review, based on projected payments over the five year period.

Since severe storms are infrequent (the Met Office estimated for the DTI that a storm of similar severity to strike some part of the country every 2-10 years[3]), the average is not representative of a typical year. An "expected payments" allowance would therefore result in over-recovery against price control assumptions in most years. However, in a year of a severe storm, they would under-recover compared to expectations, unless they have substantially improved their performance on reconnection. This, of course, would be the aim. By exposing companies fully to financial effects of storms, the regime would provide incentives to minimise the disconnections caused by storms, and to reconnect swiftly.

Finally, we note that this payment system is not the only one providing incentives for companies to maintain supply. The IIP provides penalties for poor performance on supply quality. Again, there may be exemptions for severe weather, but the application of these exemptions to measured supply failures for the IIP need not be the same as the decisions on specific customer claims for compensation.

3.3.1 Application of the decision tree

Materiality

An increase in compensation costs resulting from a storm similar to that of late 2002 would be clearly material.

[3] Quoted in *October 2002 Power System Emergency, Post Event Investigation* (BPI, for DTI, 2002).

Separability

Companies have substantial possibilities to substitute between payments and general price control expenditure (both operating and capital expenditure). Investment (such as undergrounding) could reduce the effect of severe storms, and operational expenditure (such as providing a reserve of maintenance crews) could result in faster reconnection.

Thus, it would be undesirable to establish a separate regulatory arrangement for costs of payments for severe weather. If the payments are set to reflect (roughly) the costs imposed upon disconnected customers then, ideally, Ofgem would like to see companies taking an optimal decision between reductions in operating and capital costs and any consequent increases in the expected total costs of compensation payments. This will only happen if the payments are governed by the same regime as operating and capital costs.

Controllability

Clearly, companies have no control over the weather. However, they can control the impact that it has upon their network performance, within limits. For example, companies can incur operating expenditure in getting people out faster and reconnecting customers more quickly, or they could incur capital expenditure to improve network resilience. Companies may be unable to have much impact on customers being off supply in the initial period after the event but as time passes their degree of influence may increase.

Financial diversifiability

It seems unlikely that there are any significant options for creating a diversified portfolio to reduce the risk of being responsible for payments relating to severe weather (unless, of course, Ofgem establishes a system in which "winning" DNOs receive payment from "losing" DNOs – which automatically has such properties). If the risk from removing the exemption is material, then there may be a case (depending on materiality and unpredictability) for increasing allowed returns to reflect an increase in the cost of capital, unless other mechanisms are put in place either to mitigate risk or to provide shareholders with compensation for increased risk.

If DNOs could insure themselves against the risk, then this provides a clear initial value for any compensatory allowance, although allowances would need to be assessed in the same way as allowances for expected payments, to ensure that high-risk companies with substandard network quality are not fully compensated.

Predictability

Clearly, the timing and magnitude of any claims resulting from severe weather is highly unpredictable. From the frequency of "severe" events since privatisation to date, it cannot even be stated with certainty that any, or less than any given number, of events will occur within a five year price control period. The predictability of payments is even worse as it will depend on network quality (which may be known to the companies – but the link between quality and failures in severe weather may be highly non-linear and the effects of a given storm on a given network therefore hard to assess).

However, the strong controllability of these costs suggests an incentive-based regime.

Correlation over time

Network failures in response to storms may be correlated over time – poorer quality networks will suffer more often. In principle, Ofgem might have to decide whether to re-open the price control for a company facing repeated, high claims. In practice, if the regulator regards these costs as controllable in the long term, it may prefer not to bail the company out.

The weather itself is assumed to be uncorrelated (unless climate change results in stormier conditions in general). This suggests in principle that the price control period should be lengthened so that the randomness imposed by the low frequency of severe storms is smoothed out. However, the frequency is, we understand, so low that a very long price control period would be required to ensure that "average" annual costs were close to "expected" annual costs. A ten-year price control, for example, would not be sufficient. There could easily be three severe storms in that time, or none. Changing the price control period is therefore not recommended. In any case, such a change would have incentive and other effects that go well beyond any need for reform driven solely by this exemptions regime.

Correlation between companies

This will vary. Storms can have different localised effects, but in some cases companies can be considered to have faced similar conditions and their responses (and the implied existing state of their networks) compared. Consequently, benchmarking can be used. If Ofgem allows companies "expected" severe weather payment costs at the start of a five-year price control, payments based on expected disconnections (and reconnection times) could be used to set the projected additional revenue. Regional variations, would be needed.

3.3.2 Conclusions: optimal regulation

The results of using the decision tree suggest that:

- Companies should face incentives to improve the way they build and maintain their networks, and reconnect customers, to reduce storm-related disconnections, to balance the incentives they face to reduce costs, i.e. they should have incentives relating to network resilience.

- The risks to companies from a simple incentive scheme (such as removal of the severe weather exemption) may be large, as the potential *uncontrollable* cost variations are material, unpredictable and cannot easily be diversified.

- There is a role for benchmarking in assessing the allowable costs for payments to customers disconnected due to severe weather. However, any benchmarking must be reasonably sophisticated to account for variations in inherent conditions and the regional severity of storm impacts (a simple approach of "beating the average" in reconnection times would not suffice).

In addition, we note that other regulatory mechanisms also affect the balance between network quality and cost – notably the IIP.

The risks involved in providing a blanket incentive – by removing the exemption and allowing an "expected" average annual cost seem very high. Given the infrequency of severe events, the average is not meaningful and the incentive could be expected to have very different effects on companies with different attitudes to risk and perceptions of the severe weather risk. It is therefore hard to predict whether the incentive would lead to under- or over-provision of measures to reduce the impact of storms.

This suggests that simply removing exemptions (and treating additional costs as part of general price control costs) is not the appropriate answer.

This in itself answers the question posed in this case study. However, this does not imply that the existing system is appropriate either. The same process of considering risks and incentives provides some guidance as to what a solution should look like.

Ideally, Ofgem should therefore establish a mechanism that passes through uncontrollable payments made under severe weather conditions (i.e. payments that would be made even by a company that had designed and maintained its network appropriately and responded effectively and efficiently to such an event). However, companies should be exposed to the costs of payments for the additional number or duration of outages that is within their control.

The obvious alternative is for Ofgem to set guidelines on what constitutes controllable and uncontrollable time spent disconnected. It therefore seems sensible to clarify and formalise the circumstances in which exemptions will be allowed. For example, in the event of "severe weather" companies might be liable for claims only for reconnection after a longer period of time than the 18-hour standard applying in normal circumstances. Such a system would expose companies to increased risk of "unfair" decisions as pre-defined criteria are adopted, but equally would reduce the uncertainty in the period between a severe weather event and Ofgem's decision. From a very cursory examination of this issue, it seems to us that a rules-based system should provide better incentives for efficient management of network quality before and after storms, because it can more readily be incorporated into companies' management decisions.

4. Distributed generation

4.1 Introduction

Increased connection of distributed generation is generally held to represent one of the largest sources of uncertainty facing DNOs in the next price control period and beyond. In this section, we therefore extend the application of the decision tree framework to consider the appropriate regulatory response to the additional uncertainty faced by distribution network operators arising from distributed generation. The assumption is that DNOs face uncertainty about the scale, costs and network performance effects of increased generation connection. Ofgem is at least as uncertain about these issues, and in addition is not likely to be in a position perfectly to assess the accuracy of companies' statements on the subject.

It should be stressed that firstly, we are concerned only with the regulatory response to the additional *distribution network* effects of distributed generation, not with system effects such as imbalance charges, or shallow connection costs, or a more general cost-benefit analysis of increased use of distributed generation. Secondly, we are using distributed generation merely as an example (albeit an important and complex one) of additional uncertainty, to test the decision tree framework set out in Section 2. As described in the introduction to section 3, this is merely the first step in the regulatory process to dealing with these issues. The next step in the process is to confirm that the general regulatory approach indicated by the decision tree is appropriate, and then to move on to parameterise the regulatory regime in more detail.

4.2 The issues

Ofgem has provided us with some detailed scenarios for distributed generation to test the decision-making framework, i.e. to characterise the uncertainty associated with distributed generation[4]. In many cases this provides clear guidance on the answers to questions raised in the decision making framework.

[4] These scenarios were produced solely for illustrative purposes to test this framework. In no sense should they be regarded as an Ofgem position on (or forecast of) the likely course of increased connection of distributed generation.

When a generator requests a connection to a distribution network, the DNO is faced with a range of possible increases in cost, arising from:

- "shallow" connection costs (solely incurred to connect a specific plant);
- reinforcement costs, changing capacity (and more importantly configuring the network for connected generation at that location) elsewhere in the network;
- effects on quality of supply to final customers, in the absence of any (presumably costly) countervailing action; and
- effect on losses performance.

We understand that there are three main sources of uncertainty in principle:

❒ The volume of DG to be connected is uncertain, both nationally and for any given DNO.

❒ The costs of reinforcement and effect on service quality will be highly specific to, among other things, the connection point, the type of DG connecting and the presence of any existing DG. This can make it extremely difficult to derive simple forecasts or comparisons of cost/MW. Furthermore, it may be hard for Ofgem to determine whether any expenditure to accommodate a proposed connection is genuinely additional, or simply reflects activities the DNO might have undertaken even if there had been no connection request (general reinforcement). Similar arguments apply on the quality side – the effects will be highly specific and therefore variable across projects.

❒ Finally, there could in principle be uncertainty about the costs of specific actions to accommodate DG (such as the costs of installing standard equipment).

In effect, what is lacking is a simple and well-understood cost driver. It may appear straightforward to base regulation on a MW or MWh volume driver – but costs vary for other reasons, so such a driver imposes some residual risk, and potentially perverse incentives to discourage DG connections that may be expensive in distribution terms but are economic overall. A volume driver that properly took account of the variables described in the second bullet point would be an effective proxy for a cost driver (because the unit costs, described in the third bullet point are well known). However, Ofgem does not (yet) possess the data to construct such a volume driver.

Finally, in this section, we should note that DG can be expected to have very different effects, depending on the degree to which DNOs have accommodated DG in the past. Here, we define the short and long terms in relation to this difference. **In the short term** connecting DG is an activity that is additional to the DNOs' core business – the distribution of electricity from Grid Supply Points to end-users. It can be expected to add to costs, and perhaps detract from network quality (although there is no definite link between the volume of DG connected and any adverse effects, indeed in some circumstances, network quality may be enhanced by such connection). Companies will be prepared to identify the costs of connection and reinforcement separately, although (as noted above) Ofgem may have difficulty in assessing such estimates for efficiency and true additionality.

At some point in the future (**"the long term"**), if the use of DG expands in line with Government targets, this will change. Accommodation of DG will no longer be an additional activity for distributors, but a core function. DNOs would have active networks, in which expansion and maintenance plans are based upon serving both their generation and load customers. In these circumstances, the regulatory problem changes significantly. It becomes less meaningful to identify costs on a project-by-project basis as being DG-related or load-related[5]. In addition, the quality effect of additional DG connection may become more positive, creating greater possibilities for isolating part of the system from faults. Finally, the cost impact of DG may even become negative, at least in some parts of the network, as local generation reduces the need for reinforcing some part of the distribution networks compared to what would be required in the absence of DG. In some ways, therefore, uncertainty is even higher in this long term position. However, it is reasonable to assume that better information will by then have been acquired on some elements of the costs and benefits of connecting DG.

These short and long term situations seem to us to be so clearly different as to require different analysis using the decision tree. However, ideally the short term regulatory framework should be capable of evolving to a framework suited to the long term problem. In the analysis that follows, we therefore consider these two situations separately and comment at the end on the compatibility of the two regulatory arrangements.

[5] Any more than it makes sense for National Grid to do the same with general reinforcement of the transmission system. Reinforcement helps to transport power from generation to load; it is almost meaningless to identify one of this pair as being "responsible" for the capacity requirement.

4.2.1 Application of the decision making framework to Ofgem's central scenario

In much of the detailed application of the decision making framework to the problem of distributed generation, we received substantial guidance from Ofgem, in assumptions set out in Ofgem's proposed scenarios. These assumptions are reproduced at Annex 3. Again, we note that these assumptions were created solely for the purpose of this study; they do not constitute an Ofgem "view" on the distributed generation issue.

We have not, in general, considered the network quality dimension of the DG problem as a separate item. Under the IIP, and other quality regimes, poorer network quality has financial implications for DNOs. In an ideal quality regime, the social costs of poorer quality are precisely reflected in the financial penalties to DNOs. Such an ideal is probably unattainable, but any system providing a smooth link between quality and penalties implies that effects of events on quality can be re-cast in cost terms. The quality dimension of Ofgem's role cannot be assumed away, but by establishing a quality incentives regime, the regulator removes the need to consider quality separately in every other regulatory development, isolating the quality problem within the design of the quality incentive regime. Where we describe incentives to improve efficiency, therefore, efficiency should be understood as total outputs (e.g. quality) divided by total inputs (e.g. costs) and the term "costs" includes quality-related penalties as well as direct operational and capital costs.

Materiality

We understand that the additional uncertainty resulting from increased expected connection of distributed generation may well be large. There is considerable uncertainty about the volumes and average costs of new connections nationally. Perhaps more importantly, the distribution of new connections between DNOs and the costs of connection and consequent reinforcement are highly uncertain. Some DNOs may see only a small cost impact in the immediate future, others could experience a significant increase.

We therefore assume in the remainder of this section that the uncertainty is material.

Separability

In this decision tree, we need to draw a clear distinction between the short-term and long-term positions of the impact of DG on expenditure to reinforce the DNOs' infrastructure. Again, the "short" and "long" terms are defined not over time, but by the degree to which the DNO has previously accommodated DG.

In the short term, DG costs are assumed to be separable, but imperfectly so. Volume drivers (requests from generators) are observable, companies will identify the costs separately from other price control costs but Ofgem will not be able to verify that all of the reinforcement costs of a proposed new connection are solely attributable to the additional generation. Companies could game the system, by including general network maintenance and reinforcement costs in estimates of DG costs. If, for example, DG costs were simply passed through, while general price control costs were subject to the incentives provided by RPI-X, the DNOs would have an incentive to try such games. They could, for example, under-spend relative to price control revenue, or achieve better than expected quality performance (and benefit through the IIP), while passing the costs through in "DG-related" cost estimates. This suggests that Ofgem should not establish a separate regime unless it is confident that it can assess DG reinforcement cost estimates to identify any elements that are not incremental costs strictly required to accommodate DG, but more general network improvements (that should properly be included in the main cost base).

In the long run, we suspect that costs will not be separable at all, in that Ofgem would be unable to divide capital expenditure proposals into those relating to generation and those relating to load. A DNO would no longer be a company serving load with some "additional" costs associated with allowing some generation to connect, instead it would be a network connecting load and generation. It is almost meaningless to assign particular projects to one or other of these customer classes – network costs relate to linking the two.

We conclude that DG should not be governed by a separate price control regime in the long term. In the short term, the degree to which a separate regime can be established will depend upon the confidence Ofgem has in its ability to distinguish DG-related expenditure from expenditure on the network more generally.

Controllability

Although there are obviously large uncontrollable elements in the costs associated with distributed generation, it appears that companies do have some control even now over all three of the areas of uncertainty we previously identified:

- Volumes connecting;

- Reinforcement requirements;
- Unit costs of specific activities.

Controllability of volumes represents an unusual problem for Ofgem. Although DNOs should respond to requests for connection, it may not occur (or not at the rate it could) if it is against DNOs' interests to facilitate connection. Ofgem's proposals on new connections may have diminished the problem by creating a clearer understanding of what services and payment options DNOs should offer, but ideally Ofgem would prefer companies to be motivated efficiently to connect DG.

This suggests that some sort of regulatory arrangement is required to encourage DNOs to respond to demands for connection and reinforcement.

The decision tree clearly indicates an incentive-based system to minimise cost, even if this imposes some risk on the DNOs. In the long term, costs should become more controllable still as companies gain experience.

The two areas of controllability – volumes and costs – together create a dilemma for Ofgem. If DNOs are encouraged to facilitate connection, by for example reimbursing them for any declared costs of doing so, then there is no constraint on inefficiency and gaming. If, on the other hand, the regulatory arrangements are excessively "tough" on DNOs, in seeking to limit excessive expenditure, then they might also limit the volume of connection. For example:

❒ If DNOs were able only to claim standardised benchmarked costs (per kW, say) for connection, then they could "cherry-pick" the cheaper connection requests, if they do indeed have control over swift acceptance of connection requests. This is in some ways efficient. However, it would be inefficient to turn away DG which is sufficiently valuable to justify those connection costs (e.g. because of low generating costs and ROCs).

❒ A rigid overall cap on capital expenditure for connections could result in a halt in DG connections work mid-way through the price control period even if, again, the benefits from further connections would exceed the costs.

Diversifiability?

It might be possible to diversify the risks of DG connection between DNOs and by creating a diversified portfolio including owners of DG. If, for example, there is little uncertainty about the volume of connection but great uncertainty about its location, then there may be winners and losers among the DNOs.

If such diversified portfolios can be constructed, then the decision tree suggests that increasing the allowed return is not an appropriate response to any increased risk. This does not imply that the risk should be ignored – risk reduces managerial incentives for which compensation may be required – just that a higher allowance for the cost of capital may not represent the right solution.

Predictability

DG costs can be assumed to be unpredictable. Ofgem's guidance to us on DG scenarios form the basis of this exercise which is that we should assume that only the upper and lower bounds of national *volumes* can be predicted in advance. Furthermore, DNOs might experience different volumes and that costs are hard to predict.

On the predictability decision tree, the question "Is the impact predictable?" can be answered "Not by anyone". Given that we assume costs are (partly) controllable, this points to an incentive-based regime.

If, however, the companies possess more information than Ofgem, an incentive regime could lead to gaming. Companies could predict higher costs than they truly expect and even if the uncertainty is so great that realised costs could be higher still, the most likely outcome is excess returns. To some extent this is inevitable – if companies possess private information, they can exploit this information asymmetry to make gains.

In the longer term, DG-related expenditure should become predictable, indeed arguably no less predictable than general network costs. Predictability will not be perfect, of course, but any incentive mechanism for investment that Ofgem might adopt for the existing regime would probably remain valid when DG is an integrated component of a distribution network.

Correlation over time?

We understand that reinforcement (deep connection) costs may be positively correlated over time because the existence of DG may create a benefit for new DG plant. Beyond a certain point, however, this correlation will tend to diminish, and it is less likely that the costs will be positively correlated over time.

The implication of a positive correlation is that it should lead to consideration of the possibility of an interim review or sliding scale mechanisms to provide flexibility, as we discuss in our conclusions section.

In the longer run, there is no obvious reason why DG costs should be positively or negatively correlated over time. When new DG connection is rare, and costs relate principally to general maintenance of the network, they should be no less stable than they are now.

Correlation between companies

Ofgem, in its central scenario, asks us to "Assume that costs will not be comparable across companies (unit costs not comparable due to differences in network design), so benchmarking will not be possible". Thus, companies' efficiency (or gaming in proposing capital expenditure plans) cannot directly be compared, because costs are so location- and timing-specific. In effect, Ofgem does not possess sufficient understanding of the cost drivers for DG connection, or data on the values of those drivers, to enable it to make valid comparisons of costs between DNOs.

In the short term, therefore, Ofgem will have difficulty in using inter-company comparisons to assess the efficiency of DNOs' capital expenditure plans and will certainly be unable to carry out formal benchmarking, let alone incorporate this into the price control regime through yardstick competition. In the long run, however, increasing volumes of data, and increasing understanding of the cost drivers should become available. Although any comparison of costs between DNOs would doubtless require a significant econometric exercise to identify the appropriate adjustments to make for different cost drivers, it is still possible to apply yardstick competition as long as those adjustments are a reasonable approximation of the real drivers of costs.

Ofgem does not need to wait until all DNOs possess active networks to introduce this statistical approach to setting allowed revenue. In addition to its incentive power, yardstick competition also has the potential to insure companies against common cost shocks, as costs common to the industry are passed through but company-specific cost shocks are not. As long as the relationship between drivers, costs and quality is understood, yardstick competition has some value, even if companies are at different stages in an evolution towards active networks.

4.3 Recommended regulatory framework

We report our conclusions from this analysis separately for the short term (when information is scarce and DG activity is low) and the long term (when Ofgem and the DNOs possess better information and a substantial amount of DG is an integrated part of all DNOs' businesses). Finally, we consider the compatibility of the two arrangements and the triggers for a transition between the two.

4.3.1 Short term

As we noted under the discussion of controllability, Ofgem faces a particularly difficult decision on dealing with the uncertainty arising from increased connection of distributed generation. If the volumes connecting are controllable for the companies, there is a danger that some distributed generation that is economic to connect from society's point of view could be delayed if companies are not fully reimbursed for the costs of doing so. Depending on how constraints on reimbursement operate, this could result either in a general reduction in connection activity, or "cherry-picking" to avoid the most costly connections, which may not be efficient for the system as a whole. This points to a low-powered incentive regime, in which companies are fully compensated for the connection work they undertake.

However, costs of reinforcement are also controllable, in that companies could incur inefficient costs in connecting, and not separable, in that companies could substitute main price control costs into declared DG connection costs. This points to an incentive-based regime, in which allowed revenue for DG connections is driven by factors other than the costs that the company declares. The extreme "cost pass through" alternative could lead to inefficiency and also to substitution of costs to "game" the main price control.

Ofgem would like to see DG connected (where it is economically efficient for the deep connection costs to be incurred) but will also be reluctant to provide a blank cheque for any costs incurred in doing so. There is perhaps an analogy in Ofgem's work to encourage DNOs to improve network quality, without allowing companies simply to spend whatever sums they like to achieve desired network quality levels. "Balancing" these incentives for increased outputs and reduced unit costs is not a straightforward problem, as the parallel work on incentives that Frontier is undertaking discusses in depth.

Identifying this dilemma immediately prompts two questions:

- What is the preferred balance between the risk of DG not being connected and the risk of inefficient or "gamed" costs being reimbursed through regulated charges?

- ❒ Can this trade-off be improved? Must a regime that facilitates all reasonable requests for DG connection necessarily result in the removal of all incentives for efficient connection?

The first of these questions is of course a matter of policy . The answer to the second depends critically on the information available to the regulator. Suppose (for illustration) that Ofgem has no information whatever on the costs of DG connection. Then if it allows any declared costs to be recovered, there is no incentive for efficient connection; while if it fixes a lump sum for recovered costs in advance, there is no incentive for companies to connect any DG. If, on the other hand, Ofgem could determine efficient connection costs and was able consistently to allow efficient costs to be recovered, then all requests for connection that the generator valued more highly than the efficient costs of connection would be met.

Additional information about the drivers of efficient DG-related costs therefore has a very high value to the regulator. The regulatory regime needs to be designed with this in mind.

The exercise of running this problem through the decision tree suggests to us a solution of the sort outlined below. In terms of the dilemma set out above, this regime emphasises cost efficiency over insurance against cost over-runs and failure to meet volume requirements. Obviously, alternative value judgements would lead to an alternative solution, and we provide an example of what such a solution might look like after setting out our preferred option.

Volume-related revenue drivers

Controllability of volumes of DG connecting requires a **volume-related revenue driver** (or "unit cost allowance") for any allowed revenue for distributed generation. If a cost allowance is made without such a driver, companies have an incentive not to connect DG. In principle, a pure cost pass-through provides such a driver (if each project's costs are fully reimbursed, a project is itself a driver). If DG-related costs are to be incentivised, then some less controllable variable needs to be used as a driver. One crude revenue driver would be kW connected. Using crude revenue drivers there is a danger of companies "cherry-picking" and only connecting those DG with (for example) lower than average connection costs/kW. However, in the absence of any information on relative costs, more sophisticated drivers (such as differentiated revenue drivers according to the location of the new DG, or its type) will inevitably be based on companies' own assessment of the cost differentials, potentially weakening the incentive power of the regime and producing arbitrary differentials.

Ofgem therefore needs to investigate whether enough information exists to enable it effectively to establish revenue drivers for different types and connection points for DG.

Incorporation into main price control

If it is to provide similar incentives for cost-efficiency in DG-related costs as for other costs, Ofgem could bring DG-related costs into the main price control system. Companies would forecast capital (and operating) expenditure for DG, with a proposed set of measurable outputs (revenue drivers). The measurable outputs could be simple (kW) or complex (a specific list of projects). Allowed revenue would be conditional on delivery of those outputs. In effect, companies forecast their own unit costs but there is a cap on total volumes. Ofgem could use some degree of informal benchmarking between the capital expenditure proposals and assessment of efficiency using expert advice, as it does for normal capital expenditure today.

This approach has a number of advantages, apart from the administrative simplicity of avoiding major change to the regulatory approach. It imposes a cap on total expenditure, limiting consumers' exposure to the total cost of DG. Bringing DG costs within the overall price control framework limits the potential for gaming substitution. The revenue driver limits the DNOs' ability to achieve excess profits by failing to deliver the connection volume. Crude revenue drivers do provide an incentive for cherry-picking but at least incentivise a known volume. For example, if a DNO is committed to connecting 500MW of DG, then it will not receive its full price control revenue if it does not connect 500MW. The disadvantages are that the cap imposes a potential constraint on new connection, that the requirement to forecast volumes creates a danger of excessive or inadequate caps and that the information asymmetry probably implies that, in the first period at least, Ofgem's efficiency analysis of capital expenditure plans will be limited and companies can be expected to make excess profits.

Amendments to increase flexibility

Given the significant uncertainty about volumes and costs, this option results in some risks for DNOs and the regulator's objectives. As we have noted throughout the discussion of regulatory responses to uncertainty, the risks associated with price cap regulation can be reduced through the use of more flexible mechanisms within the price control period. Two mechanisms that have been used in the past are particularly relevant: logging-up of capital expenditure over-runs and specification of the conditions for interim price controls. A more fundamental change to produce greater flexibility would be a sliding-scale.

- **Logging-up** (discussed in Annex 1) is a mechanism with which the regulator can provide companies with reassurance that capital expenditure in excess of the regulator's projections at the price control review will be included in the RAB. All regulators operate such a system informally at least - in that a company faced with an uncontrollable requirement for additional investment can request some form of comfort letter and regulators are unlikely to refuse to discuss the issue. Ofwat's logging-up approach is more formal and would probably be inappropriate for Ofgem's existing main price control because it requires a degree of monitoring of capital expenditure outputs that Ofgem, unlike Ofwat, does not carry out. However, the need for volume-related revenue drivers for distributed generation implies an inevitable increase in monitoring delivery on Ofgem's part, and therefore makes a formal logging-up system feasible. The uncertainty surrounding volumes of DG seeking to connect in the next price control period may make it attractive. The drawback, of course, is that it diminishes incentives for companies to forecast volumes accurately at the previous price control review.

- **Interim price controls**, similarly, have always been a feature of UK RPI-X regulation in that gross discrepancies between the forecasts made at price reviews and out-turn performance can lead to price controls being re-opened. The ease with which price controls can be re-opened has a direct effect on the trade-off between incentives and risk. *In extremis*, if price controls are recalculated on the basis of actual costs every year, regulation reverts to a cost pass-through. Simply signalling a greater readiness to re-open price controls for reasons connected to distributed generation can therefore allow Ofgem to exert finer control over the trade-off between incentives and risks. Providing guidance in advance of the price control period on what might trigger such a review and how it might be conducted should *improve* the trade-off, by reducing risk with a smaller reduction in incentives. This would represent a change from the traditional discretionary approach. Such guidance could include, for example:

    - specification that the interim review would apply to DG-related costs only (as established in the main price control review);

    - definition of the conditions that would trigger a review – such as percentage divergences from the volume (revenue driver) or cost projections for DG at the main review (using costs as the trigger reduces risk but also reduces incentives for cost-efficiency, compared to the volume trigger – again, there is a trade-off between risks and incentives);

- procedures to be followed in an interim review – such as a mechanical update of the DG volume and cost forecasts, with limits on the degree to which allowed unit costs will change; or

- some penalty for DNOs that request an interim review, to encourage them to do so only when facing serious difficulties. A 1% automatic reduction in price control revenue for the remainder of the review period, for example, might serve such a purpose.

❒ Finally, the price control framework could be modified by making the relationship between costs and revenue drivers more flexible *within* the price control period, through a **sliding-scale mechanism**. For example, companies could submit actual costs of the projects to which they are committed through their volume forecasts as those projects are incurred. Price control revenue could then be modified by a fixed proportion of the difference between unit costs actually incurred and unit costs specified in the revenue driver.

Summary

In summary, based upon our own assessment of this value judgement, we recommend the following approach in the short term:

❒ Incorporate DG-related expenditure in the overall RPI-X framework, to provide reasonably balanced incentives to reduce DNOs' DG-related costs.

❒ Assessment of DG-related capital expenditure plans is likely to be difficult. Expect companies to make excess returns in the early years, but by doing so they reveal information. Increasingly, Ofgem should be able to incorporate benchmarking, or other formal tests for efficiency, into its assessment of capital expenditure plans.

❒ Incorporate a volume driver into the price control formula (i.e. regulate the average £/MW DG-related revenue rate, not the total DG-related revenue), or audit volumes built (and penalise under-delivery) after the event, to encourage companies to connect DG .

❒ Consider increased flexibility through more formal logging up and interim review arrangements than now, or through a sliding scale.

All of the above provide Ofgem with options for trading off:

- risks of cost inefficiency against risks of non-delivery of volumes; and
- risks to DNOs against incentives on DNOs to improve efficiency.

The choice between them, in the absence of good information, is largely a value judgement. We have outlined a scheme that consciously emphasises incentives for efficiency over guarantees for delivery and insurance for the companies, although it does not ignore such issues. The three options for introducing flexibility would allow this emphasis to shift; they are designed to promote objectives other than cost efficiency, at some expense of a reduction in incentives for such efficiency.

We would not characterise this view as being the only one consistent with regulatory economic theory as formalised through our decision tree. Ultimately, Ofgem's dilemma between risks to costs and risks to volumes requires a value judgement to be made on the basis of broad public policy. At present, the state of knowledge is such that one objective cannot be met without sacrifices in meeting the other. Any compromise between the two is sure to result in some clear problems in meeting both objectives. Our aim in proposing options is to make such trade-offs clear, but also to propose approaches that minimise the trade-off as far as it is possible to do – buying the most of one objective for the smallest possible reduction in the other.

4.3.2 Alternative options

If the risk of non-delivery of DG were judged to be more significant than that of cost over-runs and gaming, the optimal solution might look very different. If this is the case, and the flexibility mechanisms described above were not sufficient to allay concern over such risks, Ofgem could reverse this methodology – begin with a low-powered pass-through regime and seek to "tweak" it to include some efficiency incentives.

A cost pass-through regime is straightforward enough. In response to demands for connection, DNOs could submit cost estimates to Ofgem. Allowed revenue for DG-related costs would then ultimately rise by the full value of whatever costs are accepted by Ofgem. To avoid volatile charges, any additional charges resulting from specific work could be profiled in an NPV-neutral fashion to smooth their immediate impact.

Any efficiency incentives resulting from such a regime would arise from Ofgem's assessment of the proposed costs. Initially, this could only be on an ad hoc basis, but increasingly Ofgem will acquire information enabling it to make benchmark comparisons between different companies' estimates. If Ofgem believes that some proposals can accurately be assessed for efficiency solely using engineering criteria, then it can use these as the benchmark frontier against which to assess others. If benchmarking involves the comparison of unverifiable proposals against one another, then it is essential that proposals below the "average" cost be rewarded by being granted a larger increase in average revenue than they have asked for. If Ofgem does not do this, there is no incentive for companies to attempt to undercut one another (and they could submit consistently high cost proposals to avoid ever establishing a benchmark against which they could unfavourably be judged).

Naturally, such comparisons work well only when costs of different projects are comparable, either because the projects are similar or because Ofgem is developing an understanding of the cost drivers involved in distributed generation. At present, neither condition holds, so comparative efficiency assessment of companies' proposed costs will be poor. Even when the information available to Ofgem improves with experience, there will likely remain major uncertainties in the short term. That is why this option is not ideal – if Ofgem is prepared to take no risks on delivery, it risks inefficiency and gaming on costs.

4.3.3 Long term

At this stage, it is neither necessary nor sensible to set out a detailed set of regulatory arrangements for the long term, assumed to be at least one price control period away and probably more. However, it is important to understand how Ofgem might ideally regulate DNOs when the current uncertainty about the volumes and costs of DG is past and when DG is a more integrated part of a DNOs business, to check that any short term solution is not incompatible with such a vision.

In the long run, DG can be assumed to become a more "normal" part of what DNOs do. It becomes less of a separate problem and simply a part of the general price control regime. In effect, once DG connection cost drivers are as well understood as cost drivers for load, it should be possible to use benchmarking, incentives for accurate capital expenditure forecasts and consultant estimates of efficiency in much the same way as the main price control is set at the moment, for the network as a whole, not for an artificial "DG" element of cost. Equally, of course, if the main price control system were to change (for example, to make more formal use of benchmarking), it should be possible to bring DG costs into that new framework as well.

- Consider DG-related costs entirely integrated with general price control costs. It should no longer be necessary to create volume-related revenue drivers, as the volume of new DG connections falls and as connection of DG has become more routine, reducing the ability of DNOs to control volumes by manipulating the connection process. In any case, the identification of some costs over the price control with generation and others with load would become increasingly arbitrary, as the network develops towards a transmission role, in which its function is to connect generation to load.

- Use the data acquired over time to establish a cost function for distribution businesses, incorporating (possibly detailed) cost drivers relating to distributed generation as well as to load. Collect data on these cost drivers for each review to use benchmarking to provide incentives for efficient network expansion and management.

4.3.4 Comparison of short term and long term regimes

In summary, the short term regulatory regime is very company-specific. Price controls are driven by companies' own business plans, audited for efficiency by Ofgem using whatever information it can. Informal benchmarking may be part of this efficiency testing, but benchmarking results are too uncertain to incorporate directly in price-setting.

The long run regime is based more upon comparative analysis. Data are assumed to exist to enable Ofgem to estimate the performance of an efficient company based upon the performance of the best actual company. This requires the estimation of a number of key relationships, particularly identification of external cost and quality drivers.

The final question is therefore whether there is a reasonable transition path between the two, or whether Ofgem will one day have to declare that the long term has been reached and the regulatory system is being revolutionised. Actually, the two systems are not as different as they might appear. Ofgem's audit of companies' cost projections in the short term would involve informal benchmarking, even if it can only be used to ask questions ("justify the difference between your costs and theirs"), rather than provide answers. Increasing use of benchmarking, and increasing sophistication in the adjustments required to compare costs from different companies leads naturally to the long term solution.

It is possible to make this transition more automatic. Ofgem could use formal benchmarking from the start, but with very wide confidence bands initially, so that the discriminatory power of the benchmarking model is very low. Over time, the confidence bands could be narrowed, reflecting better information and yielding a more discriminating model.

4.3.5 Other Ofgem scenarios

The discussion above is based on such a general vision of distributed generation, that detailed changes are unlikely to result from consideration of different scenarios. We describe below how the balance of decisions using the tree could change in response to the different circumstances envisaged by Ofgem.

Scenario 1: more unevenly distributed DG

If DG is more unevenly distributed across DNOs:

- uncertainty will be more likely to be material, for any given national expected variation in cost;
- risks will be less diversifiable between DNOs; and
- benchmarking will be still harder.

This scenario does not appear to be significantly different from our main case, when assessing the short term regime. We have assumed in any case that uncertainty is material, that risks are largely not diversifiable between DNOs and that benchmarking is difficult or impossible. If the uneven distribution is known in advance (to the same level of confidence as existing forecasts) then it would not appear to require any change to our proposed mechanism at all. If it appears over time, then in effect it represents an increase in general uncertainty. This should lead Ofgem to consider the flexibility mechanisms that we describe above more favourably (with some consequent diminution of incentives).

Our longer term proposal is based on benchmarking. Uneven distribution of DG does not necessarily make this proposal unworkable, as the key condition for effective benchmarking is understanding the relevant cost drivers, rather than possessing a set of *similar* comparators. A good understanding of cost drivers enables valid benchmarking to be carried out between dissimilar companies. It could delay introduction of the long-term regime, as acquiring a sufficiently diverse data set to allow econometric analysis of costs will take longer if experience is "concentrated" in a few DNOs. However, even if DG remains unevenly spread – so that companies are managing very different networks in the long term – it should still be possible to use yardstick competition, as long as sufficient data exist to correct for the resulting cost and quality differentials[6].

Scenario 2: higher volumes of DG everywhere

If higher volumes imply larger uncertainty, this will obviously raise the risks for the companies, and also raise the risk for the regulator in setting five year capital expenditure targets. In the framework above, materiality and presumably unpredictability become greater. However, both were assumed to be significant in any case. Ofgem could be expected to consider the flexibility mechanisms that we have set out more favourably, if the problem becomes "larger" in this way.

If the higher volumes are not associated with greater uncertainty, then only the increased materiality of uncertainty should be considered when assessing the flexibility mechanisms. DG-related costs would become a larger proportion of total DNO costs (sooner) and to the extent that they are more uncertain than load-related costs, this increases uncertainty. However, it is worth noting that if Ofgem expects significantly higher DG demand than in its main case, then it may be more reluctant to introduce flexibility in the volume of DG that DNOs connect. The main reason for flexibility over the cap was to guard against inefficient outcomes in which valuable DG is prepared to pay to connect but DNOs are prevented by the cap from accommodating it. If enough DG to, for example, meet renewables targets, is included in DNOs' forecasts at the next price control review, Ofgem may take the view that it is prepared rigidly to cap total connection at this level to promote cost-efficiency.

Obviously, with faster connection rates for DG, the transition to the long-term arrangements will occur sooner.

Increased availability of information on costs

Better cost data has great value to Ofgem, because it enables the trade-offs identified earlier in this section to the improved. Ofgem could bear down more effectively on costs, without increases in the risk of non-delivery or financial instability, for example (or equivalently, could improve performance on the latter without damaging cost incentives).

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6 As a general principle, these two are substitutes for one another in regulatory practice. Similar companies can be benchmarked against one another without much adjustment for different circumstances. With a good understanding of how different circumstances affect cost functions, very dissimilar companies can be compared against each other. Our long term proposal emphasises the construction of a cost function, so dissimilarity in experience of DG is less of a problem than it might appear.

Within our short-term proposals, better cost information would enable Ofgem better to assess efficiency in proposed expenditure plans and to improve the effectiveness with which the three flexibility mechanisms are applied. Better information should enable Ofgem to move more rapidly from the case-by-case approach to assessing forecasts envisaged in our short term proposal, to the data-intensive statistical method envisaged in the long term. Indeed, if a stochastic yardstick approach is used, the increased availability of data should automatically increase the yardstick element of the price control without the need for a regulatory decision to do so. Yardsticks provide powerful cost incentives while insuring companies against common uncontrollable shocks, so this is likely to result in a better regulatory regime.

Comparable costs across companies

This scenario seems to us to be very similar to the one above. The most effective source of "increased information", for the purposes of improving the trade-offs that Ofgem faces, is comparable information between companies. Although there are other sources of information that can be used to assess efficiency, comparative data not only indicates what a company's efficient cost level should be but also provides the possibility of distinguishing controllable from uncontrollable costs, common shocks from firm-specific effects *and* gives companies incentives truthfully to reveal their actual cost levels.

If costs are comparable between companies, then benchmarking and yardstick competition can be introduced more formally and earlier. Because incentives for cost reduction are so strong under an effective yardstick regime, it may also be possible to reduce the period of the price control, if that is required to allow Ofgem to take account of the rapid improvement in knowledge about DG-related costs that is likely to occur over the next few years.

Unit costs uncertain

In this scenario, Ofgem assumes that information submissions from the companies are insufficient to constitute a basis for setting capital expenditure targets. Obviously, the required response depends on the scale of the problem. It may be worth providing incentives and penalties to encourage better information provision, or incorporate revelation mechanisms that directly reward accuracy.

If the problem is extreme, then Ofgem faces a stark choice between incentives and risks. It could set capital expenditure forecasts (and use them in price controls) on the basis of no information whatever – risking large excess or insufficient returns - or it could diminish incentives. If information is almost entirely lacking, the inaccuracies involved in attempting five year forecasts as envisaged in our main proposal are likely to be insuperable. If it is necessary to reduce the power of incentives for efficiency, this change should apply to DG alone. This points to a separate regime involving a shorter price control period or even a "cost plus" approach as described earlier in our alternative proposal.

There are no easy options for this scenario. We have referred throughout to the trade-offs and dilemmas that Ofgem faces. These trade-offs become better with better information. Lacking information, any regulator can only produce a regime with significant drawbacks. The discussion underlines the importance of encouraging companies to submit meaningful information.

Annex 1

Examples of regulatory practice from other sectors and countries

Annex 1: Examples of regulatory practice from other sectors and countries

In this section we provide a survey of regulatory mechanisms that have been employed by other regulators to deal with uncertainty.

We consider cost pass-through, firm specific, comparative and formal yardstick mechanisms and their application with respect to uncertainty. We then move on to consider the treatment of capital expenditure, volume-related revenue drivers, the allowed cost of capital, the length of a regulatory period, the provision for an interim review and the use of separate controls. Under each section we provide an illustration of how the mechanisms have been applied in practice and a summary of any issues that have arisen in their application.

Incentive mechanisms

If managers in a firm can control or mitigate uncertainty then it is appropriate for the regulator to put in place an incentive mechanism to encourage them to do so[7]. There are a number of broad choices open to the regulator.

Ex post or ex ante

Where the regulator possesses reasonable information on the future level of costs (possible based on historical data) it might choose to implement an *ex ante* mechanism, where the regulator provides a target level of costs. If the company is able to beat that level of costs then it retains any profit and continues to do so until the next review.

In cases where information on the future level of costs is less reliable the regulator might choose to implement an *ex post* system, sometimes referred to as an error correction mechanism. Under this kind of approach the regulator might take a view on the future level of costs but will formally or informally commit to correct that view based on actual data at the next regulatory review.

7 As we know from Section 2, the regulator can design a mechanism under which the profits of the company vary according to performance. In such a regime shareholders will give their managers incentives to engage in efficient behaviour.

Degree of comparison

There are many ways of comparing firms.

At one extreme the regulator might choose to pass the costs of the firm through to consumers. Strictly this does not represent an incentive mechanism at all, but we can classify mechanisms of this type as those with the weakest (i.e. zero) incentive properties.

Alternatively the regulator might choose to avoid comparisons through some form of **firm specific regulation**[8], under which its prices depend solely on its own costs and outputs. Such a regime is likely to provide only weak incentives for cost reduction, unless the regulator possesses excellent information on the efficient level of costs. In general, companies will be able to exploit the usual asymmetry of information between itself and the regulator and is more likely to put effort into justifying costs rather than reducing them.

In practice, of course, regulators *always* compare firms to some extent even if only informally[9]. Under "traditional" RPI-X approaches, past costs and quality performance enter into the formal calculation of prices but in setting X and quality targets for the future, regulators will have regard to the performance of other firms. At the very least, regulators will have anecdotal evidence on comparative performance. Even with companies such as NGC, Transco or Railtrack some functions can be considered in relation to other companies. A firm-specific investigation of efficiency will in fact make use of such comparisons. Unlike the regulator in our spreadsheet model presented in an annex to this report, real regulators do not mechanically apply formulae to set price controls.

If there are a number of broadly comparable companies the regulator might choose to use some form of **comparison between companies** in order to arrive at a view on what costs should be disallowed. We might characterise this as the approach that has been adopted by most of the regulators in the UK to date. Under such a regime companies are aware that their costs will be compared to their peers, but that regulatory judgement will also play a role in determining allowed revenues. For example, the regulator might require the companies only to narrow the gap between their own performance and that of peer companies, rather than make up the entire distance to the frontier.

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8 The use of logging up used by Ofwat and profit sharing used by ORR for Railtrack's property revenue are both examples of firm specific regulation (see Annex 1).

9 Oftel and the ORR both use informal mechanisms to compare the firms they regulate (see Annex 1).

Finally, the regulator might choose to impose formal yardstick competition[10]. Under such a regime the allowed revenue of a company is determined not by its own costs but the costs of comparable companies. Such a rule can provide very strong incentives to the companies. However, it is worth noting that yardstick competition does not necessarily imply low rates of return for the companies involved. A yardstick based on the costs of the *worst* performing company has almost identical incentive properties to a yardstick based on the costs of the *best* performing company, despite having clearly different implications regarding the distribution and timing of efficiency savings to customers.

Implementing yardstick competition is clearly not possible in cases where a unique company is regulated. More generally, the regulator will need to be sure that it is able to undertake comparisons with a sufficient level of rigour before proceeding to introduce yardstick competition.

Form of control

The final dimension on which we might differentiate incentive mechanisms is in their form of implementation. The regulator might choose to impose a price cap form of regulation, such as RPI-X. Such mechanisms are likely to be appropriate where the regulator has sufficient information to be able to predict the future path of costs (or unit costs) with enough accuracy to be able to depend on a point estimate.

The most common alternative to this kind of mechanism is some form of profit sharing arrangement, such as sliding scale regulation. Under sliding scale arrangements the regulator identifies a range of possible outcomes and agrees with the company a schedule for sharing the benefit of "good" performance between the company and the consumer.

Regulatory experience of incentive mechanisms

Pass through – ex-ante, ex-post

Pass through of a regulated firm's costs to its customers is the lowest-powered of the incentive mechanisms available to a regulator in that it provides no direct incentives for efficiency. However, a number of regulators use it in practice to shield regulated firms from uncertainty. In this section we provide examples of cost pass through mechanisms used by the CAA and the Jamaican electricity regulator to deal with uncertainty.

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10 The Dutch energy regulator, Dte and Ofwat both use formal yardstick mechanisms as part of their regulatory approach (see Annex 1).

CAA

The CAA is responsible for regulating the four airports of Heathrow, Gatwick, Stansted and Manchester. In setting their price caps the CAA has had to take account of the uncertainty that has surrounded the level of security requirements required in the sector and their cost.

In the present price caps for the four airports, security costs can be passed through to customers. When the Government imposes new security requirements on an airport, that were not anticipated at the previous review, the airport identifies the incremental costs of the impact of the requirements and submits this to the CAA for approval. If approval is given, 95% of the costs are included in an S factor in the price cap. The recovery is allowed one year in arrears of the additional expenditure.

As part of the consultation process carried out by the CAA for the Airport Reviews, the CAA reviewed the case for and against cost pass through.

The main argument that has been used to justify the use of the cost pass through mechanism for security costs in the past is that they are costs over which the firm has very little control. As the forecasts of these costs are subject to great uncertainty, the CAA has previously opted to impose these costs on customers rather than firms. Where this is the case, the argument is made that such a mechanism has very little effect on the incentives in place for efficiency.

However, in its report to the Competition Commission the CAA recommended that this pass-through be reduced to 75% of any variations from forecast cost. The CAA argued that airports have some control over security costs and secondly that the risk involved is likely to be diversifiable. The airports should bear the risk: they are better placed than the airlines to manage it. Removing the option for passing through security costs in the price control mechanism means that it would be necessary to make a forecast of the likely security requirements over the next review period.

Jamaica electricity regulation

The Jamaican electricity regulator has acknowledged in its first price control period beginning in 2004 that the electricity industry is likely to be affected by exogenous shocks. In recognition of this, he intends to provide an explicit adjustment mechanism for unexpected costs incurred in the previous control period. The adjustment is made through an explicit provision in the price cap for events not covered in other elements of the price control. Electricity prices are allowed to increase according to inflation, quality of service improvements minus a productivity increase. The Z factor is included so that prices can be increased to reflect special reasons not captured in the formula. This provision in the price control is called a Z element.

It is difficult to forecast exogenous events so the Z factor of the price cap has to be retrospective. It will be set equal to zero in the first period and then in the next price control period it will be set at a level that reflects unexpected events from the previous period.

The Z factor covers events that:

- affect the Licensee's costs;
- are not due to the Licensee's managerial decisions; and
- are not captured by the other elements of the price cap mechanism.

This includes Government obligations imposed after the date of the licence such as:

- environmental standards, laws and regulations;
- licence fees;
- taxes other than general income, corporate or general consumption tax; and
- any condition that applies specifically to the Licensed Business.

Firm specific – ex-ante, ex-post

This section provides examples from Ofwat, the ORR and Oftel of their use of firm specific mechanisms employed when there is uncertainty over costs.

Ofwat

Ofwat recognizes that efficiently incurred capex costs may differ, in some circumstances, to ex-ante projections. At the beginning of each regulatory control period the companies undertake a detailed process of working out what should be invested in the water industry over the next five years. Where investment expenditure at the end of the control period, differs from the amount that was estimated, a process of logging up or down is used.

Logging up and down involves adding or removing some of the additional investment to or from the RAB. Logging up is only used if the difference in investment expenditure from that allowed was not sufficient to trigger an interim determination and if the item of expenditure relates to a 'relevant change of circumstance' or a 'notified item'.

A 'relevant change in circumstances' is defined to be one of the following:

- a new or changed legal requirement;
- a difference in the proceeds of land disposals from that assumed when price limits were set;
- a failure to achieve some output provided for in the last price setting; or
- a relative change of the construction price index to the RPI index compared to that assumed.

A notified item is a requirement, which has specifically not been allowed for, in part or whole, at the last periodic review such as:

- an increase in the take-up of the free meter option;
- a change in cost due to the prohibition of connection of household supplies for non-payment of charges; and
- an increase in cost due to the administration of the statutory scheme for abatement of metered charges to domestic customers in vulnerable groups.

The company finances the logged up capital costs between the date on which they are incurred and the start of the next review period. However, those capital costs that the regulator believes to be the expenditure of an efficient company are added to the regulatory asset base at the start of the next review period. From then on, the companies earn a rate of return equal to the cost of capital on the logged up capital costs and, if the expenditure relates to depreciable assets, companies are allowed a current cost depreciation charge in their price limit.

Ofwat is currently carrying out a consultation on the process used for logging up. The main concern of the consultation is that there is a difference between the logging up process and the interim review in the following areas:

- the treatment of financing costs for capital investment; and
- the treatment of operating costs and revenue losses.

This has implications for incentives because in an interim determination the financing costs of a capital investment are returned to the company from the day on which they are incurred, whereas under the logging up process, the company must fund the financing costs between the date the expenditure was incurred and the next periodic review. In addition, there has been some concern expressed by companies that the current process leads to increased regulatory uncertainty as the process used for logging up is not formally codified.

As part of the consultation process, Ofwat has noted the following benefits of the current process of interim determinations and logging up.

- ❒ Providing a mechanism to deal with changes in outputs between reviews and reducing the business risk to which companies and hence their customers are exposed.

- ❒ Encouraging companies to work to define all possible obligations as part of the periodic review rather than leaving them to be recognised as changes between periodic reviews.

- ❒ Allowing the regulator to retain a position of challenging the companies' assumptions, proposals and performance rather than managing directly the outputs required.

- ❒ Avoiding additional monitoring costs and data collection required to ensure all favourable as well as unfavourable changes are identified.

Ofwat also recognizes that the present process of logging up may have costs because it gives rise to regulatory uncertainty, which could result in a higher cost of capital. However, it was dismissive of the companies applications for a higher cost of capital.

ORR

The ORR applied a profit-sharing mechanism to property revenue generated in excess of Railtrack's forecasts for the control period from 1995-2000 because of the considerable uncertainty surrounding it. Forecasts of revenue of £1 million over the period were made ex-ante. However, it was decided that any net income generated in excess of this figure would be shared in the following manner;

- 75% to Railtrack; and

- 25% to its customers, the franchised train operators.

In the 2000 review the ORR decided that profit sharing should also be applied to income from franchised stations. They felt that the profit sharing mechanism provides incentives to achieve efficiency savings whilst at the same time sharing the benefits of those efficiency savings in the form of increased profit between shareholders and customers.

However, the ORR recognises that the proportion of profits retained by the regulated utility have a strong effect on the incentives for efficiency. If the share of profits for the company is very low, the mechanism may have many of the disadvantages of rate of return regulation, in particular the reduction on incentives to achieve efficiency savings.

Oftel

Oftel considered the use of a profit sharing mechanism for BT because it may prevent prices getting significantly out of line with costs during the price cap period by automatically triggering a price reduction if profits exceed a certain threshold.

However, Oftel decided to reject profit sharing for the following reasons:

- it would dilute the incentives to productive efficiency;
- the system was too complex; and
- it was likely to encourage "gaming" by the regulated company.

Furthermore, Oftel considered that the development of competition would reduce the need for mechanisms such as price caps and profit sharing. Increased competition will help to ensure that customers receive the benefits of reduced costs without the need for an explicit profit sharing mechanism.

Comparative (limited) – ex-ante, ex-post

Comparisons of regulated companies with their counterparts is one potential mechanism for the regulator to deal with uncertainty over their costs. This mechanism has been employed by a number of regulators including Oftel, the ORR and in Latin American electricity regulation.

Oftel

Oftel uses the performance of other companies to set efficiency targets for BT. For the control period starting in 2001, Oftel made ex-ante projections of achievable cost reductions for BT based on the performance of the US Local Exchange Companies (LECs). Oftel set the X factors for BT's price control review based on a real unit operating cost reduction of 3.27% per annum including the effects of expected catch-up but excluding the effects of real input price changes and volume effects.

These X factors were calculated by comparing BT's efficiency with comparator companies, principally the US LECs. BT was estimated to be 1.2% to 4% less efficient than the best performing LECs in 1999-2000, which translated to a real unit operating cost reduction of 3.27%.

ORR

The ORR made its assessments of the appropriate efficiency savings on controllable costs to be applied by Railtrack by using a bottom up assessment combined with a comparison of other privatised industries, the assumptions made by other regulators and benchmarking of productivity trends in other railways.

Railtrack disputed the efficiency targets set by the regulator because:

- top down evidence supported a lower range; and
- Railtrack's path of efficiency change is expected to be flatter than its comparators because of relative price inflation.

The regulator adjusted his proposed efficiency savings downwards to reflect the risk that real input prices for Railtrack will rise due to the increased activity in the construction sector. In particular, the rate of investment in enhancements is likely to increase input prices.

Latin American electricity regulation

In Latin America electricity regulation benchmarking has been introduced. The regulation aims to make the private monopoly compete with a reference efficient model company with a yardstick competition approach. This methodology has been complex to apply with bitter disputes among the parties involved where the tariff process often ends up in legal courts.

Formal yardstick – ex-ante, ex-post

A yardstick mechanism has been applied by Ofwat for the regulation of capital enhancement by water companies. However, the yardstick is not of a traditional form because it is not based on actual costs. The yardstick mechanism being implemented by the Dutch electricity regulator, Dte takes a much more traditional form.

Dte

The Dutch Energy Regulator (Dte) is currently in the process of implementing a formal yardstick mechanism. The following mechanism will be used:

- an X factor will be estimated looking-forward for the 3 year control period; and
- at the end of the control period, costs will be examined and the X factor adjusted according to industry total factor productivity growth.

This mechanism allows account to be taken for industry wide shocks but not company specific shocks. However, at the beginning of a control period, a company can apply for a specific adjustment for events beyond their control.

Ofwat

Ofwat uses yardstick competition to assess companies' efficiency requirements for its capex plans. The capex plans are divided into two components, capital enhancement and capital maintenance and these components are treated differently.

Every capital program is made up of a number of generic tasks that must be performed. Each company submits cost estimates for each generic task and the total cost of its overall capex plans. The cost estimates for the capital enhancement programmes are scrutinized by the company reporters who assess the company's approach to risk, consideration of alternative approaches, technological innovations and the consistency of their estimates of the cost of a generic task and that of their overall capital enhancement programmes.

The companies also provide estimated capital costs for specimen projects based on their audited cost estimates for generic tasks. The regulator uses the costs for specimen projects to compare the efficiency of different companies and to set their required efficiency catch-ups. For capital enhancement projects the regulator uses the specimen project cost estimates to set the efficiency target for each company. The efficiency target was set equal to the most efficient company in the industry. The companies are required to remove 75% of the gap between their company and the 'frontier' company in the first year of the price control.

For capital maintenance projects, the regulator uses econometric analysis in addition to the cost estimates for specimen projects to set company's efficiency targets. The econometric modelling aims to adjust for the relative effectiveness of company's total expenditure on maintenance. The regulator requires the companies to remove 50% of the gap between their company and the most efficient company in the first year of the price control.

Treatment of Capex

Broadly speaking, there are two approaches to the treatment of capital, with investments being reimbursed as they occur or being carried forward and depreciated over time[11].

Treating investments as a cash cost is a straightforward approach but has some serious drawbacks. In particular, since investments are by nature "lumpy", customers are likely to be exposed to large fluctuations in price from year to year. The regulator might also need to consider whether it is fair for consumers in a single year to pay the entire cost of an investment that might have a lifetime of many years.

It is more usual for regulators to treat assets as long lived and require companies to recover the cost of investments over a number of years. This raises a number of important issues.

Cost of capital

Where the cost of an investment is not recovered immediately it is necessary to reimburse the investor for the opportunity cost of capital, modified to reflect the level of undiversifiable risk to which the investor is exposed[12].

If uncertainty is both:

- positively correlated among the regulated firms; and
- not diversifiable throughout the rest of the economy.

Then there is an argument for increasing the cost of capital for the regulated firm. Conversely, where shareholders are able to diversify, either because:

- the uncertainty is uncorrelated among the regulated firms; or
- the uncertainty is diversifiable throughout the rest of the economy.

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11 Most regulators roll capex forward, include it in the RAB and depreciate it over time. The ORR, however, use the more unusual approach of providing a cash allowance for Railtrack's renewals expenditure each year (see Annex 1).

12 ORR, Ofwat and Oftel all considered effect of uncertainty on the cost of capital and the allowed rate of return for companies (see Annex 1).

Then the uncertainty will not increase the financing costs of the firm. As such a higher cost of capital is inappropriate. We also note that a higher cost of capital has no impact on the incentives to which the firm is exposed, as long as the regulatory allowance for the cost of capital is set equal to that cost of capital.

Measurement of performance

Where the capital costs associated with past investments are included in present efficiency measures one needs to consider who is responsible for any measured under-performance. This is consistent with Ofgem's approach of regarding costs as inherent, inherited or incurred. Furthermore, any comparison that includes capital costs will be sensitive to the accounting assumptions used to transform the stock of capital into an annual measure of capital consumption.

Regulatory experience of treatment of capital costs

Capital expenditure

The use of annualised measures of capital costs in determining allowed revenue is so common across regulators in the UK and world-wide that we do not provide examples with discussion. Instead, we illustrate the rarer case of a regulator setting charges to recover capital expenditure rather than annualised cost – the so-called "pay as you go" approach.

ORR

Railtrack's renewals expenditure is treated on a pay-as-you-go basis rather than using a traditional depreciation approach. In the 2000 price review, the regulator discussed the advantages and disadvantages of each approach at some length. The pay-as-you-go approach was retained in general, but the regulator has adopted a different approach towards one aspect of renewals expenditure on train control systems. It has allowed for an error correction adjustment for expenditure on train control systems. It has also adopted the depreciation approach for one part of the expenditure on train control systems.

Under the pay-as-you-go approach, the full cost of renewals expenditure in each year is charged against profit for that year. This means that the RAB remains constant unless the network is enhanced (or reduced). However, since the RAB is significantly less than the replacement cost of the network, renewals expenditure is likely to exceed depreciation on the RAB. Under the depreciation approach, renewals expenditure is added to the RAB and then depreciated. This results in an increase in the RAB over time even in the absence of any enhancements to the network.

The pay-as-you-go approach has further benefits because it provides a strong incentive for Railtrack to improve the efficiency of its renewals programme and to understand the condition of its assets and the relationship between renewals, maintenance condition and performance. However, it also exposes Railtrack to the full impact of unanticipated changes in renewals requirements. By contrast, if actual expenditure on renewals is included in the RAB at the next periodic review, incentives for efficiency are reduced but the immediate effect on profits is also reduced and the cost of any inefficiency is potentially shared with customers through an increase in the RAB.

The pay-as-you-go approach also removes the incentive that exist under the depreciation approach to reallocate expenditure between the categories of renewals expenditure and maintenance expenditure as they are treated in the same way. However, it also increases the need for a clearer distinction between renewals expenditure and enhancement expenditure as one is include in the RAB and the other is not. However, the problem of misclassification of items of expenditure has been addressed by the ORR in their appointment of railway reporters in October 2002. They will be responsible for providing an independent view on the data provided by Network Rail. In particular, they will check that the expenditure that is made by Network Rail is recorded correctly as renewal, replacement or enhancement expenditure and that the expenditure is efficient. This should help to alleviate the incentive problems for Network Rail to misclassify items of its expenditure.

The pay-as-you-go approach requires the ORR to have greater confidence at the current review that the underlying expenditure projections are soundly based. In contrast, the depreciation approach requires greater analysis at the next review of the extent to which the costs have been efficiently incurred and correctly capitalized.

During the 2000 price control review the ORR decided that it did not have sufficient confidence in Railtrack's projections of renewals expenditure on train control systems. Consequently, they decided that an error correction mechanism should be implemented:

- The current periodic review should allow for the expected level of renewals expenditure over the next control period on a pay-as-you-go basis.

- The RAB should be adjusted following the next review to compensate for under or overspend relative to this allowance.

- This adjustment should be subject to an efficiency review.
- The adjustment to the RAB should be implemented on a five year rolling basis to provide continuous incentives for efficiency improvement over the next control period.

In addition, part of the expenditure for renewal of train control systems has been included in the RAB rather than being funded on a pay-as-you-go basis.

Cost of capital

ORR

The real pre-tax rate of return for Railtrack was set at 8% in the 2000 price control review. In reaching a decision on the appropriate rate of return, the key priority for the ORR was to calculate the cost of capital using an approach that was consistent with the approach taken by other regulators.

The final range of estimates for the cost of capital of 6.9% to 8.2% were higher than those proposed by Ofgem and the ORR argued that this reflected the difference in the underlying risks that Railtrack was exposed to. It also reflected the need for Railtrack to raise substantial new finance. In one case, that of Thameslink 2000, the ORR specifically recognised that there was additional risk associated with construction of this particular project. He decided that this was sufficient to warrant a premium over the cost of capital for Railtrack's business as a whole.

The regulator also considered how the proposed introduction of volume incentives would affect the cost of capital. Railtrack argued that a volume incentive would affect their exposure to undiversifiable risk. Therefore, the lower end of the range of values for the equity beta should be adjusted upwards should cost reflective charges be introduced. Railtrack argued that more cost reflective charges mean that backward looking evidence should provide an absolute lower bound on the assumed beta. The ORR decided that the volume incentive did not create any material downside risk to the company so there was no need to adjust the proposed range for the equity beta.

There was some uncertainty surrounding the value for the risk free rate. The ORR with regards to its duty to ensure that the rate of return should be set at the top of the assumed range for the cost of capital at a value of 8%. The ORR made its decision based on the scale of Railtrack’s investment program and the need to raise substantial new debt and equity finance to deliver this investment.

Ofwat

In 1994, Ofwat suggested removing the shipwreck clause from companies' licences or making it symmetrical so that positive shocks could also trigger an interim review. The shipwreck clause provides the company with protection from any change in circumstances, which would have a substantial adverse effect in net present value terms, of more than 20% of the company's turnover in the previous year. Several companies agreed to the removal of the clause from their licences.

Since the shipwreck clause was asymmetrical, it limited the degree of exposure of the companies' shareholders to an adverse shock. As a result, the removal of the clause increases the undiversifiable risk to which a regulated company was exposed. In addition, the removal of the shipwreck clause potentially made debt financing more expensive also indicating a potential need for an increased cost of capital. Ofwat indicated that it would take account of the removal of the shipwreck clause when setting the allowed rate of return for the companies. However, there is no additional evidence of whether this was applied in practice.

Shipwreck clauses have subsequently been reintroduced into all but two company licences in a symmetrical form. In addition, companies are required as part of their licence to maintain investment grade status. Ofwat intends to treat all companies the same way when setting their rate of return.

Finally, as part of its ongoing consultation on logging up and interim determinations, Ofwat has asked companies to indicate how the logging up process affects their cost of capital. The logging up process is not formally codified but forms part of the periodic review process. As a result of this, the companies have indicated that the process increases the regulatory uncertainty to which they are exposed and therefore increases their cost of capital because it is unclear how such changes in costs will be treated at the next review. To date, the companies have been unable to provide evidence to support this claim.

Oftel

In the 2001 price control review, Oftel set a rate of return before tax, in nominal terms of 13.5%. Oftel justified its estimates of the cost of capital with reference to the fact that BT's network business is increasingly unlike a traditional stable utility business. The business is likely to grow rapidly and be subject to considerable uncertainty. In addition, considerable investment will be necessary to meet demand but BT's capacity to assume debt may be limited. Given these high growth assumptions it would therefore be inappropriate to assume a cost of capital appropriate to a stable utility business that could readily assume a lot of debt.

Volume-related revenue drivers

The inclusion of a volume driver in a price control is one mechanism by which uncertain changes in volumes can be accounted for. The CAA has considered the use of such a mechanism in the price controls it sets for the airports.

CAA

Under the present price control arrangements for the airports regulated by the CAA, the price caps are set as a control on revenue per passenger. This creates a risk that passenger volumes can deviate substantially from their predictions. It also provides an incentive for airports to release a very pessimistic forecast of passenger volumes over the period of the price control where the incremental cost of an additional unit of volume is less than the average cost. If the airport forecasts a very low figure for passenger volumes the price cap that is set is looser, and when volumes turn out higher than forecast, the airports make additional profits.

The CAA has considered but decided not to include a volume term in the price cap to overcome this problem. In its simplest form, a volume term would act to increase prices, where actual volumes were lower than forecast, and decrease prices, where actual volumes were higher than forecast.

There are a number of problems created by the introduction of a volume term.

- It dulls the incentives providing under the current mechanism, for the airport to attempt to increase passenger numbers.
- It is not always clear that it is beneficial for the airport to underestimate its passenger volumes if incremental costs of additional units outweigh average costs, upon which average revenues are based.
- Demand forecasts may be subject to regulatory scrutiny between periods.
- The term should be symmetrical so that it reduces prices when volumes are greater than forecast, but it is not clear that this is likely to be accepted by the industry.

❒ If incremental costs are greater than average costs, the volume term should move in the opposite direction so that it provides higher prices when volumes are more than forecast.

Length of regulatory control period

Where the length of the regulatory period is not specified in law, the regulator may choose to vary its length[13]. The impact of varying the length of the regulatory length is well understood. A longer regulatory period allows the company to retain the benefit of any cost reductions it makes for longer and thus provides the companies with stronger incentives to make cost reductions. However, a longer regulatory cycle is not necessarily a good thing for consumers, since the longer period implies that consumers do not see the benefit of any reductions as quickly as they otherwise would[14].

While these effects are well understood in principle, in practice there is typically insufficient information available to allow the unambiguous identification of the optimal length of period.

Uncertainty has complex effects on the optimal length of the regulatory period, as we discuss in a detailed series of modelling examples in the annex to this report. Longer periods:

- reduce the possibilities for the regulator to react to uncertainty and therefore are likely to have poor incentive properties when the effect of uncertainty is to create a persistent and increasing divergence of actual from expected costs; **but**

- allow more time for small, random or cyclical effects of uncertainty to average out.

The regulator should therefore consider shortening the regulatory period (or moving to an inherently short-term approach such as sliding-scale) if the uncertainty is expected to persist and build over time. However, this would be the wrong response if the uncertainty takes the form of random variations in costs and outputs. Short regulatory periods in this latter case are more likely to result in regulatory price controls that inappropriately

13 ORR, Ofwat and Oftel have also considered changing the length of their regulatory review recently. There is a discussion of these issues in Annex 1.

14 We note that this discussion does not apply to yardstick competition, where it can be shown that incentives are not weakened even in the case of annual updating.

take too much account of small random changes in costs (mistaking them for efficiency changes or, in the extreme, trends).

Obviously, the poor incentive properties of short price control periods represent a constraint on the regulator's ability to build flexibility in, in this way. If such a change is unavoidable, the regulator should consider a simultaneous change to a higher-powered regime (such as yardstick competition) to compensate.

We note that this discussion strongly suggests that benchmarked "allowed costs" should probably be applied to projects that are separable, short term and which the regulator is unlikely to mistake for trends: such as the IT costs associated with the 1998 programme or the Millennium Bug.

Regulatory experience of choice of price control period

ORR

The ORR decided on a price control period of five years for Railtrack. The regulator felt that a shorter period would have reduced the incentives on Railtrack to generate efficiency savings because they would have not provided the certainty necessary to enable Railtrack and the train operators to plan developments in services. However, a longer period would have led to an increased risk of a divergence between projections and outturns for reasons outside the control of Railtrack's management.

Oftel

The length of the price control period has been a particularly important issue for Oftel because of the uncertainty surrounding how competition will develop in the market. In 1997, Oftel considered a number of different price control lengths and possibilities of reviews within price control periods.

Oftel did not consider that the current market conditions were sufficient to ensure genuinely effective competition for all customers and so it did not consider that it was possible to remove particular services from the next retail price control. The following four options were considered:

- a four year cap on the existing basket of services;
- a two year cap (set on the basis of a four year cap) with a review in early 1998 to consider what price controls, if any, were appropriate in 1999;

- a four year cap with a mid term review as to whether it should continue unchanged or be lifted; or
- a control covering only the residential and small business markets.

Oftel rejected a four year cap because it did not reflect the increase in competition that had occurred over the past few years. Those consultees who felt continued price regulation threatened the continued development of competition welcomed the proposal of a two year cap as being a significant improvement over a four year cap. However, others pointed out that Oftel's proposal would involve making decisions about market conditions too far in advance, given the need to leave time for an MMC reference, and that this time lag could have serious consequences for the quality of the decisions made in the review. Many felt it could create considerable uncertainty in the market.

It was also felt that a four year cap with a mid term review would give rise to uncertainty in the industry as to the medium term prospects for regulation and deregulation in the UK. Moreover, given Oftel's views of the state of development of competition for most residential customers and small businesses and the small probability that genuinely effective competition would be a reality for this segment of the market by August 1999 there would be little likelihood of control for these sectors being removed after only two years.

Oftel decided that the most practical option was to restrict the formal price cap to the revenues earned by BT from low and medium spending residential customers and to separately require BT to offer a safeguard package for small businesses. This would allow BT greater flexibility in pricing services whilst maintaining the overall safeguard that customers seek.

Ofwat

As part of its 2004 price control review, Ofwat is currently considering the possibility of lengthening the control period from a five-year horizon from 2009. Lengthening the period by up to three years would provide greater stability for the industry to plan its services.

However, for the current period there exists uncertainty about the quality programme. The regulator has therefore decided to set five year price controls in the context of a longer horizon. Ofwat already encourages a long term planning approach to the asset management and maintenance requirements of the water companies.

Interim review provisions

If the regulator is unable or unwilling to adopt a short regulatory cycle, he could establish conditions under which he will undertake an interim review and reopen the price control[15]. Such arrangements are usually triggered when it has become clear that a judgement made by the regulator is clearly wrong and is likely to lead either to extremely high levels of profit or, at the other extreme, financial difficulty for the company. The re-opening of Offer's first distribution price control review is an example. It could be argued that there has always been an informal, if crude, "sliding scale" regulatory regime in effect (in that extremes of higher or lower profit than expected could be compensated).

Such arrangements can also be designed to accommodate situations where the responsibilities placed on the company are changed and where such changes are likely to have a substantive impact on a company's costs.

However the regulator should be cautious in designing the arrangements that might trigger an interim review. Regular interim reviews would have exactly the same effects as reduced price control periods (or sliding scale rules that pass high proportions of benefits to customers), in that managers would be reluctant to undertake large effort for fear that the resulting high profits would trigger a review to remove them.

Regulatory experience of setting rules for re-opening price controls

Ofwat

The conditions set by Ofwat to trigger an interim determination vary between companies. They are either specific to a particular event or take the form of a general 'shipwreck clause'. Only a 'relevant change in circumstances' or a notified item can trigger an interim review.

An interim review can only be triggered when the net present value of the aggregate changes in specified items exceeds 10% of turnover. There have been between 8 interim determinations in the water sector in the last 2 years. In the last few years, several of the interim determinations have related to metering. The Water Industry Act (1999) stated that everyone in the UK should be allowed to have a water meter installed free of charge. The number of individuals expected to take advantage of such an

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15 Ofwat, ORR and the CAA all make the provision for an interim review for the companies they regulate (see Annex 1).

offer was completely unknown, so Ofwat decided to allow a very low number within the price control but made it an applicable circumstance for a specific interim determination should the number of installations greatly exceed the allowed figure.

Severn Trent Water Ltd applied for an interim determination in September 2002. Ofwat issued its provisional response in November 2002 in which it declined the application because Ofwat's calculations indicated that the application did not reach the materiality threshold. The application for the interim determination covered costs arising from seven items. Ofwat decided that some of the covered costs were not relevant change of circumstances. In addition, for those that it considered to be a relevant change of circumstance it recalculated the estimated costs provided by the water company to take account of the benchmarked costs it had available and to include any efficiency gains it believed could be made.

Yorkshire Water Services Ltd also applied for an interim determination in September 2002. Ofwat accepted their application and has set new price limits to apply from April 2003. Ofwat considered that all of the increased costs qualified as relevant changes of circumstance or notified items. It adjusted some of the cost estimates downwards to compare with benchmark costs and also included some efficiency gains to arrive at the final figures for the adjusted prices to apply from 2003.

A shipwreck clause has been re-introduced into most company licences. These provide the company with protection from any change in circumstances, which would have a substantial adverse effect. In this case, substantial is defined as an effect, in net present value terms of more than 20% of the company's turnover in the previous year. They also allow Ofwat to take account of favourable changes of the same magnitude.

ORR

The ORR felt that a price control of five years should provide appropriate incentives for efficiency and investment. However, they also made provision for a general interim review and a number of specific interim reviews to ensure that Railtrack was able to finance its relevant activities.

The general interim review was to apply only in the event of a material change in circumstances. It was only to be used in the case of a major external shock to Railtrack's costs or revenues that would result in financing difficulties for the company. A major shock of this sort was thought to be most likely to result from the imposition of additional obligations, which were not included in baseline outputs, such as safety or environmental concerns.

There was some debate between Railtrack and the ORR as to what events could trigger an interim review. Railtrack wanted the review to be triggered if the cumulative consequences of relevant changes in circumstance were likely to be greater than a predetermined materiality threshold. It proposed a threshold in line with that in the water industry for relevant changes in circumstance (net present value greater than 10% of annual turnover). Although the impact on value was easy to measure, the ORR felt that it was too simplistic; it is the impact of a shock on Railtrack's financial ratios that should trigger a review.

A specific interim review was allowed for narrowly defined elements of the periodic review where there was benefit to allow the arrangements to evolve in the light of experience or new information. The scope of any such interim review was narrowly defined and any modifications would be confined to the specific questions at issue, for example, station long term charges, in relation to modern facilities at stations, are subject to review.

The ORR issued a statement following the Hatfield rail disaster stating how it intended to deal with the consequences. Railtrack was required by the regulator to bear the direct financial implications of Hatfield for the remainder of the existing price control period. However, the regulator agreed that changes might need to be made during the next price control period to reflect the ongoing implications of the disaster.

Following the Hatfield disaster, the regulator stated that an application for an interim determination by Railtrack during the next price control period, when the full implications of Hatfield were known would be viewed favourably if Railtrack could demonstrate that:

- the effects in terms of additional expenditure requirements or financing costs were material; and

- the impact on Railtrack's financial position would, without further regulatory action in the second control period, make it unduly difficult for the company to finance its relevant activities.

In July 2002 the ORR consulted interested parties to assess whether the conditions for an interim review would be met when Network Rail completed its proposed acquisition of Railtrack. This interim review has now been initiated. During the review of the appropriate adjustments to the track access charges paid by the franchised train operators, the ORR intends to do the following:

- define the outputs Network Rail is expected to deliver in operating, maintaining and renewing the network;

- assess the efficient amount of expenditure required to deliver these outputs;
- incentivise Railtrack to improve efficiency and deliver the outputs; and
- allow Network Rail revenue sufficient to finance its necessary expenditure.

CAA

The CAA also includes a provision for an interim review in the licence for National Air Traffic Services (NATs). It can only be triggered in 'exceptional circumstances' and if it was not possible to wait until the next review. Any application for an interim review would need to be assessed on a case-by-case basis.

The CAA has recently reached a final decision on the review requested by NATs in response to the substantial decline in traffic following the September 11th attacks. NATs requested an amendment to their X factor to take account of their substantial fall in income during the period. This application was initially rejected by the CAA.

NATS had felt that the decline in actual and forecast traffic was outside the control of management and its impact on their financial position was so substantial as to make an interim review essential. NATs outlined the reasons why they felt a review should occur.

- ❒ They would be forced to reduce costs that would result in a reduction of services and airspace capacity.
- ❒ They would be unable to pursue the investments necessary to enhance capacity and improve quality.
- ❒ They would not be able to finance those activities which were authorised, or indeed those which are required, by its Licence.
- ❒ There may be an increase in the future cost of capital because of the increased risk profile.

The CAA rejected NATs application as they felt that to accept it, as it had been submitted, would irreparably dilute the incentive properties of the price cap framework. They rejected it because:

- there was no volume term in the price control and the cost of capital used to set the price cap assumed that NATs would bear the volume risk;

- NATs was seeking compensation for the entire reduction in volume rather than any fall beyond what might have been reasonably expected when the price cap was set;
- the government had given NATs a higher price cap than recommended by the CAA and this provided for significant headroom against the possibility of downside risks;
- NATs was expecting to make major savings compared to previous expectations; and
- NATs had scope to raise some of its non-regulated charges further.

Although they rejected NATs application, the CAA stated that they would consider allowing an exceptional user contribution to solve NATs financial difficulties if NAT's users were in favour of that move. Following a series of revised applications from NATs, agreement was reached between NATs and the CAA on an acceptable application. The application allowed for a reduction in the X factor in the price control from 2003-05 and allowed for the dilution of NATs volume risk over 2003-05. NATs would bear only 50% of volume risk rather than 100% and their exposure would be further reduced to 20% of volume risk if traffic fell below 80% of NATs current base case forecasts. In order to qualify for these allowances, NATs had to meet a number of conditions set down by the CAA.

Separate controls - stand alone versus incorporated

A separate regulatory mechanism[16] for one activity of a regulated firm is only appropriate when:

- all the costs associated with that activity can be entirely separated from all other costs of the firm; and/or
- there is very limited scope for the firm to shift costs from one activity to another.

Where the above conditions are not met there might be scope for companies to game across two or more regulatory mechanisms. The regulator would then need to consider whether the impact of such gaming would be observable, or whether the benefits of separate regulation outweigh the potential detriment arising from any gaming. Where the

[16] Separate control mechanisms are used by the ORR and CAA (see Annex 1).

inefficiencies engendered as a result of such gaming are potentially substantial separate regulation is unlikely to be optimal.

Regulatory experience of stand-alone versus incorporated controls

ORR

The ORR proposed regulating the delivery of the West Coast Route Modernisation separately to the rest of Railtrack's business. They proposed paying Railtrack a fixed sum for the enhancement element of the modernisation that would fully reimburse them for the efficient delivery of the project. In order to incentivise Railtrack, the ORR specified a number of milestones that Railtrack would be expected to achieve and proposed the following measures if they failed to meet any of the milestones:

- the ORR would require Railtrack to provide evidence of the remedial measures it plans to take;
- the ORR would require Railtrack to carry out the remedial action or a modified programme as deemed appropriate;
- any monetary penalty for failing to deliver the remedial programme would be proportionate to the under delivery of the milestones;
- the penalty would be based on the assumed cost of delivering the milestones when they were established but would be adjusted to avoid any double counting; and
- if monetary penalties were levied for late delivery these would be added to the RAB when the outputs were delivered in full.

CAA

The CAA has recommended that the airports of Heathrow, Gatwick and Stansted should be regulated separately because it removes a regulatory distortion favouring Stansted over other non-BAA airports in the South East such as Luton. Regulating all three airports under one system created a distortion whereby BAA was willing to fund investment at Stansted even through the costs may be higher than the benefits to users of Stansted because the cost could be recovered through higher charges at Heathrow and Gatwick.

Annex 2

Terms of Reference

Annex 2: Terms of reference

DEVELOPING NETWORK MONOPOLY PRICE CONTROLS

REGULATORY MECHANISMS FOR DEALING WITH UNCERTAINTY

WORKSTREAM SPECIFICATION FOR FRONTIER ECONOMICS[17]

Introduction

Set out below is a workplan for providing advice on the most appropriate regulatory mechanism for dealing with uncertainty under price controls. The workplan details the high level requirements for the workstream, the key deliverables and dates for completion, and a specification of what the consultant will be expected to cover.

In setting price controls Ofgem must come to a view about the efficient level of costs that a company will incur over the period of the next price control. In doing so, it must consider a number of variables including the level of demand, the number of consumers, and other factors that may impact on the future costs of the company.

Over at least the next 5 years, the level and nature of investment that will be required, to facilitate the connection of distributed generation to the distribution network is uncertain. This is because:

- different types and sizes of distributed generation are likely to have to different implications for the networks – this impact may also vary depending on the existing type and strength of the network; and
- it is not possible to predict with accuracy the amount of distributed generation that will require connection to the network and when, where and at what voltage level, it will need to be connected.

[17] This workstream falls under the existing contractual agreement between Frontier Economics and Ofgem (CON/SPEC/2002-57) for which all relevant terms and conditions apply.

An increase in the level of distributed generation on the network may also have an impact on how the network is operated and so in turn on the operating costs of a company.

These matters raise significant questions about how the price control arrangements should deal with this uncertainty. Where appropriate and practicable Ofgem prefers to put in place mechanisms that allow companies (and consequently the price control) to respond to changing circumstances.

Workstream A

There are a number of possible options for dealing with uncertainty and the consultant will be expected to consider ways in which more flexibility can be incorporated into the price control framework to deal with uncertainty that is likely to impact on a companies' costs. In particular, the consultant will need to:

- review existing mechanisms (including those within the energy sector, other UK utility sectors and in other countries) for dealing with uncertainty, outlining the advantages and disadvantages of different approaches.

The consultant will also be expected to consider for each different approach:

- the implied balance of risk between companies and consumers and in particular the potential impact on the cost of capital and the level/volatility of prices that consumers pay. It is also necessary to consider whether any approach has particular implications for different categories of consumers (e.g. the fuel poor/industrial consumers);
- the incentives that companies are provided with to manage the uncertainty efficiently;
- the circumstances—especially in terms of nature and level of uncertainty--for which different approaches (or combination of approaches) might be applicable; and
- the approach that would be most appropriate for dealing with uncertainty associated with distributed generation and the potential impact that it may have on the incentives on DNOs to

connect distributed generation to their networks and the implied balance of risk between DNOs/distributed generators /consumers.[18]

The consultant is not required at this stage to undertake any specific empirical analysis, for example providing an estimate of the impact on the cost of capital or prices of different options.

Description of each deliverable

A description of how Ofgem expects the work to be undertaken is set out below.

Initial presentation to Ofgem – in this presentation the consultant will be expected to outline their initial thoughts on the issues identified above. This will help to identify whether any further issues need to be considered before a draft report is prepared.

Draft report to Ofgem – in this draft report to Ofgem the consultant will be expected to outline their findings on the issues identified above. The consultant will be expected to agree a structure for the report before it is written, initially providing a draft structure for comment by Ofgem.

Final report to Ofgem – the consultant will be expected to produce a final report that takes into account Ofgem's comments on the draft report. Ofgem may require the consultant to make a presentation of their final report.

Key deliverables and timetable

A suggested timetable is set out below. This needs to be agreed with the consultant.

- Initial presentation – **end September 2002**
- Initial report – **end October 2002**
- Final report – **end November 2002**

[18] ILEX are presently carrying out work for Ofgem on the costs, incentives and uncertainties for distributed generation Ofgem is considering undertaking further work in this area in the coming months, to which the consultant will have access.

Annex 3

Ofgem guidance on examples to test the framework

Annex 3: Ofgem guidance on examples to test the framework

DEVELOPING NETWORK MONOPOLY PRICE CONTROLS

REGULATORY MECHANISMS FOR DEALING WITH UNCERTAINTY

Workstream A Phase III[19] Specification

This document is supplementary to the "Workstream Specification for Frontier Economics" provided to Frontier Economics at the start of workstream A (at Annex 2 of this report).

In the first two phases of workstream A, Frontier developed an initial view of a decision-making framework, set out in its initial report. For phase III of workstream A, Ofgem expects the consultant to carry out the following tasks, in order to convert the initial report into a final report.

1. Refine the decision-making framework, to result in a complete set of decision rules, using relevant regulatory experience in addition to logic to support its conclusions.

2. Test and demonstrate the decision-making framework using the following examples, to reach recommendations for an appropriate regulatory mechanism in each case (where necessary stating assumptions used). The present regulatory treatment may be different from that suggested by the framework.

   For all of these examples, the consultant should include an evaluation of its **impact on incentives for efficiency,** in particular on **incentives to manage the uncertainty efficiently** as set out in the original workstream (below).

   - **Brief – Licence fees**

[19] This workstream falls under the existing contractual agreement between Frontier Economics and Ofgem (CON/SPEC/2002-57) for which all relevant terms and conditions apply.

- **Brief** – **Lane rentals**, presently pilot schemes are being run in the local councils in Camden and Middlesbrough (which affect, of the DNOs, LPN and NEDL) which may be expanded across the country.

- **Brief – NGC exit charges for DNOs** with a potential for companies to alter behaviour over time

- **Brief** – need an example of something which is not sufficiently separable or subsequently auditable to be excluded from the main RPI – X control, e.g. the costs of a planned IT project.

- **In greater detail – Impact of severe weather events** (by abolishing the present exemptions from the Guaranteed Standard for supply interruption due to 'exceptional' weather events) and thereby requiring companies to manage the uncertainty of severe weather impacts on their network.

- In-depth – **Distributed generation** – using a set of scenarios, to be set out separately by Ofgem (below), for the areas of uncertainty surrounding distributed generation. For example if you are reasonably aware as to what costs/demand will be, then use one regulatory treatment, and if not use another. Ofgem expects the consultant that will provide a clear recommendation for a certain type of treatment.

3. Agree with Ofgem a structure for the final report, including considering:

   - Integrating the checklist for policy design (2.4) with section 3

   - How to best present material in Annex C.

Description of each deliverable

A description of how Ofgem expects the work to be undertaken is set out below.

- Presentation of work in Phase I and II with Ofgem

- Presentation of some of the work to industry group

- Provide a draft final report, in particular Ofgem expects that the examples (with the exception of distributed generation) under section 2 will be provided in draft form at an early stage, so that their presentation can be discussed and agreed by Ofgem and the consultant.

- Final report to Ofgem – the consultant will be expected to produce a final report that takes into account Ofgem's comments on the draft final report. Ofgem may require the consultant to make a presentation of their final report to industry.

Key deliverables and timetable

A suggested timetable is set out below. This needs to be agreed with the consultant.

- Presentation of work in Phase I and II with Ofgem – December 2002

- Presentation of some of the work to industry group – December 2002

- Draft final report – w/c 13 January 2003

- Final report – w/c 27 January 2003

Timetable assumes phase III starts in w/c 6 January.

Workstream A – Phase III

Scenarios for distributed generation

These scenarios are provided to detailed scenarios for distributed generation to test the decision-making framework. The scenarios require the consultant in some cases to assume that answers to questions raised in the decision-making framework are as set out below. The consultant should focus on distribution network effects.

These scenarios were produced solely for illustrative purposes to test this framework. In no sense should they be regarded as an OFGEM position on (or forecast of) the likely course of increased connection of distributed generation.

Central case

- Assume that marginal costs will be increasing in short to medium term (because of lumpy investment requirements) but reducing in the longer term as DNOs actively utilise distributed generation.
- Assume that we do not know the exact timing of distributed generation emerging, but that it will be between 2005 – 2010, its volume will be as given by the high end of the forecasts in the Regional Renewable targets table (attached), and its location will be as given by the forecast for each region.
- On unit costs, will have reasonable information (supplied by the DNOs, not market data). To begin with this data will be fairly separable, but it may not be complete or perfectly disaggregated, and gaming and monitoring issues are likely to remain. For example information on the costs of individual projects will be available, but capex may be used to improve Quality of Supply performance as well as to connect DG. Over time, if and when DNOs are integrating distributed generation actively (e.g., in place of network reinforcement) there will be a blurring of the boundary between investment for distributed generation and general network investment.

- The cost impact is unlikely to be correlated across companies, unless there is a manufacturer supply side issue or if, for two DNOs under the same ownership, a pro-active approach to DG in one area (e.g. Scottish Hydro) attracts DG to the other area (e.g. Southern).

- Assume that costs will not be comparable across companies (unit costs not comparable due to differences in network design), so benchmarking will not be possible.

- The area of concern is only the monopoly element of costs from connecting DG, i.e. the deep reinforcement costs of DNOs, not competitive or contestable elements, such as generation or the shallow segment of connection, and costs associated with upgrading networks to active management.

Using Frontier's **Framework for classifying uncertainty**, the central case can be classified as follows:

- Initial view is that uncertainty is likely to be material for all DNOs (though of varying magnitude).

- The uncertainty is possibly separable to begin with, but over time may be only imperfectly or not at all separable, as networks become more 'actively managed.'

- At its first occurrence, the uncertainty is of limited predictability (can only identify upper/lower bound for volumes), and at subsequent reviews, predictability may be improved in respect of when, where and how much DG will be connected, but the shape of costs makes the past a poor guide to the future.

- Once the uncertainty is realised (once much more DG has been connected), the regulator will be able to measure it only imperfectly – the timing, volume and location of previous distributed generation should be clear, but its costs will become increasingly blurred with those of the entire network.

- The impact of uncertainty is not correlated between companies because of the potential for variation between companies in the timing, volume, location and costs of both connecting and utilising distributed generation (with the exceptions noted above).

♦ The uncertainty will have an impact on initially costs and increasingly on volumes of units distributed and network quality, potentially positively or negatively, and there will also be an impact on investment planning (capex).

Variations from the central case

What is the impact on the consultants' recommendations of each of the following variations (taken separately):

1. Significantly different volumes of distributed generation connect in different areas. In particular assume that for all sources (except biomass and offshore wind), only the low end of the targets in all regions is met between 2005 – 2010, with the exceptions of biomass, where assume the volume in all regions is zero, and offshore wind, where assume an additional 1000MW is connected in Scotland.

2. Assume that the volumes of DG connected are much greater everywhere than assumed in the central case.

3. Increased availability of information on costs, (potentially increasing over time), which is complete for all companies.

4. Assume that costs are comparable, so unit costs can be benchmarked across companies.

5. Unit costs uncertain (the data is not available from companies nor comparable due to its incompleteness.

Range of Volume for DG Development 2005-2010

Source of information: "Regional Renewable Energy Assessments, A Report to the DTI and the DTLR", OXERA & ARUP, Feb 2002

All regions (English regions and devolved administrations) made assessment for the potential for renewable energy generation by 2010. The assessments were guided mainly by resource considerations only. Factors identified that may impact on the pace and feasibility of development but not analysed and incorporated in the figures in detail are:

- planning system. In its current form the planning system may take several years to incorporate the regional RO targets into forward plans and hence into the development control decisions, therefore the realisation of the potential may be beyond 2010;

- economy of different technologies. In particular, energy from biomass, almost a quarter of the total renewable energy, needs to be treated with caution as it is expected to have prices straddling the 5p/kWh limit of support from the RO;

- further potential for offshore wind projects. More (eg 1000MW in Scotland) could be made possible by the government's offshore wind grants and consenting policy announced after most of the regional studies were completed.

Regional Renewable Targets for 2010 – Capacity (MW)

	East	E Mids	London	N East	N West	S West	W Mids	Y&Hmb	Scot	Wales
Onshore wind	647	121	8	221~468	248	149~273	512	82~305	1272	248~573
Offshore wind	371	100	0	3	171	0~46	0	0~160	0	60~450
Marine tech	0	0	0	0	0	0~34	0	0	0	0~38
Landfill gas	76	56	8	20	75	36	111	82	2	35~42
Biomass	94	68	4~11	15~61	105	55~141	18	47~177	10	25~90
Anaerobic digestion	0	18	12	1	14	8	17	0~1	0	0~4
Small hydro	0	12	2	7	6	8~11	3	0~1	49	5~20
PV	0	5	6	1~2	10	4	4	3~16	0	1~5
Biodegradable waste	0	0~25	0~44	0~20	1~51	2~18	0~53	0~27	0	0~8

Regional Targets for 2010 – Energy (GWh/yr)

	East	E Mids	London	N East	N West	S West	W Mids	Y&Hmb	Scot	Wales
Onshore wind	1700	319	22	580~1230	651	390~716	1345	215~800	3343	651~1507
Offshore wind	1300	350	0	10	600	0~160	0	0~561	0	210~1577
Marine tech	0	0	0	0	0	1~90	0	0	0	0~100
Landfill gas	600	438	64	157	588	284	877	645	15	276~331
Biomass	700	505	30~80	113~453	780	413~1050	133	348~1316	73	186~670
Anaerobic digestion	0	137	87	8	105	58	123	0~7	0	2~31
Small hydro	0	39	5	22	18	25~34	10	1~3	158	16~65
PV	0	14	16	1~4	26	10	11	9~42	0	3~12
Biodegradable waste	0	0~189	0~326	0~150	7~383	11~131	0~392	0~204	0	0~61

The high end of the above targets add up to just under the overall government target of 10% of all consumed energy. Note that these figures are the total renewable targets, i.e. include both existing and new generation. Some of the wind projects may well be connected directly to the transmission system rather than the distribution system. However, for the purpose of the uncertainty work, the central scenario can assume that the high end of the targets above will materialise and all will be connected to the distribution system between 2005 and 2010. For the first variation on the central case, adopt the low end of the targets in all regions, assume biomass in all regions is zero, but include an additional 1000MW of offshore wind energy in Scotland.