

## The Updated Proposals as a package

- 1 Our detailed responses to Ofgem's Updated Proposals are embodied in the appendices attached to this document. In this overview, however, we try to bring together our main concerns about the proposals as a package.
- 2 In short, it is our view that:
  - (a) The proposals (covering, inter alia, capital expenditure, operating costs and a variety of new incentives and adjustment mechanisms) would not allow us to meet our statutory and licence obligations to develop, maintain and operate efficient gas and electricity transmission networks, while earning even the rate of return currently assumed by Ofgem. In fact, the current proposals give us unprecedentedly strong financial incentives **not** to invest in gas and electricity transmission networks.
  - (b) Ofgem's current 'modelling assumption' for our cost of capital is itself inadequate and is not consistent with the factors which Ofgem believe should be taken into account in determining an appropriate base rate of return for National Grid Electricity Transmission (NGET) and National Grid Gas Transmission (NGGT).
- 3 In this overview, we cover, in turn, components of Ofgem's calculation of regulated revenue for the two National Grid UK transmission businesses which constitute the main gaps between us and Ofgem, i.e.:
  - (a) capital expenditure;
  - (b) operating costs;
  - (c) incentives and adjustment mechanisms; and
  - (d) cost of capital.

### Capital expenditure

- 4 Some of our licence obligations lack precise specification. On the one hand, we do have unambiguous obligations with respect to, for example, the connection of new users to the electricity transmission system and, via our Security Standards, to the deep reinforcement of the network to accommodate their use of the system. On the other hand, our obligations do not tie down, for example, what level of reliability the electricity transmission network should achieve.
- 5 This latter point is an important issue when considering Ofgem's proposals because one of the biggest gaps between us is with respect to how much capital expenditure we should be incurring to replace existing electricity transmission network assets. The gap between us reflects both Ofgem's assumption of a lower volume of asset replacement and Ofgem's unrealistically low assumption of the unit costs of asset replacement.

- 6 We accept that Ofgem's responsibilities include the making of judgements on the appropriate balance of costs and reliability, and on the cost of achieving any given level of reliability. However:
- (a) There is no evidence that customers actually want a lower level of reliability – not least because the nature of transmission systems is such that, when asset failures occur, they will have very unpredictable effects that may well be widespread either regionally or nationally.
  - (b) We strongly believe in our own analysis of what spend will be required to maintain existing reliability, not just for the next few years but in the long term.
  - (c) The incremental cost of National Grid's proposed electricity network asset replacement plans, compared with Ofgem's Updated Proposals, is less than £1 per customer per year.
- 7 Our analysis of the gap between us and Ofgem on the capital expenditure required on the electricity and gas transmission networks is attached to this response as **Appendix 1**. Here, we summarise the main points from this analysis - first for electricity and then for gas.

### Electricity

- 8 Summarising the main asset replacement points from the **electricity** section of the appendix (the differences on load-related spend are material but smaller and are covered both under Adjustment Mechanisms – below and in Appendix 3 - and in Appendix 1):
- (a) Ofgem are assuming that we need to spend around £670m less than we have proposed on **asset replacement**. This breaks down between:
    - (i) around £400m due to a lower **volume** of asset replacement;
    - (ii) around £270m due to lower **unit costs**.
  - (b) On **asset replacement volume**, the gap breaks down between:
    - (i) **differences in the modelling of replacement volumes** – we believe that Ofgem have incorrectly modelled our data; and
    - (ii) **adjustment of asset lives to reflect our own past rates of asset replacement**. This adjustment is illegitimate, in our view, because Ofgem's judgement assumes that these past rates of replacement were what we thought was the correct rate of replacement, i.e. unconstrained by resource unavailability and past regulatory funding.

This was not the case. We did face short term resource constraints in increasing the rate of asset replacement and, as Ofgem have always intended that we should, we tried to

balance our view on what the rate of replacement should be with the funding embedded in the current price control (albeit that we still over-spent, confirming our belief in the seriousness of the situation).

We do not see resources as a significant constraint on what we can spend in the next price control period – and the price control constraint is exactly what we are now discussing

- (c) On **asset replacement unit costs**, the gap breaks down between:
- (i) a gap of around £125m on what is currently achievable on unit costs (which we believe is due to an inappropriate degree of selectiveness in looking at actual capital schemes);
  - (ii) around £90m attributable to future improvements in procurement efficiency (which Ofgem assume are achievable from 1 April 2007, despite simultaneously judging that our 2005/06 spend is not inefficient); and
  - (iii) around £50m due to lower allowance for above (RPI) inflation cost increases – in our view, this gap could be dealt with by indexation of our revenue to widely used measures of industry costs.

9 The gap between us and Ofgem on the above points is exacerbated by other aspects of the Updated Proposals. In particular, Ofgem are proposing that any overspend by us against the price control assumptions should result in us losing **25%** of the gap between what we actually spend (even when that spend has been deemed to be not inefficient at the next price review) and what Ofgem have assumed in setting the price control which will run from April 2007.

10 This exposure to over-spend, in the context of proposed levels of spend which we think are substantially less than what we actually need to spend, is considerably greater than we face under the current price controls. Even if Ofgem assumed (as we believe they have done) that over-spend is incurred equally over each year of the price control period, then our current exposure to foregoing depreciation and return on the over-spend through the rest of the price control period is around 18%. However, in practice, over-spend is more likely to occur towards the end of a price control period, not least because the further one moves from the last price review the more likely it is that assumptions made at that review will be wrong. If over-spend is assumed to be concentrated in the last two years of the price control period (the position for NGET in the current period), then our exposure under the current regulatory regime is around 7%.

*Potential ways forward on electricity asset replacement*

11 In our view, if we are to meet our licence obligations as we currently interpret them, including the maintenance of long term system reliability at around current levels, then the gap between us on electricity asset replacement needs to be closed. Specifically:

- (a) Asset replacement volumes need to move into line with the range of condition evidence supporting our plans, not just into line with historical replacement rates which have been constrained by, not least, past price controls.
- (b) More realistic provision needs to be made for the unit costs of replacement. In particular:
  - (i) The starting point for projecting costs has to be what we currently spend.
  - (ii) Future increased procurement efficiencies need to be phased in over a realistic period.
  - (iii) Acute uncertainty over future market trends in the supply of plant and equipment and contracting services needs to be allowed for. Our preferred way of dealing with this would be through indexation to appropriate industry measures of cost – which would reduce the risk of windfall gains or losses. However, if Ofgem is set against this option, then any fixed allowance for above RPI cost movements should include an appropriate premium above the mean expected path of future prices.
- (c) The penalty for over-spend – and this point applies to both gas and electricity - should be reduced to something more in line with what the current position is. On this basis, we do not believe that the penalty should be more than 10% of the gap between actual spend and what will be eventually assumed in setting the new controls.

## **Gas**

- 12 Our main issues on future load-related gas spend are covered under Adjustment Mechanisms and Incentives. Our other main gas capex issues are:
- (a) the proposed disallowance of £75m of St Fergus-related investment; and
  - (b) the proposals related to existing compressor stations.

### *St Fergus investment*

- 13 Our view on the proposed disallowance of St Fergus spend is similar to our view on Ofgem's recent partial disallowance of electricity SO constraint costs in Scotland<sup>1</sup>. In both cases, the issue is how we should deal with the cost of

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<sup>1</sup> Determination under Special Condition AA5A Part 2(i), paragraph 12(a) of National Grid Electricity Transmission plc's Transmission Licence in respect of Scottish Constraints and CAP047, September 2006.

potential constraints on the transmission networks and the scope for exploitation of local monopoly power in relation to those constraints.

- 14 In principle, we can deal with these costs in one of the following two ways:
- (a) We can take actions in advance of the constraint being exploited, either by enhancing network capacity to reduce or remove the constraint or by entering into a contract with the relevant parties to limit the costs arising from the constraint. In the case of St Fergus, we recognised that Ofgem's setting of capacity 'baselines' above actual system capability (at the last Transco price review) would always expose us to opportunistic nominations to flow gas in excess of actual system capability – and, in this case, invested in extra network capacity.
  - (b) We can pay the relevant parties when the problem arises (e.g. buying back gas entry capacity from shippers or by paying generators to generate behind an import constraint or not to generate behind an import constraint). This is what we opted to do during 2005/06 in relation to electricity transmission constraints around the Peterhead power station.
- 15 In both cases, and in hindsight, Ofgem have determined that we should have taken the reverse action – even though experience at St Fergus this summer (when a constraint resulting from routine work on the network resulted in constraint costs of around £10m per day) showed the risks of setting baselines above network capability, even for a part of the network where flows would appear to be in secular decline. In the case of St Fergus, Ofgem's proposed disallowance is totally unreasonable in the light of their own setting of baselines at the last Transco price review. It also has the effect of increasing the probability that future capital expenditure will be contentiously judged to have been inefficiently incurred – and stranded – with all the implications that this necessarily has for the base rate of return which any owner of transmission assets will require.
- 16 If, despite all of the above, Ofgem does opt to strand, then consideration needs to be given to the treatment of the relevant assets outside of the price control. Clearly, baselines would need to be adjusted. However, there is also the question of whether we would be able to withhold the relevant capacity and treat any associated relevant revenue as unregulated.

*Compressor station asset replacement*

- 17 At issue under this heading is:
- (a) expenditure to replace and overhaul compressors and related plant and equipment; and
  - (b) spend to replace compressors in order to comply with emissions legislation.
- 18 Our main points on these issues, elaborated in Appendix 1, are that:

- (a) Ofgem are looking at too narrow a range of scenarios for future use of the network in coming to their conclusions on which existing compressors will not be needed.
- (b) Ofgem have not allowed for the implications of the recent auctions of long term gas entry capacity for future compressor requirements.
- (c) Ofgem have over-estimated the savings which would result from closure of the compressors at issue.
- (d) Ofgem are not currently adjusting baselines for the compressors which they think are not needed.

*Potential ways forward on gas asset replacement*

19 On gas asset replacement:

- (a) We see no reasonable outcome on the St Fergus issue other than allowance of the relevant capital costs into the NGGT RAV.
- (b) On compressor stations, our view is that:
  - (i) Allowance needs to be made for the proposed asset replacement at the Warrington compressor station in the light of the results of the recent long term entry capacity auctions.
  - (ii) Other compressor station investment needs to be viewed in the context of a wider range of scenarios for future investment than Ofgem have considered thus far. However, in the event that Ofgem decides to maintain its current narrow focus, then:
    - A more realistic view needs to be taken of the cost savings which would result from relocation of the decommissioned assets.
    - Provision should be made for a 'logging up' mechanism<sup>2</sup> which would cut in if events proved to be in line with scenarios other than those envisaged by Ofgem.
    - Baselines need to be adjusted downward to reflect the demise of the compressors in question.

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<sup>2</sup> By 'logging up mechanism', we mean a mechanism whereby the relevant capex would not be remunerated within the forthcoming price control but would be logged up for remuneration at the next price review, on the basis that the relevant capex, including depreciation and return through the next price control period, would be included in the NGGT RAV as from April 2012.

## Operating costs

- 20 The gap between us and Ofgem on the cost of meeting our obligations, including maintaining the reliability of the transmission networks, is not just about capital expenditure – it is also very much about operating costs. At the moment, there is an opex gap between us of £203m (over the five years of the next price control and across gas and electricity), albeit that £47m of this gap relates to issues which Ofgem explicitly sees as still under consideration.
- 21 The reasons why we think that Ofgem’s proposed assumptions on opex are inconsistent with us simultaneously delivering on our obligations and achieving a return equal to our deemed cost of capital are spelt out in **Appendix 2** of this response. In brief, we think that Ofgem have:
- (a) made unreasonable assumptions about the scope for efficiencies in particular areas - most notably, insurance and what has come to be referred to as ‘quasi capex’ (activities which are capex by their nature but classified as opex because of accounting rules on capitalisation);
  - (b) been over-rigid in the disallowance of particular cost items on the basis of ‘policy’, e.g.:
    - (i) employee share scheme costs, disallowance of which has the effect of discouraging the implementation of efficient remuneration packages; and
    - (ii) ‘costs to achieve’ efficiency improvement. In our view, to disallow the costs of achieving efficiency ‘frontier shift’ (a significant part of the overall cost reduction envisaged in the Updated Proposals) is to fail to acknowledge that such costs would be remunerated in a competitive market;
  - (c) made mistakes in the treatment of certain cost items, not least by removing costs that were not in the projected cost base to start with.

### *Potential way forward on operating costs*

- 22 These three areas of contention amount to around £156m of the £203m referred to above, the remaining £47m being in the pot which is still ‘under consideration’. In our view, a gap of up to £203m would mean no reasonable prospect of being able to deliver our licence obligations.
- 23 Again, as with capex above, if we are to meet our licence obligations as we currently interpret them, then the gap between us on operating costs needs to close. We would hope that Ofgem will revisit their judgements on efficiency and policy, and correct what we see as the mistakes in their calculations.

## Adjustment mechanisms and incentives

- 24 Our detailed analysis of Ofgem’s proposals for adjustment mechanisms and incentives is set out in **Appendix 3** below.

- 25 In brief, Ofgem's proposals in this area comprise:
- (a) 'revenue driver' mechanisms to deal with uncertainty about future requirements for load-related capex; and
  - (b) 'incentive mechanisms' which include:
    - (i) the mechanism, referred to above, to discourage over-spend (against price control assumptions) of electricity capex and non-load gas capex by disallowing 25% of the over-spend from entering into RAB;
    - (ii) mechanisms designed to penalise us for the late delivery of new gas entry and gas exit network capacity; and
    - (iii) the proposed penalty-only electricity transmission network reliability incentive.
- 26 The issues with each of these are discussed briefly in turn.

### **Electricity revenue drivers**

- 27 Ofgem's proposals for electricity revenue drivers for NGET comprise a number of different elements, including: remuneration of a baseline level of load-related spend in the main price control revenue; the use of a 'revenue driver' RAV to modify that baseline; zonal £/MW revenue drivers for local connection costs; and zonal £/MW revenue drivers for deep reinforcement costs.
- 28 Some of the implied £/MW revenue drivers are not obviously consistent with the unit costs underlying Ofgem's assumptions for non-load electricity capex. It is currently not clear how Ofgem plan to deal with this but, to the extent that this involves the load-related numbers tending towards those for non-load capex, then all the points which we make on non-load unit costs will apply.
- 29 That aside, we think that the current proposals for dealing with load-related electricity capex are broadly sensible, with the very important caveat that we think that 25% incentive (which Ofgem propose will apply to load-related and non-load electricity capex, as well as non-load gas capex) to spend in line with £/MW revenue drivers is too sharp in the context of uncertainties about what costs will eventually need to be incurred.
- 30 We think that the proposed revenue driver RAV mechanism can be simplified (along the lines proposed in Appendix 3 below), albeit that this simplification depends on the load-related capex baseline remaining a broadly central view of what load-related capex will be required through the next price control period.

### **Gas revenue drivers**

- 31 On the basis of the current proposals, we have more (and more serious) issues with the revenue drivers for NGGT than with those for NGET. Specifically:

- (a) We do not think that the unit costs (UCAs) currently being proposed represent a reasonable ex ante view of investment costs.
- (b) The issues raised by (a) are exacerbated by the proposed degree of our exposure to any difference between eventual actual costs and the UCAs (around 38%). The Updated Proposals effectively imply an exposure far above even the 25% exposure proposed elsewhere (which, as already noted, we think is too high anyway) and well above the **current** revenue driver mechanism for gas load-related capex. The proposals, as they stand, would imply that we could still be exposed to UCAs (which we think are wrong in the first place) through to 2019 or even 2020.
- (c) As is noted under cost of capital below, NGGT's cashflows are systematically weaker than those for NGET, not least because of the longer regulatory asset lives envisaged for gas (45 years), compared with electricity (20 years). The way that cash flows are generated by the gas revenue driver mechanisms – which delay all revenue until contractual delivery of the new capacity (unlike with electricity where some revenue flows from the point of user financial commitment) – will exacerbate this issue.

### **The 25% over-spend disincentive**

- 32 In principle, the proposed mechanism is a symmetrical mechanism – allowing us to retain 25% of capex under-spend (against price control assumptions) and taking away 25% of over-spend. However, as implied under capex above, under-spend against the current proposals would look to be out of the question on any reasonable view of our obligations.
- 33 **Therefore, viewed as penalty for over-spend**, the implication of the 25% mechanism is that NGET and NGGT are being strongly encouraged to spend less on networks which, especially in the case of electricity, need substantially increased spend to maintain reliability, albeit that Ofgem's proposed 'safety net' mechanism provides some sort of floor on this effect. Because measured reliability depends on events (e.g. storms) as well as asset condition, there is no easy way of measuring what underlying network reliability has been delivered over a given price control period (which is why we target asset condition as the best way of underpinning long term reliability). Thus, within a given price control period, the owner of the transmission assets would be encouraged by the incentive to reduce spend on the basis that any resulting fragility in the network might not show up as lost supply in that period.
- 34 Ofgem may feel that National Grid would, as a responsible network operator, respond to its licence obligations to develop and maintain efficient transmission systems, in preference to making money from under-spend. However, the current proposals nevertheless go against the philosophy that financial incentives should be designed to reinforce broader obligations or, at least, not totally undermine them, whoever owns the assets.
- 35 In our view, even if Ofgem are determined to retain a fixed incentive to under-spend against regulatory assumptions (and we agree that the incentive to under-spend is present in current arrangements, albeit with the periodicity which Ofgem wants to remove), then the 25% value should be reduced – it is

substantially above the effective exposure to over-spend which we currently face (see para 11 above) and creates an unbalanced trade-off between achieving an acceptable rate of return and meeting broader licence obligations. Given, as suggested in para 10 above, that our effective exposure to over-spend by NGET in the current price control period is around 7% under current arrangements, we suggest that the penalty going forward should be no more than 10%. This figure should apply across electricity and gas.

### Penalties for late delivery of new gas entry and exit capacity

- 36 Ofgem are proposing that we would have an exposure of £36m per annum to late delivery of new gas entry capacity and an exposure of £36m per annum for the late delivery of new gas exit capacity (albeit that this latter will not effectively become operative until the fourth year of the control period), although we would also have an unspecified number of 'permits' which would allow limited penalty-less delays in delivery as long as the permit was invoked before the relevant auction
- 37 These proposals offer no reasonable balance between risk and reward, not least because:
- (a) There **is no** reward - we can only lose under the scheme. Ofgem suggest that we might be able to get extra revenue from the sale of non-obligated capacity in the event that the capacity was available before the due date. However, in some cases, there would be no value to the relevant shippers from early delivery and, in any event and as noted below, the default timescales being proposed by Ofgem would allow very little scope for early delivery.
  - (b) The structure of the proposed penalties means that we could, on a large scheme, be through the annual collar on buybacks within a few days after the date for contractual delivery – we would then have no further penalties for the rest of the year.
  - (c) Given Ofgem's proposal that we should (up to the proposed collar) be fully exposed to the consequences of planning delays and appeals, the proposed default timescales – 42 months is insufficient, given the current timing of the September auctions and the inability to construct through winter.
  - (d) Given the lack of the reward in the scheme, the penalty proposals are inconsistent with the envisaged base rate of return. Leaving aside the arguments for a higher base rate of return than Ofgem's modelling assumption (which are summarised below), even one £36m penalty within a year would equate to **more than 100 basis points (pre-tax)** off the rate of return for NGGT. In our view, this issue would best be addressed by reducing the maximum annual penalty and by balancing that reduced penalty with a symmetrical upside. However, in the absence of this, NGGT would require a substantial increase in the base rate of return to give it a reasonable chance of earning a return even equal to Ofgem's eventual assessment of its cost of capital.

### **Operational buybacks and gas baselines**

- 38 NGGT currently has an operational buybacks regime for entry capacity (whereby it buys back capacity which has been made available for sale but which cannot be physically delivered). The maximum annual exposure under this scheme is currently £12.5m per annum. Although, we are assuming that the new operational buyback regime will be part of the gas SO proposals (which are running behind the TO proposals), Ofgem have proposed increasing this collar (and the associated cap) to £36m per annum.
- 39 The practical impact of this proposal will depend on how baselines are set. At present, there is some uncertainty about Ofgem's thinking in this area. However, if Ofgem continue with their past policy of setting baselines above the physical capacity of the system, then this risks adding another downside bias to the overall package of incentives.

### **Electricity network reliability incentive**

- 40 The current incentive penalises or rewards us depending on how annual unsupplied MWh outturn against a pre-specified target. Ofgem are now proposing that the new incentive will be penalty-only but have given few clues as to what the target level of reliability will be and as to the materiality of potential penalties for failing to meet that target.
- 41 In the absence of more detail on what will be proposed, our view is that an incentive scheme should normally offer the prospect of both rewards and penalties, albeit that the overall proposals could accommodate new penalty-only incentives through adjustment of the base rate of return/assumed cost of capital to allow for increased bad outcome risk.
- 42 In the event of Ofgem finally proposing a penalty-only scheme, we would expect that decision to be balanced by achieving consistency between: the target level of lost supply (which will need to take account of the volume of asset replacement which will be funded by the eventual capex allowance); the link between penalties and failure to meet that target; and the base rate of return used to calculate NGET's revenue.

#### *Potential ways forward on adjustment mechanisms and incentives*

- 43 Potential ways forward in this area are implied or spelled out in the above paragraphs. In our view, progress would include:
- (a) for both gas and electricity, reducing exposure to the difference between actual and assumed (load related and non-load related) capex to no more than 10%;
  - (b) having gas UCAs which represent a reasonable ex ante view of future capital costs (perhaps by setting the UCAs after the relevant auction);
  - (c) resolving uncertainty on electricity unit costs and, if they are to change, new values should be informed by our comments on non-load electricity unit costs;

- (d) bringing the profile of gas revenue driver cash flows more into line with those envisaged by Ofgem for electricity;
- (e) set gas and entry and exit baselines in line with the physical capability of the gas transmission network;
- (f) rebalancing the investment delivery incentives so that they:
  - (i) are symmetrical;
  - (ii) have a smaller total exposure;
  - (iii) have a more gradual build-up of that exposure;
  - (iv) have more realistic default timescales;
- (g) set an electricity network reliability incentive which is either internally consistent (i.e. in terms of symmetry and targets) or has its asymmetry compensated elsewhere in the package, e.g. through the base rate of return.

## Cost of capital and financeability

- 44 Ofgem suggest (para 8.1 of the Updated Proposals) that their final decision on NGET/NGGT's cost of capital will take account of:
- (a) past regulatory decisions;
  - (b) the investment focus of the current review;
  - (c) the work by Ofgem's consultants (Smithers & Co) on cost of capital;
  - (d) Ofgem's financeability assessments; and
  - (e) the overall balance of risk the companies will face.
- 45 Of these factors:
- (a) On **financeability (and allowance for the cost of raising new equity)**:
    - (i) We agree with Ofgem that there are unlikely to be serious financeability issues for NGET over the next price control period on the basis of Ofgem's modelling assumptions. This is, not least because of Ofgem's proposal that the regulatory asset lives of post-privatisation assets should be reduced from 40 years to 20 years.
    - (ii) At the same time, and in the absence of a shortening of gas regulatory asset lives (the major source of NGGT's weaker cash flows), we believe that there will need to be an equity injection into NGGT to meet Ofgem's suggested financial

ratios. In our view, the costs of additional equity raising should be recoverable within the price control period.

- (b) On **the overall balance of risk the companies will face**, it is our presumption that Ofgem will want the eventually proposed cost of capital/base rate of return to be on a comparable basis to that of other regulated UK energy networks, not least so that Ofgem can demonstrate consistency with past regulatory decisions and provide a platform for the consistency of future decisions.

However, to the extent that this is not the case, then new and material asymmetric risks which are part of these proposals (and several of these have been identified, not least in relation to the proposed incentives and adjustment mechanisms), then the only obvious way that the Final Proposals will add up as a package is via a higher base rate of return. Ofgem will be aware that such adjustments could need to be rather large – for example, an expectation of losing even £30m a year on the new investment delivery incentives (against a collar of £72m), very plausible in the light of the other currently suggested parameters for the schemes, would reduce NGGT's rate of return by around 100 basis points on a pre-tax basis.

- 46 Putting the above two issues on one side leaves the impact on base rate of return of three factors to be considered, i.e.:
- (a) past regulatory decisions;
  - (b) the investment focus of the review; and
  - (c) the work on cost of capital by Ofgem's consultants.

### **Past regulatory decisions**

- 47 Although there is now a reasonably long history of UK utility price control conclusions on utilities' costs of capital, the most obviously relevant past decisions are the 2004 water review ('PR04') and the 2004 DNO price review (DPCR4). This is because they are the most recent main price reviews relating to businesses with similar overall risk profiles. Ofgem intentionally and explicitly avoided a serious review of NGET's cost of capital in the 2005 'mini review'.
- 48 The cost of capital deemed for the large water and sewerage companies in **PR04** was 5.1% (post-tax, real), albeit with significant extra return embedded in the PR04 outcome through financeability adjustments.
- 49 The cost of capital deemed for DNOs in **DPCR4** was 4.8%, albeit with explicit scope for companies to earn a higher rate of return if they spent in line with Ofgem's assessment of how much capex they needed to incur.
- 50 From the perspective of the transmission price review, we would draw out the following potential implications of the DPCR4 cost of capital outcome:

- (a) Ofgem, rightly we think, set itself the task of estimating a **long term** cost of capital. It is not clear in our view (or, we think, in the view of Ofgem's consultants, Smithers) that anything much has happened over the last two years to change estimates of the long term risk free rate or the long term market return on equity.
- (b) Ofgem's stated reason for going to the top end of the Smithers range for cost of equity was the "investment focus" of the review. More broadly, Ofgem went close to the top of its stated range for overall cost of capital (4.2% - 5%).
- (c) Ofgem's stated range in its Initial Proposals for the TPCR was 2.8% to 4.8%, although Ofgem also stated that "However, we do not consider that figures in the lower reaches of this range would represent a sustainable return in the long term".

### **Investment focus of TPCR**

- 51 Ofgem have repeatedly made clear that the big issue in TPCR is investment in the gas and electricity networks. We agree with this and, on the basis of DPCR4, can think of no obvious reason why Ofgem would not again use this as a basis for going to the top of the range for market cost of equity and towards the top of the relevant range for cost of capital overall

### **The Smithers report**

- 52 For TPCR, Ofgem sought the advice of Smithers & Co, who had also provided the earlier report which informed Ofgem's conclusions on cost of capital at DPCR4. Our analysis of the Smithers report and its implications is attached as Appendix 4 but we offer below our main conclusions.
- 53 Smithers' 'central estimates of the key magnitudes' for TPCR are contained in Tables 1.1 and 1.2 of their report and are as follows<sup>3</sup>:

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<sup>3</sup> Smithers & Co. Ltd., Report on the Cost of Capital provided to Ofgem, 1 September 2006

**Table 1.1**  
**The Cost of Equity**

	<b>Estimate</b>
<b>Real Market Return: Compound Average</b>	5.5%
<b>Adjustment to Arithmetic Average</b>	1 to 2%
<b>Real Market Return: Arithmetic Average</b>	6.5% to 7.5%
<b>Risk-Free Rate</b>	2.5%
<b>Implied Equity Premium</b>	4% to 5%
<b>Estimated "Value Effect"</b>	0 to 1.25%
<b>Implied Real Cost of Equity with beta=0.5</b>	4.5% to 6.25%

**Table 1.2**  
**The Cost of Debt**

	<b>Estimate</b>
<b>Real Risk-Free Rate</b>	2.5%
<b>Term Premium</b>	0 to 0.75%
<b>Real Long-Term Risk-Free Yield</b>	2.5% to 3.25%
<b>Default Premium on A-Rated Debt</b>	1% to 1.5%
<b>Real Yield on Long-Term A-Rated Debt</b>	3.5% to 4.75%

- 54 Compared to our submission on cost of capital as part of this review<sup>4</sup>:
- (a) Our estimate of cost of debt fell towards the lower end of the Smithers range.

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<sup>4</sup> Cost of capital of National Grid's GB electricity and gas transmission businesses, May 2006

- (b) Our estimated of cost of equity was higher, based on market returns of 7.5% (i.e. top of the previous Smithers range on the DPCR4 basis of the investment focus of the review) and an equity beta of 1.

55 A question, therefore, is whether the Smithers report justifies an equity beta of 0.5. In our view, it does not for at least the following reasons:

- (a) The first point to make about the Smithers table 1.1 is that Smithers do not claim in it that a beta of 0.5 is their central estimate for beta. They simply give what, in the light of their other estimates, the cost of equity would be if beta=0.5.

- (b) Much of the text of the Smithers report is devoted to explaining how hard it is to tie beta down within a narrow range. Thus Smithers write

“In the appendix we show, for each company, confidence intervals for beta calculated both using rolling regressions and the Kalman Filter. For all companies these are very different indeed. Taking Scottish Power as an example: while the rolling regression approach implies that we can be 95% certain that the “UK” beta lies between 0.5 and 0.8, the Kalman Filter suggests that with the same probability we cannot (quite) rule out beta being currently equal to either one, as Ofgem assumes in setting the WACC, or zero.”

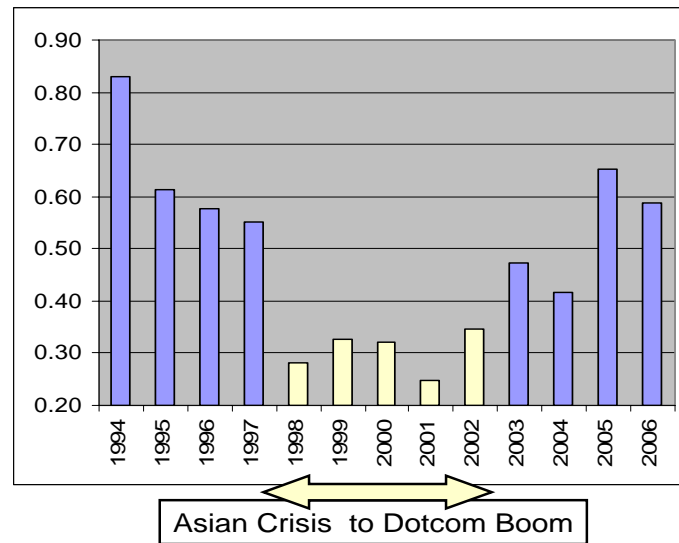
Smithers go on to suggest that rolling regression is likely to understate the true degree of beta uncertainty but that the Kalman Filter will be likely to overstate it.

- (c) On the basis of the graphs in Smithers, the beta estimates for National Grid look very similar (both in terms of mean and variance) to those of Scottish Power.
- (d) On the basis that one method underestimates the true degree of uncertainty about beta and one overestimates it, the mean of these two would seem to be suggesting that the top of the 95% confidence range is a beta of around 0.9.
- (e) Thus, on the basis of Smithers’ own analysis – which produces quite wide ranges for many of the inputs into a CAPM cost of capital estimate – a table which fairly represented their text would probably see a beta with a low end below 0.5 and a high end of around 0.9.
- (f) Given that Ofgem have consistently implied that the investment focus of the review inclines them to the upper end of the relevant range, then it is not unreasonable to say that Smithers’ own analysis does not preclude an equity beta of around 0.9.

56 However, there are good reasons why the Smithers’ analysis systematically underestimates betas for the network utilities in their sample. The reasons for this are described in Appendix 4 but, in brief, are as follows:

- (a) Network utility betas were severely depressed by the dotcom/telecoms bubble of a few years back and any method of estimating betas which

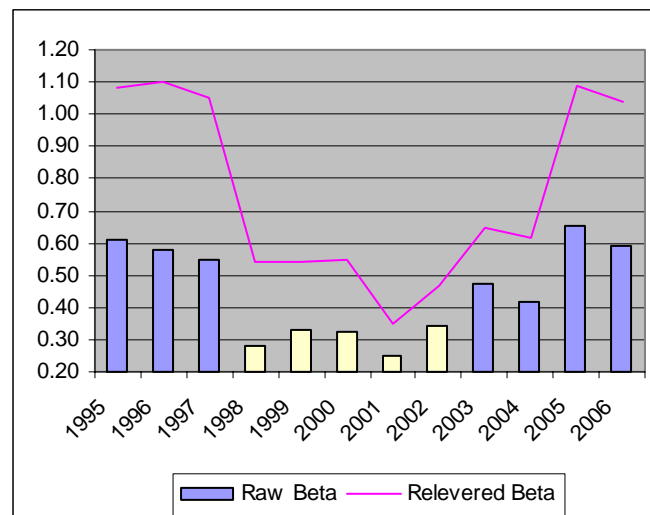
uses data from this period (as Smithers do) will include this effect. The effect is shown in the following diagram which simply uses daily data for each year from 1995 to 2006.



Average equity betas for each calendar year based on daily data, averaged across the seven **network** utilities surveyed by Smithers (i.e. sample excludes International Power and Centrica).

This shows that betas, at least for the group as a whole, fell to implausibly low levels either side of 2000 and have been on a rising trend since. **For this reason alone, beta estimates which average over the last five years are likely to under-estimate betas through the next price control period.**

- (b) The betas in the Smithers sample reflect the actual gearing of the companies involved, whereas Ofgem plan to deem a cost of capital on the basis of optimal gearing – 60% in the current modelling assumption. The next diagram shows the betas from the previous diagram – but also shows the effects of releveraging gearing to 60%, using one of the two standard formulae which have been used in the past by both Ofgem and the Competition Commission/Monopolies and Mergers Commission.



This shows that a beta of 1 is not in any way outlandish for either the period before 1998 or more recently (without even looking for the top of 95% confidence ranges).

Although Ofgem (and Smithers) seem to question whether increased gearing does increase equity betas, this would seem to be, at least in part, influenced by the observation that utility betas were declining at a time when utility gearing was rising. However, this seems, again at least in part, to be a result of looking at moving averages of betas which conceal the particular, and rather unusual, things which were going on in equity markets around the turn of the century. Beyond this, the assertion that higher gearing does not increase equity risk flies in the face of not only the massed ranks of corporate finance academic orthodoxy but also of common sense.

- 57 We therefore suggest that there is nothing in the Smithers analysis which convincingly rules out the assumption of beta=1. **In fact, the above diagrams suggest that the case for beta=1 is now rather stronger than it was at the time of DPCR4.**
- 58 Given this, what range for cost of capital should Ofgem therefore be looking at for the transmission price review? For what it is worth, plugging gearing of 60% and an equity beta of 1 into the top of Smithers' estimates from Table their Table 1.1 and 1.2 suggests a ceiling cost of capital of **5.5%**.
- 59 Is this 'fair' in the sense that, **beta apart**, would this represent the rest of Smithers' text as to the top of the feasible cost of capital range? Probably not. This is because the high end of Smithers' estimates includes 1.25% of 'value effect' in the cost of equity. Although there is nothing inconsistent (either theoretically or empirically) between the value effect and a higher beta, Smithers themselves are clearly dubious about whether the value effect should be included<sup>5</sup>. However, even leaving out the value effect but leaving

<sup>5</sup> "If we lean over backwards to extract as much evidence in favour of the value effect as we can, a "pooled" estimate using data for all regulated companies in our sample suggests it might add at most around 1.25% to the cost of equity."

beta at 1 implies a top-of-the-range cost of capital of **5%** (the top of the range used by Ofgem in DPCR4).

*Potential way forward on base rate of return*

- 60 Overall, and given the factors which Ofgem have deemed should be taken into account when deciding on an appropriate cost of capital for this review, we can see nothing inconsistent with our earlier suggestion to the Authority and in our written submission that a reasonable base rate of return for NGET and NGGT (before consideration of new and material asymmetric risks associated with other aspects of Ofgem's proposals) should be **4.7%**. This would, as with the DPCR4 outcome, be towards the upper end, but not at the top, of the range which Ofgem should be considering.