Nienke Hendriks
Senior Price Control Review Manager
Office of Gas and Electricity Markets
9 Millbank
London
SW1P 3GE

Head Office
Inveralmond House
200 Dunkeld Road
Perth
PH1 3AQ

Telephone: 01738 456400
Facsimile: 01738 456415
Email:

Our Reference:
Your Reference:

Date: 19 November 03

Dear Nienke

**Electricity Distribution Price Control**

I attach SSE's response to the Update document on the above, which was issued in October.

Please let me know if you would like clarification of any point.

Yours sincerely

Rob McDonald
Director of Regulation

**Electricity Distribution Price Control Review – October 2003 Update**

**Response by Scottish and Southern Energy plc**

Timetable and Consultation Process

It is apparent that the project timetable, as set out in table 2.1 is very tight, with little "headroom" for slippage. In particular, we would urge Ofgem to clarify as many of the outstanding policy issues as possible earlier in the process. For example, we believe that Ofgem should confirm in the December paper the policy towards, for example: depreciation; metering price controls; the methodology to determine operating cost allowances; the cost of capital methodology (i.e. pre- v. post-tax); and the details of the fixed retention formula for opex and capex. Further detail underpinning the proposed hybrid mechanism for remunerating investment to accommodate distributed generation is also urgently required.

That would allow sufficient time in the New Year for discussions about the detailed numbers and implementation of each of these policies. By contrast, we are concerned that delaying the policy decisions until the March paper will lead to a rather "rushed" implementation of the price control, which has been a failing in previous price reviews.

Form, Structure and Scope of the Price Control

**Form and structure of the price control**

As noted in previous responses, we support the overall RPI-X framework and we therefore welcome Ofgem's decision to adopt the same broad approach at the current price review.

**Pass-through costs**

We would be firmly opposed to any suggestion that the present pass-through of NGC's exit charges would not continue to be subject to pass-through. DNOs are not able to control these costs and indeed they are separately and directly regulated by Ofgem. It is also clear that Ofgem and NGC seem to be almost continually reviewing NGC's (and indeed other) use of system charges. It would be unacceptable to expose DNOs to this new regulatory risk and accordingly we believe that the present pass-through arrangements should continue.

We agree that Ofgem licence fees should continue to be subject to pass-through.

We welcome Ofgem's commitment to reimbursement of under-recovery of rates for the current price control period. We are however concerned at the suggestion that rates may not be passed through in future, seemingly based on the assumption that there are now appeal mechanisms in place. In practise, rates are agreed with the Valuation Office every five years (coincident with the price control period). After agreement, the Valuation Office view is that rates are not a controllable cost and should be expected to increase annually by RPI. In addition, although there is ostensibly an appeals mechanism in place at the review, if the Valuation Office sees a significant drop in revenues it can revoke the appeals mechanism and re-impose prescription. We therefore see no reason why rates should not still be a pass-through cost.

**Rolling opex adjustment**

We have a few concerns about the way in which the rolling opex adjustment is set out in the Update document. The document suggests that the methodology proposed by OFWAT is broadly appropriate although a number of issues need further consideration. The paper does not set out those issues but we believe they are as follows:

- opex is not defined as to whether it is SCC (standard controllable cost), total costs or something else. Presumably it would in any case exclude exceptional and atypical items;

- the only benefit in the next price control period is the savings made between 2002/03 and 2003/04, all subsequent years are reviewed at DPCR5. This is in our view too uncertain and undermines the strength of the incentive significantly. We would prefer to see a rolling mechanism coded into the Licence which builds year on year. This should be possible given Ofgem's desire to monitor progress against the price control year by year through the Regulatory Accounts.

  Failing that, we are concerned about the treatment made in the last year of the price control i.e. 2004/05. Without adjustment at DPCR5, DNOs would keep those savings for six years. To adjust them could be seen as retrospective regulation. OFWAT have recognised this and have proposed that savings are kept for six years i.e. the year in which the savings are made and the five following years (as opposed to four years as proposed by Ofgem). This removes the need for what could be seen as a retrospective adjustment at the next price control review and we support this;

- as we have noted before, OFWAT are proposing a "multiplier" to give additional rewards to those companies at or close to the frontier, to provide stronger incentives to continue to drive the frontier forward. Not only do we believe that this is important, but we see no reason for OFGEM and OFWAT to adopt different methodologies in such similar areas.

**Rolling Capex**

We agree with Ofgem that the position with respect to capex overspends needs to be urgently clarified.

**Distribution losses**

Ofgem is aware of our specific concern about the effect of certain types of distributed generation increasing distribution losses in the north of Scotland. Against this background, we strongly support the continuation of some method by which the losses incentive term can be adjusted where a DNO can demonstrate that a particular distributed generation scheme or set of schemes has had (all other things being equal) a negative effect on losses.

We would caution Ofgem against planning further “disaggregation” work on the causes of losses on a reference network basis. We believe that simplified theoretical network models cannot give a true picture of what losses “should” be and that it is impossible to devise a fair value for the optimal level of losses on any real network given the long-lived nature of network assets. For historic reasons, current network assets may not reflect the optimum configuration for the present pattern of load on the network. We would therefore be opposed to any work that had the aim of deriving an external losses benchmark for each DNO area.

Quality of service and other outputs.

**Consumer Survey**

We note Ofgem's summary of the key findings from the first phase of the consumer survey. We note that customers are broadly satisfied with the service received and agree with the conclusion that the existing scope of the quality of service incentive scheme is broadly appropriate. Therefore Phase 2 of the survey should focus on the "gaps" which customers have identified as important, and/or where there is a willingness to pay for such improvements. Phase 2 should also start from the basis that there is no case for general tightening of existing standards.

Our comments on each of Ofgem's other conclusions in turn are as follows:

- Consumers expect interruptions in severe weather/other exceptional circumstances. Although companies are under pressure to improve performance in events like the October 2002 storms to that of the frontier/benchmark companies, there is no mention of improving the benchmark performance i.e. network resilience / investing in the networks to reduce both the number of incidents and the number of customers affected by each event. We discuss this further below;

- Time periods prior to compensation are too long. In the case of severe weather Ofgem and the DNOs have recently agreed interim arrangements for compensation payments, and we believe this is a workable arrangement going forward. In normal weather conditions, we would not support tightening the 18 hour restoration period as this would incur significant additional costs. With regard to the number of interruptions, we remain firmly of the view that the Multiple Interruption Guaranteed Standard (MIGS) is basically flawed i.e. it assumes an implied failure rate, whereas the purpose of the Guaranteed Standards was always that companies should be able to avoid failure by management action. In addition, in the Highlands and Islands of Scotland due to the frequency of storms and the lower design/security standards to which the network was built, it is likely that many customers would be entitled to compensation every year; and reinforcing the network is not an economic option. The reason that there has only been a handful of claims to date is that customers are not aware of the standard. However, the number of claims will inevitably increase as customers are made more aware of compensation entitlements. It is not sensible that those customers should expect the same network performance as other GB customers;

- Business consumers consider that compensation payments need to be increased significantly. It is important to recognise that compensation payments should reflect what customers have paid for their electricity distribution and are not intended to insure against consequential loss;

- There is a need to increase customer awareness of GSs. We believe this is already happening. There is a developing "compensation culture" in the UK, and the public reaction to the October 2002 storms is evidence of this. This will increase costs incurred by DNOs. It is important that provided DNOs have performed appropriately then they should be able to recover efficiently incurred costs;

There are a number of additional conclusions, which Ofgem have omitted, which we believe can be drawn from the consumer survey. These are as follows:

- Those carrying out the survey had a quota of rural customers to meet. The rural/urban ratio (and therefore the findings from the survey) do not represent the national average. This needs to be taken into account when interpreting the results;

- Ofgem state that a minority of customers expressed some willingness to pay for other improvements, for example undergrounding of overhead lines. We believe that the survey indicates that customers were much more firm about this (c. 36% of customers willing to pay something for quality improvements and c. 15% of customers in favour of additional undergrounding);

- No mention is made of the finding that only 15% of domestic customers found short interruptions to be inconvenient. It is clear therefore that transient faults are not a high priority;

- Neither is it reflected that in general there was a positive experience of planned interruptions;

- Although customers were in principle in favour of automatic GS payments, they were not prepared to pay for the systems required to enable this e.g. linking customers to the LV network. There is therefore no case for extending the IIP customer / network connectivity model to cover sub-LV feeder incidents.

**Comparing quality of supply performance**

We support the work that has been carried out on disaggregation. It will be a useful tool in understanding gaps between the DNO's performance and how these might be closed, when it has more data. However, we are very concerned at how this work is being used currently, in particular in arriving at benchmarks for the Forecast Business Plan Questionnaire – Quality of Supply Scenario. Ofgem claim that this work will enable them to "compare performance at a more disaggregated level". We are not at all confident that this is robust yet.

**Use of benchmarks**

Ofgem ask us to assume for the FBPQ QoS Scenario, 40% of gap closure by 2010 and the remainder by 2020. In our view the benchmarks assumed are unrealistic. This will be reflected as a significant investment requirement to achieve the benchmark, even after making adjustments. Customers' willingness to pay for improvements has to be a key input into the consideration of quality of supply targets going forward. The cost of achieving benchmarks will vary significantly between DNOs according to, for example, the current configuration of networks. To ask for the information requested in the FBPQ to inform the inform scaling of the analysis to be undertaken in Phase 2 of the consumer survey, is the wrong way round. It is also not a linear relationship, assuming that a DNO will always choose the cheaper option for the same output, the incremental cost of improvements will increase as a DNO gets nearer to its benchmark. In our view, the Quality of Supply scenario is therefore irrelevant and uninformative. In addition, Ofgem should base the Phase 2 survey on DNOs' own Quality of Supply scenarios.

**Rewarding frontier performance**

IIP was intended as a mechanism to reward frontier performance, and to incentivise companies to continue to seek out continual improvement. The only reason we can see for introducing at this stage an additional reward for frontier performance is that some DNOs have claimed that their IIP targets are inequitable. Nevertheless those were the targets all accepted at DPCR3 as part of the package of proposals (and all companies had the option of a subsequent re-opener). It is not good incentive regulation to introduce ex-post adjustments at this stage of a price control. For example, Ofgem recognise the perverse incentive properties of the "within range" adjustments made in the final stages of DPCR3. These were made with little regard to the effect they would have on DNOs' behaviour in the following price control period.

Also rewarding value-for-money rather than specific output targets is in our view unworkable. Indeed, CEPA recognise in their report that incentive mechanisms for quality should be separate from cost incentives.

**Network resilience**

As we have referred to above, unless the issue of resilience is addressed then the performance of the benchmark companies in the October 2002 storms is implicitly accepted and although the overall industry performance should improve due to the measures currently being undertaken by a number of DNOs, the frontier will not improve. In fact, unless adequate investment is made in the networks over the next ten years to counter ageing networks, the frontier may never be reached again for an identical incident. The configuration of the networks i.e. radial networks with large parts overhead, is a legacy of history. If companies were to design a network today to serve the current customer base, they would look quite different.

The Network Resilience Working Group has been reviewing this issue and we support their recommendations.

It is not immediately clear how resilience can be measured robustly, and we would be pleased to help Ofgem with further work in this area. However, we do believe it is appropriate to introduce additional incentive arrangements in this area, and to reward the frontier companies. SEPD was penalised c. £15m in DPCR3 in effect for having re-invested capex efficiency savings into resilience measures. Our investment was borne out by our benchmark performance in the October 2002 storms and we believe that rewards should start with reimbursement of that penalty. We believe that this could be achieved by adding the previous £15m penalty to our RAV.

Distributed Generation

As noted in our response to the previous price control paper, we consider that it is vital to provide certainty to DNOs that their costs will be recovered. It follows from this, in our view, that the pass-through element of the incentive framework should provide 100% of the DG-related reinforcement costs at the agreed cost of capital. The £/kW term would then provide the incentive element: a premium return to cover other costs and uncertainties surrounding the introduction of greater quantities of DG onto the DNO systems.

Notwithstanding these views, we recognise that Ofgem seem determined to set the hybrid mechanism parameters such that all capital-related costs are not covered by the pass-through term. Consequently, there will be an element of capital cost that DNOs will need to see recovered via the £/kW incentive term. There are inevitably risks associated with this approach, and we comment on these in more detail below.

As we understand it, under the proposals, a connecting generator will pay a "shallowish" connection charge with any remaining reinforcement costs required to accept its generation onto the system funded initially by the DNO. At some point, the MW connected will be counted towards the incentive term and the DNO's allowable revenue will be increased by the amount calculated under the incentive term. Separately, the allowable revenue will also be increased by the pass-though element of the incentive scheme.

**Forecast Risk**
Against this background, the first point to consider is how the timing of the DG-related revenue allowances would match the actual expenditure. It will be important for Ofgem to clarify exactly how this would work. Our understanding is that in the June return following the end of financial year t, the parameters of DG-related capital expenditure and DG MW connected would be added to the other price control parameters that determine what the allowable revenue in year t actually was. Thus the allowable revenue entitlement would largely be provided in the year that the capital costs were incurred, which we would support.

This does, however, bring with it an additional forecasting requirement for DNOs who would have to forecast the MW connecting and the capital expenditure incurred some months before the start of year t to tie-in with the tariff setting process. This additional element on forecasting risk could be mitigated by relaxing the percentages of over and under-recovery of allowable income at which the penalties and restrictions set out in the special conditions of the licence come into effect.

**Timing Risk**
Our understanding of the incentive term is that it would be payable over 10 years starting in the year that a formal point in the DG connection process is reached. This brings with it the possibility that the DNO's full investment costs would not be covered in the year in which the investment is made and this risk would have to be addressed in the size of the premium return provided by the incentive term.

There is also the question of the starting point for payment of the incentive term. This should occur early in the connection process to avoid any significant delay between the expenditure incurred by the DNO and the inclusion of the relevant incentive amount in the allowable revenue. We propose that the date of signature of the relevant connection agreements is taken as the confirmation of delivery of capacity as this marks the generator's formal commitment to the project and is easily auditable. While there can be a delay between the date of signing of the connection agreement and the actual electrical connection being commissioned, it is precisely this period in which the DNO's capital investment has to be delivered. This approach would therefore match the start of the incentive term revenue stream with the financial year in which the investment is made. Ofgem must recognise, however, that even this approach is likely to result in a delay in bringing forward investment to accommodate new renewable generation (unfortunately, this is an inevitable outcome of any scheme which provides for less than 100% pass-through).

**Credit Risk**
There is then the question of the risk of DG MW being commissioned but, for whatever reason, coming off the system before the DNO's reinforcement costs are fully remunerated through the incentive term. In our view, it is unacceptable for DNOs to be exposed to the range of economic considerations affecting the viability of the generation market, including the path of renewable benefits such as ROCs, which may be key to the economics of some schemes. Thus, in our view, once a DG scheme has connected, the appropriate MW should stay in the incentive term for the appropriate term irrespective of whether the scheme subsequently stops operating.

The alternative would be to establish a framework of credit arrangements whereby prospective DG connections provide cover for the outstanding reinforcement costs not funded by the connection charge. This does not seem a particularly attractive route given that we are still in the process, after some years, of trying to establish an acceptable set of credit arrangements for energy suppliers. Generator credit arrangements would be likely to lead to similar problems

**Location Risk**
This risk is associated with the variability of reinforcement costs required for DG schemes at different points in the network. As is indicated by the information provided in our DG-BPQ submission, the costs associated with shared assets for future schemes in the north of Scotland can range from zero (for those schemes where no reinforcement is required to accommodate the connection) up to around £1000/kW reflecting, for example, the cost of subsea links. There is clearly a risk to any DNO that the range of DG projects which go forward to connection have more expensive reinforcement than the average of forecast schemes would suggest. As we have noted in previous responses and discussions, the change of connection policy towards a more shallow approach for DG connections will inevitably lead to more "higher reinforcement cost" connections going ahead. Indeed, DG schemes which were previously abandoned due to the high cost of the necessary reinforcement, and which are not in our future forecasts may again apply for connection once it becomes clear what proportion of reinforcement costs the new connection policy allows the scheme to avoid. This will create an upward driver on reinforcement costs compared to the levels shown in the future section of the DG-BPQ.

In our view, the only way to resolve this risk is to include a right for DNOs to refuse to connect particular generators (or to delay making the connection until the incentive framework parameters have been reset accordingly) in circumstances where the price control will not allow legitimately incurred costs to be recovered. Sections 17 and 19 of the Electricity Act 1989 (as amended) deal with a distributor's power to recover expenditure and exceptions from the duty to connect. In our view, a case could be made that it was not "reasonable in all the circumstances" for a DNO to be required to make a connection if the legitimate costs of that individual connection were not going to be met by the combination of connection charge and price controlled revenue allowance associated with that connection. Thus, it would have to be acknowledged that there were limits on the costs of DG connections that could be included in the incentive scheme. There would be protection for individual DG customers if this circumstance arose, in their ability under the Act to seek a determination of the dispute.

**Regulatory risk**

Our understanding of the DG incentive proposal is that the allowable income associated with the incentive term would be payable over ten years at least. This time span extends over at least two price control periods and brings with it the regulatory risk that the initial arrangements on which DNOs make their assessment of risk and reward might be changed at a later date. It would thus be necessary for Ofgem to give a firm commitment that the details of the final proposals would not be retrospectively changed except in specific, previously notified circumstances.

**Conclusion on Risk Aspects**

We have discussed above the different types of risk that we foresee should Ofgem not accept that the pass-through element of the incentive framework should provide 100% of the DG-related reinforcement costs at the agreed cost of capital. We have also suggested ways in which these risks could be mitigated. Even within these parameters, uncertainties and risks remain which would require a substantial premium on the cost of capital for DNOs to undertake and, in our view, these risks are such that the great majority of DG-related costs should still be remunerated through the pass-through element of the DG incentive framework. In addition, Ofgem must recognise that any scheme which does not provide for 100% pass-through will result in a delay in investment until the DNO is certain that sufficient MW will connect to make that investment worthwhile. It must also be recognised as an inherent feature of this hybrid mechanism, that investment will be "patchy" and additive in response to individual requests. Accordingly, this could lead to inefficient investment overall as DNOs would be less willing to install additional capacity over the specific scheme requirements even if the marginal cost of doing so would be small.

**Other issues**

Turning to other points raised in the consultation document in this chapter, our views are as follows.

1. The summary of DG-BPQ information underlines the variability of DG costs across different DNOs and also the range of future forecast £/MW cost figures. This variability supports our view that DNO-specific incentive elements should be applied in conjunction with full pass-through of investment costs.

2. On the question of DG network access on an ongoing basis, we are concerned about proposals for DNOs to compensate connected DG at a £/MW per hour basis

for network unavailability. In our view, DNOs are already incentivised through standards of performance on network availability and do not have control over all causes of network failure. The proposal introduces a further element of risk for DNOs and we are firmly opposed to this.

3. In our view, present arrangements for load-related capital expenditure work well and no case has been made to apply these more complex arrangements to demand connections.

4. In relation to the Innovation Funding Incentive, as noted in our previous comments on this subject, we believe that it will be difficult to fit potential projects into rigid categories. We believe that allowable funding for all approved projects brought forward under the IFI scheme should be 100%. We note that any future reduction in operating or capital costs - including those resulting from such projects - will automatically flow though to customers after an initial period through the existing RPI-X price control framework.

5. As we have stated in previous correspondence and discussions with Ofgem on the subject of RPZs, we are supportive of the concept but are concerned that the currently proposed framework is too complex in practice. In our north of Scotland area, the type of area where there may be an opportunity for an RPZ scheme is in the island groups where further DG is already potentially constrained by the network characteristics. However, the detailed scheme rules – particularly the 50MW limit – would preclude most (if not all) potential schemes.

6. We agree that there will be costs for DNOs in accommodating the anticipated DG development. A good baseline for these expected costs is provided in DNOs' DG-BPQ submissions for the 2005-10 period. However, as discussed above, the eventual costs are likely to be higher as further DG schemes come forward, influenced by the reduced reinforcement cost that individual schemes are likely to see as a result of the proposed "shallowish" connection charge boundary.

Assessing costs

**Historic Business Plan Questionnaire**

In our view, the financial information published in the update document was neither informative nor useful. It was draft and unaudited information and it was not comparable. For example, the information had not been standardised for clearly differing capitalisation policies. It would have been far preferable in our view to have waited until after Ofgem had carried out the HBPQ visits to DNOs and companies had been given the opportunity to re-state numbers on a more consistent basis. To be clear, we support transparency (subject to commercial confidentiality and Stock Exchange rules), but at Ofgem's recent workshop the financial community confirmed that they rely on Ofgem to publish tested and quality data. We would therefore urge Ofgem to only publish standardised information in future papers.

In addition, we are concerned that Ofgem have introduced a new ratio (EBIT/RAV) at this stage, with no consultation as to its usefulness. In our view, this served no purpose other than to raise concerns amongst the financial community that Ofgem were flagging early to them an important area of concern. Our comments on the unreliability of the data in the previous paragraph again apply, but in addition in our view this in effect amounted to a comment on performance, which Ofgem had said to us, and state in the document, they would not do. Not only is this kind of comment share price sensitive, but it is also not a ratio on which the current price control was based. Ofgem have yet to consult on the financial ratios to be used in the price control review, and to this end we welcome Ofgem's commitment at the workshop to meeting with the financial community (together with the DNOs) to discuss the information they require.

**Forecast Business Plan Questionnaire**

We do not believe that it is possible or appropriate to benchmark capex in the same way as opex i.e. on a cost per customer/km/unit basis. This is in the main due to the many and various capex drivers, but also due to the difficulty in defining capex. Assessing DNO's capex forecasts going forward can only be achieved by reviewing DNOs' forecasting processes. Ofgem would then need to satisfy themselves that these are robust, collect detailed capex forecasts from the DNOs and then use these forecasts to set future capex allowances.

However, with regard to the opex forecasts, we believe that the amount of detail requested is excessive and unnecessary (even though Ofgem have reduced the amount of information requested in response to DNOs concerns). Companies do not forecast in that level of detail and we see nothing to be gained by being required to force these forecasts into detailed tables. In our view, the outcome Ofgem are trying to achieve is a roll forward of the 2002/03 base year for the industry or average DNO and to make company specific adjustments for known future costs where appropriate. This only requires forecasts at a reasonably high level. We would urge Ofgem to bear this in mind in assessing the detailed FBPQ responses and in formulating any supplementary questions.

As we have said previously, we believe that the Quality of Supply scenario in the FBPQ is of little use or relevance. In our view, the DNO scenario is the key scenario and the Base Case and Quality of Supply scenario can only be checks on this, not the other way round.

**CEPA's background study on benchmarking**

We see much to be commended in the CEPA report. We also continue to support COLS and believe that DEA will provide a useful additional test as to the statistical robustness of the regression output (although, as noted in previous responses, DEA is commonly criticised for producing "clustering" of relative efficiencies).

We agree with CEPA that the COLS in 1999 (as supplemented with expert industry judgement) was robust. DNOs are essentially similar businesses and regression is a valid technique for assessing opex efficiency (we have commented above that we do not believe that capex can be benchmarked in this way) with a few relatively simple adjustments. In particular:

- allowance needs to be made, as in previous reviews, for the additional costs associated with operating in very urban locations i.e. London, and at the opposite extreme, remote locations i.e. the Highlands and Islands of Scotland;

- capitalisation policies need to be normalised. This is not a complex issue, relating only to the capitalisation of faults, tree cutting and overheads and does not require complicated and detailed capitalisation policies. Ofgem have collected enough information to be able to make judgements on this and the resultant adjustments to normalise;

- a bottom-up assessment of fixed costs needs to calculated, to test the slope of the generated regression line. This is not difficult; DNOs have relatively few and simple to define fixed costs for this purpose, for example corporate/Head Office costs and IT systems/software costs (or to put it another way those costs which do not vary with size i.e. number of customers or length of network) and companies have submitted information on this in the HBPQ;

- mergers – it is probably helpful to look both at the 14 DNOs and the 8 managed groups. However, in our view there are no single DNOs, all are part of a bigger Group in some way, and therefore there is no need to make any specific merger adjustment.

We do not agree with CEPA that the use of international data will improve the robustness and quality of the benchmarking analysis. In our experience, cost information is extremely difficult to obtain for overseas distribution businesses alone on a consistent and comparable basis, and overseas companies are almost always operating in different conditions with subsequently different costs. As a consequence, international comparisons tend to lead to a "clustering" of the relative efficiency of domestic firms. We also do not believe that panel (time series) will be particularly helpful, due to the inconsistency in the presentation and aggregation of costs over recent years (in no small part due to the discussions which have been going on for some time on developing the Regulatory Accounting Guidelines). It is of course right to study the base year costs in detail to arrive at a Standardised Controllable Cost, but to attempt the same for previous years will be onerous if even possible.

We are not convinced that dropping customers as a scale variable in the regression (on the basis that it is highly correlated with units distributed) is robust. However, we would presume that as part of that, EHV units, which vary significantly between DNOs, would be excluded. Otherwise, DNOs with a large proportion of heavy industry relative to the domestic customer base, would look artificially efficient.

**Ofgem's approach to assessing costs**

Our comments on the CEPA report above have already covered much of Ofgem's approach to assessing costs. We have three further comments:

- any adjustments made to standardise costs must be transparent;

- we would again strongly urge Ofgem to move away from the frontier methodology introduced in DPCR3 and back to the average costs methodology which was used in previous reviews and which we believe has stronger incentive properties. Not only does it provide stronger incentives for the frontier companies to continue to drive the frontier forward but it also overcomes the doubts many observers had at DPCR3 about the robustness of the frontier. It also addresses Ofgem's commitment in the Update document to "ensuring the benchmark is as robust as possible and not overly dependent on any single firm or unduly affected by outliers". We have already submitted a Paper on this to Ofgem's Incentives Working Group and attach this at Appendix 3 to this response;

- We have serious concerns about the use of TFP to assess future efficiency targets for the industry as a whole. In particular, it is apparent that TFP is highly sensitive to the choice of comparator industries and the assumptions about any future privatisation effect. More fundamentally, we do not believe that it is appropriate for Ofgem to forecast future savings without providing explicit cost allowances for the investments that will be required to achieve those savings (otherwise, an averagely efficient DNO, improving performance at the TFP level, would earn less than its allowed cost of capital).

Financial issues

**Treatment of pensions costs**

We welcome Ofgem's generally positive re-action to the serious issue of pension fund deficits. This has raised new issues which we have not previously had to address. The guidelines seem to set out a clear way forward for future costs and obligations. However, we still have three fundamental concerns with regard to pensions deficits. These are:

- Past underfunding of pension contributions in the price control. There is clearly doubt as to whether the present price control has fully funded DNOs' pension costs i.e. allowed opex was based on a frontier where at least one company was on a pensions "holiday". We welcome Ofgem's recognition of our concerns and note that they will be addressed in the December document. However, we see no benefit in spending time on trying to agree what was allowed in the current price control. A particular, and unsatisfactory, feature of the current control is that it is not possible to un-pick the detail of the "package" which was accepted;

- Regulated / unregulated split. It is not acceptable that the funding of liabilities should be limited to the regulated business as currently defined. All accrued pension liabilities in respect of pensioners of the former regulated PES (i.e. prior to Utilities Act separation) are legitimate costs of the current regulated DNO;

- Benefit enhancements – customers have already benefited from the cost savings made as a result of redundancies. This is no justification for taking account again of pension fund surpluses which have been used to fund such redundancies.

Representatives of the DNOs are meeting with Ofgem to discuss these concerns and have sent to Ofgem papers which explain our concerns outlined above in more detail.

# The Incentive Properties of the "Average Costs" Methodology

## Introduction

1. In determining the revenue each company needs to cover its operating costs, Ofgem will need to consider two questions:

   - How quickly should efficiency savings be passed on to customers? and

   - How should companies be incentivised to continue to seek out efficiency savings, especially when those savings are becoming harder to find?

2. As Ofgem have recognised in the work on incentives, these questions are linked and (potentially) conflicting. It is also apparent that these issues do not arise in a competitive market.

3. In DPCR3 Ofgem introduced the "frontier" costs approach to assessing operating cost efficiency and projecting future costs. This paper argues that this approach has significantly weaker incentive properties than the "average" cost methodology used in previous price control reviews, and which better mimics a competitive market.

## Background

4. The "frontier" costs methodology was introduced on the premise that companies had to be allowed their own costs at the start of the price control period, and that companies not on the frontier should be allowed a catch-up period ("glidepath"). These companies were allowed four years to catch up 75% of the way to the frontier. Presumably the 25% discretion was to allow for perceived uncertainties and inaccuracies in the estimation of the frontier.

5. The frontier was not expected to improve over the price control period, but remained at the 97/98 level of base costs for the frontier companies. However, it can be argued that this represented no reward comparatively for the efficient companies in recognition of their frontier status and hence did not provide any incentive for those companies to further strive to improve efficiency during the next price control period. The glidepath that was introduced for the "laggards" provided a generous grace period before those companies were required to achieve frontier performance. In effect, therefore, the glidepath approach provided the inefficient companies with the opportunity to gain benefits from efficiency savings that were not available to the frontier companies that had already achieved those savings. This produced a further disincentive to efficient companies to continue to drive the frontier forward.

6. Ofgem made a token recognition of frontier performance by allowing at a late stage in the review an arbitrary 1% additional allowed revenue to the three

companies on or near the frontier, for the duration of the price control. Not only was this not symmetric with the benefits available to the laggards but such "within range" adjustments are not consistent with Ofgem's declared aims of transparency and predictability of regulation.

7. It is noted that the importance of rewarding the frontier companies has been recognised by OFWAT in the current price control review in the water industry. This is particularly important, since it is the performance of those companies that determines the price control outcome for the whole industry and hence all customers.

8. Ofgem have since committed to an additional fixed retention period for opex savings made after 1 April 2003, ostensibly to solve a perceived periodicity problem. However, it can be argued that this mechanism alone will not completely resolve the periodicity problem. In particular, as long as a company's allowed future costs are dependent on past performance there will always be a residual incentive to consider the effect on future allowances of delaying individual efficiency improvements.

9. Ofgem also assert in the July consultation paper that the application of fixed retention periods on their own will not weaken incentives on companies that are at the frontier. As noted above, the glidepath adopted at the last price review rewarded inefficient companies by providing them with additional revenue for failing to achieve the standard of the frontier companies. The fixed retention period works in the same way as the glidepath and there is a real danger that it will further reward those companies in contrast with the frontier companies.

10. This arises because there is significantly more scope for the inefficient companies to reduce costs compared to companies that were at the frontier at the last price control review. Indeed, as noted above, the frontier approach at the last price control review only required those companies to achieve three quarters of the difference in cost with the frontier companies over the price control period. There is thus a greater prospect for additional returns for less efficient companies under the fixed retention period than for companies that have made identical savings earlier in the regulatory cycle. As above, this reinforces the poor incentive framework for frontier companies.

11. However, the fixed retention period for operating cost savings is welcome, particularly given the fact that the marginal investment necessary to achieve future savings is likely to be much greater than in the past. This paper argues that this cannot be combined with a frontier costs approach but that this methodology should be supplemented by an average cost approach to setting future operating costs allowances. Otherwise, elements of the periodicity problem will remain and incentives on the frontier companies will be weakened further.

The "Average" Costs Methodology.

12. The benefits of competition depend on reward for winning and penalty for losing. Those companies that are efficient survive, those that are not make low returns and have their management replaced. This creates an ongoing pressure to maximise efficiency.

13. Under competition, prices are set by the market and individual firm's costs have a negligible impact. A drop in prices only occurs if all companies reduce their costs. A firm will always be better off than it would be without the cost reduction and will keep the benefits until its rivals catch up. This can be contrasted with the frontier costs regulatory approach, whereby if a company performs well it receives a tougher target (i.e. the "ratchet" effect).

14. Under the average costs methodology, a company's allowed costs are based on the industry average for a firm of their size (this has been arrived at in the past by regression analysis, although there is no reason why other suggested statistical techniques should not be used to find the average as well as the frontier). This better replicates how a competitive market works, by relating operating cost allowances to factors that are, as far as possible, exogenous to the individual company's past performance.

15. Under this approach, since no individual company could be expected to materially affect the industry-wide regression line (i.e. the average), there is no incentive to delay efficiencies. An average cost approach would thus resolve the periodicity problem and the regulator would no longer have to worry about the speed of transfer of efficiency savings to customers. It would also mimic the outcome of competitive markets where companies with lower than average costs receive higher returns and vice versa. Such an approach would therefore provide the strongest possible incentive on all companies to reduce operating costs.

16. Basing allowed costs on the industry average would also be consistent with an industry cost of capital (i.e. set for the average company). An inefficient company would earn a return less than the cost of capital for as long as they under-performed the average.

17. In aggregate the use of average costs produces the same allowed cost for the industry as the total of companies actual costs, with the added benefits that customers pay the same whether served by an efficient company or an inefficient company. An average cost approach would also avoid benchmarking against the frontier, which was heavily criticised at DPCR3.

18. The rolling opex incentive "bolted on" to the average cost methodology would then provide a catch-up mechanism and link back to companies' actual costs at the start of the period, replacing the glidepath.

19. The benefits of the average costs approach were also recognised by Ofgem's consultants Frontier Economics. In their report they point out that companies will eventually reveal the efficient level of costs through the level of profits

made. However, assuming that companies have differing levels of efficiency, they argue that benchmarking provides additional information about how far costs can fall and therefore allows earlier price reductions. If benchmarking is based on the average, then as we have also argued above, a company should not be worried about reducing costs and benchmarking because the change in its own costs does not affect the average.

To illustrate this, Frontier calculate that under a five year fixed retention mechanism a company keeps 29% of its opex efficiency savings. The proportion retained increases as the number of firms increases, for example with 14 companies the retention is 29% + (71%*13/14) = 95%, because under an average costs methodology a company's own cost reduction is weighted by 1/14 when calculating the industry cost reduction.

The attraction is that all firms face this same high incentive, however the incentive power has increased without reducing customer benefits. For example, if they all make the same cost reductions then each firm's price falls at the price control review by the full amount of the cost reduction, and customers receive the full 71% of the benefit.

**Conclusion**

20. We have discussed above the strong incentive properties of an average cost approach to setting operating cost allowances, which in our view should be used to supplement the five year retention period. There is a real danger that alternative approaches, including a repeat of the frontier methodology adopted at the last price review, will significantly blunt incentives for the efficient companies to constantly strive to reduce operating costs. We would therefore urge Ofgem to commit to the use of an average cost approach at the earliest opportunity, with subsequent discussions about the detailed approach to setting the average line following the work by Cambridge Economics.