Electricity Distribution Price Control Review

Response to Ofgem Consultations:

1) Second Consultation

2) Ofgem Financial Model

3) CEPA's Report on Total Factor Productivity

February 2004

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Appendices

1 Executive Summary

This document integrates our response to Ofgem on:

The December Consultation Document on the Distribution Price Control Review;

The Consultation on the draft Financial Model (Appendix 2); and

The Report by CEPA on Total Factor Productivity (Appendix 3).

The summary below identifies the key points made across the three consultation documents.

- We are concerned that some of the policy framework and much of the detailed price review methodology remains to be finalised. Whilst there is still time for these to be completed by Ofgem in time for the March Policy Statement and the June Initial Proposals, the absence of a detailed plan of how all of the current elements of work will come together needs to be addressed urgently.
- We believe that the basic form, structure and scope of the control require little change, but we support evolution of additional elements in an (RPI-X)+I+Q structure.
- The level of uncertainty around future costs is very large and needs to be dealt with via precise mechanisms, which are agreed in advance.
- The balance of incentives needs to be reviewed to ensure that both performance and efficiency are suitably rewarded.
- Given the progress of competition in the market, over-regulation of the metering part of the business should be avoided.
- The risks of stranded metering costs and assets need to be dealt with as part of the main price control.
- We see only limited need to modify the approach to Guaranteed and Overall Standards.
- We recommend stability in the IIP Framework, and only minor changes to its detailed operation.
- We believe it is possible, and appropriate, to develop a measure of Network Resilience.
- The outcome of Ofgem's Willingness to Pay survey of customers, together with companies' submitted costs, should be used as a key input in order to fine tune marginal service performance.
- We believe that more realistic incentive levels are required if targets for distributed generation are to be met.
- The strategic and enabling investment required within our network for DG should be dealt with as part of the main price control, with funding coming from both generators and demand customers.
- The uncertainty and range of costs for DG needs to be recognised more fully.
- Both IFI and RPZs warrant further development work.

- We support the work so far to establish a consistent and comparable data set from which to assess companies' efficiencies. This work needs to be completed as an urgent priority.
- Quality of supply, total cost, and the effects of mergers must be taken into account in comparing efficiency.
- The uncertainties in any 'top-down' analysis are substantial. It is therefore unlikely that it can be disproved that all companies are approximately equally efficient.
- A report by Horton 4 Consulting, which reviews CEPAs TFP work, notes that there are no grounds to expect DNO TFP growth to be much higher than for the economy as a whole.
- The existing financial ring-fence is sufficiently robust.
- We support a post-tax approach to the cost of capital, reflecting individual companies' circumstances.
- The work to complete the financial model should be accelerated since it is an integral part of the process to ensure that all work streams in the review are completed on a timely basis.
- We expect early confirmation of the financial indicators to be used to test financeability. These must be consistent with being comfortably within investment grade credit rating.
- We agree with Ofgem's high-level principles on pensions. However, the retrospective application of these price controls principles to previous price review periods, is an area of considerable concern. The most important issue is to ensure that adequate funding is provided for the future.

We would welcome the opportunity to discuss our detailed comments with Ofgem's staff.

2 Timetable and Consultation Process

2.1 Timetable

We welcome Ofgem's clarification of the major milestones but we are concerned that some of the policy framework and much of the detailed price review methodology remains to be finalised. Whilst there is still time for these to be completed by Ofgem in time for the March Policy Statement and the June Initial Proposals, the absence of a detailed plan of how all of the current elements of work will come together needs to be addressed urgently.

A great deal remains to be done. Specifically the data upon which the comparative efficiency work will be based needs to be finalised. At the same time the policy framework needs to be completed – particularly in the areas of: the structure of charges; metering; quality of supply, standards and IIP; distributed generation; customer willingness to pay; the treatment of pensions costs; and other financial issues. The financial model is in its early stages of development and yet it will need to be capable of correctly representing these and other areas in order for the price control to be set in the form of Initial Proposals in June. Another example here is how it will be difficult to incorporate the results of the customer survey in the initial proposals, given that the results will be available only shortly before the proposals need to be finalised for publication. Without completion of these work areas the review remains an opaque methodology for setting future revenue.

It would be helpful to all parties if we could review and comment on the detailed plan for all of this work, at a level of detail below that presented in the consultation document. We appreciate that we would need to comment very quickly and accept some decisions that will be compromises by Ofgem, but are concerned that in the absence of seeing the plan we can help little more than to identify the key areas for attention.

It would be worthwhile for Ofgem to represent the flow chart setting out the timing and interrelationships of the separate work packages. This might provide reassurance that the overall project plan is still deliverable.

3 Form Structure and Scope of Price Control

- We believe that the basic form, structure and scope of the control require little change, but we support evolution of additional elements in an (RPI-X)+I+Q structure.
- The level of uncertainty around future costs is very large and needs to be dealt with via precise mechanisms, which are agreed in advance.
- The balance of incentives needs to be reviewed to ensure that both performance and efficiency are suitably rewarded.
- Given the progress of competition in the market, over-regulation of the metering part of the business should be avoided.
- The risks of stranded costs and assets need to be dealt with as part of the main price control.

3.1 The structure of the price controls

We support the continued use of 'RPI-X' price controls. As we have discussed before, this structure can be extended to provide separate specific incentives for particular behaviours. This is already the case for distribution losses and some elements of quality of supply (through IIP). The proposed incentives in respect of investment to support Distributed Generation would also fit this model. It will be appropriate to wait until the customer survey results are available before finalising the scope of the control, but further additions to the basic form of control may be needed to reflect other issues, such as growing concern on network resilience. We continue to see a model based on (RPI-X)+I+Q as a suitable structure for the future.

3.2 Revenue Drivers

We agree that the use of revenue drivers is intended to protect companies from cost volatility driven by demand growth. In our view, there are two main sources of uncertainty in this respect – the impact of energy efficiency commitments and distributed generation. We are moving into an era where volume reductions are as likely as increases, so the protection that is required is somewhat different. So long as the base assumptions for setting the price control reflect the likely trend in sales volumes, it can still be appropriate to include a revenue driver split equally between customer numbers and kWh delivered.

Whilst in theory it may be better to include a capacity related element for large customers, we remain to be convinced that this extra complexity can be justified.

3.3 The scope of the price controls

3.3.1 NGC exit charges

The treatment of NGC exit charges has been consistent since 1990, with the costs excluded from distribution price control, but falling within the regulated income of NGC. This ensures an adequate level of customer protection. DNOs have little short term control over their asset requirements (these being driven more by P2/5 requirements). Most work at GSPs is currently driven by asset replacement considerations rather than power flows, so there is limited opportunity for DNOs to make alternative arrangements. Furthermore, the level of 'exit charges' is set to fall substantially (by about 50% in our case) leaving a much smaller quantum to consider. We are not aware that the theoretical risk of gaming is a major practical concern. There are examples of companies choosing the least cost option, even though it may not use NGC assets. So long as Ofgem continue to reward efficient investment in price control settlements there is no reason to change the current scope of the price control.

We share the concerns of other respondents to your previous consultation in respect of wheeled units. It would help to balance incentives if payments made to neighbouring DNOs for wheeling were treated in the same way as NGC exit charges. Where there are alternative ways of increasing the import capability of our network, there should be no regulatory distortion of the analysis of the options.

There is one other 'wheeling' issue that we think should be addressed in this review. It is likely that the electricity distribution market may follow the same course as for local gas distribution and small, separately regulated, embedded networks develop. The extent to which this happens will not be within the control of the existing DNO, and any revenue for network usage up to the boundary with the new networks should therefore be excluded from price control. This becomes all the more important since many such networks may have generation (especially CHP) embedded within them, making volumes and load profiles particularly unpredictable.

3.3.2 EHV charges

We have observed before that our EHV customers have not expressed any dissatisfaction with our approach to pricing. There seems to be some confusion in Ofgem over the appropriate means of monitoring DNO performance. We understand our obligations to require us to avoid undue discrimination. This does not necessarily align with a common rate of price movement. The balance of costs to serve EHV customers will often be different from those relating to other, smaller customers. This can arise because NGC charges tend to make up a larger proportion of the total costs to serve EHV customers and because a much smaller proportion is usually needed to cover billing and administrative expenses. It is also right to point out that EHV customers have, in the past, had more opportunity to negotiate the balance between connection and use of system charges, again increasing the likelihood that future prices need to cover a different mix of costs.

These observations need not imply that a new tariff basket for EHV charges is inappropriate. However, care would be needed in designing the approach and in understanding subsequent performance. This may be no more complex than the current arrangements, where companies seem to be unable to provide sufficient evidence to satisfy Ofgem that EHV charges are soundly based.

3.3.3 Non-contestable connection charges

We support Ofgem's desire to introduce more competition into the connections market. By providing choice over who undertakes connections work, customers will have the opportunity to seek improved value for money, either through lower prices or variations in service quality. However, the success of the competitive market depends on support from the DNO. There will inevitably be some non-contestable services that protect the existing network owner where third parties are going to connect to the existing asset base. Such services, and the related charges, are specified in Condition 4 statements, and are therefore subject to Ofgem review prior to publication. This may be a more effective form of control than trying to design a price control to cover what are essentially one off costs that depend significantly on the details of the project under consideration.

We agree that customers need to see evidence of protection where monopoly services are provided by a DNO, but this does not always have to take the form of formal price control. Non contestable service charges can be challenged by individual customers if necessary, and Ofgem can provide routine monitoring of published rates including inter-company comparisons. It is already the case that service standards are set and DNOs report regularly to Ofgem on performance.

3.3.4 Business rates and other excluded services identified by DNOs

Ofgem have previously given DNOs to understand that local authority rates would be treated as a pass-through in future price controls. It is difficult to separate discussion of this particular issue from the more general question of how to deal with uncertainty in cost estimates for the price control period. However it is worth confirming the principle that excluded services should embrace all activities where costs or volumes are sufficiently uncertain as to make it impractical to include them within an overall revenue cap.

3.4 Dealing with uncertainty, new obligations and costs

There is a general recognition that the level of uncertainty around future costs is greater than at any time since privatisation. It is particularly important that the price control settlement acknowledges this. We are uneasy with the idea that we might only be offered some kind of general comfort letter. The early work by Frontier Economics provided a framework on which to build some more precise mechanisms for dealing with specific areas of uncertainty. In some cases pass-through may be appropriate, in others incentive mechanisms could be defined that would encourage efficiency in dealing with events of unknown impact.

The detailed review of Frontier's proposed approach was raised in the Dealing with Uncertainty Working Group some months ago. It is now important that this work is followed through to narrow the areas of uncertainty. Within that process we would not yet rule out the tools used by Ofwat, although we agree that this may offer weaker incentives than more targeted options designed to address specific issues.

3.5 Duration of the main price control

We are pleased to see confirmation that the next price control will be designed to run for five years. This clarity will help our internal planning. There is a separate question about the duration of benefit retention within efficiency incentives. The work that has been done on both the rolling RAV adjustment and the opex benefit retention enable these to apply for different time periods than the price review intervals.

3.6 Incentive framework

We are concerned that more work needs to be done to consider the interaction of incentives that are in place or have been proposed. The table in 3.83 is a helpful check-list, and the discussion in the paper raises a number of important issues.

The initial work by Frontier Economics provided an early stimulus for discussion, but subsequent progress has been slow. This may be because the objectives are not yet sufficiently clear, (if we cannot describe desired outcomes, it is impossible to specify appropriate incentives).

The overall objective must be to ensure that customers receive both the right services and an appropriate price. This can lead to tension between rewards for performance and incentives to reduce costs. We can see circumstances in which eligibility tests can provide a link between the two strands. It can even be the case that incentives can be strengthened simultaneously on performance and efficiency, if there is an eligibility test.

However, we believe that the development of an incentive framework is more complex than this and care is needed to ensure that the interactions between different incentives are considered sufficiently. Our work on incentives around the connection of distributed generation has helped to clarify some issues. For example, we can now distinguish between mandatory and discretionary investment, and see that they must be treated separately. Where investment is discretionary, companies can only be expected to spend where this represents the best use of marginal capital. This will depend upon both the marginal reward and the risk of non-performance.

This approach is equally appropriate wherever marginal performance attracts marginal reward (such as in the IIP or the losses incentive). On the other hand, some aspects of performance have absolute standards, such as those defined in Guaranteed Standards. The position is further complicated because the costs that companies expect to incur will deliver a combined effect across a range of different types of measure. Investment to improve expected speed of restoration will not only contribute to GS performance, but also towards IIP rewards, for example).

It is unlikely that expenditure can be unbundled entirely and therefore eligibility tests for any broad efficiency rewards must also be broad. We suggest that five-year rolling average fault rates may be a suitable measure to secure capex efficiency gains, while opex benefits could be linked to CML performance. Neither will be a perfect measure, but we anticipate a gradual move towards a wider range of output/outcome related rewards, reflecting dimensions of performance valued by customers (or by Ofgem, on customers' behalf).

Where there is no absolute performance measure of acceptable standards, it will be important for Ofgem to allow rewards to be sufficient to encourage genuinely discretionary expenditure. As well as the case of investment in advance of specific distributed generation projects, we would also highlight the position on losses. Investment to reduce losses must compete with other discretionary projects for finance and management time. For such investment to be undertaken it must offer the prospect of returns as great as those available from improving CI/CML or facilitating future DG connections.

Further, Ofgem must set reward levels that reflect the strength of their desire to see performance changes, or they must price each incentive on the basis of a valuation of customer benefit and leave the commercial behaviour of DNOs to identify the optimal mix of outputs.

We recognise that this is not an easy area, and as the desire for a wider portfolio of incentives grows, it becomes more difficult to keep them in balance. Once initial proposals for individual incentives have been made, it will be easier to review their potential interaction. In the meantime, we would recommend that the Incentives Working Group be encouraged to develop a set of principles to guide future work. Through this group it may also be possible to identify suitable means of countering the gaming risks identified in 3.80. It should be possible for Ofgem to establish, ex-ante, the reasonableness of a company's capex forecasts. This is indeed a key task for the Cost Assessment work-stream. It would be wrong to assume that larger investment programmes are necessarily inflated and less deserving of incentives to manage out-turn costs. The investment should be justified in terms of the various measures used to judge network performance.

3.7 Price controls for metering services

We accept that Ofgem have no.w concluded that metering services should continue to be subject to price control beyond 2005. However, our prime concern in this area remains the appropriate treatment of costs falling on the distribution business as a result of its past and continuing licence obligations in respect of metering services. We do not accept that these can be satisfactorily addressed through price controls on a competitive service.

3.7.1 A separate metering price control

It is important for Ofgem to move quickly to develop more detailed proposals for a separate price control, since it is only when that has been settled in principle, that the true extent of the distribution business exposure, as a result of market reform, will become clear. We assume that Ofgem's intention is to provide a 'safety-net' to reassure customers and suppliers in respect of metering charges and that this will apply equally to all meter operators.

We are pleased that Ofgem have, in principle, accepted the depreciated replacement cost valuation of existing metering assets, but it is important not to believe that this protects the DNO from asset related risk. Whilst it will be effective at the time the price control is first set, it will not protect against future changes in technology or shifts in supplier behaviour, (for example to move to an alternative prepayment system). DNOs can be expected to use termination fees to further protect their existing investments.

It is also pleasing to note that Ofgem have recognised the stranding of opex as another issue to be dealt with for as long as a last resort service obligation is in place. Our FBPQ has been presented in a way that helps to identify these costs. The costs associated with existing employees (including the related pension liabilities) and IT systems will be just as important to our future financeability as the metering asset base.

3.7.2 Scope and duration of the metering price control

In our opinion no price control is necessary post 2005. Early notice of this intention would act as a further spur for suppliers to enter the competitive market. Nevertheless we can understand Ofgem's more cautious approach of seeking to undertake a competition assessment before making this change. However, any such assessment needs to take account of the fact that suppliers will inevitably say that such obligations should remain in place.

It is important therefore that the competition assessment focuses on awareness and capability rather than absolute measures of market share. Given the nature of the metering market where it is licensed suppliers who are the customers for DNO metering services, any analysis based on absolute measures could be distorted by suppliers who have metering businesses within their own groups. Once a major supplier has demonstrated that it is possible for suppliers to migrate from the DNO to a third party meter provider, then this should be evidence of capability.

3.7.3 Form of the Price Control

If Ofgem remain determined to put price controls in place for metering services, we strongly favour simple price caps on key services. The non-discrimination provisions in the distribution licence can then be used to ensure that other prices are kept in step with the core regulated prices.

Our suggestion would be to cap the MAP charges for a single phase credit meter and for a prepayment meter. For a meter operator the installation charges for the same equipment could also be capped. It is likely that competition will be the main driver of future prices, and any price caps should act only as a safety net. This suggests that they do not need to be set at a level that implies great efficiency savings. Indeed to do so may remove the headroom for competitive market entry. Our simple suggestion would be to use the upper quartile of 2003/4 published prices as the cap, to apply equally across all meter operators.

4 Quality of Service and other outputs

- We see only limited need to modify the approach to Guaranteed and Overall Standards.
- We recommend stability in the IIP Framework, and only minor changes to its detailed operation.
- We believe it is possible, and appropriate, to develop a measure of Network Resilience.
- The outcome of Ofgem's Willingness to Pay survey of customers, together with companies' submitted costs, should be used as a key input in order to fine tune marginal service performance.

4.1 Guaranteed and Overall Standards of Performance

In general both Guaranteed and Overall Standards provide an appropriate means of protecting customer service standards. OS provide a suitable public metric to compare companies' macro performance against minimum service levels whilst GS provide an appropriate and material guaranteed payment for individual customers. IIP should in contrast, allow the fine-tuning of service performance against an estimate of customers' willingness-to-pay for marginal service variations.

There is considerable merit in stability in the form and scope of incentive mechanisms. It is only when companies can understand the long-term consequences of their actions, that they are likely to respond positively to incentives to change behaviour. We believe that the combination of GS, OS and a relatively simple form of IIP is an appropriate basis for managing performance in terms of Quality of Supply and customer service.

Turning to the specific suggestions contained in section 4.7 of the consultation:

4.1.1 Severe Weather

We support the interim arrangements and welcome Ofgem's intention to put longer-term arrangements in place. Any revised arrangements must recognise the inherent interaction between capital expenditure for Quality of Supply and Network Resilience purposes, and the operation of exemption criteria. For example:

- a DNO that invests in network automation to improve customer service and to gain rewards under IIP, would perversely be less likely to meet the current materiality threshold for a given level of storm damage. (Even though there are an exceptional number of CIs, if these are restored effectively as a result of targeted investment, the CMLs may be lower than the materiality threshold).

- Equally if a DNO invested to increase the resilience of its overhead lines, for a given storm these would result in less CIs, again potentially exposing the DNO to the full value of GS failures below the exemption gate.

It might be necessary to review the gate criteria annually to reflect the underlying changes in network performance arising from capital investment to mitigate the potential for perverse incentives. An alternate mechanism would be to allow the DNO an upfront allowance in anticipation of such exceptional events occurring in a given period. The DNO would therefore be incentivised to reduce its exposure to actual GS failures and retain any out performance. This approach would transfer additional risk to the DNO and an appropriate reward would be required, however it would have benefits for customers, as the risks are best transferred to the stakeholder best placed to mitigate them.

4.1.2 Automatic Payments

The provision of an automatic GS payment service is an achievable goal in the forthcoming regulatory period. We believe that the most significant benefit of such a mechanism is to provide such payments promptly to customers. This objective does not in our view require the creation of a complex and expensive single phase connectivity model. However, it would be essential to recognise the impact of such a change on the companies. In particular there are three features to take into account:

1. that automatic payments would be more numerous than claimed payments;
2. that systematic over-payments would be made where single phase low voltage faults occurred;
3. that higher administrative costs (including new IT) would be incurred.

Our response to the FBPQ QoS question 4 outlines in detail our views on how such a mechanism may be implemented.

4.1.3 Business Customers

We do not support the imposition of different regulatory standards for business customers. Our network has been designed to historic P2/5 standards: these in turn are intended to deliver predetermined levels of supply security dependent upon the size of load and voltage of connection. There is no separate standard for customers according to their usage of electricity. Medium and large business customers do however have the opportunity to specify their required level of supply security. This is reflected in both capital connection costs and ongoing DUoS charges. This opportunity is not afforded to domestic and smaller customers.

It would certainly not be appropriate to make large GS payments to business customers who had chosen to take less secure connection arrangements. We would also be wary of the potential impact on restoration policy, which currently aims to secure the highest volume of restored supplies in the shortest possible time.

If there were a genuine demand for greater insurance among business customers we would expect to see a market develop, led probably by suppliers. Such commercial arrangements could operate in parallel with a non-discriminatory approach to restoration from DNOs.

4.1.4 Scope of Exemptions

We welcome Ofgem's proposal on the clarification of current exemptions, as these have historically been subjective and inconsistently applied, which has led to uncertainty for customers.

Any tightening or removal of the current exemptions must be accompanied by appropriate protection, such as the introduction of GS1 payment pass-through as part of the interim storm payments arrangements.

Any consideration of changes to exemptions must also extend to encompass both the scope and threshold of exemptions. With regard to scope, events such as Foot & Mouth Disease, a national fuel crisis etc, are currently classified as non-exempt despite being beyond our reasonable control and having material impacts on performance.

With regard to threshold, current exemptions, such as that in respect of industrial action, protect us against potentially very large GS exposure. Whilst we agree industrial action is to some extent controllable, it is questionable whether it is reasonable to expose us to its unlimited effects without appropriate allowance for insurance. A compromise might be to raise the threshold for example to material industrial action lasting longer than 5 days, but even this would add to our risks and would need to be offset by an additional revenue allowance.

We believe that all the issues outlined above in respect of exemptions would be best dealt with by the application of a general mechanism which applied exceptionality and materiality threshold tests. Such events would then invoke an appropriate exemption mechanism. We would welcome the opportunity to work with Ofgem to develop the detail of such a mechanism.

4.1.5 Voltage Complaints

Companies' performance in response to voltage complaints is already good. In reality the time taken to respond to the initial complaint is usually a relatively small part of the total period to fix the problem, (since this often involves the design and implementation of a reinforcement scheme). We see little need (or value to customers) in compressing the allowed time to respond to the complaint. This would add to the risk for companies, whilst having little material effect on the time taken to solve the customer's problem.

4.1.6 Replacement of Overall Standards

As stated previously we support Overall Standards as an appropriate mechanism for defining minimum customer service levels. The fact that these standards are generally satisfied is a measure of success, not a reason for change. We would also support an extension of performance reporting so long as this was not a step towards inappropriate targeting at a disaggregated level.

4.1.7 Priority Service Register Customers

We are sympathetic to the needs of customers on the Priority Services Register, and already take special action to protect them where necessary. However we see major flaws in the proposal to implement special standards of performance.

As we have explained above, our network is designed to meet criteria that apply to the generality of customers. It would be difficult, if not impossible, for us to tailor service levels to individual customers. Furthermore, the PSR fulfils a number of separate purposes, and not all customers included on the register need special consideration in all circumstances. We would not wish to see customers (or their suppliers) clamouring to enter the register in order to obtain preferential restoration.

If there is genuine evidence of concern, we would prefer a more targeted approach to particular customers, for example we could install Power Outage Devices (PODs) at individual premises to give more rapid alerts of supply interruptions. This is likely to be a more cost effective solution for small numbers of vulnerable customers.

4.2 Reviewing IIP

We fully support the concept of the IIP and see it as an important element in an incentive structure that focuses on value for money rather than just cost efficiency. In this context the use of Willingness-to-Pay estimates to support the pricing of incentives is essential if customers' best interests are to be served.

4.2.1 Scope of Output Measures and Financial Incentives

The current IIP mechanism focuses on CIs and CMLs. We believe that these represent a reasonable measure of primary customer service and, post disaggregation, are readily comparable between companies.

In the current period, the introduction of IIP has meant that customers have benefited from earlier investment initiatives as IIP has served to focus company attention on the annual delivery of performance targets, rather than end of period delivery. However the incentives were only attractive if the rewards were anticipated to continue for the foreseeable future. A period of stability in target scope and level is necessary to allow companies to realize the benefits of investments made.

4.2.1.1 Distinguishing between types of consumer for reporting

We are happy to prepare disaggregated performance data, where this will be meaningful and useful. However, any proposals to extend the scope of IIP reporting must take account of its cost and effectiveness. Having developed robust reporting systems that meet audit standards, any modifications would have to be as rigorous and be fully tested. The costs of this would be substantially greater than producing a one-off indicative report on a new basis.

Furthermore, we would need to be convinced of the long-term benefits of additional reporting. This could include confirmation of non-discrimination, (which might be an effective counter to the concerns received on behalf of business customers). However such data collection could be seen as a forerunner to new customer specific reward schemes. These would be as inappropriate as the variable GS/OS arrangements discussed earlier.

4.2.1.2. Protecting Worst Served Customers

In our view the recently introduced Multiple Interruption GS and OS go a long way towards adequately protecting 'Worst Served Customers'. Such individual customer based metrics are well developed and are more representative than targeting worst performing circuits. Targeting of circuit-based metrics is generally open to manipulation and has not historically produced significant benefits for customers.

We remain open to the possibility of incorporating MI performance into IIP, this could help to narrow the gap between average and worst service experienced, if there is general acceptance of this objective from customer research.

4.2.1.3. Disaggregated Performance Data Provision

As discussed in 4.2.1.1, developing new reporting systems that meet IIP audit standards is not necessarily cheap. However if disaggregated data is valuable to customers it should be made available.

4.2.2 Form of the incentive for interruptions to supply

We acknowledge the weaknesses in the current IIP that Ofgem have identified. The problem can be characterised by the need to reconcile a desire for consistent incentives with an inherently volatile level of performance. This can best be achieved by removing the more extreme fluctuation in performance and then providing assurance as to the consistency of the incentives and targets for future years.

4.2.2.1 Annual Rewards and Penalties

We would support a move to greater symmetry in the IIP, with rewards as well as penalties available each year. So long as there is long-term stability in the targets and the incentive rate reflects (a reasonably constant) willingness to pay, the fluctuations around average performance should balance out.

4.2.2.2 Use of Dead-bands

Dead-bands are appropriate where the target performance is constant. They can, in those circumstances, recognise the inherent volatility of short-term performance. However, they would distort incentives, if (as in the initial period) the IIP was aiming to drive performance improvements, rather than preserve the status quo. As we have argued elsewhere, we are unconvinced of the support from customers for further improvements in performance, given the likely associated costs. We are therefore more willing to accept dead-bands now than in the initial phase of IIP.

Nevertheless we believe that the stability of IIP still depends upon removing the impact of substantially abnormal events. In our own case, 2002/03 performance was significantly distorted by a small number of EHV faults that happened to have a particularly large customer impact. This was outside the probability range we modelled before accepting the IIP.

Ofgem have acknowledged the need to adjust for some forms of severe weather and we now consider conditions for other exceptional events should also be defined and excluded from reported performance.

4.2.2.3 Rolling Average Performance

Using rolling averages is another way of dampening the effect of individual year movements in performance, but the overall effect is not necessarily reduced. Indeed, if there is an upper limit on rewards or penalties, rolling averages can increase the impact of an abnormal year. As discussed above, we would prefer to find ways of excluding such events, so that the scheme can work effectively on an annual basis.

4.2.2.4 Weighting of Incentives

We agree that any review of relative weights should be delayed until the customer survey results are known. Even then it will be important to consider the potential value for money from different initiatives before agreeing to any changes.

4.2.3 Targets, incentive rates and financial exposure to the incentive scheme

We have consistently maintained that the current Quality of Supply targets should be retained. We have no evidence that customers would prefer to pay more for a higher quality of service. However we are prepared to review any alternative evidence from Ofgem's customer survey against the costs identified in our mid-January FBPQ submission.

It would be more appropriate for Ofgem to set marginal rewards that reflect customers' valuation of incremental changes in quality and leave companies to identify the most cost effective outcome.

4.2.4 Planned interruptions in final year of the current scheme

The issues outlined in section 4.21 of the consultation arise because of the asymmetrical nature of the current incentive mechanism. Such potential for gaming would be removed once the system became symmetrical.

4.3 Network resilience

We welcome Ofgem's increased interest in resilience. Although it is a complex and multi-dimensional concept, it is important that ways are found to balance the elements of performance, so that good restoration practice can be valued against more robust network arrangements. We have been working along these lines to produce a resilience measure, taking inspiration from the work of the Network Resilience Working Group, and would be pleased to share our thinking with Ofgem. Our comments below draw on our other work and summarise our present views.

4.3.1 Existing incentives relating to network resilience

We agree that the existing incentives under IIP, GS and OS are inadequate to quantify and incentivise resilience as:

- Current IIP and OS metrics relate to average performance not peak storm performance.
- Whilst GS1 has exemptions for storm conditions for justifiable reasons, it does tend to weaken its effect as a resilience incentive.
- Current measures are exclusively backward looking in their assessment of resilience.

It is important to differentiate between network resilience and softer issues such as communication with customers during storm events. The latter, whilst important, is extremely subjective and open to influences beyond the reasonable control of UU, for example, differing customer expectations across the operating area. We believe that customer communications satisfaction is adequately covered by current quality and speed of telephone response measures. It may be appropriate to expand the size of the sample during storm events, but in principle the existing mechanism is quite adequate.

4.3.2 Improving the ability of the network to withstand severe weather

We agree that more work is needed to improve our ability to understand the relative performance of companies. This is partly a question of identifying the differences in circumstances faced by DNOs, and partly about measuring the network's inherent resilience.

We are hopeful that a set of measures can be agreed, but recognise that a second best option might be to define input requirements that would be subject to separate monitoring by Ofgem. However, such an approach would only be effective if there was already acceptance of the network performance characteristics that were being targeted.

4.3.3 Ability of a company to respond to a severe weather event

All networks will sometimes suffer damage, causing loss of supply. In these circumstances speedy restoration is necessary to meet customer expectations. However, we are concerned that too much emphasis could be placed on restoration without considering the inherent strength of the network. A significant weakness of the October 2002 inquiry was that it identified as best practice companies who suffered large numbers of CIs, which they quickly restored. We prefer to see best practice as a combination of robustness against CIs and restoration performance.

We have significant reservations over the proposal to introduce staged percentile restoration targets at 6, 12, 24 hours etc. Percentile targets are fraught with difficulties and perverse incentives. For example these could incentivise companies to turn off automation schemes prior to storms to improve their percentile restoration performance. All such proposals have to be seen in the wider context of the overall incentive framework.

We agree that post storm performance assessment is a valuable discipline and a necessary part of the IIP exclusion mechanism. We disagree that such assessments should underpin the reward/penalty regime. Such assessments are extremely subjective and could discriminate against companies investing to reduce storm CIs.

4.3.4 Management of communications during an event

We broadly support the proposal to allow no storm exclusions from general telephony incentives. These, in our view, already provide adequate incentives for good quality service.

To adequately reflect a company's performance it is however essential to significantly increase the sample size of customer calls for such events.

Again we view ex-post performance assessments as extremely subjective, particularly when linked to numbers of complaints / calls to energywatch and Ofgem. Such referrals are generally reflective of the size and duration of the event rather than how well a company communicates with its consumers. For example, a DNO may accurately communicate with several thousand customers that they will be off supply for 72 hours but this would tend still to result in a large number of complaints to Ofgem.

4.4 Incentives for telephone response

We believe that the current incentive mechanism has been extremely successful in focusing companies' attention on the quality of telephone response. This comparative mechanism has produced an upward shift in mean performance, however we agree that this has now reached a plateau with relative performance differences generally narrowing. From this point, there may be value in moving to an absolute performance target that rewards improvements in performance, whilst not necessarily penalising the lowest scoring company, if they continue to meet customer expectations.

The current mechanism does not adequately reflect the benefits to customers of automated messaging and we would support the incorporation of this element into the survey assessment.

In terms of survey bias, we would agree that companies who have generally low CIs and CMLs tend to do relatively poorly on customer satisfaction. This relationship is in our opinion due to a sampling bias towards longer duration LV faults which form a larger proportion of the CI base of such companies.

4.5 Environmental outputs

We support Ofgem's recognition that environmental outputs should also be subject to value for money testing. However, the results of the customer survey need to be checked against the Government's views on long-term social valuation of environmental improvement.

We suggest that a reward structure based on physical outputs is most appropriate, with companies able to compare the costs of delivering benefits with the valuation identified by Ofgem. This implies no 'target' is set but companies would deliver an efficient level of improvement.

We would be happy to consider a wider extent of environmental reporting if this provided a basis for future investment plans. The costs of additional data collection would have to be considered.

Finally, we note that losses are not mentioned in your discussion of environmental outputs. We are aware of separate correspondence on the refinement of the 'losses incentive', but think it is important to keep this workstream in line with a broader evaluation of incentives in the price control programme.

4.6 Other Issues

We are not aware of any other Quality of Supply issues that require development in the current review. The focus should be on refining the approach to CML and CI and to developing suitable measures of Network Resilience. Across all discussions on Quality of Supply, value for money should be the key. There is no merit in improving levels of service, unless this is consistent with customers' wishes.

5 Distributed Generation

- We believe that more realistic incentive levels are required if targets for distributed generation are to be met.
- The strategic and enabling investment required within our network for DG should be dealt with as part of the main price control, with funding coming from both generators and demand customers.
- The uncertainty and range of costs for DG needs to be recognised more fully.
- Both IFI and RPZs warrant further development work.

5.1 Review of DNO information on distributed generation

Distributed Generation is likely to be a substantial business issue in the years ahead. We are committed to supporting the Government's drive towards a lower carbon future and have been prominent in the work of the EGWG and, more recently, the TSG. We have also made proposals intended to contribute to a more supportive incentive regime that could help ensure that Distribution companies play their part in network transformation.

Against this background, we have been keen to ensure that the historic and forecast information provided in our DGBPQ should present a realistic framework, given the information available to us, and as sound a basis as possible for informing the price control development work. We were pleased that both Ofgem and MM-BPI have acknowledged the thorough approach used in our submission. At our meeting with MM-BPI two particular points emerged during the discussion of this data that deserve re-emphasis here:

- We are not convinced that historical data will be a helpful guide to future costs
- The forecast data is surrounded by inevitable uncertainties, many of them outside the control of the DNOs

In order to deal with the latter point, we developed a number of scenarios to present the potential costs of network development over the period to 2010. Our main concern now is that the summary data published in your current consultation document does not adequately bring out this uncertainty and potential range of costs. We look forward to seeing the more detailed version of this data (Para 5.4 of the Consultation Document).

In particular, we note (Para 56.) that MM-BPI identified unit cost impacts arising from differences between individual DNO design policies and we question how this information is to be used. The derivation of the forecast numbers presented in our BPQ required a certain amount of engineering judgment being applied to determine the extent to which existing "Basic Active Management" techniques, not yet in widespread application, could be used.

The document quotes (Para. 5.20) an average £44/kW cost for reinforcement (including strategic reinforcement), and a range of £10/kW to £90/kW. However it is clear from the Tables that 10% of the projects reported by DNOs have costs greater than £148/kW, up to a maximum of £1113/kW. The average is consistent with the numbers published in the October update document however it is important to note that the DNO has no control over which individual projects actually come forward for connection and that, as shown in Table 5.2, costs rise significantly for the last 20% of capacity, leading to weighted average costs well in excess of £50/kW.

As part of an exercise to identify potential RPZ projects UU has identified a number of specific examples of projects that would, if connected by traditional methods, incur reinforcement costs of £90/kW, £250/kW and £500/kW respectively. The incentive scheme needs to deal appropriately with particularly high cost schemes as all DNOs are exposed to the risk that such schemes will materialise.

Furthermore, with the proposed change in DG connection boundary from "deep" (including all necessary reinforcement) to "shallowish" (where only a proportion of necessary reinforcement is funded through the connection charge), there may well be an upward driver on average reinforcement costs compared with average levels seen at present and this needs to be fully reflected in the proposals.

5.2 Incentive framework for distributed generation

5.2.1 Introduction and Background

We welcome Ofgem's intention to introduce an incentive framework for DNOs in relation to the connection of distributed generation. We have concerns however with regard to the risk/reward profile being proposed and believe that this will be the key determinant of acceptability as details of the scheme, in particular the exact structure of charges, are developed.

In reviewing the current proposals we have kept two main issues in mind:

- In terms of risk, to what extent can DG connections be treated similarly to connections for load customers?
- Is the objective of the incentive simple cost-efficiency, or is the intention for it to be a genuine driver towards growth in DG connections?

It is important to clarify to what extent the purpose is to deliver the higher return needed to reflect the construction/volume risk on all DG assets, or to encourage some speculative infrastructure build to accelerate the prospects of DG development to meet Government targets for renewables and CHP.

This Section 5.2 of our response, dealing with the DG Incentive Framework, takes the following form:

- Consideration of the issues of risk and reward for DG
- Clarification of the distinction between mandatory and discretionary investments

- Highlighting of issues arising out of the detailed charging arrangement
- Proposal for an overall framework for DG incentives

Detailed comments on the DPCR paper, including comments on the proposed values, are contained in the following Section 5.3, "DG Incentive Scheme Parameters". Section 5.4 addresses Ofgem's "Other Issues".

5.2.2 Risk

For a DNO, the risk profile of DG connections is not the same as for load. All connections carry a degree of construction cost risk, in that fixed price quotations are given to customers in advance of the work being carried out, however for load this risk is mitigated to an extent by the volume of connections and the ability to standardize on a range of basic design "building blocks". This is not the case for DG, where by comparison very few connections are carried out annually and individual schemes tend to be highly specific in nature, both geographically and electrically. The risks associated with the connection of distributed generation clearly exceed those associated with "business as usual".

The relatively low numbers of connections, generally of a much more significant size than load connections, also make it extremely difficult to forecast the growth of DG capacity. The external uncertainties that face generation projects (in particular, market economics and the planning process to name but two) represent an additional source of risk that has to be taken into account by a DNO contemplating investment in strategic reinforcement in advance of DG requirements.

We have identified a distinction between reinforcement assets that are required by an individual connection request, and assets that are installed on a discretionary basis by a DNO having a genuine incentive to do so. This distinction is explored further below.

5.2.3 Distinction between Mandatory and Discretionary Investments

The proposals for the structure of charges imply a separation of costs associated with generator connections between shallow assets (to be recovered through connection charges) and deep assets (to be recovered through use of system charges).

Assets that must be provided to meet a statutory request can be considered mandatory. There is an obligation on the Licensee to provide such assets and the allowed return needs to be sufficient to allow an efficient DNO to finance its activities. We welcome Ofgem's acknowledgement that for the connection of distributed generation it may be appropriate to allow a higher rate of return than for the generality of assets used to service demand customers.

It is also possible to envisage a further categorisation, which incorporates discretionary investments that would facilitate future connections. Under the current proposals, such investments would only obtain their full potential rate of return if the asset were fully utilised by connecting DG. Assets that must be provided to meet a statutory connections request do not need to be subject to the same challenge.

Where investments are discretionary they must compete for funding with other projects available to the DNO. In these cases the internal investment approvals process will consider the balance between risk and reward compared with other discretionary projects. Given the practical limitations on capital availability this will require a higher 'hurdle rate' than that assumed for 'statutory work'. This is discussed further under "Reward" below.

5.2.4 Reward

We agree in principle with the statement in Para 5.16 that: "DNOs…on average can earn a return which is more than their allowed cost of capital for other investments – but which is not excessive", and with the overall objectives set out in this paragraph, however we suspect that the assumed definition of "excessive" return takes insufficient account of the risks involved in such investments.

In considering the reward available to DNOs, it appears that the premise underlying the current proposals is contained in paragraph 5.17 of the document, which states, "In terms of the incentives towards efficiency, the general capex incentive allows DNOs typically to retain about 40% of any reduction in capex". It is important to note that this statement relates to the current arrangements where the potential for capex efficiency exists through unit cost reduction or by the DNO finding alternative solutions in what is essentially a high volume activity. The risk mitigation which exists in "business as usual" is not available in the DG activity and thus a 100% pass through into the RAB, earning the Weighted Annual Cost of Capital, represents, at best, a position of simple cost recovery.

Ofgem have suggested that it might be appropriate to allow a premium rate of return on distributed generation related investments. One level of premium could be justified by the increased construction risk resulting from the one-off nature of such projects, coupled with a traditional approach to connection charging that sees charges set on the basis of estimated costs, before the work is done. This gives price certainty to the customer base, but leaves the cost risk with the company.

It is on this basis that we have previously suggested that the hybrid scheme could be interpreted as 100% pass through at the standard cost of capital, plus a £/kW (or p/kWh) allowance to provide an incentive for action. If alternative schemes providing for partial pass through are to be constructed then the cost risk being taken by the DNO, which is clearly significant at this stage in the development of DG, needs to be offset by commensurate levels of reward.

The level of risk and reward associated with discretionary strategic investments merits separate consideration. As identified in 5.2.3, above, discretionary investments will have to compete for funding with other projects. In order even to be considered, any project would be modelled against a range of planning scenarios and would have to be projected to deliver in its base case a rate of return at least equal to a pre-defined "hurdle rate". This would be a first step in the approval process, the project still being required to compete, on the basis of its risk/reward profile, with other investment opportunities.

5.2.5 Structure of Charges

The detailed payment arrangements under the incentive scheme will have a strong bearing on the risks faced by the DNO. The impact of this could be mitigated if the roll forward of actual capex into the RAB worked separately for DG related assets, rather than being combined with other investment spend, (where the incentives would encourage companies to beat the capex forecast used for price setting). If DG overspend offset this effect, companies would not be able to retain the legitimate benefits of capex efficiencies.

In commenting on the proposals our working assumption has been that the current RAB approach would be adapted for DG such that the pass through proportion would be accommodated by means of an *ex post* adjustment to a rolling RAB, and the £/kW portion would be funded by UOS levied on the generator community as a whole. We envisage a rolling sum of DG MW whereby the MW should be "counted" for the incentive arrangements at the point of signing the generator connection agreement. Once counted for the incentive arrangements, the MW should stay for the full 15 years, irrespective of the continuation of the actual generation schemes. Otherwise, DNOs could be left with stranded assets having a risk exposure similar to that affecting new generation schemes, and for which the cost of capital would need to be such as to provide the DNO with the expected returns that a generation project would earn for its owner.

Variations around this basic arrangement are possible, particularly when considering the distinction between Statutory Requests and Discretionary Investments where in the latter case our suggestion would be the *ex ante* approval of schemes and RAB allowances (see 5.2.6 below). Similarly, it is not clear at this stage in the Structure of Charges consultation process exactly what costs will appear in GDUOS and how it will be charged. In considering this, it should be noted that arrangements that rely on continuing payments being derived from individual generators would carry significantly more risk for the DNO than a general GDUOS based on charging the generator community as a whole (or charged through the supplier hub principle).

The spreading of DG costs is a significant issue at this stage of the development of DG, not only between individual generators but also on a GB basis. We understand that this latter point is an issue for ministers rather than Ofgem, but simply note here that charging arrangements should be sufficiently transparent to allow for the segregation of the excess costs of DG by individual DNOs.

5.2.6 UU Framework Proposal

The following summarises the structure proposed by UU:

a) **Shallow connection assets –** Costs would normally be recovered through connection charges. Connection charge policy should reflect the greater risks through the target margins on estimated cost.

b) **Deep connection assets –** Costs recovered through use of system charges. Allowed income should be based on:

- Estimated costs enter the RAB at the standard cost of capital
- Rolling RAB adjustment treats DG related assets separately
- The enhanced return is provided via a £/kW supplement

- The £/kW is paid over a guaranteed life
- The £/kW is funded from GDUOS levied across all generators
- The £/kW could be converted to a p/kWh allowance, where the kWh are based on network (export) capacity by half hour (see 5.4.3 below).

c) **Strategic developments** – For major infrastructure projects (typically at EHV) that involve substantial investment not linked to an individual generation scheme, a separate process for ex-ante individual project approval should be adopted, with asset values moving into the RAB in the manner suggested in (b). However, such projects would be pre-authorised by Ofgem, and may also need to be allowed a higher rate of return to be consistent with Ofgem's policy proposals, and to reflect their discretionary nature and the construction cost risk.

d) **Strategic developments (*alternative*)** – Arrangements to be similar to those for Deep Connection (Statutory Requests) except that a different risk/reward profile would apply (see comments on Average and Minimum Rates of Return, below).

Appropriate values for Pass Through Proportion, Incentive Rate and other parameters to use within this framework are discussed under "5.3 Incentive Scheme Parameters", below.

5.3 Incentive Scheme Parameters

(With paragraph references to the Ofgem document)

5.3.1 Regulatory Asset Life

Para 5.22. The scheme life is designed as 15 years, based on the assumed regulatory life of the DG connection. DNO income would be dependent on the life of the DG itself unless this risk is removed by adopting a fixed recovery period from the generator (or customer) community rather than from individual generators, as suggested in our Framework Proposal. We also suggest that this period should commence from the network capacity being made available rather than the generator physically connecting. If recovery is from individual generators (or from a tariff capped generator community) then the risk of late or non-connection/early termination should be offset by the use of a shorter regulatory life.

5.3.2 Pass Through Proportion

Para 5.24. We have identified above that the incentive scheme should be based on 100% pass through supported by a £/kW supplementary risk premium/incentive. We accept in principle that it would be possible to lower the pass through rate in exchange for an enhanced supplement, however this must consist of a £/kW driver of sufficient magnitude and certainty to offset the associated cost risk and provide an appropriate incentive for action. We note here that schemes having lower pass through proportions are the most susceptible to generator related risks. Although some of these can be dealt with directly, as described in our comment on Regulatory Asset Life, 5.3.1, there still needs to be proper recognition of the residual risk left with the DNO.

Para 5.25 – 26. Ofgem's calculations indicate that on an annuitised basis, the minimum guaranteed rates of return from the proposed approach (i.e. if no MW connect) are 1.4% and 3.2% for options A and B respectively. However, as the cash flow from an investment in the RAB has a declining profile over the years, the actual rates of return that would be seen through the pass-through element are lower than this. Even ignoring this effect, the rates of return indicated under this scenario would be totally unacceptable to UU; we would not enter discretionary projects with this rate of return, nor would we accept being required to invest at this rate to satisfy statutory requests.

5.3.3 Incentive Rate

Para 5.28. We support the pragmatic approach of designing a scheme based on a uniform national £/kW rate. We had concluded independently that attempting to design individual schemes for each technology would be hugely complex and also involve increased risks since there would be a reduction in the averaging effects which arise out of dealing with a wider range of connection types (i.e. the sum of the risks of several different schemes would be greater than the aggregate contained in one overall scheme).

5.3.4 Benchmark cost

Para 5.19 – 21 and Tables. We have already expressed our concerns regarding the use of average costs in deriving the benchmark cost ("typical DNO all-in costs", Para 5.29) and suggest that this only gives an indication of the order of magnitude of costs faced by individual DNOs, bearing in mind the high variability of costs identified by MM-BPI (Para 5.18). In particular we have identified the significant risk of high cost projects being required - the Tables showing that 10% of the projects reported by DNOs have costs greater than £148/kW, up to a maximum of £1113/kW. We have also identified an upward pressure on these costs as the DG connection boundary moves from "deep" to "shallowish". We suggest below that an appropriate way of dealing with particularly high cost schemes would be the application of a suitable 'floor' on the rate of return achievable.

Para 5.29. Our further concerns relate to the direct application of average costs in setting the benchmark for the scheme. If the incentive scheme is to be successful in bringing forward sufficient schemes to meet the Government's targets then the benchmark should be set on the basis of the incremental costs of the last project required in order for the total MW to just meet the targets.

To meet the targets will require approximately 3GW CHP[1] and 10.5GW[2] wind-equivalent renewables generation. Table 5.2 suggests that applying a benchmark of around the DNO average will bring forward around 80% of available schemes. This represents about 7-8GW (based on the October update document). It appears from this analysis that the targets would only be met if 100% of the recently announced 7GW of Round 2 offshore wind (almost certain to be grid connected) were connected by 2010. Bearing in mind the uncertainties with regard to offshore suggests that a greater contribution will be required from DNO connections, implying the use of a higher benchmark cost.

5.3.5 Average Rate of Return

Para 5.29. The distinction between mandatory work and discretionary work is highly relevant to the determination of both average and minimum rates of return. In the case of discretionary investment, projects will only be contemplated if they can deliver a return that meets individual company hurdle rates. The extents to which such projects are exposed to generator development and construction cost risks would have a bearing on the appropriate rate of return.

We note here that the approach used for Transco's new capacity sales allows a maximum return of three times the standard cost of capital (and a floor of 1% below the WACC), however this is applied in a field of activity which is far less disaggregated than DG development, and therefore less risky to predict.

For mandatory work, the focus is more upon the minimum rate of return, and our view of the average return would be dependent upon the existence of an appropriate minimum rate of return to provide a risk "floor".

5.3.6 Minimum Rate of Return

Para 5.29. One criterion for deriving the incentive rate is suggested to be that a project costing £120/kW should earn not less than 5%. For discretionary investments, a minimum rate of return of 1% below the WACC would be consistent with the Transco arrangement but it needs to be applied in all circumstances i.e. also at costs greater than £120/kW.

For investments that we are required to make under statute, it is difficult to see why DNOs should be exposed to returns representing less than cost recovery. This implies a "floor" equal to the WACC, applied either on an overall basis or at least to all costs up to the level reported by DNOs (which for UU is of the order of £500/kW).

5.3.7 Operating and Maintenance Costs

Para. 5.33. The suggestion of a simple £/kW payment leaves the DNO with a risk of under recovery on the more expensive projects (e.g. a long length of new overhead line for a wind project). Consideration needs to be given to including at least a proportion of these costs within the pass-through element.

[1] Based on 7.5GW – 8 GW in 2010. Less than the 10GW target but consistent with most recent DTI expectations.

[2] Assumed 30% load factor, generating 27.5TWh, equivalent to the shortfall between renewables generated units in 2003 and the 10.4% 2010 target. In practice, this could be delivered by 8.5GW wind plus 1GW of other renewables having an average load factor of 60%.

5.4 DG Incentive Framework – Ofgem's "Other Issues" (Para 5.34)

5.4.1 Strategic investments

Strategic Investment – Our proposal is that Strategic investment to facilitate the connection of DG generally and not associated with specific DG connections should be taken out of the incentive mechanism, be subject to ex ante approval, and be funded through the main price control settlement (i.e. subject to 100% pass-through).

If an incentive approach were to be pursued for this area of investment it would require a significantly enhanced reward profile, of more than three times the weighted average cost of capital, and with a floor no lower than 1% below WACC.

5.4.2 Choice of risk/reward package

Considering the differing requirements of the 14 DNOs we think it is entirely appropriate for there to be an option for each to pick the most appropriate risk/reward package. We suggest that there could be further flexibility, with the £/kW incentive being determined, within constraints, by an agreed methodology from a chosen pass through proportion.

5.4.3 Ongoing network access

We support the extension of the incentive design to not only encourage the provision of deep connection assets but also to support the ongoing production environment of new generators. We do not, however, support the setting up of compensation schemes with individual generators. Our proposal is that the supplementary driver should be adapted to reward the availability of export capacity, as follows:

- Form of incentive – the essence of the scheme is to reward availability on the basis of a target and a marginal p/kWh rate (based on the capacity provided for generators with the hours of availability). This scheme has the flexibility to set the p/kWh rate at a level to give an appropriate incentive at the margin, thus avoiding the issue of very low marginal reward rates.
- Value of incentive – The maximum return would be available to a company providing 98% availability, together with sliding scale down to an availability threshold of 90%.
- Possible calculation mechanism – In a manner similar to the IIP, this approach would rely on system outage data from DNOs, not on metered volumes.

5.4.4 Interaction with other incentive schemes

We have consistently argued to date that DG will bring marginal benefits and disbenefits to both losses and quality and security of supply. As such we believe the overall effect will be neutral and we have no further information that would lead us to take a different view.

5.5 Innovation Funding Incentive

We also doubt whether the current low level of R&D in DNOs is appropriate or sustainable, and agree that as a starting point, 0.5% of turnover does not seem unreasonable. It is the nature of R&D that simple measures of outturn effectiveness are not readily identifiable and that given the long-term nature of much R&D work, there is considerable pressure to minimize such Opex costs year on year. A constant erosion of R&D investment is inevitable under a pure RPI-X form of regulation. Although such regulation will incentivise the subset of R&D that leads to direct cost savings for the DNO, and where the payback is sufficiently close (ie within the current price control or possibly the next), it will not provide any incentive for R&D in areas which might directly reduce costs to customers without clear savings to the DNO.

We have many examples of R&D where specific short-term developments are undertaken with the expectation of significant costs savings accruing, again in the short term. For example in the last few years we have

- redesigned our LV joints to support single man working;
- introduced our current OH line management approach;
- designed and implemented our own 33kV gas cable joint;
- introduced a new standard 33kV jointing system;
- introduced new 11kV cables and jointing systems.

These initiatives vary in the content and balance of research and development that each contain, but all have associated business cases that deliver recognized paybacks in relatively short timescales.

To underline that this is not a complete or sufficient approach, consider the establishment of our Condition Based Risk Management approach to asset replacement that is explained in our FBPQ submission, particularly Section 22. Our ability to apply these techniques, and thereby save tens or even hundreds of millions of pounds from an age-based asset replacement programme is founded on collaborative industry R&D in areas such as partial discharge and oil condition assessment that go back 25 years. Yet it is only now that these techniques are mature enough to apply at a programme level to our investment needs. Customers will directly benefit in Xd4, and beyond, from the investments that they have indirectly funded over the last twenty-five years. The current necessary approach to R&D support in DNOs is not providing any input in to such long term research aimed at understanding the fundamental physics and engineering aspects of the asset base. Similarly R&D associated with network/system development is also grounded in attacking immediate cost pressures.

Both the above R&D development trajectories (i.e. business led specific development), or more diffuse R&D coalescing into a coherent cost reduction (or performance improvement) strategy, provide considerable benefits to customers in the long term through reduced future prices.

In common with other industry commentators we believe that the challenges to network design and operation philosophy for the medium to long term are immense. The growth of large numbers of distributed generators at domestic level will probably be unspectacular in the short term, but longer term will make for a very inefficient energy system unless its presence is fully integrated and all the value released. Ofgem will be aware of the difficulty that TSG WS5 is having in recruiting DNO (and other) experts to contribute to its projects. It is particularly striking that there was so little engagement from DNOs. UU believes that this is due to DNOs having very few engineers committed to thinking about any future issues beyond 2010, and all such resources are already fully committed. To us this is a clear argument that the Government should be concerned about R&D in DNOs. We are grateful to Ofgem for raising the profile of this issue.

You will be aware that UU is an enthusiastic collaborator in the EATL Strategic Technology Programme, which itself is a mixture of research and development projects, although with the accent on development. Again our collaboration and funding is under constant pressure and scrutiny, and EATL are increasingly focussing their work and attention on projects that give pay offs in the immediate future, or are reactive to current issues and pressures in the industry. Recent successful projects that illustrate this are:

- cable fault sniffer;
- designs for pole top switchgear earthing arrangements;
- removal of oil from redundant oil-filled cables;
- sludging of oil in switchgear (UU did not have the problem affecting the rest of the DNOs).

What EATL are not doing, because the DNOs are not funding this, is to do research where the paybacks are not likely to be within a few years at most. There are some exceptions- for example aspects of Module 5 of the STP (Distributed Generation) does have some projects for which there is no immediate prospect of application, but DNOs are happy to fund this at low level for the time being, in anticipation of DG growth, and future need. Clearly if R&D is squeezed, then in comparison to the current business related projects, these will be starved of funds or wound up.

We still therefore believe that IFI funding should be 100%. To put this in context: the Government policy on renewables indicates that by 2010, 10% of units will be accompanied by a £0.03 subsidy per unit (ROCs). We estimate this, in broad terms, to be about £1 billion per annum, or about £40 per customer per annum. The annual costs of IFI will be about £14M for GB, or about 50p per customer per annum. We make further observations on costs and benefits in our comments on developing the RPZ and IFI RIAs in Section 8 below.

A final point on the IFI proposals is that whilst we agree that DNOs will generally be active in the Development phase (with reference to the diagram on p5 of Ofgem's Innovation and RPZ Discussion Paper – July 2003), we believe that there is a role, albeit a much smaller one, for DNOs to be able to develop ideas, or have sufficient funds to find a research partner, that clearly lie in the Research part of the model. We are not arguing for this to be a significant part of DNOs' work, and we agree with your central argument that DNOs should be involved in development and demonstration phases. Nevertheless many good ideas are likely to be developed by DNOs, particularly as the challenges of DG roll forward into the DNOs, and DNOs need to be able to develop the capability of nurturing some of these ideas until their true potential can be seen.

Returning to the questions in your consultation paper, we believe that the checks and balances proposed, i.e. Annual Reports and scrutiny as part of ARM will enable Ofgem to ensure that the overall R&D programme worked by DNOs delivers all the benefits that could reasonably be expected.

UU has already indicated its current view of what R&D is required in the Xd4 period, in Section 33.4 of the FBPQ and Section 7.13.2 of the DG BPQ. The extent to which any of this programme is fulfilled does depend on funding, or perceptions of funding, in the price control settlement. If it is UU's perception that the funding available for R&D is less than 100%, or there are other irresistible pressures on Opex, then hard choices will need to be made about which parts of the intended programme have to be dropped.

5.6 Registered Power Zones

We remain supportive of the RPZ concept. We believe that it should be a simple transparent mechanism for helping DNOs overcome all the challenges of bringing new ideas into use. We explore some of the costs and benefits in Section 8 below where we comment on the draft RIA. We have a concern that the incentive rate as described in the consultation paper might be too low to be effective, particularly for any initiatives on the LV system to help DCHP or PV, where the costs per MW are high.

On this last point we hold the view, shared with some other wider industry participants, that the opportunities (and challenges) of the mass deployment of truly distributed technologies, such as DCHP, will be the most significant in the long term. We therefore believe that a significant effort will need to be made in R&D to release the full potential of these technologies, particularly in displacing the security services obtained from central generation currently, and to improve on the current security provided by networks. We do not see these as short-term issues, but we do believe that significant development effort needs to be committed in the near term to start to develop the network transformation strategies. This issue reaches right across the industry and needs wide industry participation and support. Incentives to participate that are based on MW are likely to be unattractive as the absolute level of MW involved is small.

We strongly support the simplicity of a single RPZ award scheme, with no subdivisions. We believe that it is appropriate to have an Ofgem administered peer review RPZ award process. Without peer review it will be hard to determine the novelty of an RPZ application. Having said this, we believe there is merit in awarding RPZs on a unique-per-company basis; i.e. if one DNO has implemented a novel technique, we believe that other DNOs should still be incentivised to follow, as there will be DNO specific issues to overcome in every case. This is probably an important point in helping to incentivise DG growth across all DNOs.

We believe that there is one other aspect of RPZs where your proposals are incomplete. There will be instances in most networks where a generator already exists, and the opportunity will arise to make use of that generator to provide system support or to otherwise interact with demand in novel ways. As currently envisaged, this instance could not be registered as an RPZ as there are no additional MW being connected to provide the RPZ income driver. We believe in this case that it would be appropriate to declare an RPZ and that the value of deferred or avoided reinforcement capacity could be the RPZ income driver.

We imagine that a subgroup of the TSG could fulfil this function in the short term, with appropriate steps in place to avoid conflict of interest of DNO or developer TSG members.

6 Assessing costs

- We support the work so far to establish a consistent and comparable data set from which to assess companies' efficiencies. This work needs to be completed as an urgent priority.
- Quality of supply, total cost, and the effects of mergers must be taken into account in comparing efficiency.
- The uncertainties in any 'top-down' analysis are substantial. It is therefore unlikely that it can be disproved that all companies are approximately equally efficient.
- A report by Horton 4 Consulting, which reviews CEPAs TFP work, notes that there are no grounds to expect DNO TFP growth to be much higher than for the economy as a whole.

6.1 Overall approach to assessing costs

The work on cost assessment is the most important aspect of the Price Control Review. It will underpin the review of performance in the current period and provide the basis from which to project future revenue requirements.

We are pleased with the approach Ofgem has taken to this work, and support the continued emphasis on transparency, consistency and comparability. However, we remain concerned by the amount of work that still has to be done and the slow pace of progress in establishing a consistent data set for analysis.

6.2 Cost Normalisation

We share the common view on the importance of data normalisation. Comparison of performance can only be meaningful if the data used has been prepared on a consistent basis. Ofgem's work in this area is now well defined but we do have significant concerns over the timetable for completion. The process has already taken longer than we would have hoped and there remain a large number of issues to resolve. We have every intention of keeping to Ofgem's timetable, but we recognise the risk that the project will be unsuccessful unless all companies deliver in a timely manner.

Whilst we understand the argument that a more disaggregated approach should make it easier to identify cases of potential inconsistency, we remain to be convinced that the resulting data will improve the comparisons that can be made. We still suspect that comparisons will need to be made at a more aggregated level.

6.3 Review of Actual Costs

It is helpful to be able to begin to review cost performance data for the early years of the current price control period. Companies have generally outperformed the cost allowances, but it is worth noting that the likelihood of additional, unforeseen costs increases as we move further from the date when the cost estimates were made. This can be seen particularly in respect of pension and ESQCR obligations that add to our forecast costs in 2003/04 and 2004/05. We expect all companies to show a similar profile of outperformance across the five years.

6.4 Review of Forecast Costs

We welcome Ofgem's intention to take more account of companies' cost forecasts. We appreciate the need for some form of validation, based on the modelling techniques proposed, but we expect our estimates to be used as the basis of revenue allowances so long as they fall within reasonable bounds.

6.5 Bottom-up Modelling

Our approach to cost modelling has tended to be bottom-up, based on our own experiences and the likely changes in costs and procedures that we envisage. We hope that any models that Ofgem develop will be based on the tools used by DNOs. In particular, the models must be sophisticated enough to pick up inter-company variations (such as the impact on fault repair costs of asset age and type, or the effect of a condition-based approach to maintenance planning).

Models should be used to validate normalised activity costs and will therefore need to operate with adjusted data provided by all companies.

6.6 Top-down Analysis

It was helpful for Ofgem to confirm that the role of the CEPA report on benchmarking was only to initiate debate. From that perspective, we believe it has been very successful and some of its provocative conclusions have usefully encouraged debate on a more considered way forward.

6.6.1 Key Principles

We agree with the principles identified in 6.45, but suggest that these need to be supplemented with a principle concerning rigour or robustness of conclusions. This could be an alternative interpretation of "explanatory" but we believe it implies a different approach to the "intuitively correct" criterion you have identified.

It was also important to acknowledge the use to which the benchmarking analysis will be put. In predictive mode it is presumably intended to identify the range of cost estimates that could reasonably be expected from a DNO with particular underlying characteristics. Such a probabilistic approach is consistent with the desire to validate the reasonableness of a company's own forecasts.

6.6.2 Cost Categories

We have previously expressed concern over the potential design of a hypothetical DNO from the separate benchmarking of a number of cost elements. This would be less appropriate if the models were used only for validation purposes. We agree that Ofgem should explore the benchmarking of a number of cost categories and seek to identify those with the greatest predictive capability. Subject to the agreement of an appropriate definition of capital consumption, we would expect a measure of total cost to be the most helpful.

6.6.3 Benchmarking Techniques

We are pleased that Ofgem remain open-minded on the techniques to be used. As we explained in our response to the original CEPA paper, we think it is premature to determine the analytical tools before we can see their effectiveness on a reasonably reliable data set. We have provided you with a copy of independent expert advice we have received on the CEPA report. This confirms the difficulties that are likely in opting for any particular approach to benchmarking. We believe these difficulties can be mitigated by your intention to use the output to validate, rather than set, cost estimates. We continue to favour an approach that concentrates on the 8 management teams rather than the 14 licensees although we appreciate that you will eventually have to calculate allowed revenue on an individual licence basis.

6.6.4 Frontier or Average Benchmark

We had understood that one of the few unanimous conclusions from last year's workshop with CEPA on benchmarking was a clear preference for average benchmarks. Frontiers are inherently unreliable, especially when drawn from such a small data set. In any event, we find it difficult to understand how a frontier approach fits with the general intention to use company forecasts where possible.

6.6.5 Total Cost Analysis

We are pleased that Ofgem intend to continue exploring the use of total cost analysis. Within that approach we agree that different measures of capital should be considered. We would prefer to see a measure of capital consumption added to operating expenditure, but recognise that this may compound the growing problems in normalisation.

6.6.6 International and Panel Data

We do not believe that the additional use of either international or panel data is likely to be robust in the current review. If such an approach is to be adopted in future, an early start must be made to understand the normalisation and comparability questions so that data would be immediately useful in the price control review.

6.6.7 Inclusion of Quality of Supply

We have explained before the importance of including quality of supply in any comparison. This can be looked at from two perspectives. What matters to customers is overall value for money. It is this which should be benchmarked. Yet such an approach is impossible without recognising the variations in service levels delivered by DNOs.

The second approach is to acknowledge that quality costs money, and it is therefore meaningless to compare companies' cost performance without allowing for variations in service levels.

We have suggested ways of doing this that use Ofgem's own valuation of marginal changes in service (as defined in IIP). It would be useful to consider how different adjustments might be, if they were instead derived from the customer willingness to pay identified in the current survey being undertaken by Accent.

6.7 Productivity Growth

We have commissioned a report by Horton4 Consulting on CEPA's report on Total Factor Productivity (TFP). This is included as Appendix 3. It concludes that CEPA's central estimate is not reliable because of judgements made in reaching the conclusions from the evidence. It also concludes that there are no grounds to expect DNO TFP growth to be much higher than for the economy as a whole. We would like to discuss the attached report with Ofgem and CEPA in some detail. We understand that the March meeting of the Cost Assessment Working Group will give companies the opportunity to discuss the next steps following the CEPA report on TFP.

6.8 Mergers

We strongly support the consideration of merger effects in any cost assessment. It is clear from Ofgem's own work that mergers of DNO's release cost savings that are not available from other corporate transactions. These were estimated to have a maximum value of £12.5m, but that it might take 5 years for new organisations to bed down delivering that level of savings.

We agree that other merger benefits are available to all companies and should rightly be revealed through benchmarking. However a specific adjustment (to put all licensees on an even footing) is necessary unless all benchmarking is done on an '8 management team' basis. We had hoped that the use of accepted Ofgem numbers (£2.5m pa up to 5 years) would have been a non-controversial approach, which probably underestimates the true effect.

There is then a separate question as to how future revenues should be set. For this purpose any adjustments made to allow the comparative efficiency analysis to be fairly undertaken must be reversed out. In addition the price attached to the loss of a comparator should also be levied to ensure customers' gains are sustained in the long run.

6.9 RAV Roll forward

We see the debate on RAV roll forward as an important demonstration of regulatory consistency. We believe we have correctly applied an approach to regulatory accounting consistent with the price control assumptions made in 1998/9. It is imperative that other DNOs are equally consistent, both to avoid customers paying twice for the same costs and to ensure any benchmarking is genuinely comparative. We are confident that Ofgem will pursue this issue to an appropriate conclusion.

7 Financial Issues

- We agree with Ofgem's high-level principles on pensions. However, the retrospective application of these price controls principles to previous price review periods, is an area of considerable concern. The most important issue is to ensure that adequate funding is provided for the future.
- The existing financial ring-fence is sufficiently robust.
- We support a post-tax approach to the cost of capital, reflecting individual companies' circumstances.
- The work to complete the financial model should be accelerated since it is an integral part of the process to ensure that all work streams in the review are completed on a timely basis.
- We expect early confirmation of the financial indicators to be used to test financeability. These must be consistent with being comfortably within investment grade credit rating.

7.1 The financial ring-fence

We can see no reason to further strengthen the ring fence for DNOs. The current arrangements are already more onerous than those we face in our water business (where concerns over the flight of equity have been greater). The changes discussed in your paper appear unnecessarily intrusive and have the potential to create additional uncertainty.

We believe that any ring fence must be very clearly defined and not require subjective interpretation. It would be a retrograde step to modify the licence condition in a way that removes some of the clarity that exists at present.

7.2 The cost of capital

We have commissioned independent advice on this important area and we will present these findings to Ofgem on the level that should be assumed for the cost of capital when these reports are available. It is crucial that Ofgem ensures that an adequate cost of equity and debt is reflected in the assumed cost of capital.

We strongly support the use of a post-tax methodology at the price review, using an allowed return based on a post-tax cost of capital. This requires the calculation of a post-tax cost of capital that is the weighted average of a pre-tax cost of debt and post-tax cost of equity. The allowed return used in the financial model should be set at a figure of at least this value.

Future projected effective tax rates of the DNOs will vary on a company-by-company basis. To ensure that the tax allowance provides companies with sufficient cash flow to cover their expected tax liabilities, we believe that Ofgem should forecast an allowance for tax liabilities by estimating the specific tax liabilities of each company. This approach has the benefit of treating tax costs to the DNO in the same way as any operating cost impacting on the business.

A pre-tax calculation of the cost of capital provides an inappropriate incentive for companies to adopt highly geared capital structures, creating a significant risk of systemic financial instability in the industry. We therefore strongly recommend that Ofgem should calculate the cost of capital on a post-tax basis.

Market evidence of the costs of equity and debt indicates that the overall weighted average cost of capital has increased since the last price review.

The allowed returns used in the price control should be at a sufficient level that recognises the need for equity funding over the next review period as capex requirements increase. This can be achieved by an explicit allowance or premium in the cost of equity to cover new equity issuance costs. UU is committed to a business model that uses a mix of debt and equity funding. This is evident from the group's plans to raise up to approximately £1 billion more equity through a two-part rights issue to fund the significant investment in its regulated businesses. We recognise the importance of the conventional equity model in ensuring that shareholders, not customers, bear an appropriate proportion of risks of infrastructure failure. This requires an adequate equity buffer. The success of the second tranche of the rights issue requires an allowed return for equity investors that is judged sufficient by the equity markets.

The cost of capital cannot be considered in isolation from other practical funding requirements of the DNO, e.g. it needs to allow for issuing/hedging costs incurred when raising new borrowings in the cost of debt.

There are regulatory precedents at the last price review that made an appropriate allowance for the cost of embedded debt. The extra financing cost of this debt should be fully funded in the price control if the debt was fixed at a higher rate in the past than the projected floating rate assumed model for the future. The cost of debt needs to be consistent with the assumed interest rate used in the financial model. In the case of UU these extra costs relate to unique legacy decisions taken several years ago and are unavoidable sunken costs impacting on the business. The allowed cost of debt needs to be consistent with the assumed interest rate used in the financial model.

7.3 Financial model

We welcome Ofgem's initiative to consult on the financial model as a further way of increasing the transparency of the review. This process has been aided by Ofgem sharing their financial model at the appropriate stages. We have set out in this response our detailed comments so far on the model, which we have already sent to Ofgem. In addition to these comments we would like to make the following overall points:

- The financial model will be dependent to some extent on several policy issues discussed in the December update and expected to be resolved in the March Policy Statement. As the methodology to set revenue in the review is finalised then the financial model will need to be reviewed to take account of these policy decisions.
- The above process needs to be planned for each key aspect of the model so that the policy, methodology and data gathering work streams can identify and prioritise those areas of work as soon as possible.

- Because of the importance of the effectiveness of the model to the overall price review, we strongly advise that the model should be independently audited before the final version is released to give comfort on the reliability of the results.

We have a number of comments on the latest published version of the financial model, which we have tested against our own internal model. In summary our main concerns are as follows:

- The calculation of tax. There is a significant shortfall in the calculation of tax post 2005, which is an increasingly important issue.
- The method of calculating the post-tax building blocks.
- There are crude demand assumptions in the Ofgem model. These have been oversimplified and may lead to errors in the revenue calculations.
- The conversion of required revenues into annual price limits.
- Errors in the model logic.

Some of these issues are technical and we have therefore included more comprehensive details in Appendix 2.

There are indications in this consultation of the financial ratios Ofgem intend to use at the price review. However, these have not yet been built into the model and it is important that companies are able to comment on these in the context of the financial model as soon as possible.

It would be helpful if there is a clear audit trail showing changes to the company submissions in the financial model leading to the determination. This will aid transparency and help companies replicate the modelling results at each stage of the process.

We look forward to working with Ofgem in improving the robustness of the model.

7.4 Financial indicators

The final outcome of the price control review must be a level of allowed revenue that is consistent with a fully financeable business plan. This is not just a matter of satisfying us, but more importantly, involves satisfying the providers of the finance that will be essential to support our combined investment and operation.

Companies should be able to raise finance not only from debt, but also from the equity markets, since otherwise there will be a trend away from conventional equity structures, which we consider to be undesirable as this increases the risk that customers bear.

Financial ratios are likely to be a more important issue in this review than they have been previously as we expect a significant increase in required investment. Allowed revenue needs to be set at a level that meets Ofgem's target of "comfortably within investment grade". This is commensurate with financial indicators supporting a credit rating comfortably within Moody's A3 as a minimum. An appropriate credit rating is a key factor to enable us to ensure stability, provide a buffer for cost shocks and ultimately ensure we are able to finance our functions. Furthermore, prospects of future downgrades make it difficult to raise debt without a significant increase in cost, so we need stable ratings to ensure adequate funding is available at reasonable rates.

It is extremely important that Ofgem obtains independent evidence on issues affecting debt and equity funding by talking to investors and rating agencies to seek their views.

The main points we would raise in this respect are:

- The importance of cash-based indicators. Our understanding is that agencies now consider cash based indicators and RAV based gearing rather than book gearing.
- UU has a credit status and raises finance based on its actual balance sheet. Any assumed adjustment to the balance sheet by Ofgem may mean that UU would be unable to finance its functions in the manner assumed by Ofgem.

Credit rating agencies use cash based indicators and it is helpful that Ofgem has recognised the important of these measures in assessing ratings. We focus on three key measures to demonstrate a solid investment grade. These are:

- FFO interest cover
- RCF/Net Debt
- RAV based gearing

To maintain a financeable plan may require the injection of an appropriate level of new equity funding consistent with the level of additional capex required. We do not consider that repex is an appropriate way to bridge any cashflow shortfalls, since it can put an undue burden on 'today's customers', and by reducing the RAV, has an adverse effect on a company's future ability to raise funds and to cope with cost shocks.

An increase in cost of capital may be required to ensure that the lower limits of financial indicators consistent with an A3 credit rating can be maintained, both on average over the 2005-10 period and towards the end of the plan period. The trend is also important as a downward trend may also lead to a credit rating downgrade. We believe this is consistent with the approach used by credit rating agencies.

7.5 Treatment of pension costs

Whilst we recognise the need to close down discussion on the principles in order to advance the detailed implementation, it is disappointing that there has been no formal response to the arguments presented in our submission on behalf of the ENA in November 2003.

From a UU perspective, we confirm our support for the principles you have identified, but we recognise that in your guidelines there is considerable scope for interpretation in applying those principles in practice. Our key concern remains the threat of retrospective re-examination of previous price review periods.

The recent data gathering exercise indicated the difficulty in gathering the necessary historical data to apply the principles set out. All parties will have to accept the inevitable use of some estimation in order to deliver the intent behind the principles.

7.5.1 Methodology statement

We welcome the additional details provided on the practical application of Ofgem's suggested approach, and particularly the clarity on the allowances for affiliates and related undertakings. We also support the proposal that, once an allowance has been set, the price control should not be modified to reflect the pension fund valuation in 2007 unless the variation exceeds a predefined threshold. We return to the adjustments identified in 7.73 in the sections below.

7.5.2 Allocation between price-controlled and non-price-controlled activities

We agree, in principle, with the proposal to split the assets and liabilities of pension schemes between businesses, in a way which reflects historical employment patterns. However it is also necessary to acknowledge the data limitations which affect the detailed approach that can be used.

For pre-privatisation leavers we do not have the detailed records to allow us to follow precisely this methodology and welcome Ofgem's willingness to accept a pragmatic approach based on broader employment cost records.

For post-privatisation leavers we still have difficulties in accessing records for individual employees, but we expect to be able to analyse a sample of leavers. Given our difficulties we are willing to use Ofgem's simplifying assumption (that we analyse on the basis only of last employment location), but we do have records that demonstrate the different average salary and length of service by employment group, and these should be taken into account.

We recognise the significance of the assumptions made on asset allocation. However it does seem to us appropriate to match, as far as possible, the assets to the different classes of scheme members. This will provide a closer approximation to the way that pension funds are managed.

On the final point in this section, we are concerned here, as elsewhere, that issues relating to costs associated with distribution licence obligations to provide metering services are intended to be resolved in a metering price control. This will not work. Liabilities that relate to distribution licence obligations that need to be considered in the main distribution price control. As metering competition erodes volumes and margins for meter operators, it will not be possible to cover these liabilities from metering services revenues. It is essential that Ofgem take a broader view of the costs that can be stranded by their policy decisions on competitive markets.

7.5.3 Over or under provision

Whilst we accept the principle Ofgem have proposed, its application is not without difficulty. None of the proposed options for calculating an assumed allowance aligns with the methodology used to derive opex allowances at the last distribution price control. To be consistent with this methodology it should be possible to derive the assumed contribution rates used by the frontier companies in the base year and apply the movement required towards this frontier in respect of pension costs. This would be a more acceptable approach to UU.

The data required to calculate the assumed allowances back to privatisation (other than option 2) is not available. An alternative approach is therefore to consider whether the actual level of funding made by the companies is consistent with the advice given to them by the independent actuaries throughout the period. If the actual level of contribution is consistent with this advice then no penalty should be applied.

7.5.4 Early retirement deficiency costs

It is in this area where the concerns over the retrospective application of the principles set out by Ofgem come into sharpest focus. As the position currently stands management decisions made since privatisation that have resulted in efficiency benefits for customers are retrospectively being judged as inefficient. This creates unwelcome uncertainty and risk.

Money cannot be removed from pension schemes by employers therefore there are only a limited number of ways in which pension surpluses can be utilised Continuing to place money in a scheme with a significant surplus which cannot be withdrawn would be judged as inefficient by shareholders, scheme actuaries and regulators alike.

Use of such surpluses to fund efficiency improvements in the business is therefore an effective and efficient management decision. Any disallowances should only be by reference to the specific past actions or behaviour by distributors that were demonstrably inefficient. This is not the case with UU.

7.5.5 Stewardship

We agree that some check on ‘stewardship’ is appropriate, but have no reason to believe that this will bring to light any untoward behaviour.

8 Appendices

Appendix 1 Developing the RIAs for Distributed Generation, IFI and RPZs

Costs and Benefits

We welcome Ofgem's commitment to develop Regulatory Impact Assessments for all substantial policy conclusions. This provides a vehicle for demonstrating the expected costs and benefits of Ofgem's policy initiatives. Such transparency will be helpful for both customers and companies and should aid understanding of many proposals.

The use of distributed generation as an example to build up a model RIA is particularly appropriate, since it will be necessary to show both the direct effect on companies' costs and the indirect impact on wider stakeholders, of the move towards a lower carbon future. One of the key challenges we foresee is identifying these wider social benefits and ensuring that DNOs are incentivised to act in a way that facilitates their achievement.

In our response below to the specific questions you have raised, we are concerned that the focus is almost exclusively on the immediate impact on DNOs. This in itself will not provide the most appropriate assessment of the overall impact of the policy proposals. We assume that Ofgem will aim to pick up elsewhere, the anticipated benefits of their policies, and any costs incurred by other parties.

What would be the impact of each of the:

- *distributed generation incentive;*
- *IFI; and*
- *RPZ mechanisms*

on the volume (or capacity) of distributed generation connecting to the distribution networks?

It is difficult, with this and subsequent questions, to provide an answer of any precision. There are so many factors that might affect the development of distributed generation that we cannot provide a quantified response in the form 'if these incentives are put in place, XX MW more capacity will be connected'.

As we have argued in the main body of our response, we believe the current proposals are inadequate in their impact on the attractiveness of DNO investments. We have nevertheless tried to use the cost estimates in our DG-BPQ to help explain the impact of your proposals. It may be easier to discuss the potential impact in parallel with a debate on the form of incentives proposed.

If the proposed initiatives are successful in encouraging DNOs to make strategic investment in the area of DG connection, either directly in the network or through Research or Development, then connection costs will be reduced with a positive effect on the number and capacity of schemes connecting. However the magnitude and extent of this effect can only really be determined by experience over a reasonable period of time (possibly beyond 2010).

What would be the additional expected costs of the incentive framework to distributed generators for connecting to the network? What benefits would it provide?

We estimate that the NPV over fifteen years of the proposed Ofgem incentive scheme as applied to UU's FBPQ Own Case Scenario is about £4M – although clearly this will be affected by take up and cost of connection issues. These costs could be visited upon generators in proportion to the MW of the connection capacity. By way of putting this cost into perspective this would equate in round terms to about £0.20 per customer per year, if it were to be levied on demand customers.

What would be the impact of IFI and RPZs on research and development and network innovation? What benefits would these provide to generators and other connected consumers in comparison to the associated costs that would be incurred?

Both IFI and RPZs offer the prospect of an improved environment for innovation, research and development. We would expect them to have some positive effect, but we do not feel able to quantify it at present – not least because of our uncertainty regarding the base costs, against which any improvement should be measured.

It is particularly hard to link IFI to absolute DG growth numbers since IFI is by its nature a long-term incentive. The benefits of IFI are likely to accrue in terms of overall reduced cost of DNO operations that will be of benefit to both demand and generation customers. We do believe, however, that the significant growth of distributed technologies, both demand-side and generation, will need significant innovation across the whole industry. We believe that a strong and vibrant innovation culture and capability is necessary to meet these challenges and strongly support Ofgem's concerns to promote these abilities in the DNOs. For this reason we believe that the RIA should specifically support IFI for all suitable projects, not just DG related ones.

Our initial thoughts on the RPZ proposals are:

- The most likely candidates for RPZ will have costs much greater than the expected national average
- We will only pursue projects that provide a discretionary rate of return at the expected outturn costs - this is dependent on the terms of the incentive scheme, but we would suggest that the target RPZ cost would have to be at or below the £50/kW average
- This rules out obtaining small incremental improvements on high cost projects
- A single £/kW allowance will also fail to encourage RPZs for domestic or other micro-generation projects.

Our underlying concern is that, when considering individual projects, the risk effects of the incentive scheme would tend to outweigh the explicit RPZ income available, and therefore discourage innovation.

- The specific RPZ income = £10k/MW NPV (£2.5/kW for 5 years @ 6.5%[3])
- In theory this, together with the effects of the incentive scheme, should provide 13% return on projects with outturn costs of £50k/kW
- However, under the incentive scheme the return is highly susceptible to the achieved costs of the project and is therefore probably insufficient to support discretionary investment

This highlights the need for an appropriate minimum rate of return "floor" within the incentive framework, and an expected rate of return that matches the DNOs' requirements for discretionary investments. An alternative approach might be that the incentive scheme should not apply for RPZ projects and that these should be funded ("on application") as a subset of the overall IFI arrangements.

What would be the impact of each of the proposed incentive schemes on the costs of connecting distributed generation in the period to 2010 and in the longer term – both in terms of £/kW and total system costs?

We believe there is significant scope for cost reductions through the application of more sophisticated means of network management. There are likely to be a number of steps on the path towards such an outcome, which will depend on the right test environment and sufficient projects to allow ideas to develop We would expect the benefits to be seen further into the future than 2010, but do not have a strong feel for the likely overall effect.

How would you expect new technological developments to reduce the £/kW cost of connecting distributed generation over that period?

See previous question.

To what extent does the connection of distributed generation require new R&D by the DNOs?

As has been discussed in the development of RPZ and IFI to date, it seems likely that significantly more development work will be needed rather than new research. We believe that the main effort needs to be in the amalgamation of current techniques and thinking into new ways of implementing, probably on a larger scale (particularly for technologies such as SCADA and communications) than hitherto. Nevertheless there will be real risks associated with employing untested solutions and it is important that appropriate risk taking is incentivised.

[3] For consistency with the Consultation Document, present values are calculated in this Appendix using the cost of capital from the last review of 6.5% real pre tax.

What would be required to do to administer each of the proposed incentive schemes and what would be each of the associated costs?

We believe that operation of the incentive scheme can be largely "automatic", ie with no more intervention by licensees and regulators than occurs now, for example, with the IIP. In saying this we would expect DNOs to keep records of generators connected, which would form the basis of an auditable return to Ofgem. We believe that RPZs and IFI would need more intensive management again by both licensees and Ofgem. However, we foresee the number of projects in either category as being between half a dozen and a dozen per annum and this is unlikely to be an overwhelming burden on either party. We would imagine that it equates to less than one man-year per licensee per annum, and possibly about half a man-year of management by Ofgem per annum.

What would be the impacts of changes in the volume of distributed generation on

- *quality and security of electricity supply; and*
- *losses?*

Will distributed generation provide benefits in these areas, and if so, can they be quantified?

We have consistently argued to date that DG will bring marginal benefits and disbenefits to both losses and quality and security of supply. As such we believe the overall effect will be neutral and we have no further information that would lead us to take a different view.

How much of the increased volume in distributed generation would be of environment friendly types (e.g. renewables)? By how much would this be expected to replace electricity from non-renewable sources?

Would such generation contribute to the reduction of emission levels and, if so, how should these benefits be quantified?

Again, in accordance with our DG BPQ, we believe that the renewables targets for 2010 are just about achievable, although what the mix is between offshore and onshore wind remains to be seen. Similarly we believe that there should be an increase from the current levels of high quality CHP, although not as much as the Government's target of 10GW. Given stable demand for electricity we would expect each MWh of renewable electricity to displace a MWh of non-renewable centrally produced electricity, and similarly each MWh of new high quality CHP to displace a MWh of centrally produced electricity. We do not have the information or expertise to forecast the effect on the MW of central or other non-renewable generation that remains in commission.

Distributional effects

Would there be significant costs outstanding if expansion of the network was not taken up by distributed generators? Could the additional capacity be utilised in another way, and if so, how should any costs be treated?

It is hard to know, given the current uncertainty on the development of DG, particularly types, sizes, and locations, what the risks of unused network expansion is. However, based on UU's DG forecasts, we can see some £40M of strategic investment needed by 2010 primarily in the 132kV system to connect renewables. The remaining DG investment (£70M) we have forecast is driven by projects. This means that the risk of stranded pre-investment is £40M, although there could be other stranded investment associated with generators who then subsequently cease operating before the design life of 15 years expires.

We firmly believe that any stranded costs should be picked up by the general bulk of customers, ideally GB wide, since it is consumers who are the intended beneficiaries of the Government's environmental policies.

Are the IFI and RPZs likely to provide benefits to all consumers connected to the network, and if so, how would these compare to the benefits realised by distributed generators and DNOs?

We believe that IFI will be used by DNOs across the range of its activities, and that through the normal operation of RPI-X regulation innovation will bring immediate benefits to quality of service and supply reliability and in time reduced costs through the operation of price controls.

RPZs are intended to benefit generators, and will do so by incentivizing DNOs to find more cost-effective ways of making connections. Ultimately, of course, consumers benefit from cheaper generation costs as this will eventually feed through into supply tariffs (and reduced Renewables Obligation costs). As has been shown above, the typical costs to consumers is modest: IFI is about £0.50 per customer per annum; we believe that RPZ might cost of the order of a few pennies (4p) per customer per annum. By contrast the Renewables Obligation is likely to cost the average domestic customer £40 per annum in 2010.

The incentive framework for distributed generation assumes an asset life of 15 years for infrastructure assets required for connecting distributed generation. Is this appropriate and how does it compare to the assumed lives for other network assets?

We believe that 15 years is on the long side for assets associated with DG, given the uncertainty of their operating life. We believe that assuming 15 year or shorter asset lives will considerably reduce issues of asset stranding and risk to DNOs. Clearly most physical assets will last longer, comparable with other network assets. However at the local level the DNO's ability to obtain full utilization of assets specifically installed is most unlikely following the demise and/or disconnection of the DG that prompted the investment. The relevant life to consider under the DG incentive scheme is the life of the payment stream rather than the physical life of the asset.

Risks and unintended consequences

Ofgem would welcome views in this area, including, where possible, quantification of the likely impact.

Clearly any incentive scheme or arrangement will have a propensity for some unintended consequences. We are unable to point to any likely ones, barring those that have been outlined above. In this context it is worth pointing out that the RPZ in particular is quite modest. Ofgem will need to consider carefully if the rate is sufficient to overcome all impediments to innovation.

Competition

Views are invited on the impact of the incentive framework for distributed generation on competition in the generation sector.

Clearly any measures that favour the growth of DG can be expected to increase competition in generation. UU does not have any information to estimate this effect in absolute terms.

Review and compliance

Views are invited on the likely costs of any monitoring that would be required for each of the incentive framework for distributed generation; the IFI; and RPZs.

We would imagine that the cost of managing and monitoring the IFI and RPZ framework equates to less than one man year per licensee per annum, and possibly about half a man year of management by Ofgem per annum.

Appendix 2 Comments on the Draft Financial Model

For completeness, these comments capture all the issues raised so far in our review of the Ofgem financial model. It is our understanding that many of these items are now incorporated in the latest version of the model.

The comments identify the sheet and cell references in the model wherever possible. We have a number of major concerns, particularly with regard to tax, the post-tax building blocks and the use of the tariff algorithm. These are important areas of the model, directly affecting price limits.

COMMMENTS RELATING TO OFGEM'S DRAFT FINANCIAL MODEL (VERSION I) ISSUED 16 SEPTEMBER 2003

Tax Calculation

- The model only adjusts for capital allowances and depreciation and ignores any permanent timing differences such as entertaining, disallowed legal fees, depreciation of land and short term timing differences such as the movement on general provisions.

- The model shows a split for capital allowances over tax revenue, long life, IBA and P&M. There is no scope to include non-eligible expenditure or expenditure on leased assets. It is too simple to apply the same proportions each year and there should be a facility to use a different tax analysis for each year, which allows for the annual variation. This would overcome the problem of using a fixed % of non-load operational capex as a proxy for "non-load" expenditure for tax purposes. As an example:

Tax Category	2005-06	2006-07	2007-08	2008-09	2009-10
Tax Revenue – 100% Expensed					
Tax Revenue – Accounting Life	30%	35%	30%	35%	40%
Long Life – 6% reducing balance	30%	30%	30%	30%	30%
IBA - 4% straight line	10%	5%	10%	10%	5%
P&M – 25% reducing balance	15%	15%	20%	15%	15%
Leased Assets	10%	10%	6%	5%	5%
Non-eligible	5%	5%	4%	5%	5%
Total	100%	100%	100%	100%	100%

The percentages in the table are purely for illustration and would be applied to the capex for the relevant year.

- The WDA on IBA should be 4% straight line on costs not on a reducing balance (cell C32 – formula input sheet).

- We do not follow the formulae in cell R103 (notes to fin reps sheet) onwards regarding deferred revenue. This seems to use a combination of lives. For statutory accounting purposes we use a fixed number of years from new.

- The deferred tax calculation in the model appears incorrect. Deferred tax should be 30% * Profit before tax less current tax on a non-discounted basis after adjusting for permanent timing differences. The deferred tax in the model seems to be based on the opening balance rather than the closing accelerated capital allowances (net book value less tax written down value), using a discount rate based on the real cost of debt. We assume a discount rate based on bond rates for producing our statutory accounts and therefore there should be the option to input a separate bond rate. Discounting using an appropriate bond rate conforms to FRS19. The introduction of international accounting standards will remove the option to discount the deferred tax liability.

- The sheet "financial reports (real)" is missing deferred tax in the profit and loss account (see line 24 of the financial reports (nominal) sheet.

- On the user interface sheet the tax treatment of non-load capex will be based on accounting lives. Therefore the option showing regulatory lives is redundant and could be deleted (cell G9).

- Cell B119 (selected inputs sheet) should read non-load not load (minor point).

Post Tax Building Blocks

- We do not understand this part of the model (lines 47 to 50 of the price control calcs sheet). Instead of the pre-tax return using a pre-tax methodology the post tax approach should substitute actual current tax (as calculated above for the profit and loss account) and a post-tax return (based on a pre-tax debt plus post-tax equity WACC * RAV). It is important that the model is clear and transparent on this issue.

Projected Revenue

- The Po and X factors should be calculated from the projected revenue for 2004/05 under the tariff algorithm set out in the licence. This is how revenues are allowed in the regulated distribution business. This allows for changes in demand across categories and customer numbers and applies a predefined weighting factor. It also allows for losses. The Po and X factors should be adjusted so that NPV of the projected revenues using this approach equals the NPV of the required revenue using the building blocks over the price control period, e.g. 2005-10.

- The model counts non-regulated revenues (i.e. de-minimus income) as regulated revenues in the revenue calculation. Lines 37 and 77 of the price control calcs sheet include non-regulated revenues and these are included in total allowed revenue and compared with total required revenue when calculating the X factors. We assumed that the model would exclude all non-regulated revenues and costs in the X calculation.

- Key outputs from the model are the Po and ongoing X factor, which should be clearly shown.

RAV Rolled Forward

- The row that adds LRE to the RAB picks up the net value for 2005/06 but then switches to the gross value from 2006/07 (see Cell R13 and S13 on the rav roll forward sheet). This requires correction.

- If a depreciation life for non-operational of say 5 years is used then the model continues to depreciate after the life has expired and the RAV eventually goes negative (see lines 37 and 38 of the rav roll forward sheet).

- The section Mar 03 Real RAV on the price control sheet (lines 93 to 99) does not add down in the table. The opening/closing and average RAV values derived in this section exclude non-operational. This affects returns, total reported RAV, balance sheet adjustments etc.

Allowed Returns

- The allowed returns on line 13 of the price control calcs sheet do not include the returns on the non-operational RAV.

Capex Incentive

- The logic in the model is not quite the same as the model the industry presented in the meeting on 26 June 03. The adjustment for depreciation (line 18 of the capex incentive sheet in the model) should be 5 * annual depreciation on the out-performance 5 years earlier. This adjusts the RAV for the cumulative depreciation already allowed in the previous price control and ensures the RAV is rolled forward correctly.

- Cell G9 of sheet capex incentive should show the formula that picks up the projected actual capex for 2004/05 but is currently blank. This distorts the efficiency incentive calculation.

Replacement Expenditure

- Repex requires greater flexibility and therefore there should be the facility to vary the % of capex classified as repex each year.

Dividends

- It would be helpful to have the option of applying a dividend growth assumption annually, e.g. 0% real. It this case the dividend would be linked to the prior year value plus a growth assumption.

Links with the FBPQ

- It would be helpful if the inputs to the financial model were referenced to the FBPQ so that an audit trail can be established. It would also be helpful if the outputs from the model were consistent wherever possible with the profit forecasts, balance sheets and cash flows in the FBPQ Tables 0, 1, 5 and 11. For example dividends paid are included within "returns on investments and servicing of finance" in the model whereas Table 11 of the FBPQ shows dividends outside.

As discussed at the last DNO meeting it would be helpful f you could issue a more comprehensive set of instructions and a description of each sheet in the model (initially we had difficulty getting the macro to run because of incomplete cells).

We would also appreciate the opportunity to comment on the areas of the model that are yet to be developed, e.g. financial indicators, opex and losses incentives and incentives for distributed generation at the appropriate stage.

COMMENTS RELATING TO OFGEM'S DRAFT FINANCIAL MODEL (VERSION 2) PUBLISHED 7 NOVEMBER 2003

Opening Balance Sheet Inputs

- Debtors Intercompany Balance (UUE Inputs sheet, cell O222) – this cell is not picked up and the balance sheet in the Financial Reports sheet does not balance. Entered into Debtors Other (UUE Inputs sheet, cell O223) as default in order to balance.

- Other Reserves (UUE Inputs sheet, cell O255) – this cell is not picked up and the balance sheet in the Financial Reports sheet does not balance. Entered into P&L Reserves (UUE Inputs sheet, cell O254) as default in order to balance.

Cost of Sales

- The model appears to be ignoring <u>all</u> cost of sales (UUE Inputs sheet, cells R23-AF26) in the building block methodology. Opex (UUE Inputs sheet, cell R28-AF28) has been used as default to include NTR costs and other costs of sales. Although this corrects for the building blocks the notes to the accounts can be in error.

Capex Incentive Scheme

- In the Price Control Calcs sheet (cell R14-AF14 and R54-AF54), the capex incentive scheme revenues are picked up as a negative when a company has outperformed the allowances. This is incorrect since allowed revenues should increase under these circumstances.

Tax

- Capital Allowances for 2002/03 IBAs (UUE Inputs sheet, cells O290-O294) deducts the WDA for the year from the closing balance. IBAs are calculated on a straight-line basis and therefore this allowance should use gross values before WDA's are deducted.

- The Total Additions section (UUE Inputs sheet, cells O343-AF346) requires three more categories:

  - Ineligible
  - Deferred Tax Revenue (allowed as depn)
  - Tax Revenue – General (allowed as 100% tax deductible)

This will then allow for the tax change in 2005 when tax revenue – general effectively switches to deferred tax revenue. Without these tax categories the allowance in the post tax building blocks will be grossly understated.

The tax computation (Price Control Calcs sheet, cells R53-AF53) is 'solved by iteration' and it is not clear how this calculation works. To date we have not been able to reconcile the numbers. Under certain assumptions this can produce tax credits post 2005 when we have already established implied tax rates greater than 30% in this period.

- There are two lines in the model that calculate tax charges (Price Control Calc lines 89 and 90). Line 89 refers to the number used in the profit and loss and line 90 refers to the post tax building blocks. Under the scenarios we have run both produce quite different results. Also the line 89 calculation does not involve iterations whereas line 90 does. I do not understand why the ordinary tax number (before deferred tax) in the P&L is different from the number in the post-tax building blocks – <u>the two should be the same</u>.

Smoothing of P0 and X Factors

- The model appears to calculate a P_0 value (Price Control Calcs sheet, cell Q35) for 2005/06 as the balancing item, after using the input X Factor for years 2006-10 (UUE Sheet, cells S19-V19) – the input X Factor for 2005/06 (cell R19) does not appear to be used. It would be helpful if the model also included an option to calculate the flat X factor equivalent, i.e. what X factor in each year of the price control is equivalent in NPV terms.

Appendix 3 Comments on CEPA's Report on Total Factor Productivity

Comments on

"Productivity Improvements in Distribution Network Operators"

for

United Utilities Electricity

by

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1 Introduction and summary

As part of its review of distribution network operators (DNOs) the Office of Gas and Electricity Markets (Ofgem) has published work by Cambridge Economic Policy Associates Ltd (CEPA) entitled *Productivity Improvements in Distribution Network Operators*. United Utilities Electricity (UUE) has asked Horton 4 Consulting to comment on it.

Why estimate productivity growth?

Work on comparative efficiency has tended to confirm that it is difficult to reach reliable conclusions on the comparative efficiency of DNOs. If, as seems likely, it is not possible to reject the hypothesis that companies are efficient, price controls should be set on the basis that an individual company's future costs will only differ from present ones in real terms insofar as total industry productivity growth (or factor price change) is likely to differ from that in the economy as a whole. It is therefore to be welcomed that Ofgem has commissioned work on DNO productivity improvements. However, there are several possible definitions of productivity and which one is appropriate depends in part on the use to which it will be put.

Methodology

CEPA makes a number of estimates of total factor productivity (TFP) growth in sectors it considers to be comparable to DNOs from which it derives a range for future DNO productivity growth that it then compares with a figure for UK general productivity growth. It does so by examining an international data set compiled by the National Institute for Social and Economic Research (NIESR), regulated accounts of companies in the UK and in Norway and the US, and its own surveys of analysts and companies.

It also discusses partial factor productivity growth, sometimes labour productivity and sometimes operating cost efficiency.

While we have some concerns about details of the analysis, the main problem in CEPA's report concerns the judgmental leap between the evidence presented and the conclusion. CEPA's central TFP growth estimate is simply the mid-point of an upper and lower bound. The former is derived entirely from performance by companies in an immediately post-privatisation period that cannot be expected to be sustained over the longer term. The latter seems almost arbitrarily selected from a range of figures that would appear to imply a significantly lower number. It follows that CEPA's central estimate is not reliable.

A number of features of the methods used may affect the results.

- CEPA appears to have used the CCA modern equivalent asset method to measure capital assets employed, which will introduce revaluation effects. We prefer an inventory approach rather than use of figures taken directly from current cost accounts.
- Adjustments are not made for changes in cost allocations that have occurred, although these will have resulted in large overstatements of DNO productivity growth – particularly in 2000/01 when 14% of operating costs were reallocated away from DNOs.

- Outputs are measured in different ways when compiling productivity measures that are then compared with each other.

- When including quality as an output CEPA incorrectly calculates its weight by multiplying the assumed value by the number of lost units. However, the quality service that is delivered is not the number of units that is lost but the number that is *not* lost.

Estimates of trend productivity growth

CEPA's report concentrates on total factor productivity. It rightly draws few conclusions as regards partial factor productivity or operating cost efficiency. The figures derived from the NIESR data set are all of labour productivity, which is not directly comparable with measured operating cost efficiency but would be expected to be higher. The figures for operating costs are either for the post-privatisation experience of the DNOs themselves, NGC and the water companies or for Norwegian and US electricity distribution companies. Experience of these two last is of modest operating cost efficiency growth of 1.6% and 0.5% respectively. However, there is no similar whole economy measurement with which these can be compared in order to calculate the extent to which the sector outperforms the RPI.

Our assessment of TFP, based on the evidence presented, differs from that reached by CEPA. It is that the forecast of the potential for trend DNO TFP growth is subject to significant error but there are no strong grounds to expect it to be much higher than that for the economy as a whole.

- DNO past performance is subject to substantial measurement error and is influenced by privatisation effects and so is not a good guide to future performance.

- Similar considerations apply to the evidence from other UK utilities.

- Evidence from US and Norwegian distribution companies has unexpected features but is consistent with a growth similar to the UK economy average.

- US, French and German national accounts data suggest TFP growth in the utility sector slightly lower than that for the UK economy and around that for their economies as a whole.

- CEPA's survey of analysts is small but the results are consistent with TFP growth similar to that for the economy as a whole.

- TFP growth in the UK utility sector was also 0.7% higher than that for GDP as a whole in the 1950-90 period but this is on the basis of a utility output definition that grows faster than that used by Ofgem.

- The composite sectoral TFP estimate (excluding post-privatisation utilities data) gives a TFP growth rate slightly higher than that for the economy as a whole.

2 Differences in productivity measures and their use in price control

Previous price controls have assessed the scope for cost reduction during the coming price control period primarily by attempting to assess the extent to which companies' productivity is below an efficient level. The extent to which the efficient level might itself move in the future has been a secondary consideration to which comparatively little attention has been paid.

If, as seems likely, it is not possible to reject the hypothesis that companies are efficient and there is no scope for catch-up cost saving, the potential for efficiency growth will be that of the industry as a whole. Cost savings would be possible, relative to an economy-wide price index like the RPI, if industry productivity growth exceeded that for the economy or if the relative price of the industry's inputs falls. Price controls should therefore be set on the basis that an individual company's future costs will only differ from present ones in real terms insofar as total industry productivity growth (or factor price change) is likely to differ from that in the economy as a whole.

Further work on comparative efficiency has tended to confirm that it is difficult to reach reliable conclusions on the comparative efficiency of DNOs. It is therefore to be welcomed that Ofgem has commissioned work from CEPA on DNO productivity improvements. However, there are several possible definitions of productivity and which one is appropriate depends in part on the use to which it will be put.

Previous DNO price control reviews have used a "building block" approach that has necessitated a disaggregated view of productivity.

- A judgement has been taken of the scope for improvement in an operating cost productivity measure that is the ratio of controllable operating costs deflated by the retail price index (RPI) to a weighted sum of three outputs – customer numbers, units distributed and line length. The question has been whether the particular circumstances of the electricity industry are likely to result in greater gains in efficiency than those in the economy as a whole that are embodied in the RPI. There has been debate as to whether this partial measure will be affected by changes in the capital output ratio or by unusual movements in relative factor prices but no specific adjustments have been made for those reasons.

- Capital cost productivity has also been assumed to rise relative to that in the economy as a whole in that the unit price of installed pieces of capital equipment has sometimes been assumed to fall in real terms.

- In the last (1999) review financing costs were assumed to fall and the cost of capital was reduced.

- These efficiency judgements have been used merely to forecast costs and an X factor has been calculated to equate net present values of expected costs and revenues. There has been no systematic attempt to derive X from productivity trends.

The productivity measures assessed in CEPA's report include more general measures whose application would be different. It discusses "partial factor productivity", relating to operating costs, but its major conclusions concern growth in a measure of total factor productivity and the difference between it and that for the economy as a whole, which *"over the longer term …. it can be appropriate for the X factor to approach".*

Most productivity analysis attempts to relate physical outputs to a weighted sum of physical inputs such as labour or materials or the services of items of capital equipment. Given a view of likely productivity growth of this sort a forecast of cost movements relative to the RPI can be obtained, but only with additional assumptions about productivity growth in the economy as a whole and likely movements in the prices of the inputs relative to the RPI. Given an appropriate starting price level, X could be set equal to forecast industry productivity growth less that for the economy as a whole less relative input price increases.

CEPA's work on DNOs relates output in physical terms to the money value of costs deflated by the RPI and therefore combines physical productivity changes with the impact of relative price movements. The resulting productivity estimates are compared with similarly derived measures for other utilities in the UK and overseas and with national accounts data for the US, France and Germany. The method implicit in the national accounts data differs in that expenditures on inputs are deflated separately, not by a general measure such as the RPI, and the productivity estimate attempts to derive only the physical measure.

Bearing these conceptual differences in mind we now proceed to discuss:

- CEPA's method of arriving at its conclusions (section 3);
- The theoretical problems involved in making the estimates (section 4);
- The estimates themselves (section 5);
- Partial factor productivity (section 6); and
- Our conclusions (section 7).

3 CEPA's method of drawing conclusions from the evidence

CEPA attempts to forecast future DNO productivity growth by considering:

- Past DNO productivity growth (calculated from regulated accounts);
- Past productivity growth in other UK utilities (calculated from regulated accounts);
- Past productivity growth in electricity distribution in other countries (calculated from regulated accounts);
- Past productivity growth in comparable sectors of the economy and in gas, electricity and water in the United States, France and Germany (calculated from national accounts);
- Forecasts by analysts and comparable companies.

This produces a number of estimates from which CEPA derives a range for future DNO total factor productivity growth that it then compares with a figure for UK general productivity growth derived from the national accounts.

While we have some concerns about details of the analysis (see sections 4 and 5), the main problem in CEPA's report concerns the judgmental leap between the evidence presented and the conclusion.

Having obtained a set of TFP estimates CEPA then says[4]:

"from the discussion above, the trend rate of growth in DNOs, and in the utility sector provided by the NIESR data set provide an upper bound for future trend growth by the DNOs. The NIESR estimated rate of growth is the lowest of these, and therefore our estimate of the upper bound of future TFP growth is 3.4%. This upper bound is consistent with the longer term trend in DNO performance excluding a portion of the exceptional gains achieved in 1999/00-2000/01; and

"Trend TFP growth in the sector from most other sources was above that expected for the UK economy. This included median analyst expectations, the trend for utilities in other countries, and expected productivity gains in other industries. The lower bound of these is provided by the German utilities aggregate industry TFP trend at 1.4%.

"We therefore expect total factor productivity over the next five years to lie in the range 1.4-3.4%, with a central case expectation in the middle of this range of 2.4%, or just over 1% above the rate of growth for the economy."

In other words, an upper rate of 3.4% is set by UK utility performance, a lower bound of 1.4% by performance in Germany and splitting the difference gives the central estimate.

However, this reasoning is seriously flawed:

[4] p57

- The upper bound consists almost entirely of the post-privatisation performance of the DNOs themselves and of other privatised industries, which of course involves much higher productivity growth than any likely sustained trend rate. The two figures given are the DNOs' own 1991-2001 performance and the national accounts figure for "UK utilities" 1990-99. The former consists of the post-privatisation period, is likely also to be affected by data errors and includes the probably anomalous year 2000-01 (see section 4.2). The latter is actually the gas, electricity and water sectors, which include not only the DNOs themselves, but also the recently privatised generators, NGC, Scottish electricity companies, English and Welsh water companies and British Gas.

- The lower bound of 1.4% is said to be the figure for gas, electricity and water in Germany for the last ten years. Figure 33 on page 47 of CEPA's report actually gives 1.2% as the volume-adjusted rate. The similar figures for France and the United States are 1.5% and 0.2%. There is a separately calculated figure for US electricity distribution of 2.2% and one for Norway of 0.2%. The seven analysts surveyed produced a range of estimates from minus 0.2% to 2% with a median of 1.5%. Undescribed forward-looking analysis of twelve companies was said to produce a figure of 2.3%. These figures represent practically all the quoted recent results other than those for companies immediately after privatisation. It is, to put it mildly, unclear why CEPA adopted a *lower bound* of 1.4% from studying the numbers. The simple average of the seven estimates is 1.3%, and so another commentator might pick CEPA's lower band as a central estimate.

It follows that CEPA's central estimate, which is the mid-point of an upper bound set by post-privatisation performance and a seemingly arbitrarily selected lower bound, is not reliable. The figures cited would seem to imply a significantly lower number.

4 Methodological issues

The estimation of total factor productivity growth is not a simple matter. Both outputs and inputs must be measured and weighted together. The movement in the ratio can then be calculated but some of that may be due to other factors, notably economies of scale resulting from increases in output.

In this section we discuss problems relating to:

- The measurement of capital factor inputs;
- Operating cost uncertainty;
- Weighting;
- Unmarketed outputs such as quality; and
- The effect of output growth.

4.1 Capital inputs

As CEPA explains, neither historic cost capital asset values nor the regulatory asset base is likely to provide a suitable estimate of the asset base, whose return and depreciation should be included as a capital factor input. CEPA says it uses current cost values but the method used is not described in detail.

We prefer an inventory approach rather than use of figures taken directly from current cost accounts. Current cost values taken from regulatory accounts will include the effect of revaluations (other than those for RPI changes) that may suggest changes in capital input that did not in fact take place.

Even using an inventory method, there are several possible approaches. For example, in other work, we have constructed an estimate of DNO network assets by calculating asset value and depreciation estimates from the reported CCA network values at vesting and network investment since then. Constant price values are derived by indexing using the RPI. Post-vesting assets are assumed to depreciate 2.5% a year for forty years. Pre-vesting assets are assumed to have an age profile ranging from 0 to 40 years that can be represented by a straight line that is tilted so as to produce an average age equal to that reported at vesting[5]. Depreciation in each subsequent year can be calculated from that assumed age profile.

We do not know precisely what method CEPA has used but it appears to have been the CCA modern equivalent asset method, which will introduce revaluation effects.

[5] Thus an average age of 20 years would be represented by a flat line with an equal amount of assets in each of years 1-40. Some companies had such short average ages that the age line was not only tilted but also truncated to avoid it passing through zero before 40 years. The method was tested against the depreciation profile used for Northern Ireland Electricity by the MMC to replace the truncated profile by which all vesting assets are fully depreciated at the average age (see MMC 1997 report on Northern Ireland Electricity paras 2.98ff. and appendix 2.5), and it produced a reasonable approximation.

4.2 Operating cost uncertainty

Operating costs are normally much more easily measurable but, in the case of the DNOs, there are still problems. Throughout the 1990s there have been changes in the methods of transfer pricing and cost allocation between businesses. The trend has been to move the allocation of costs away from the distribution business, which will tend to overstate productivity growth. Indeed the accounting changes following the 1999 distribution price control review are likely to have been a significant cause of the large apparent cost reduction between 1999-00 and 2000-01 noted by CEPA.

The transfer of costs to supply in the 1999 DNO review (net of the increased capitalisation also assumed) represented a reduction in standard controllable costs of more than 14%. This followed earlier transfers of costs such as meter reading, advertising, corporate and IT.

The situation is exacerbated because there is reason to believe that DNO costs in the early 1990s were overstated. Domah and Pollitt[6] *"note that there was a rise in real unit distribution and supply controllable costs by about 15 per cent immediately after privatisation in 1990. The cost remained at a high level until 1994–95, after which there was a dramatic fall. The rise in controllable cost of £358 million (in nominal terms) between 1989–90 and 1990–91 represents a 21 per cent increase in nominal terms or a 7 per cent rise in real controllable costs per unit distributed."* In other words, given an expectation of continuing productivity growth, total operating costs in the regional electricity companies immediately after privatisation were about 10% higher than might have been expected. The reason for this has not been established clearly but it is likely that there was an element of provisioning and other means of bringing costs forward to the 1990-94 period when the price control regime was relatively generous and reported profits would otherwise have been higher.

Relative to the present level of operating costs, DNO costs at the start of the period contained substantial elements that are now allocated elsewhere and were probably also temporarily increased in the immediate post-privatisation period. Therefore the fall in costs and the estimate of productivity growth is overstated.

4.3 Weighting and money values

The contrast between CEPA's approach of deflating money values by the RPI and that in the national accounts data, where inputs and outputs are separately deflated, was discussed above in section 2.

However, CEPA does not treat all costs as a single monetary unit but deflates capital and operating costs separately and weights them together. It does so using weights from the average over the period rather than using the weights for each individual year. The difference this makes has not been reported.

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[6] Preetum Domah and Michael G. Pollitt *The Restructuring and Privatisation of Electricity Distribution and Supply Businesses in England and Wales: A Social Cost–Benefit Analysis* Fiscal Studies (2001) vol. 22, no. 1, pp. 107–146

4.4 Quality and other outputs

The DNO output term is weighted together using the weights Ofgem used in its operating cost equations, but omitting line length because of data problems. Whether the same weighting is appropriate when considering total costs is debatable. The same or similar methods appear also to have been used by CEPA for US and Norwegian electricity distribution and for BT but this differs from what has been used in the national accounts utilities comparisons and for the water companies and NGC, all of which use units delivered. We have not checked the figures but units delivered tend to rise more rapidly than customer numbers and so the difference in method would tend to increase the figures derived for those comparators[7].

The addition of quality as an output, which has a significant impact on some of the results, raises considerable problems. Some of these relate to its measurement but the greatest is the decision of what weight to assign to it. In water a cost based approach is used (and is discussed in 5.3 below) but in other industries, including electricity distribution, the weight is derived from customer valuation – a price times a volume. While difficult to do, the value of a marginal increase in quality can be estimated and a price derived. The real problem lies in assessing the volume of the service that is delivered. CEPA incorrectly multiplies the assumed value of a lost kWh (£2.80) by the number of lost kWh (14 million) to derive a weight of about £40 million or 2%. However, this is the wrong weight as can seen from the fact that, if more effort is put into quality and fewer units are lost, the weight would be reduced. The quality service that is delivered is not the number of units that is lost but the number that is *not* lost. Use of that figure (i.e. all units successfully delivered) would produce an absurdly high weight for quality but the method that produces the 2% weight is flawed.

An alternative method would be to exclude quality-related costs, thereby removing the need to adjust output. However, this would be difficult to do, particularly as regards capital assets.

4.5 Scale

As CEPA explains, if there are economies of scale, some productivity improvement can occur purely as a result of output increase. Depending on the means of conducting the price control calculations and, in particular, on whether the price control formula assumes scale effects, the measure of productivity growth that should be used may be that after removing that part which is due to scale.

The adjustment is to subtract (1-?)/? times the change in output, where ? is the elasticity of costs with respect to scale. CEPA reports a regression estimate of 0.7 for the scale elasticity in distribution in a log equation and Ofgem's assumptions of £25 million fixed operating cost and linear form imply DNO controllable operating cost scale elasticities ranging from about 0.35 to 0.6 depending on the size of the company. The figure actually used in the adjustment is 0.85. This is justified mainly on the basis of findings in other countries. We do not wish to contest the figure but merely point out the degree of uncertainty and the possible inconsistency with what Ofgem assumes elsewhere.

[7] Between 1993 and 2000, for example, GB electricity customer numbers grew 0.7% per annum and units 1.6%. Ofgem's composite variable would show 1% growth, a difference of 0.6% per annum from units delivered.

5 The evidence

Given the methodological problems it is not surprising that results are uncertain and varied. CEPA presents and discusses them intelligently but then proceeds to draw unwarranted conclusions.

5.1 The UK economy

TFP growth in the UK economy is estimated at around 1.4% pa, 1.3% after a small adjustment for economies of scale. Although there is bound to be some uncertainty over the figure, it appears to be soundly based and stable. It lies between the (unadjusted for scale) 1974-99 TFP trend growth figures for the United States and France of 1% and 1.5% respectively.

However, all these TFP growth estimates are calculated on a different basis from the accounting analysis in sections 5.2, 5.3, and 5.4.1 below.

5.2 DNOs

CEPA derives a TFP growth of 4.2% but this is of little help in making forward projections. Firstly, performance in the period has been affected by post-privatisation improvements for which there will be much less scope in the future. Secondly the estimate is uncertain since it depends on assumptions on the method of compiling the capital stock, the size of the economies of scale effect, the treatment of quality and the consistency of the regulatory accounting data over time. Significantly different views can be taken on all these factors. CEPA reports the impact of removing the single year 2000-01 from the calculation as reducing the average annual growth figure from 4.2% to 3.2%.

5.3 Other UK utilities (accounting data)

Three other groups of UK utilities are investigated – NGC, the water companies, BT and Railtrack. These too are of little help in making forward projections for the same reasons.

Firstly, although the immediate post-privatisation periods are excluded for the water companies and BT, the results will still be affected by privatisation effects, strongly so in the case of NGC and, probably, Railtrack.

Secondly, the estimates are uncertain.

- The output of the first two is assessed on the basis of units delivered rather than the composite (? customers, ? units) used for DNOs.
- The results for water companies depend entirely on the treatment of quality. When this is given a 42% weight (based on costs) TFP growth from 1994-95 to 20001-02 is 7.7% pa, with a 2% weight (based on customer valuation) the answer is 0.1% and, if quality is excluded, TFP growth is negative. Both the cost and customer value weights appear to have been calculated incorrectly. The cost weight is a share of capital expenditure, not total costs or even total assets. The customer value weight appears to result from a similarly flawed calculation as that for DNOs discussed in 4.4 above.

In any case, the results are so diverse as to be of little use in making projections for DNOs even if they were good indicators of future productivity growth in those companies. The water company estimate can be minus 0.3% or 7.7%, depending on the treatment of quality, NGC is said to be 2.4%[8], Railtrack, based only on four years (1997-98 to 2001-02), 2.9% and BT, based on the same four years, 13.2%.

5.4 International comparators

International comparisons are made for electricity distribution from regulated accounts for the United States and Norway and for gas/electricity/water ("utilities") from national accounts data for the United States, France and Germany.

5.4.1 Electricity (accounting data)

While much accounting data for Norway and the US was available from the regulatory authorities CEPA has had to construct estimates of CCA assets from HCA data. We have not examined the data but wonder if either the method or special features of the time period analysed may in some way have affected the results. While opex productivity is calculated at 0.5% in the US and 1.6% in Norway, the results for capital assets are very different (4% and minus 1.1% respectively) with the result that the US TFP estimate is 2.2% and that for Norway 0.2%

5.4.2 Gas, electricity and water (national accounts data)

The National Institute of Economic and Social Research (NIESR) has compiled measures of productivity growth by sector and for the economy as a whole for the UK and for a number of other countries. These NIESR estimates have been carefully prepared but require the use of assumptions that may not be correct. The results are therefore uncertain. For example, the 1974 oil price rise may have made a part of the capital stock redundant in some countries so the increase in inputs (from a lower base than assumed) may be understated and TFP growth exaggerated.

In the 1990-99 period calculated TFP growth in the gas/electricity/water sector was reported by CEPA as 0.2% in the US, 1.5% in France and 1.2% in Germany. The electricity sector in the US recorded higher TFP growth (1.7%) than gas and water but the US utility sector had low growth in the longer 1974-99 period when even electricity had only 0.5% pa TFP growth. France's utility TFP growth in 1974-99 is estimated at 2.1%[9].

Over an even longer 1950-99 period US utility TFP growth is calculated at 1.4% (electricity 1.7%). TFP growth in France was very rapid in the 1950s and 1960s, when utility output was growing at almost 10% per annum, producing a reported 4.4% for the period as a whole.

The simple average of utility TFP growth estimates for the US, Germany and France 1990-99 was 1% and for US and France in the longer period 1974-99 0.9%. If the US electricity sector is used, rather than the utility sector, the figures are raised to 1.5% and 1.3% respectively.

[8] But only 1.1% compound annual growth rate because of movements in the first and last years. The NGC figure is differently reported as 4.3% in the summary table but this appears to be an error. The text of section 7 gives yet another number but seems to confirm the lower table 7.1.2 estimate.

[9] German data are only available for the 1990-99 period.

5.5 UK sectoral estimates

Similar figures for the UK gas/electricity/water sector show 3.4% for 1990-99, 2.8% for 1974-99 and 2.5% for 1950-99. This implies growth of 3.4% in the post-privatisation 1990-99 period, 2.5% in 1974-90 and 2.2% 1950-74. CEPA also quote their own rather different trend estimates (3.2%, 2.0%, 1.2%) which imply 3.2% in the recent period, 1.3% 1974-90 and 0.4% 1950-74. However, we cannot reproduce these results.

CEPA also reports a TFP growth estimate for DNOs by disaggregating their functions, comparing them with other sectors in the economy (18% construction, 36% engineering, 28% utilities, 9% business services and 9% communications) and calculating the weighted sum of 1990-99 TFP growth in those sectors.

Like CEPA, we do not find this approach particularly convincing.

- The method is suspect because it implicitly assumes distribution is more intensive in engineering, communications, business services and construction than are utilities in general but the method used to derive the weights did not attempt to test whether that was the case but merely assigned activities to those categories.
- The weighted sum calculated is 2.0% but this depends in part on the (circular) use of the high post-privatisation utility TFP growth. If the 2.5% figure is substituted the estimate falls to 1.8% and use of the 1.3% CEPA 1974-90 trend produces an estimate of 1.5%.

5.6 Further analysis of the NIESR database

Since we did not fully understand the derivation of the figures CEPA calculated from the NIESR database, in particular the "trend" figures quoted in figure 35, we calculated TFP growth estimates for gas/electricity/water and the whole economy for the UK, US, France and Germany for 1950-99 and a number of sub-periods using the NIESR data set.

We estimated trend growth rates for the periods 1950-74, 1974-90, and 1990-99 (and for the longer periods 1974-99 and 1950-99) by regressing the log of the NIESR estimate of TFP against a constant and a time trend. This produced the trends given in table 5.6.1.

Table 5.6.1 TFP growth - trend coefficients

	Electricity, gas and water					Whole economy			
	France	Germany	UK	US	US elect'y	France	Germany	UK	US
1950-74	6.9%		2.6%	3.6%	4.1%	3.8%		1.1%	1.7%
1974-90	2.9%		2.7%	-1.1%	-0.3%	2.1%		1.7%	0.8%
1990-99	1.5%	1.6%	3.9%	0.6%	2.2%	0.7%	1.3%	1.5%	1.2%
1950-99	4.6%		3.0%	1.3%	1.8%	2.7%		1.4%	1.1%
1974-99	2.4%		3.1%	0.1%	0.6%	1.5%		1.5%	1.0%

We then adjusted them for economies of scale using elasticities of 0.85 for electricity, gas and water and 0.95 for GDP, which resulted in the figures shown in table 5.6.2.

Table 5.6.2 TFP growth - trend coefficients volume adjusted

	Electricity, gas and water					Whole economy			
	France	Germany	UK	US	US elect'y	France	Germany	UK	US
1950-74	5.2%		1.7%	2.4%	2.9%	3.5%		1.0%	1.5%
1974-90	1.9%		2.3%	-1.4%	-0.7%	2.0%		1.6%	0.6%
1990-99	1.1%	1.3%	3.4%	0.3%	1.9%	0.6%	1.2%	1.4%	1.0%
1950-99	3.4%		2.3%	0.6%	1.0%	2.6%		1.3%	1.0%
1974-99	1.6%		2.6%	-0.2%	0.2%	1.4%		1.4%	0.8%

Table 5.6.3 shows the differences between TFP growth in the utilities sectors and that for the economy as a whole.

Table 5.6.3 Difference between utility and whole economy volume adjusted TFP growth

	France	Germany	UK	US	US elect'y
1950-74	1.6%		0.7%	0.9%	1.4%
1974-90	-0.1%		0.7%	-2.0%	-1.4%
1990-99	0.5%	0.1%	2.0%	-0.7%	0.9%
1950-99	0.9%		1.1%	-0.4%	0.0%
1974-99	0.1%		1.2%	-1.0%	-0.6%

Thus it appears that gas/electricity/water TFP growth in the UK was about 0.7% higher than that of GDP in 1974-90 and around 2% higher in the post-privatisation period. However, this does not seem to have been the case in the United States, France and Germany where, apart from in France in the 1950s and 1960s when output increased eight-fold, experience has varied somewhat but TFP growth seems to have been around that for the economy as a whole.

It should be remembered that all these measures use a definition of utility output that is likely to have grown significantly faster than that used for distribution by Ofgem and so a likely downward adjustment to productivity growth is required.

5.7 Surveys

CEPA reports the results of their surveys of analysts and companies tersely.

Only seven analysts replied to the survey and their answers are widely dispersed. The highest TFP estimate was 2%, the lowest minus 0.3% and the median 1.5%. Given the apparent skewedness of the distribution it may be a reasonable guess that the mean was lower than the median. The analysts do not appear to have been asked for TFP projections for the UK economy as a whole.

Twelve company projections were considered. CEPA do not describe the method used to convert the data but they calculate that three chemicals companies expected 3.1% TFP growth, three oil companies 1.1%, two metals companies 2.8% and four engineering companies 2.1%. It is not clear why these companies where chosen or why they should be expected to perform differently from the economy as a whole. It would appear that the resemblance to DNOs is one of capital intensity but the figures cited throughout the report do not suggest that capital efficiency growth is normally high.

6 Partial factor productivity

CEPA presents some figures for partial factor productivity. These sometimes consider operating costs deflated by a general price index as an input and sometimes give figures for labour productivity. The two are not directly comparable. The latter is normally higher than the former since real wages tend to increase and so labour input deflated by wages will rise less rapidly than the same money expenditure deflated by a general price index.

The figures derived from the NIESR data set are all of labour productivity. The figures for operating costs are either for the post-privatisation experience of the DNOs themselves, NGC and the water companies or for Norwegian and US electricity distribution companies. Experience of these two last is of modest efficiency growth of 1.6% and 0.5% respectively. However, there is no similar whole economy measurement with which these can be compared.

Operating cost efficiency growth will differ from that for total factor productivity because of the impact of changes in the proportion of capital relative to other inputs (capital substitution). The rate of growth of operating cost productivity will be equal to that for TFP plus the difference between the rate of growth of capital and other inputs times the elasticity of output with respect to capital. Thus the likely rate of growth of operating cost efficiency can in principle be derived from likely TFP growth given a forecast of the increase in capital assets (other than that for other purposes such as quality improvement) and an estimate of the elasticity. However, this is not simple and, unsurprisingly, is not addressed in CEPA's paper.

CEPA report DNO capital stock as increasing around 6.5% per annum relative to opex in 1991/92-2001/02. This sort of change in relative factor inputs is not expected to continue and so the difference between DNO TFP and opex efficiency growth is likely to be less marked.

7 Conclusions

CEPA has produced an interesting report but it appears to be one of work in progress. There appear to be inconsistencies in some of the numbers, the methods used are not fully described and the conclusions drawn are not justified.

Our assessment, based on the evidence presented, is that the forecast of the potential for trend DNO productivity growth is subject to significant error but there are no strong grounds to expect it to be much higher than that for the economy as a whole, which has been around 1.3%.

- DNO past performance is subject to substantial measurement error and, since it is influenced by privatisation effects, would not (even if correctly measured) be a good guide to future performance.
- The evidence from other UK utilities is also not a good guide to future DNO performance. It is strongly affected by the assumptions used and/or derived from limited data periods. The results are diverse and affected by privatisation.
- Evidence from US and Norwegian distribution companies has unexpected features but is consistent with a growth similar to the UK average. The simple average is 1.2%.
- NIESR estimates derived from US, French and German national accounts data suggest TFP growth in the utility sector slightly lower than that for the UK economy. The simple average growth 1990-99 was 1%. Apart from in the period of rapid growth in France 1950-70, utility TFP growth in those countries has been around that for their economies as a whole.
- TFP growth in the UK utility sector, apart from having been stronger in the 1990-99 post privatisation period, was also 0.7% higher than that for GDP as a whole in the earlier 1950-90 period but this is on the basis of a utility output definition that grows faster than that used by Ofgem.
- CEPA's composite sectoral TFP estimate excluding post-privatisation utilities data gives a TFP growth rate (1.5-1.8%) slightly higher than that for the economy as a whole (1.4%).
- CEPA's survey of analysts is small but the median TFP figure (1.5%) and the downward skewed distribution are consistent with TFP growth similar to that for the economy as a whole.
- The evidence from company accounts produces a higher figure (2.3%) but - given the lack of definition of the concepts used, explanation of method applied, justification for the selection of the twelve particular companies or explanation why these might be expected to differ from the economy as a whole – we do not consider that much weight can be placed on it.