Promoting choice and value for all gas and electricity customers

Transmission Price Control Review: Initial Proposals

Document type: Appendices

Ref: 104b/06

Date of publication: 26 June 2006

Deadline for response: 24 July 2006 to tpcr.responses@ofgem.gov.uk

Target audience: Transmission licensees, Gas transporters, users of the transmission network, consumer groups and other interested parties

Overview:

This document sets out our initial proposals for the transmission price controls that will apply from 1 April 2007. It represents a key milestone in the Transmission Price Control Review (TPCR) as it sets out our initial thinking on the allowances that we intend to provide to fund efficient expenditure of the transmission licensees over the period 2007 - 2012.

We present our initial findings from our historic and forecast cost assessments of the transmission companies, which, together with our initial financial assumptions, allow us to calculate revenue allowances for each company. We have also set out further information and more detailed proposals in relation to the design of the price controls

Contact name and details: Robert Hull, Director Transmission

Tel: 020 7901 7050

Email: robert.hull@ofgem.gov.uk

Team: Transmission Directorate

Office of Gas and Electricity Markets, 9 Millbank, London, SW1P 3GE
www.ofgem.gov.uk

Context

Transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain. Timely investment in the networks is essential to ensure their efficient operation.

There have been a number of changes in the external environment since the current transmission price controls were set and there is significant uncertainty concerning the future development of the networks. This uncertainty arises, in particular, from:

- changing patterns of gas supply resulting from the decline of UK gas production and its replacement by imports;
- changes in the electricity generation mix, largely relating to the development of renewable generation; and
- changes in wider energy policy, especially concerning environmental issues.

Against this background, the objectives of the review include developing incentives for investment in gas and electricity infrastructure, to promote efficient and timely investment in our transmission networks and to allocate risk appropriately.

Associated Documents

- TPCR Initial Proposals, June 2006
- Access Reform in Electricity Transmission: Working group report and next steps, May 2006 (Ref No. 83/06a)
- A framework for considering reforms to how generators gain access to the GB electricity transmission system: A report by the Access Reform Options Development Group April 2006, May 2006 (Ref No. 83/06b)
- TPCR 2007-2012: Third Consultation, March 2006 (Ref No. 51/06)
- TPCR 2007-2012: Third Consultation, Supplementary Appendices, March 2006 (Ref No. 51/06b)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)

Responses to the Ofgem consultation documents can also be found on the Ofgem website (www.ofgem.gov.uk).

Table of Contents

Appendix 5 - Price control calculations

Introduction

1.1. This appendix sets out the way that the revenue allowances for each of the transmission licensees has been calculated for the period 2007/08 to 2011/12, including the key assumptions that have been adopted in order to derive price control revenue allowance.

1.2. We first provide an explanation of how the calculations are constructed. We then set out the calculations for each of the four companies in turn.

Explanation

1.3. Price controls provide a company with a level of revenue that is sufficient to finance an efficient business. This is based on an estimate of operating expenditure; capital expenditure; financing costs; and corporation tax for the period 2007/08 to 2011/12.

1.4. The revenue calculations for the electricity transmission companies include income from the innovation funding incentive (IFI). However, we are still considering whether an IFI incentive should apply for NGG NTS and therefore it has not been included.

The balance between 'R0' and 'X'

1.5. In setting the price control a decision needs to be made about the balance between the immediate change in revenues in the first year of the price control ('R0') and the path of revenues over the remaining years (or 'X'). There is no "right" answer on the appropriate balance between 'R0' and 'X', but there are two main considerations in coming to a decision, namely the financial profile of companies and the longer-term trend in revenues.

1.6. We have assumed, for modelling purposes, that revenues will be held constant in real terms over the entire five year period. It is for consideration whether this approach is appropriate.

Approach to the revenue calculations

Calculating the movement in the RAV

1.7. The calculation of the movement in the RAV is shown in lines 1 to 6. In each year total capital expenditure (line 2) is added to the opening RAV (line 1) and the allowed level of depreciation (line 3) is subtracted from it to give a closing asset value (line 4). The closing value in any year (line 4) then becomes the next year's opening value (line 1).

1.8. The difference between the present values of the opening RAV in 2007/08 and the closing RAV in 2011/12 (are shown in line 5). The present value movement in the RAV is then derived but subtracting the present value of the closing RAV in 2011/12 from the present value of the opening RAV in 2007/08 (line 6).

Calculating allowed items

1.9. The allowed levels of costs and associated items are shown in lines 7 to 15. Line 7 shows the allowed level of operating expenditure (excluding pensions costs which have been considered separately) in each year. This is the sum of controllable and non-controllable operating cost allowances. The annual allowances for capital expenditure are given in line 8. Ofgem's proposed allowances for pensions costs are then set out in line 9.

1.10. Ofgem's proposed allowances for corporation tax are set out in line 11 based upon the methodology set out in Chapter 8. The total annual cash costs that will be incurred by each licensee is calculated by adding together lines 7 to 11 in each year (line 12). The annual cost is then discounted to determine the present value equivalent cost (line 13). This is calculated by discounting the total allowed items figure by the vanilla WACC[1] of 4.84 per cent.

1.11. We then derive the total cost allowance for the five year period (line 15) by summing the present value of the annual cash costs (line 13) and adding the prevent value movement in the RAV (line 14).

Calculating allowed revenue

1.12. To ensure that the price controls provide a company with a level of revenue that is sufficient to finance an efficient business, the total present value of annual revenues (line 20) must equate to the total present value of allowed costs (line 15). We have profiled the present value total of revenue according to our assumption that revenues will be held constant in real terms (i.e. X equal to zero). The present value

[1] Calculated as the average of the pre-tax cost of debt and post-tax cost of equity weighted by the assumed gearing level. This is consistent with a post-tax cost of capital of 4.2 per cent.

of the revenue line is then divided by the discount factor (line 17) to derive the total revenue allowance (line 18). For electricity transmission companies, we then add our allowance regarding the IFI scheme (line 20) to derive total TO revenues (line 21).

NGET

1.13. The table below sets out how the revenue allowance proposals for NGET set out in Chapter 3 of the main document have been calculated.

Table 5.1: NGET revenue allowances

All prices are £m in 2004/05 terms

		2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV						
1	Opening asset value		5,198.5	5,409.0	5,543.7	5,695.3	6,068.9
2	Total capital expenditure		584.4	526.4	556.4	554.6	568.5
3	Depreciation		-374.0	-391.7	-404.8	-181.0	-194.8
4	Closing asset value		5,409.0	5,543.7	5,695.3	6,068.9	6,442.6
5	Present value of opening/closing RAV		5,198.5				5,086.6
6	5 year movement in PV of RAV						111.9
	Allowed items						
7	Operating costs (excluding pensions)		251.5	242.0	238.8	241.0	242.3
8	Capital expenditure		584.4	526.4	556.4	554.6	568.5
9	Pensions allowance		35.9	35.7	35.9	36.7	36.8
10	Tax allowance		85.9	81.0	73.9	64.6	57.2
11	Total of allowed items		957.7	885.1	905.0	896.8	905.0
12	Present value of allowed items		935.3	824.5	804.1	760.1	731.6
13	5 year movement in PV of RAV						111.9
14	Total present value over 5 years						4,167.5
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Total TO Revenue	1004.6	936.0	936.0	936.0	936.0	936.0
18	Present value of TO revenue		914.1	871.9	831.6	793.2	756.6
19	Total present value over 5 years						4,167.5
20	IFI revenue (0.4% of line 17)		3.7	3.7	3.7	3.7	3.7
21	Total price control revenue		939.7	939.7	939.7	939.7	939.7

SHETL

1.14. The table below set out how the revenue allowance proposals for SHETL set out in Chapter 4 of the main document have been calculated.

Table 5.2: SHETL revenue allowances

All prices are £m in 2004/05 terms

		2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		282.2	309.7	325.3	336.0	349.1
2	Total capital expenditure		44.0	33.0	28.8	31.9	26.8
3	Depreciation		-16.5	-17.4	-18.1	-18.7	-19.4
4	Closing asset value		309.7	325.3	336.0	349.1	356.5
5	Present value of opening/closing RAV		282.2				281.4
6	5 year movement in RAV						0.7
	Allowed items						
7	Operating costs (excluding pensions)		9.3	9.7	9.1	8.9	8.9
8	Capital expenditure		44.0	33.0	28.8	31.9	26.8
9	Pensions allowance		0.7	0.8	0.8	0.8	0.8
10	Tax allowance		6.4	5.5	5.2	4.8	4.4
11	Total of allowed items		60.5	48.9	43.9	46.4	41.0
12	Present value of allowed items		59.1	45.6	39.0	39.3	33.1
13	5 year movement in RAV						0.7
14	Total present value over 5 years						216.8
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Total TO Revenue	50.8	48.7	48.7	48.7	48.7	48.7
18	Present value of TO revenue		47.6	45.4	43.3	41.3	39.4
19	Total present value over 5 years						216.8
20	IFI revenue (0.4% of line 17)		0.2	0.2	0.2	0.2	0.2
21	Total revenue		48.9	48.9	48.9	48.9	48.9

SPTL

1.15. The table below sets out how the revenue allowance proposals for SPTL set out in Chapter 5 of the main document have been calculated.

Table 5.3: SPTL revenue allowances

All prices are £m in 2004/05 terms

		2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV)						
1	Opening asset value		746.1	797.7	828.4	854.7	965.8
2	Total capital expenditure		114.4	96.4	94.3	138.1	111.7
3	Depreciation		-62.8	-65.7	-68.1	-27.0	-30.5
4	Closing asset value		797.7	828.4	854.7	965.8	1,047.0
5	Present value of opening/closing RAV		746.1				826.6
6	5 year movement in RAV						-80.5
	Allowed items						
7	Operating costs (excluding pensions)		27.4	26.9	27.6	27.6	27.7
8	Capital expenditure		114.4	96.4	94.3	138.1	111.7
9	Pensions allowance		1.2	1.2	1.2	1.2	1.2
10	Tax allowance		16.8	15.3	13.9	11.9	9.7
11	Total of allowed items		159.8	139.9	137.1	178.8	150.2
12	Present value of allowed items		156.1	130.3	121.8	151.6	121.5
13	5 year movement in RAV						-80.5
14	Total present value over 5 years						600.8
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Total TO Revenue	159.6	134.9	134.9	134.9	134.9	134.9
18	Present value of TO revenue		131.8	125.7	119.9	114.4	109.1
19	Total present value over 5 years						600.8
20	IFI revenue (0.4% of line 17)		0.5	0.5	0.5	0.5	0.5
21	Total revenue		135.5	135.5	135.5	135.5	135.5

NGG NTS

1.16. The table below sets out how the revenue allowance proposals for NGG NTS set out in Chapter 6 of the main document have been calculated.

Table 5.4: NGG NTS revenue allowances

All prices are £m in 2004/05 terms

		2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
		£m	£m	£m	£m	£m	£m
	Regulatory Asset Value (RAV						
1	Opening asset value		2,872.7	3,198.3	3,282.8	3,224.0	3,158.6
2	Total capital expenditure		421.8	188.7	48.0	41.1	37.0
3	Depreciation		-96.3	-104.2	-106.9	-106.5	-105.9
4	Closing asset value		3,198.3	3,282.8	3,224.0	3,158.6	3,089.7
5	Present value of opening/closing RAV		2,872.7				2,439.4
6	5 year movement in RAV						433.3
	Allowed items						
7	Operating costs (excluding pensions)		137.3	135.8	135.0	133.2	134.9
8	Capital expenditure		421.8	188.7	48.0	41.1	37.0
9	Pensions allowance		24.5	25.4	26.2	26.9	27.8
10	Tax allowance		58.4	53.1	53.6	57.0	59.3
11	Total of allowed items		642.0	403.0	262.8	258.1	259.1
12	Present value of allowed items		627.0	375.4	233.5	218.8	209.4
13	5 year movement in RAV						433.3
14	Total present value over 5 years						2,097.5
	Revenue						
15	Revenue index		1.000	1.000	1.000	1.000	1.000
16	Discounted revenue index		0.977	0.932	0.889	0.848	0.808
17	Total TO Revenue	442	471.1	471.1	471.1	471.1	471.1
18	Present value of TO revenue		460.1	438.8	418.6	399.2	380.8
19	Total present value over 5 years						2,097.5

Appendix 6 - Overall impact on charges

Introduction

1.1. The TPCR will re-set the maximum revenues that the transmission companies are permitted to recover. These allowances are recovered by NGET in electricity (for itself and on behalf of SPTL and SHETL) and by NGG NTS in gas through charges to network users.

1.2. This appendix provides an indication of how our initial proposals might impact on charges if they were implemented, and given the current methods through which charges for network users are calculated.

Electricity

1.3. Transmission charges are levied by NGET pursuant to its connection and use of system charging methodologies. Our proposals will have little impact on connection charges, which are calculated on a site-specific basis linked to the actual costs of the relevant connection assets.

1.4. The main impact of our proposals will be on Transmission Network Use of System (TNUoS) charges. TNUoS charges are levied on generators, large industrial customers who are connected to the transmission system, and electricity suppliers. The charges comprise an element which varies by location and an element which is fixed. Charges are set in aggregate such that 27 per cent of total revenues are recovered from generators, and 73 per cent of total revenues are recovered from demand users.

1.5. Our proposals will not affect the locational element of charges. This element of charges depends on the pattern of generation and demand across the country - which is not directly affected by our proposals. The proposals will however affect the fixed, non-locational element of charges.

1.6. The monetary impact will be different for generators compared to demand users, but will be the same for all generators and the same for all demand users. Our initial proposals, assuming our baseline estimates of new generation, will result in a reduction of £85.5m in the combined total revenues for NGET, SPTL and SHETL. As such, generators would pay £23m less in aggregate each year and demand users would pay £62m less in aggregate each year.

1.7. In terms of tariffs, this represents 29p per kW off the generation tariff and 99p per kW off the demand tariff. As a proportion of a customer's bill, these are

negligible amounts. The table below sets out the impact on a illustrative sample of users:

Table 6.1: Impact of Initial Proposals of transmission charges

Customer type	Estimated impact of Initial Proposals on TNUoS charges (£ per year)
Domestic customer	- £0.31
Large industrial customer (100MW max offtake)	- £99,000
Small transmission connected generator (100MW)	- £28,500
Large transmission connected generator (1500MW)	- £428,000

Gas

1.8. Gas transmission charges are levied by NGG NTS pursuant to its charging methodology. Approximately 50 per cent of the revenues are recovered through the entry capacity auctions and TO commodity charges. The remaining revenues are recovered through charges to transmission exit points. Our proposed change in TO revenues for NGG NTS will flow through to entry and exit charges in approximately equal proportions.

1.9. The complexities of the gas transmission charging arrangements make it difficult to evaluate the impact of our proposals on different customer groups however, as a proportion of a customer's final bill transmission charges represent a relatively small amount.

Appendix 7 - Cost assessment - capex

NGET

1.1. This section sets out how the allowances for capex for NGET underpinning our initial proposals have been derived.

Table 7.1 NGET capex assessment details

NGET historical & forecast capex details	Historical 2000/01 - 2004/05	Forecast 2005/06 - 2006/07	Forecast 2007/08 - 2011/12	Notes
Licensee reported actual/forecast				
Net load related	874.2	440.6	1336.9	
Net non-load related	853.3	601.3	2460.2	
TSS	35.3	9.8	19.4	**1**
Adjustment for baseline capex				
Excluded costs		-6.8	-24.8	**2**
Non-operational capex	-54.8	-21.6	-55.0	**3**
Quasi capex		0.0	68.9	**4**
Internal profit margin	0.0	0.0	0.0	**5**
Entry volume adjustment		-80.4	-170.4	**6**
Adjusted baseline capex actual/forecast	**1672.6**	**933.2**	**3615.8**	
TSS	35.3	9.8	19.4	
Excluded costs		6.8	24.8	
Adjustment for RAV / allowed expenditure				
Load Related Expenditure				
Entry/Exit sole-use	0.0	-14.1	-24.5	**7**
Infrastructure	0.0	0.0	-58.8	**8**
Abatements	0.0	-0.3	-24.6	**9**
Procurement efficiency	0.0	-17.3	-52.9	**10**
Non Load Related Expenditure				
Asset replacement & refurbishment				**11**
Transformers	0.0	-8.0	-45.7	
Reactors	0.0	-4.0	-19.0	
Switchgear	0.0	-26.7	-151.4	
Substation other	0.0	0.0	0.0	
Overhead Lines	0.0	-86.1	-206.4	
Underground Cables	0.0	-6.9	-44.2	
Protection & control	0.0	0.0	0.0	
Other TO	0.0	0.0	-34.1	**12**
Abatements	0.0	-1.6	-115.3	**9**
Procurement efficiency	0.0	-22.0	-91.7	**10**
Other adjustments				
TSS	0.0	-0.5	-1.0	**10**
Allowed RAV / expenditure	**1672.6**	**746.2**	**2747.2**	
TSS	35.3	9.3	18.4	
Excluded costs		6.8	24.8	

Notes

1. Historical TSS costs are under NGET's SO internal cost incentive, which allows depreciated value of efficient spend to be rolled into TO RAV at next price control. The treatment of future TSS capex is discussed in Chapter 7.

2. Costs have been identified for separate treatment outside TO baseline.

3. We have identified cost items that should be categorised as opex instead of capex.

4. We have identified cost items originally in licensee's opex forecast which will be considered as capex, and are still reviewing the appropriate level of costs.

5. None identified.

6. The reduction is due to our assumption of lower future generation and associated system boundary flows for the baseline.

7. An estimated amount of avoidable early replacement of assets in load related projects has been removed.

8. The reduction is due to removing double counting between load related and non-load related capex.

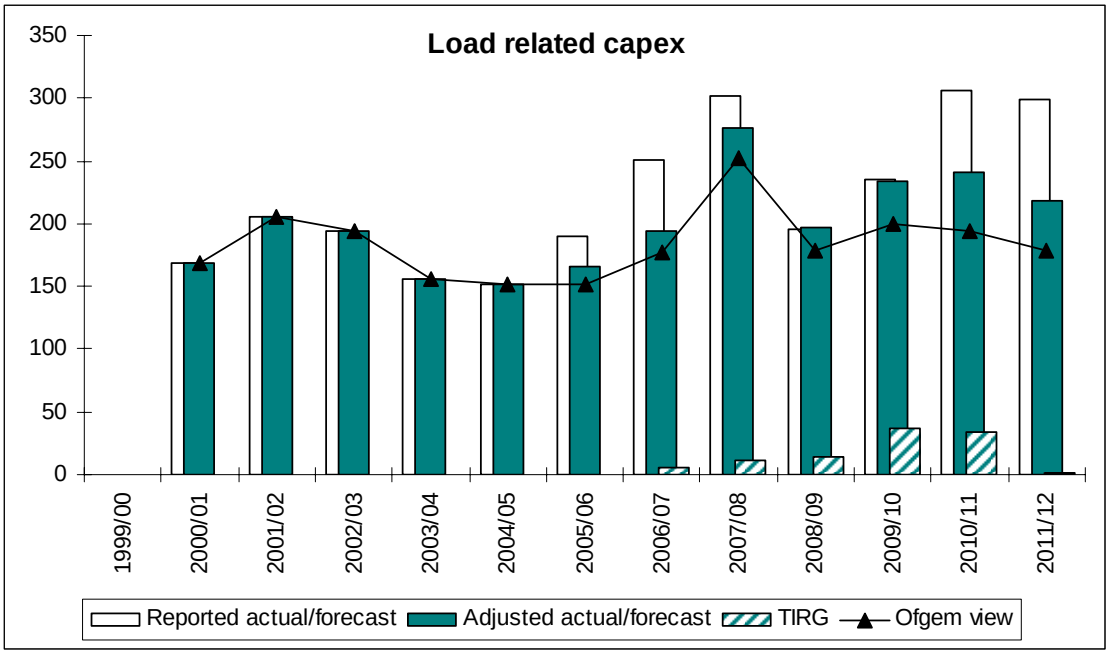
9. Licensee's forecast of overall impact of future market price increase removed for further review.

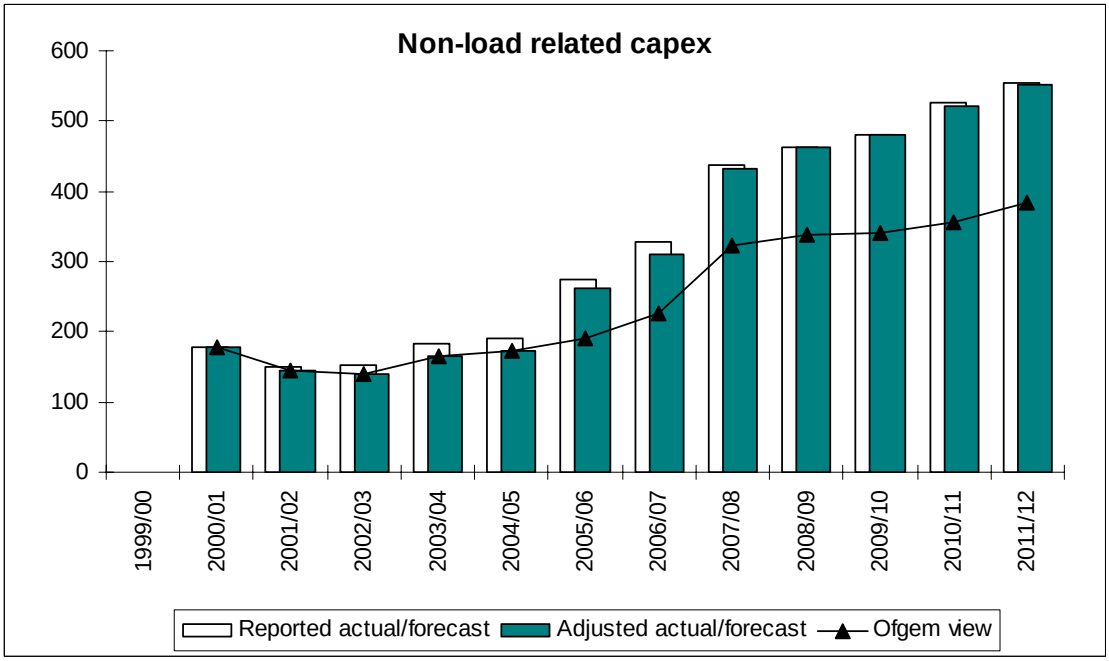
10. Our initial assessment of licensee's procurement efficiency revealed scope for improvement. Within a range of possible savings on capex, 5% saving is assumed here.

11. Our initial assessment is that a lower level of asset replacement and refurbishment is required with more efficient unit costs.

12. Licensee has forecast investment to accommodate the potential change of service level from BT's telecom network for carrying its system protection signals. This is removed for further review. Licensee's other forecast costs relating to operational telecom is also still under review.

Figure 7.1 Summary of NGET's historical and forecast capex





SHETL

1.2. This section sets out how the allowances for capex for SHETL underpinning our initial proposals have been derived.

Table 7.2 SHETL capex assessment details

SHETL historical & forecast capex details	Historical 1999/00 - 2004/05	Forecat 2005/06 - 2006/07	Forecat 2007/08 - 2011/12	Notes
Licensee reported actual/forecast				
Net load related	25.0	25.0	766.1	
Net non-load related	42.7	24.6	56.1	
TSS			12.0	**1**
Adjustment for baseline capex				
Entry volume adjustment		-4.4	-651.9	**2**
Adjusted baseline capex actual/forecast	**67.7**	**45.3**	**170.2**	
TSS			12.0	
Adjustment for RAV / allowed expenditure				
Load Related Expenditure				
Entry/Exit sole-use	0.0	0.0	0.0	
Infrastructure	0.0	-1.4	-13.0	**3**
Procurement efficiency	0.0	0.0	0.0	**4**
Non Load Related Expenditure				
Asset replacement & refurbishment				**5**
Transformers	0.0	-1.0	-4.8	
Switchgear	0.0	0.0	0.0	
Substation other	0.0	0.0	0.0	
Overhead Lines	0.0	0.0	0.0	
Underground Cables	0.0	0.0	0.0	
Protection & control	0.0	0.0	0.0	
Other TO	0.0	0.0	0.0	
Procurement efficiency	0.0	0.0	0.0	**4**
Other adjustments				
TSS			0.0	
Allowed RAV / expenditure	**67.7**	**42.9**	**152.5**	
TSS			12.0	

Notes

1. The treatment of future TSS capex is discussed in Chapter 7.

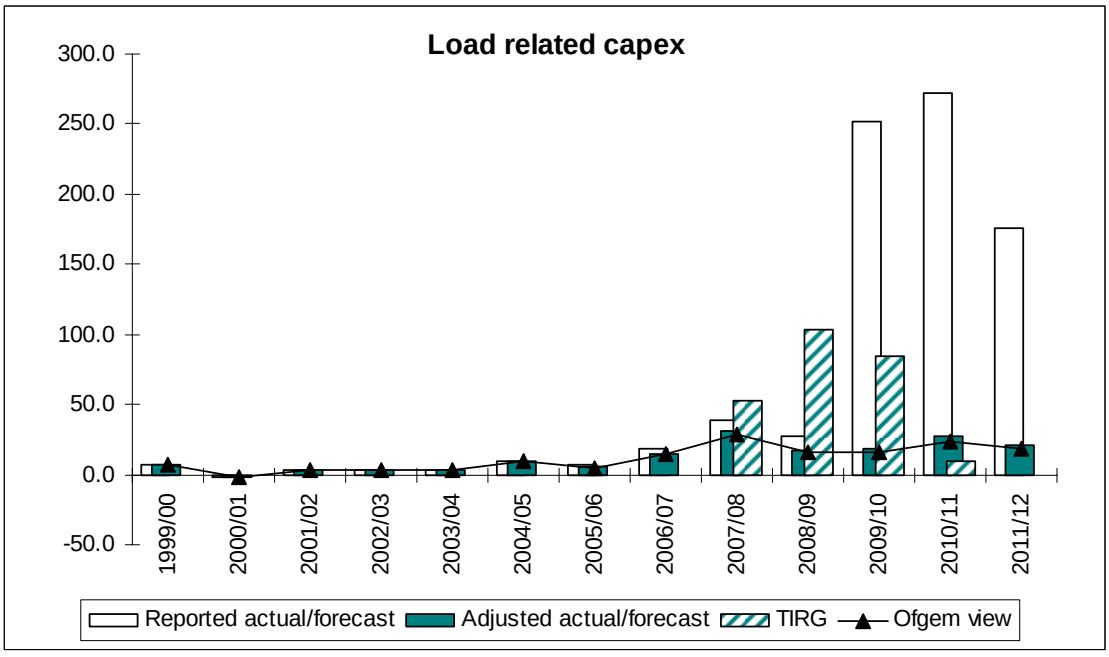
2. The reduction is due to first, the request by SHETL that a group of large schemes (of some £626m in total cost) relating to future wind generation development be taken out of the consideration for baseline. Some further reduction has been made based on our assumption of a lower future generation and associated system boundary flows for the baseline.

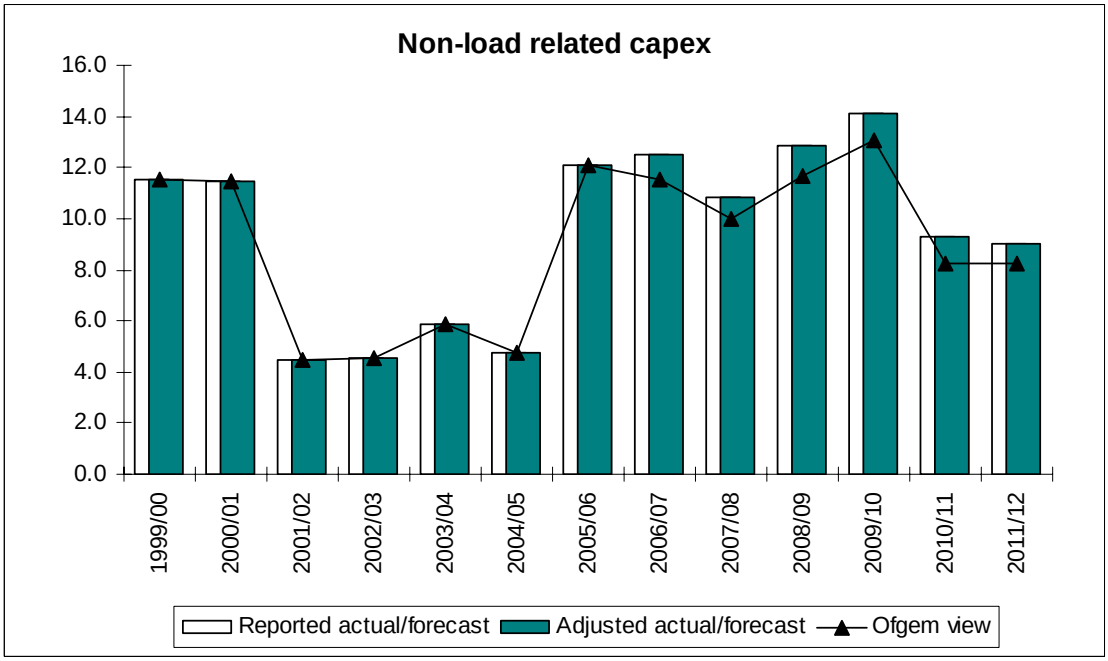
3. We have made reduction due to assumption of more efficient connection designs for smaller wind generating station.

4. The procurement efficiency for SHETL is still under consideration.

5. Our initial assessment is that lower level of asset replacement and refurbishment is required (transformers only).

Figure 7.2 Summary of SHETL's historical and forecast capex





SPTL

1.3. This section sets out how the allowances for capex for SPTL underpinning our initial proposals have been derived.

Table 7.3 SPTL capex assessment details

SPTL historical & forecast capex details	Historical 1999/00 - 2004/05	Forecast 2005/06 - 2006/07	Forecast 2007/08 - 2011/12	Notes
Licensee reported actual/forecast				
Net load related	36.4	60.8	346.9	
Net non-load related	156.8	111.9	366.5	
TSS			3.1	**1**
Adjustment for baseline capex				
Non-operational capex	-6.0	-3.2	-2.8	**2**
Internal profit margin	-9.6	0.0	0.0	**3**
Entry volume adjustment		-5.6	-39.8	**4**
Adjusted baseline capex actual/forecast	**177.7**	**163.9**	**670.8**	
TSS			3.1	
Adjustment for RAV / allowed expenditure				
Load Related Expenditure				
Entry/Exit sole-use	0.0	0.0	0.0	
Infrastructure	0.0	-6.4	-27.6	**5**
Procurement efficiency		0.0	0.0	**6**
Non Load Related Expenditure				
Asset replacement & refurbishment				**7**
Transformers	0.0	-3.2	-17.1	
Switchgear	0.0	-6.5	-10.8	
Substation other	0.0	0.0	-6.2	
Overhead Lines	0.0	-5.0	-25.5	
Underground Cables	0.0	-0.8	-3.3	
Protection & control	0.0	-3.1	-27.5	**8**
Other TO (Diversions: non-rechargeable)	0.0	0.0	0.0	
Procurement efficiency		0.0	0.0	**6**
Other adjustments				
TSS			-0.9	**9**
Allowed RAV / expenditure	**177.7**	**138.9**	**552.8**	
TSS			2.2	

Notes

1. Treatment of future TSS capex is discussed in Chapter 7.

2. We have identified cost items that should be categorised as opex instead of capex.

3. We have removed profit margin charged by related party service provider.

4. The reduction is due to our assumption of lower future generation and associated system boundary flows for the baseline.

5. We have made reduction to entry expenditure due to an assumption of more efficient connection designs for smaller wind generating stations. We have also reduced exit related expenditure by removing avoidable/deferrable investment relating to demand growth.

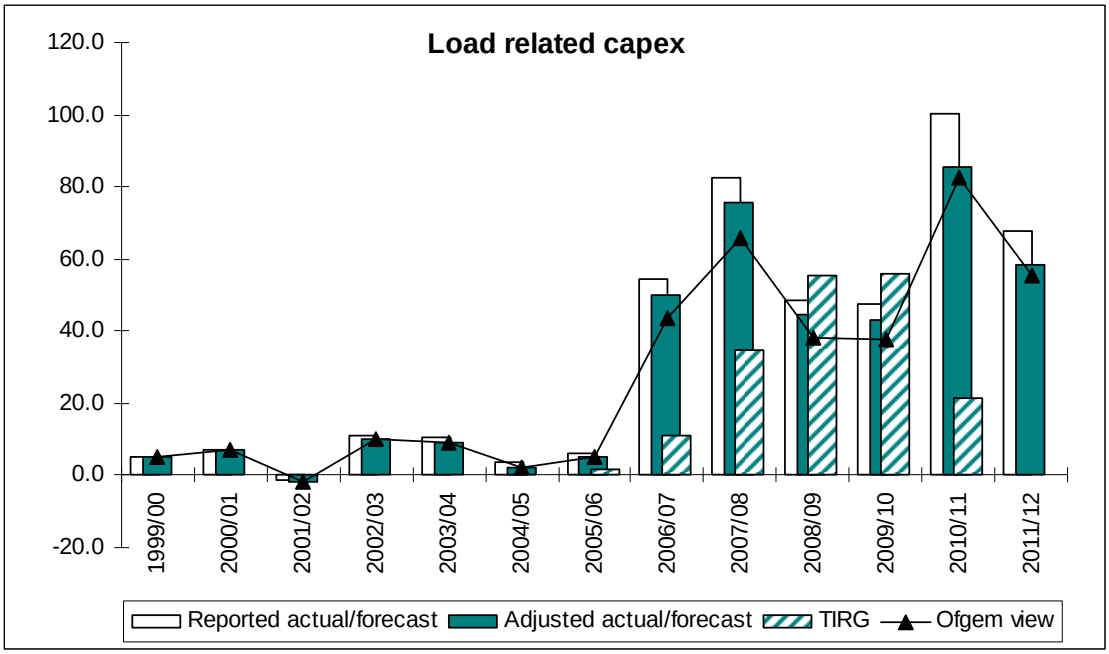
6. The procurement efficiency for SPTL is still under consideration.

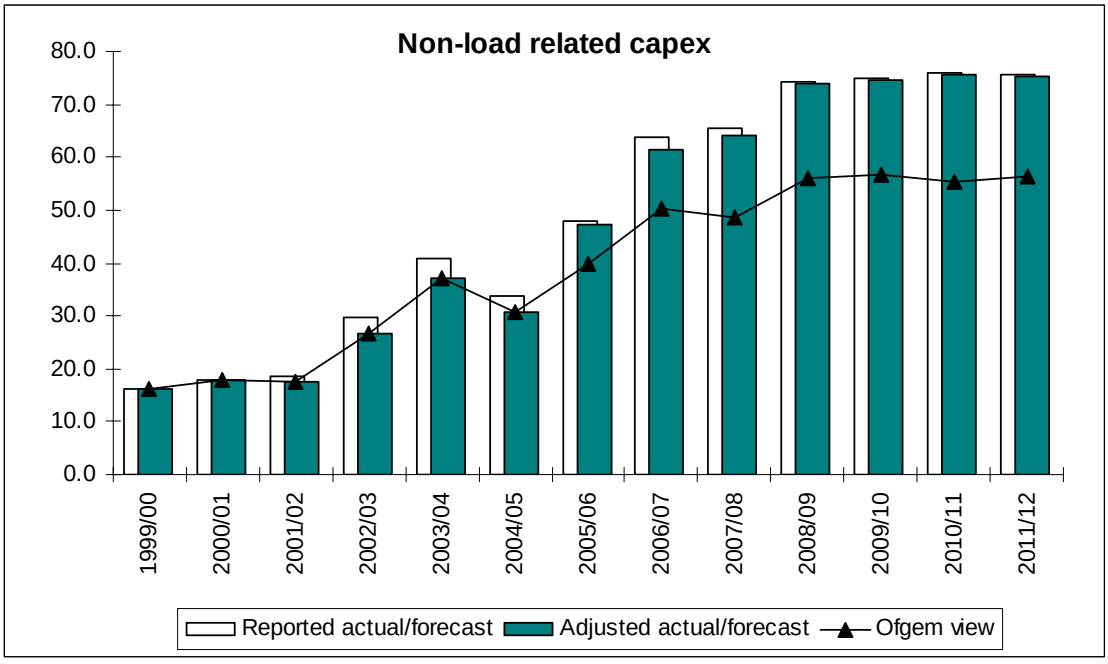
7. Our initial assessment is that the level of asset replacement and refurbishment can be lowered together with more efficient unit costs.

8. SPTL has forecast investment to accommodate the potential change of service level from BT's telecom network for carrying its system protection signals. This has been removed for further review.

9. Our initial assessment is that the required TSS investment can be provided at a lower cost.

Figure 7.3 Summary of SPTL's historical and forecast capex





NGG NTS

1.4. This section sets out how the allowances for capex for NGG NTS underpinning our initial proposals have been derived.

Table 7.4 NGG NTS capex assessment details

NGG NTS historical & forecast capex details	Historical 2002/03 - 2004/05	Forecast 2005/06 - 2006/07	Forecast 2007/08 - 2011/12	Notes
Licensee reported actual/forecast				
Net load related	311.5	211.3	673.8	
Net non-load related	46.9	132.8	448.1	
Milford Haven	5.7	359.8	224.0	
Adjustment for baseline capex				
Excluded costs	0.0	-5.6	-19.5	**1**
Non-operational capex	0.0	0.0	-19.6	**2**
Quasi capex	0.0	0.0	2.1	**3**
Internal profit margin	0.0	0.0	0.0	**4**
Entry/offtake volume adjustment	0.0	-29.9	-389.9	**5**
Adjusted baseline capex actual/forecast	**358.4**	**308.5**	**695.0**	
Milford Haven	5.7	359.8	224.0	
Excluded costs	0.0	5.6	19.5	
Adjustment for RAV / allowed expenditure				
Load Related Expenditure				
Project need case & efficiency	-73.8	-1.3	0.0	**6**
Future market price impact	0.0	0.0	-41.4	**7**
Procurement efficiency	0.0	-9.0	-12.1	**8**
Non Load Related Expenditure				
Compressor - emission reduction	0.0	-6.8	-64.8	**9**
Other non-load related	0.0	0.0	-69.7	**10**
Procurement efficiency	0.0	-6.0	-13.8	**8**
Other adjustments				
Milford Haven	0.0	0.0	0.0	**11**
Allowed RAV / expenditure	**284.6**	**285.4**	**493.2**	
Milford Haven	5.7	359.8	224.0	
Excluded costs	0.0	5.6	19.5	

Notes

1. Costs have been identified for separate treatment outside TO baseline.

2. We have identified cost items that should be categorised as opex instead of capex.

3. We have identified cost items originally in licensee's opex forecast which will be considered as capex, and are still reviewing the appropriate level of costs.

4. None identified.

5. We have excluded certain offtake projects to reflect Baseline definition.

6. Our initial assessment has identified that there is a case for excluding investment associated with increasing entry capacity at St Fergus, together with some inefficiency in delivery.

7. The licensee's forecast of overall impact of future market price increases has removed for further review.

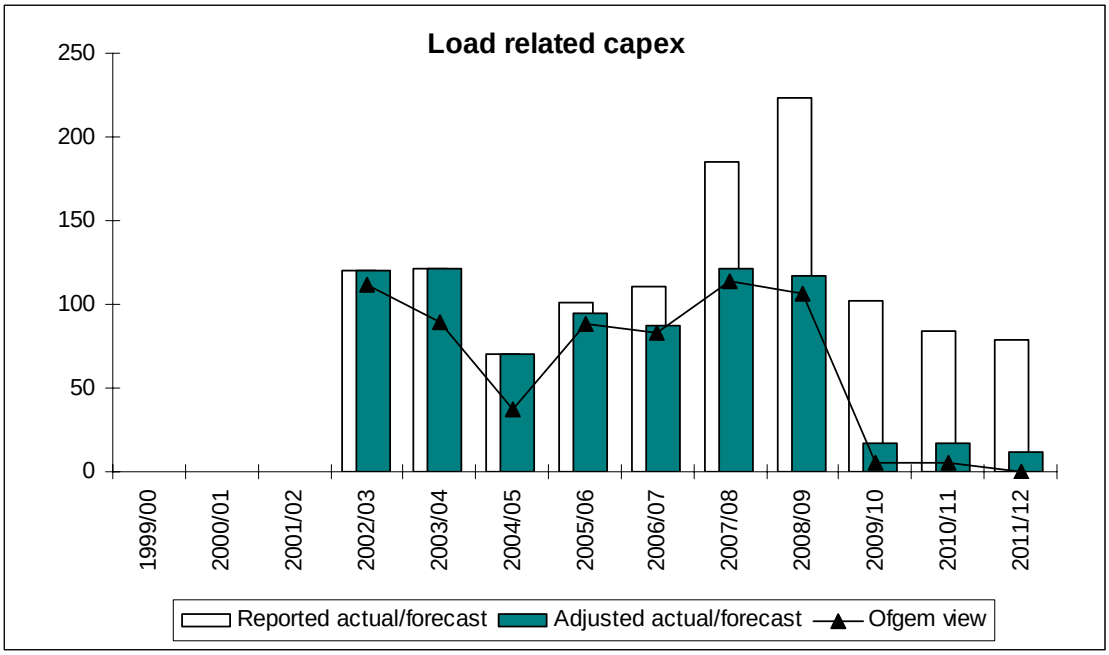
8. Our initial assessment of licensee's procurement efficiency revealed scope for improvement. Within a range of possible savings on capex, 5% saving is assumed here.

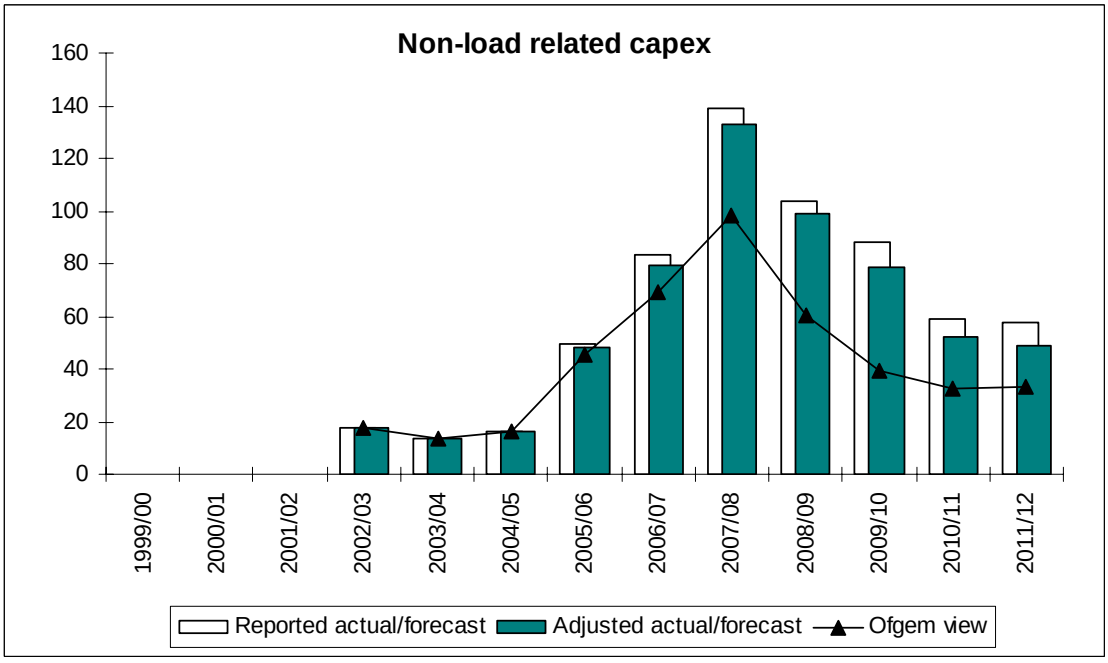
9. Of £248m total cost forecast by NGG NTS to replace compressor to comply with new emissions requirements, a reduction of £72m is considered appropriate due to the weak need case at sites with very low future utilisation level, together with possible relocation of existing assets.

10. Low utilisation; relocation of assets; alternative ways of refurbishing assets.

11. Assessment of Milford Haven project forecast is still underway hence no adjustment at this stage. NGG NTS's forecast is based on its latest official submission, but is likely to be updated.

Figure 7.4 Summary of NGG NTS's historical and forecast capex





Appendix 8 - Cost assessment - opex

1.1. The following tables set out the controllable operating costs allowances summarised in Chapters 3 to 6.

Table 8.1 NGET Controllable opex allowance

	Notes	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
NGET Forecast Controllable Opex	*1*	**179.3**	**177.2**	**178.8**	**177.5**	**182.9**
NGET RCCC 2004/05	*1*	**149.9**	**149.9**	**149.9**	**149.9**	**149.9**
Efficiency adjustments	*2*					
Shared services		(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Corporate Centre		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Engineering opex		(1.5)	(2.8)	(4.1)	(6.4)	(7.7)
Information Services		(0.7)	(1.1)	(1.7)	(2.1)	(2.7)
Insurance		(3.3)	(4.8)	(3.5)	(1.7)	0.5
Property	*3*					
Frontier Shift	*4*	(2.2)	(4.5)	(6.6)	(8.8)	(10.9)
Total efficiency adjustments		**(12.8)**	**(18.2)**	**(21.0)**	**(24.0)**	**(25.8)**
Efficient cash costs		**137.1**	**131.7**	**129.0**	**125.9**	**124.1**
Upward cost drivers						
Real wage growth	*5*					
Atypical/New costs/Quasi Capex	*6*	13.9	16.3	16.6	18.0	23.9
Quasi-capex transfered to capex		(12.7)	(15.1)	(15.4)	(16.8)	(22.7)
Quasi-capex to remain in opex		1.2	1.2	1.2	1.2	1.2
Total upward cost drivers		**1.2**	**1.2**	**1.2**	**1.2**	**1.2**
Ongoing opex allowance		**138.3**	**132.9**	**130.2**	**127.1**	**125.3**
Additional Opex allowances						
Non-operational capex	*7*	11.6	7.6	7.4	12.8	15.9
Total additional Opex allowance		**11.6**	**7.6**	**7.4**	**12.8**	**15.9**
Ofgem total controllable allowance		**149.9**	**140.5**	**137.6**	**139.9**	**141.2**

Notes

1. These numbers exclude £6.7m p.a. (ongoing pensions costs) as these costs are subject to a separate assessment and allowances

2. The efficiency analysis is discussed later in this appendix

3. This assessment is presently underway we will revise the numbers accordingly in September

4. See Chapter 7 for further details, the frontier shift has been applied after other efficiency adjustments each year

5. We have assumed no real wage growth

6. Transfer to capex are the costs we have allowed to be included in the capex allowance discussed in Chapter 7. Our latest view is that £68.9 million should be included (2007-12) in capex. We are continuing to assess these costs.
7. These costs have been removed from capex, they are subject to a separate assessment and may be revised accordingly in the September update.

Table 8.2 NGG Controllable opex allowances

	Notes	**2007/08 £m**	**2008/09 £m**	**2009/10 £m**	**2010/11 £m**	**2011/12 £m**
NGG Forecast Controllable Opex	*1*	**63.3**	**65.0**	**63.5**	**65.5**	**66.9**
NGG RCCC 2004/05	*1*	**60.0**	**60.0**	**60.0**	**60.0**	**60.0**
Efficiency adjustments	*2*					
Shared services		(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Corporate Centre adjustments		(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Engineering opex		(0.6)	(1.0)	(3.6)	(3.6)	(3.6)
Information Services		(0.0)	(0.0)	0.0	(0.0)	(0.1)
Insurance		(1.8)	(2.7)	(1.9)	(0.9)	0.3
Property	*3*					
Frontier Shift	*4*	(0.9)	(1.8)	(2.7)	(3.5)	(4.4)
Total efficiency adjustments		**(4.8)**	**(6.9)**	**(9.6)**	**(9.6)**	**(9.3)**
Efficient cash costs		**55.2**	**53.1**	**50.4**	**50.5**	**50.7**
Upward cost drivers						
Real wage growth	*5*					
Atypical/New costs/Quasi Capex		0.7	2.2	0.3	0.4	0.5
Quasi-capex transfered to capex	*6*	(0.3)	(1.8)	0.0	0.0	0.0
Quasi-capex to remain in opex		0.4	0.4	0.3	0.4	0.5
Total upward cost drivers		**0.4**	**0.4**	**0.3**	**0.4**	**0.5**
Ongoing Opex allowance		**55.6**	**53.5**	**50.7**	**50.9**	**51.2**
Additional Opex Allowances						
Non-operational capex	*7*	2.5	3.2	5.5	3.4	5.0
Total additional opex allowance		**2.5**	**3.2**	**5.5**	**3.4**	**5.0**
Ofgem total controllable allowance		**58.1**	**56.7**	**56.2**	**54.3**	**56.2**

Notes

1. These numbers exclude £2.8m p.a. (On going pensions costs) as these costs are subject to separate assessment and allowances

2. The efficiency analysis is discussed later in this appendix

3. This assessment is presently underway. We will revise the numbers accordingly in September

4. See chapter 7 for further details, the frontier shift has been applied after other efficiency adjustments each year

5. We have assumed no real wage growth

6. Transfer to capex are the costs we have allowed to be included in the capex allowance discussed in chapter 7

7. These costs have been removed from capex, they are subject to a separate assessment and may be revised accordingly in the September update

Table 8.3 SHETL Controllable Opex Allowances (£m, 2004/05 prices)

	Notes	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
SHETL Forecast Controllable Operating Costs	*1*	**6.0**	**6.4**	**6.8**	**7.1**	**7.5**
SHETL RCCC 2004/05	*1*	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
Efficiency Adjustment						
1.5% Frontier Shift	*2*	(0.1)	(0.1)	(0.2)	(0.3)	(0.4)
Total Efficiency Adjustment		**(0.1)**	**(0.1)**	**(0.2)**	**(0.3)**	**(0.4)**
Efficient Cash Costs		**4.9**	**4.9**	**4.8**	**4.7**	**4.6**
Upward Cost Drivers						
Real wage growth	*3*	-	-	-	-	-
Ongoing BETTA costs		0.4	0.4	0.4	0.4	0.4
Increases in costs relating to existing assets		-	-	0.1	0.1	0.2
Increases in costs relating to new assets	*4*	0.5	0.9	0.4	0.2	0.2
Total Upward Cost drivers		**0.9**	**1.3**	**0.9**	**0.7**	**0.8**
Ongoing Opex Allowance		**5.8**	**6.2**	**5.6**	**5.4**	**5.4**
Additional Opex allowances	*5*					
Non Operational Capex		-	-	-	-	-
Total Additional opex allowance		**-**	**-**	**-**	**-**	**-**
Ofgem total controllable allowance		**5.8**	**6.2**	**5.6**	**5.4**	**5.4**
Non Controllable Costs						
Network Rates		3.5	3.5	3.5	3.5	3.5
Total Opex (excluding pensions)		**9.3**	**9.7**	**9.1**	**8.9**	**8.9**

Notes

1. These numbers exclude £0.5m p.a. On going pensions costs as these costs are subject to separate assessment and allowances

2. See Chapter 7 for further details, the frontier shift has been applied after other efficiency adjustments each year

3. We have assumed no real wage growth

4. We have scaled back these costs so they are consistent with our proposed capex allowance for SHETL

5. SHETL did not include any non operational capex its FBPQ and we do not anticipate any further allowances

Table 8.4 SPTL Controllable Opex Allowances (£m, 2004/05)

	Notes	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
SPTL forecast Controllable Operating Costs	*1*	**17.7**	**18.3**	**19.0**	**19.3**	**19.2**
SPTL RCCC 2004/05	*1*	**14.5**	**14.5**	**14.5**	**14.5**	**14.5**
Efficiency Adjustments	*2*					
Engineering opex		(2.0)	(2.0)	(2.0)	(2.0)	(2.0)
1.5% Frontier Shift	*3*	(0.2)	(0.4)	(0.6)	(0.7)	(0.9)
Total Efficiency Adjustments		**(2.2)**	**(2.4)**	**(2.6)**	**(2.7)**	**(2.9)**
Efficient Cash Costs		**12.3**	**12.1**	**11.9**	**11.8**	**11.6**
Upward Cost Drivers						
Real Wage Growth	*4*	-	-	-	-	-
Engineering opex	*5*	1.2	2.0	2.8	3.0	3.2
Insurance	*6*	-	-	-	-	-
Total Upward Cost Drivers		**1.2**	**2.0**	**2.8**	**3.0**	**3.2**
Ongoing Opex Allowance		**13.5**	**14.1**	**14.7**	**14.8**	**14.8**
Additional Opex allowances						
Non Operation capex	*7*	1.3	0.3	0.4	0.4	0.4
Total Additional Opex allowances		**1.3**	**0.3**	**0.4**	**0.4**	**0.4**
Ofgem total Controllable Allowance		**14.9**	**14.4**	**15.1**	**15.1**	**15.2**
Non Controllable Costs						
Network Rates		12.5	12.5	12.5	12.5	12.5
Total Opex		**27.4**	**26.9**	**27.6**	**27.6**	**27.7**

Notes

1. These numbers exclude £0.5m p.a. (ongoing pensions costs) as these costs are subject to separate assessment and allowances

2. The efficiency analysis is discussed later in this appendix

3. See Chapter 7 for further details, the frontier shift has been applied after other efficiency adjustments each year

4. We have assumed no real wage growth

5. These main cost drivers include plant maintenance and tower paint

6. We have not allowed any increase based on our view on forecast insurance costs (see below)

7. These costs have been removed from capex, they are subject to a separate assessment and may be revised accordingly in the September update.

Opex Efficiency Analysis

1.2. Outlined below is a summary of our analysis of the different areas of the transmission companies' operating costs.

Electricity engineering opex (NGET & SPTL)

1.3. We assessed the forecast expenditure of the companies in relation to the asset management (engineering) activities to determine an efficient profile of costs based on the companies' forecasts.

1.4. Our consultants modelled historic and forecast costs related to planned and unplanned inspection, maintenance and repairs across the following main network asset categories

- overhead lines
- cables
- transformers
- substations

1.5. In addition we also considered other relevant factors such as asset condition, asset management, organisation procurement etc. The proposals we have presented for NGET are broadly equivalent to a reduction of 2 per cent p.a. from 2007 to 2012.

Gas Engineering Opex (NGG NTS)

1.6. We assessed the forecast expenditure of NGG NTS in relation to the asset management (engineering) activities to determine an efficient profile of costs based on NGG's forecasts. We were advised by consultants in this assessment.

1.7. Our consultants' overall conclusion was that historic spend had been incurred efficiently but noted that there were some areas of efficiency savings wre achievable, in particular the consultants noted the following areas for cost reduction in NGG's forecast:

- Environmental monitoring and reporting
- Capital planning
- De-manning of non operational compressor stations
- Repair of defects on pipelines and above ground installations (AGIs)
- Support Functions and Overheads

NG (NGET & NGG NTS)

1.8. Our consultants conducted a benchmarking exercise for the 'back office' business services which run centrally for NG's UK regulated businesses i.e. transmission, distribution, and other operations. The specific operating units covered included:

- HR & Scheme Trainees
- Procurement & Logistics
- Business Services Finance
- Transmission Finance
- Communications
- Legal
- Safety, Health, Environment (SHE)
- Regulation
- Audit

1.9. The analysis compared NG's 2004/05 costs against a variety of external benchmarks, NG's costs were adjusted to the upper quartile where these costs were higher. These savings were then taken across all future years. The cost reductions included in the opex allowances are at the low end of the identified range.

1.10. NG's corporate costs are provided to the entirety of NG Group which comprise the following

- Media Relations
- Audit
- Strategy
- Investor Relations
- General Counsel & Compliance
- Corporate responsibility
- Taxation
- Human Resources
- Company Secretariat
- Treasury
- Other (inc Board)

1.11. In each case we have considered whether the service provided by the corporate department is essential to the running of the regulated businesses and also whether these services are duplicated or could be absorbed without cost by NG's central support functions already provided to the UK regulated businesses. Our analysis has identified scope for cost reductions in these areas. Costs that we are allowed relate to Audit, Treasury, Taxation and Company Secretariat. In addition we have excluded the proportion of salary costs of senior executives that relate to non regulated businesses.

SHETL and SPTL

1.12. We benchmarked data from both the Scottish companies against a variety of benchmarks including the DNOs and NG. We generally found both companies to be around the upper quartile benchmark. However, we have not yet undertaken an extensive normalisation of these costs.

Information Technology

1.13. Our consultants undertook an analysis of total NG's Information Systems (IS) costs (opex and some capex) The assessment included detailed analysis of various 'towers' of IS including the Retained IT organisation, Application Development and Support, Desktop, and Application Servers. NG was assessed against a "reference group" of appropriate comparator organisations. The consultants assessed NG's base year (2004/05) costs and also considered NG's key forecast business plan assumptions. The efficiency savings relate to the following areas:

- Services – some limited savings were identified in NG's infrastructure support which is largely outsourced.
- System Integrator (SI) rates - SI rates charged to NG are significantly higher than the reference group.
- Applications Support – this adjustment reduced the proportion of contractors to align with our consultant's view of best practice.
- Insurance - our consultants undertook an analysis of NG's insurance costs, in particular they looked at:

    a. NG's risk management policy and practice
    b. Price, level and types of coverage purchased including analysis claims history
    c. NG's use of its offshore insurance captives

1.14. Overall this analysis showed NG's insurance premiums were efficient and competitive compared to the present market. Based on this conclusion we have not adjusted for margins charged by the captives or dividends they have paid to NG Group this is discussed in Chapter 7.

1.15. Finally our consultants considered forecast insurance costs we have used their forecast based on an extrapolation of cycles in Lloyds of London's Non Marine Index. NG and SPTL have forecast a consistent increase of insurance between 2007 and 2012.

Further Developments

1.16. In addition to our ongoing analysis and discussion with the licensees, our initial proposals on controllable opex allowances may also be revised for the following factors:

- Assessment of property costs (NGG and NGET)
- Assessment of operational telecoms (NGET) this will be coordinated with the review of certain GB SO internal costs
- Any developments in our view on real wage growth
- Our assessment of non operational capex
- Consideration of further adjustments in relation to NG's merger savings.

Appendix 9 - Financial Issues

Introduction

1.1. This appendix provides background information on our approach to setting the cost of capital for each of the companies. It also provides further explanation of our position in respect of financeability.

Cost of capital

1.2. The cost of capital is the level of return required by the financial markets - both debt and equity - in order to provide capital. We will set the regulated return for each of the companies at a level consistent with the relevant cost of capital. We have engaged consultants to help us consider a range of issues surrounding our approach to cost of capital, and to help inform our high level approach to the cost of capital debate for both TPCR and GDPCR.

1.3. We will consider the latest market information and the conclusions of our consultants to help inform our decision on the appropriate allowed rate of return.

Use of the Capital Asset Pricing Model (CAPM)

1.4. We have considered whether alternative approaches to CAPM may be more appropriate and our initial view is that it remains the most appropriate means of assessing cost of capital. The Weighted Average Cost of Capital (WACC) is the weighted average of the expected cost of equity and the expected cost of debt.

$$WACC = g*(r_f + \rho) + (1-g)*(r_f + (\beta * ERP))$$ Where

g	=	gearing (net debt:RAV)
rf	=	risk-free rate
ρ	=	debt premium
β	=	equity beta
ERP	=	Equity Risk Premium

1.5. Critics of CAPM have indicated that a single factor (i.e. beta) is insufficient to capture risk. Amongst the alternatives is the three factor Fama French model which adds two further factors which reflect additional market evidence of risk. These are

a. the higher returns earned by relatively smaller companies (the small v big effect), and
b. the higher returns earned by companies with lower rather than higher market to book value ratios (the value versus growth effect).

1.6. Our initial analysis has shown that the first of these has negligible explanatory value for regulated utilities, and the second does not exhibit statistical reliability across the sector.

1.7. Another alternative, the Dividend Growth Model (DGM) is argued to have some advantages in that it is based on observable evidence of market expectations which are forward looking and because it tends to produce a narrower range of estimates. However DGM uses forward looking dividend growth estimates which may themselves be based on expectations regarding the outcome of a price control review and this would result in a circularity of logic in the calculation. For these reasons, economic regulators in the UK have tended to use DGM as a check on, rather than a substitute for, the CAPM. The results we have obtained are consistent with those selected from the range produced by the CAPM. This is because the addition of its dividend yield component and its long term growth component are similar to the overall equity return proposed for the CAPM.

Previous and Current Controls

1.8. The existing price controls provided for differing real pre-tax allowed rates of return across the licensees - currently 6.25% for NGG and NGET, and 6.50% for the two Scottish licensees (4.37% and 4.52% real post tax respectively). The historic differences in allowed rates of return reflected two main factors: the timing of past electricity and gas transmission price control reviews; and the significant differences in the size and financial structure of the regulated transmission businesses.

Table 9.1 Values used by component

Components	Scots Dec 99	NGC Dec 00	Transco Sep 01	DPCR4 Nov 04	TIRG Dec 04	Scots RO Dec 04	NGET RO Dec 05
Risk Free rate	2.50&	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
Debt Premium	1.85%	1.70%	1.90%	1.35%	1.35%	1.35%	1.00%
Cost of Debt	4.35%	4.45%	4.65%	4.10%	4.10%	4.10%	3.75%
Equity Premium	3.50%	3.50%	3.50%	4.75%	4.75%	4.75%	4.75%
Equity Beta	1.00	1.00	1.00	1.00	1.00	1.00	0.90
Cost of Equity	6.00%	6.25%	6.25%	7.5%	7.5%	7.5%	7.0%
Gearing	50%	60%	62.5%	57.5%	50%	57.5%	60%
WACC pre tax	6.50%	6.25%	6.25%	6.91%	8.81%	6.91%	6.25%
WACC post tax	4.52%	4.37%	4.37%	4.84%	6.16%	4.84%	4.39%

1.9. Also, in December 2005, Ofreg published a decision which based its returns on those used by Ofgem for electricity distribution a year earlier in DPCR4. However, Ofreg also took account of more recent market data and reduced the overall post-tax real rate of return by 0.4% to 4.4%.

1.10. In DPCR4, we set a cost of capital that was at the high end of possible outcomes as determined by the CAPM. In doing so, we chose not to rely on observed spot market data for the real risk free interest rate, on the basis that there seemed to be exceptional factors pushing real rates down. We also used an assumption of an equity beta of 1 on the basis that observed market data was statistically unreliable in the period following the collapse of the telecoms and IT boom at the start of the decade.

Cost of equity

1.11. The risk-free rate and the equity risk premium (ERP) are market-wide parameters and apply to all firms. The ERP represents the market premium which equity investors require in order to invest in (higher risk) equity rather than (lower risk) government bonds. The equity beta measures the non-diversifiable risk which investors face when investing in a specific stock. Examples of non-diversifiable risk are macro-economic factors such as inflation and interest rate movements, i.e. factors that affect all firms in the market, albeit to a different degree, and hence cannot be diversified away by adding additional securities to the portfolio.

1.12. In DPCR4, as described above, we observed that the CAPM model gave a wide range of estimates for the cost of equity, reflecting a significant variation between long term average values for the cost of equity and observed market data at a given point in time. We concluded that we could not rely on observed market data due to exceptional factors pushing down interest rates and the instability of the equity beta. This, together with the investment focus of the review, led us to adopt a value at the top of the range.

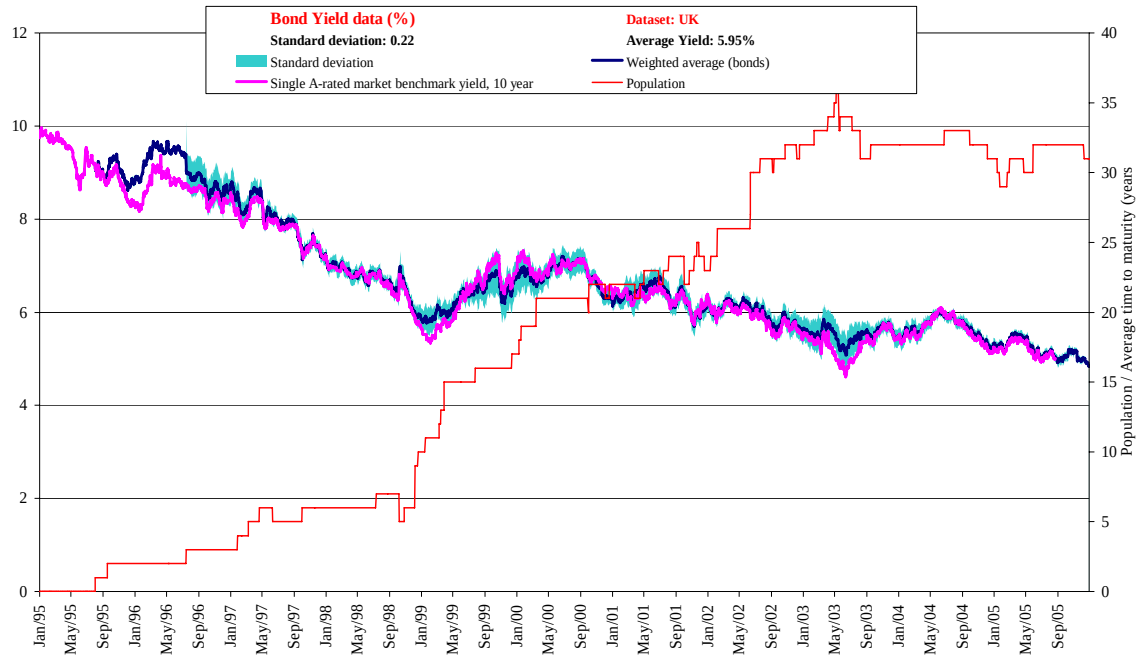
1.13. For TPCR, we are currently undertaking a study which is examining these factors, and are currently using a total market return of 7.0%, based on evidence that the long term arithmetic average of total equity market returns is between 6.5% and 7.5%.

Cost of debt

1.14. The expected cost of debt consists of the risk free rate and a debt premium. The yield on 10 year index linked gilts is currently 1.7% and the 10 year trailing average of this yield is 2.3%. The debt premium is company specific and is the premium on corporate debt over equivalent gilts which financial markets require to allow for the greater risk of default on corporate debt. The expected cost of debt is the market cost of debt and not the historic cost of the existing debt.

1.15. At the DPCR4 final proposals Ofgem assumed the average DNO debt risk premium was 1.35 per cent. However since DPCR4, bond yields have continued to fall and spreads have remained relatively narrow. A larger number of bonds have been examined for TPCR which indicates that the average spread versus nominal gilts over the last 10 years has been just fewer than 110 basis points for "A" rated bonds with a ten year maturity (although the current value is lower at around 65 basis points). The following graph demonstrates the increasing convergence over time of "A" rated utility yields and the benchmark yield for bonds for similar ratings and maturity (i.e. bond spreads have become commoditised).

Figure 9.1 Yield on "A" rated utilities 8-15 year maturity v Bloomberg 10 year benchmark



Gearing

1.16. For DPCR4, we assumed a gearing level of 57.5 per cent. There is market evidence e.g. from the levels of gearing taken on by the independent gas distribution businesses (around 75 per cent), that the companies have the ability to continue to increase borrowing without affecting credit ratings. As such, a higher gearing assumption than used in previous reviews may remain consistent with our normal requirement for a credit rating to remain comfortably within investment grade.

Modelling assumptions

1.17. As illustrated below, applying a range of plausible input assumptions to the CAPM produces a wide range of potential values for the cost of capital, ranging from 2.8 per cent to 4.8 per cent post tax real. However, we do not consider that figures in the lower reaches of this range would represent a sustainable return in the long term.

1.18. Our modelling assumption for these initial proposals is 4.2 per cent, based on:

- A real cost of debt of 3.4 per cent. This figure is consistent with current 10 year trailing average data for gilt yields and for the average spread of 'A' rated utility bonds with a ten year maturity;
- A cost of equity of 7 per cent, based on long term averages; and
- A gearing level of 60 per cent (in line with the assumptions underlying the current controls).

Table 9.2 Ranges for the cost of capital

Component	Spot (Low)	DPCR4 (High)	View in Model	Debt 10 Year average Equity @ 7.5%	Debt 5 Year average Equity @ 6.5%
Risk Free rate	1.65%	2.75%	2.30%	2.4%	2.10%
Debt premium	0.65%	1.35%	1.10%	1.1%	1.00%
Cost of debt	2.3%	4.1%	3.4%	3.5%	3.10%
Equity premium	5.85%	4.75%	5.20%	5.1%	4.40%
Equity Beta	0.5	1.0	0.9	1.0	1.0
Cost of Equity	4.6%	7.5%	7.0%	7.5%	6.5%
Gearing	60.0%	57.5%	60.0%	60.0%	60.0%
WACC pre tax	4.0%	6.9%	6.0%	6.4%	5.6%
WACC post tax	2.8%	4.8%	4.2%	4.5%	3.9%

Financeability

1.19. Under previous controls increases in gearing and relatively static levels of RAV have not required specific equity funding. The projection in the table below shows the expected cash flow for each licensee over the control period. It indicates the extent to which licensees may need to provide equity funds in the forthcoming period assuming no change in gearing. Under this assumption the financial indicators remain within the targets for Transmission companies indicated by the credit rating agency Standard & Poors (S&P). In carrying out financeability tests we will, in accordance with established policy, model future financial projections with 60% initial gearing, consistent with the cost of capital assumptions.

1.20. To illustrate this for SHETL, the regulated turnover of £243m provides a cash flow of £88m which in conjunction with additional debt funding capacity of £44m provides £132m towards the projected capital expenditure of £164m leaving £32m required from shareholders (as would be expected when regulatory asset vales increase).

Table 9.3 Ofgem estimates of company financeability (£m real 04/05 price level)

Licensee	NGGT (TO)	NGET (TO)	SPT	SHETL
	£m	£m	£m	£m
Closing RAV – 31st March 2012	3090	6443	1047	356
Opening RAV – 31st March 2007	2873	5199	746	282
Change in Regulatory Asset Value	217	1244	301	74
Five year cumulative totals	2008-12	2008-12	2008-12	2008-12
Regulated Turnover	2355	4680	675	243
Controllable opex	283	709	75	28
Non-controllable opex	393	506	63	18
Pensions	131	181	6	4
Interest	337	972	106	54
Tax	281	363	68	26
Dividends	241	434	66	25
Residual operating cash Flow after all cash outgoings (including dividends at 3.8% of Regulatory asset value)	689	1515	291	88
Additional debt funding available as RAV increases (taken as 60%, the cost of capital gearing level)	130	746	181	44
Internal funds available towards capex	819	2261	472	132
Capital Expenditure total	737	2790	555	164
Equity funding needed to meet total capex	-	529	83	32
S&P Financial Indicators (5 year ranges)				
Net Debt/RAV (S&P<68%)	32-40%	59-62%	41-48%	57-58%
Funds from Operations/Debt (S&P>10%)	17-23%	13-15%	16-25%	14-15%
Funds from Operations/Interest(S&P>2.0)	2.9-3.9	2.4-2.7	3.1-4.9	2.4-2.9

Depreciation cliff edge

1.21. Our Second and Third TPCR Consultation documents raised the issue of the loss of income from the cessation (after 20-22 years) of regulatory depreciation on pre vesting assets. This was discussed and analysed together with some options to address any financeability shortfall, of which our preferred approach would be to use a tilted depreciation approach.

1.22. For DPCR a reduction in the life of post vesting assets from 33 years to 20 years (with 15 years for smoothing) was adopted. In the Third TPCR consultation the impact of using for NG and SPTL a 25 year rather than a 40 year life was indicated (with 20 years for smoothing), and for SHETL a 40 year rather than a 48 year life (with 15 years for smoothing). It was indicated that this modelling would also take into account any wider financeability issues. We intend to employ the same broad approach to compensate for the discontinuity in cash flow that would otherwise result. Further modelling is required to determine the appropriate revision to depreciation profiles and, accordingly, we have made no allowance for this in the Initial Proposals. We will examine this issue further with the licensees and set out our further findings in the September update.

Differential rates of return

1.23. In our Third TPCR consultation, we considered whether all assets should attract the same rate of return, as an alternative approach would be to separate out classes of costs and apply differential rates of return. For example, one rate of return could apply to existing assets, while another rate of return could apply to the delivery of new assets. The intention of this would be to provide an appropriate return on existing assets, while increasing the reward available to licensees in areas where they are taking relatively more risk.

1.24. Our initial view is that the addition of new assets (at a higher rate of return) to the existing asset RAV (at a lower rate of return) is likely to result in a lower rate of return over time. A similar effect may also be achieved by establishing an appropriate rate of return over the entire asset base, which reflects the risks involved in an investment in both existing and new assets.

Appendix 10 - Revenue drivers for NGET, SPTL and SHETL

Introduction

1.25. This appendix sets out in more detail our proposals for mechanisms to adjust the allowed revenues for NGET, SPTL and SHETL if the volume and location of new generation projects turn out (as expected) to be different to what has been assumed in setting the baseline allowances set out in Chapters 3 to 5.

1.26. While we are firm on the policy of revenue drivers as a means of handling revenue allowances where there is significant uncertainty as a result of external factors outside the control of the licensees, the detailed design of the revenue driver mechanisms is still at the development stage. We plan to publish a final proposed design in our September Update document. This appendix sets out our current thoughts and forward work-plan.

Process

1.27. The development of our proposals requires input from the licensees. We are managing this primarily through a working group, chaired by Ofgem and attended by all three licensees. This is being complemented by bilateral information requests and meetings where necessary. The purpose of the working group is to explore policy and implementation issues in a co-ordinated way across all three licensees, and to provide a forum to share ideas.

1.28. This process will continue up to our September Update document, and beyond if necessary. After September, it is anticipated that the group will focus on issues of implementation and legal drafting - such that there is a detailed shared understanding of what exactly is being proposed by Ofgem when we reach Final Proposals.

Initial proposals - Overview

1.29. The broad structure of our revenue driver design is described in Chapter 10 of the main document. This sets out our view that a two-part revenue driver design is appropriate to cover (a) local connection costs, and (b) deeper reinforcement works. We think this distinction adds value because of the different uncertainties

surrounding the need for deep reinforcements as compared to local connection works[2].

1.30. The reason why we think a revenue driver is appropriate is because the alternatives do not in our view protect the interests of consuming. Setting a fixed allowance for the whole price control period runs the risk of providing unnecessary funding to the licensees. Alternatively, allowing the companies to recover whatever costs they incur provides very weak incentives to be efficient.

1.31. For each of these two types of revenue driver we need to specify the following five elements:

- The point from which the revenue driver applies (the 'baseline')
- The variable that drives the revenue
- The functional form of the revenue driver
- The point at which the revenue driver is triggered, and
- The point at which the triggered revenue allowances can be recovered.

1.32. These are discussed in turn below. At this stage, some of the elements include options rather than a single proposal.

Baseline

1.33. Revenue drivers adjust allowances in the light of events. They therefore need a reference point from which the adjustments apply. We propose to use the baseline case underpinning the capex allowances set out in Chapters 3 to 5 to set this reference point. We are taking the reference point as being consistent with the following network:

- The existing physical network; plus
- The TIRG baseline projects; plus
- A number of additional deep reinforcement projects consistent with allowances set out in Chapters 3 to 5.

1.34. The baseline is set using a forecast of future generation. It therefore includes allowances for volumes of generation that are not yet connected. Consequently, the revenue drivers need to work both ways, i.e. adjust revenues downwards if less generation than is assumed in the baseline connects, and adjust revenues upwards if more generation than is assumed in the baseline connects. For the avoidance of doubt, these adjustments will not affect allowances set as part of TIRG.

---

[2] The scope of the costs to be allowed for through the revenue driver needs to be finalised. In particular we will need to form a view on whether and how we reflect operating and maintenance (O&M) costs.

'Local works' revenue driver

1.35. When a new generator seeks connection to the network, works will be required to connect the generator to the main interconnected system such that the electricity generated can be exported on to the transmission system locally. The actual investment costs in any given scheme will be a function of a number of factors including:

- size of the generator
- distance from the existing local network
- voltage of the existing local network
- whether a new substation needs to be built, or an existing one extended
- terrain through which any new circuits will need to pass

1.36. The number of new generation connections that might come forward is, essentially, outside the control of the transmission companies. They are driven by wider commercial factors in the electricity generation market. The role of the licensees is to respond efficiently to demands for the new grid connections that might arise. The actual costs incurred by the transmission companies will depend on the volume of new connections actively seeking connection, and the specific cost drivers (including those listed above) for any individual scheme.

Variable

1.37. The variable we propose to use for the local works revenue driver is 'connection of a new generator'. It will take a value of zero for all generation connected to the network before 31 March 2007.

1.38. An area we continue to explore with the licensee is whether there needs to be a similar local costs revenue driver for demand connections also. This issue is as yet unresolved.

Functional form

1.39. We have two options for functional form. First, a relatively complex formula using a range of metrics to characterise connection of a new generator. Second, a simple £ per MW for each of the licensees with a proportion of costs being permitted to be passed through.

(a) 'Formula' approach

1.40. The rationale behind this approach is to seek to characterise accurately for each scheme the anticipated costs of undertaking the local connection works. The following functional form is an option and was mooted as a possibility by one of the transmission licensees at our revenue drivers working group. The model and form

outlined is for illustrative purposes and should not be considered as a definitive model at this stage.

1.41. The functional form assumes there are four components to the revenue driver:

= ((MW * £/MW) + (length * £/MWkm) + (no. transformers * £/unit)) * Non-firm/firm multiplier

1.42. We have tested this type of functional form data historic and current live connection applications, and have found a reasonably strong correlation between costs and revenues - although the quality of the fit did vary between licensees, with different factors raising issues. We will continue the work to test further the robustness of this approach and update in September.

(b) '£ per MW plus pass through' approach

1.43. An alternative approach we have explored is to adopt a much simpler functional form, but apply the revenue driver to only a proportion of the total costs. The rationale behind this approach is to avoid unnecessary complexity while retaining a reasonable degree of incentive to operate efficiently. We anticipate that this approach would involve setting a different £ per MW amount for each of the licensees recognising the differences in costs associated with new generation connections. It would also require setting a different £ per MW amount for 'firm' as compared to 'non-firm' local connections.

1.44. This approach has also been demonstrated to provide a relatively strong correlation between costs and revenues using the same data set. We will continue exploring both options and decide upon the appropriate approach in September.

Trigger point

1.45. In designing the revenue driver we need to define clearly and unambiguously what we mean by a 'new connection'. At one end of the spectrum, we might recognise a new connection when the party first applies for and accepts a connection offer from NGET. At the other end of the spectrum we might only recognise a new connection when the new generator is connected and participating in the market.

1.46. We propose at this stage to recognise a 'new connection' for the purposes of the revenue driver when the generator has signed its connection offer and has posted a level of security consistent with a significant proportion (e.g. a 30%) of the anticipated costs of the local works. Under the current arrangements through which new users are required to provide security, this would determined in relation to the Final Sums Liability (FSL).

1.47. Given that the FSL regime is currently under review, with potential changes imminent, it might be that we have to specify this type of hurdle in a different

manner for our proposals in September, even if we retain the same broad policy of a 'new generation connection' only counting when a certain amount of user commitment has been made.

1.48. If we adopt the approach proposed above we will need to consider whether additional measures are needed to fund pre-works (such as design studies, preparation of planning applications, etc) and preliminary works. One option is include a fixed allowance in the main opex allowance for such works. An alternative approach is to allow bilateral contracting for pre and initial works, with the revenues from such services being treated as excluded income for the transmission companies. We will consider this issue further ahead of our updated proposals in September.

Timing of revenue allowances

1.49. Once a 'new connection' is identified for the purposes of the revenue driver, we need to decide on when exactly the companies are allowed to recover the additional revenue allowances. There are two factors at work here. First, the incentives on the companies to complete the investment in a timely manner. Second, the cash flow for the companies. We think an appropriate balance is to provide some funding in advance of contractual delivery of the capacity, and provide the remaining proportion of the triggered revenue allowance on contractual delivery.

1.50. Under the 'Formula' approach described above we are exploring the options of allowing 50% of the total revenue allowance from the next available formula year once the trigger point had been reached, with the remaining 50% being recoverable on contractual delivery. To the extent that the date of contractual delivery is uncertain (which is the case under the existing access arrangements) then the allowance would be recoverable in the formula year following contractual delivery. If, under alternative access arrangements, the contractual delivery date was fixed with certainty, then the allowance would be recoverable from the formula year in which capacity was contractually delivered.

1.51. Under the '£ per MW plus pass-through' approach, the '£ per MW' element would be recoverable from contractual delivery. The 'pass through' element would be expected to trail actual costs with a lag of one formula year.

Deep reinforcement revenue driver

1.52. The cumulative effect of new generators connecting to the network, existing generators closing or reducing their output and changes in the demand for electricity from industrial, commercial and domestic users shapes the need for deeper reinforcement of the network. There are therefore more factors at work than for the identification of local works. Further, these projects can be very large and involve big, discrete increases in the amount of capacity available between areas of the network.

1.53. As with the local connection costs revenue driver design discussed above, the starting point for our revenue driver design is the baseline generation scenario and capex plan underpinning the allowances set out in Chapters 3 to 5 of the main document, and characterised in terms of an assumed physical network in the introductory text above.

Variable

1.54. The variable for the deep reinforcement revenue driver needs to reflect a wider range of influences that the variable for the local connection costs revenue driver. Our current view is that it should be generation net of peak demand in a specified area.

Functional form

1.55. The functional form for the deep reinforcement revenue driver needs, in our view, to be empirically based. This requires analysis of different investment scenarios linked to variations from the baseline assumed for the purposes of deriving the allowed revenues set out in Chapter 3 to 5 of the main document. The difficulty with deep reinforcement is that is involves, at least for SPTL and SHETL, a small number of large projects which will or will not be triggered under different generation growth scenarios. The functional form might not therefore be well suited to a smooth, continuous function of net generation. A series of step increases in revenue allowances might be more appropriate.

1.56. However, as with the local connection costs revenue driver, another approach is to adopt a simple functional form, but only apply the revenue driver to a proportion of costs - with the remainder of costs being allowed to be passed through. The risk with this approach is some of these schemes can be very large, and a pass through mechanisms without any ex post efficiency assessment might potentially introduce risks for consumers.

1.57. We will continue to explore both of these options and set out our proposed approach in our September Update document.

Trigger point

1.58. If the revenue driver is a function of net generation, then we need to address the issue of when 'new generation' counts for the purposes of the revenue driver. We also need to determine when information on generation closure counts - because the need for deep reinforcement will be influenced by cumulative effect of both new connections and closures.

1.59. For new connection, we would propose using the same trigger point as for the local connection works revenue driver, i.e. based on a level of user commitment. For generation closures, we need to avoid the risk of penalising the companies if

investment is revealed as unnecessary only with the benefit of hindsight, while at the same time ensure that funding is not provided for investment that is demonstrably unnecessary given closure decisions. This probably involves counting reduction in generation capacity with a lag. We will set out the detail of this aspect of the design in our September update.

Timing

1.60. The issues associated with the timing of revenue allowances are broadly comparable between the local connection works and the deep reinforcement work. We therefore need to form a view on the an appropriate balance between incentives on the companies to delivery in a timely manner, and a desire to avoid unnecessary stresses on cash flow for the companies, given that these are potential large investment projects with significant lead times.

1.61. Our current view is that a multi-stage mechanism is probably appropriate, as a means of striking this balance. We will update on this issue in September.

Exclusions and 'release valves'

1.62. As noted in the main document, we recognise that for some very large investment projects where capacity is being 'efficiently over-provided' relative to immediate short-term capacity needs, then might need to be a release value to enable the relevant revenue driver to be flexed. However, where possible we wish to severely limit the circumstances in which such mechanisms are necessary. Whether such measures are needed will be influenced, in part, by the form of the deep reinforcement revenue driver. Arguably, the case for such measures is weaker where a proportion of costs is permitted to be passed through.

1.63. Similar, as noted in the main document, we do not at this stage proposed to set revenue drivers to cover connections to the Scottish Islands. In our view, the technological design uncertainties at such at this stage that any cost estimates are to approximate to determine a revenue allowance if the investment is required. This in consistent with SHETL's request to, in effect, remove the initial cost estimates provided from consideration as part of the TPCR.

Appendix 11 - Entry Revenue drivers and baselines for NGG NTS

Introduction

1.1. This appendix describes in more detail our proposals for setting baseline capacity release obligations, for adjusting NGG NTS's revenues in the light of new demands for entry capacity, and for setting NGG NTS's allowances in respect of buy-back costs. It includes an initial quantification of our proposals to provide a reference point for consultation and further analysis ahead of our September update. The appendix is structured as follows:

- Process
- Data collection
- Capacity release obligations
- Revenue drivers
- Buyback incentives

Process

1.2. Our initial proposals are based on network modelling undertaken by NGG NTS with the specifications for the modelling set by Ofgem. There have been significant delays in NGG NTS providing the modelling analysis, such that the information presented in this document is based on an initial assessment of the data. Because of the late delivery of the analysis, we have not yet undertaken an audit of the analysis. We will update our proposals in September in the light of our audit and further analysis of the data provided by NGG NTS.

Data collection

Load absorption analysis

1.3. The first set of data ("load absorption analysis") concerns network capability at entry points. It estimates the amount of capacity that can be released at entry points without triggering additional investment, starting from an initial flow scenario. Our data request and NGG NTS's modelling output are summarised in the March consultation document.[3]

1.4. From a technical perspective, we asked NGG NTS to use the following network modelling assumptions, as explained in more detail in the TPCR Third consultation:

[3] Appendix 10, Modelling network capability, pp50-59.

- We asked NGG NTS to model network capability for two future years, namely 2007/08 and 2008/09.

- The network needs to stay in balance in the modelling exercise, so that the amount of gas going in at entry points (or "supply") equals the amount of gas coming out at offtake points (or "demand"). To achieve this, we asked NGG NTS to use two different approaches for adjusting the network as (in order to assess network capability at that entry point) the supply at a particular entry point is increased. Under the first approach ("load absorption"), we asked NGG NTS to scale up demand, *pro-rata*, across all offtake points. Under the second approach ("50 per cent load absorption / 50 per cent supply substitution"), we asked NGG NTS to scale up demand by 50 per cent across all offtake points, and to scale down supply by 50 per cent across all *other* entry points, both on a *pro-rata* basis.

- We asked NGG NTS to assess network capability at various levels of aggregation in the network, namely for individual entry points (or "nodes) and for combinations of entry points within a certain geographical area (or "zones"). For each zone, NGG NTS increased supply at all nodes within that zone on a *pro-rata* basis.

- The modelling requires an assumption on the physical base network (eg, pipelines, compressors, and associated network parameters) that is in place. We asked NGG NTS to assume that the physical network is the one used in NGG NTS's latest Ten Year Statement (for December 2005), for each of the two years that were modelled (2007/08 and 2008/09). We also asked NGG NTS to adjust the 2008/09 base network for the Isle of Grain investment signal from the November 2005 long term system entry capacity auctions.

- The modelling also requires assumptions on the demand and supply scenarios (i.e., gas flows coming in at entry points and going out at offtake points) that are observed on the base network. On the demand side, we asked NGG NTS to model "1 in 20 winter peak" demand for each year, taken from NGG NTS's latest Ten Year Statement. On the supply side, we asked NGG NTS to model the "Auctions+" scenario for each year, taken from the same source. NGG NTS has generated the "Auctions+" supply scenario by scaling up demand for capacity revealed through bids in long term system entry capacity auctions.

1.5. In summary, this modelling work produced four sets of data on "baseflows" (reflecting the initial supply scenario), "free increments" (reflecting network capability at individual nodes or zones), and "total flows" (baseflows plus free increments), namely for:

- 2007/08, Auctions+, load absorption
- 2007/08, Auctions+, 50 per cent load absorption / 50 per cent supply substitution
- 2008/09, Auctions+, load absorption
- 2008/09, Auctions+, 50 per cent load absorption / 50 per cent supply substitution

1.6. We published more detailed information on our data request and the modelling output information in the Third TPCR Consultation. We also made some preliminary observations about the modelling output.

Supply substitution analysis

1.7. The second set of data ("supply substitution analysis") concerns alternative estimates of baselines, i.e. assessments of network capability at individual entry points, and initial estimates of revenue drivers, i.e. the incremental revenues that NGG NTS would earn if it provides capacity above the baselines. Our data request to NGG NTS and some initial modelling output were summarised in the Third TPCR consultation.[4]

1.8. We asked NGG NTS to use the following network modelling assumptions, as explained in more detail in the Third TPCR consultation:

- We asked NGG NTS to model network capability for one year, namely 2008/09;
- To achieve a balanced network, we asked NGG NTS to use a "supply substitution" approach. Under this approach, as the supply at a particular entry point is increased, supply across o*ther* entry points is turned down to keep the network in balance. For the purpose of turning down supplies at other entry points, we asked NGG NTS to choose those entry points with "least benefit" to NGG NTS, in terms of allowing it to incur lower network reinforcement costs (as the supply at the particular entry point in question is increased);
- We asked NGG NTS to assess network capability for individual entry points (or "nodes") only, and to include potential new entry points in the analysis;
- We asked NGG NTS to assume that the physical network is the one used in NGG NTS's latest Ten Year Statement (December 20005) for 2008/09.
- We asked NGG NTS to model using "1 in 20 winter peak" demand for 2008/09, taken from NGG NTS's latest Ten Year Statement. On the supply side, we asked NGG NTS to model all three scenarios from the same source, namely ""Transit UK", "Global LNG" and Auctions+". We also asked NGG NTS to model a fourth, "minimum LNG" scenario, as a sensitivity, but NGG NTS has not provided this output to date.
- We asked NGG NTS to estimate reinforcement costs on the National Transmission System (NTS) for four different "increment sizes", ie increases in capacity at individual entry points, namely 25 GWh/d, 100 GWh/d, 500 GWh/d and 1,000 GWh/d. For potential new entry points, we asked NGG NTS to model these increment sizes over and above the flow rates anticipated by the new entrants, as they expressed in meetings or correspondence with NGG NTS, after estimating

[4] Appendix 10, Modelling revenue drivers, pp59-64.

network reinforcement costs associated with the smallest likely, anticipated, and maximum likely flow rate.

1.9. In summary, this modelling work therefore produced three sets of data on baselines and revenue drivers (with the latter including four observations on incremental revenues for different increment sizes), for both existing and potential new entry points, namely for:

- 2008/09, Transit UK, supply substitution
- 2008/09, Global LNG, supply substitution
- 2008/09, Auctions+, supply substitution

1.10. We received most of the results for the Transit UK scenario in March (except for some potential new entry points) and they were summarised in the March consultation document.[5] Following publication of the Third TPCR consultation document, NGG NTS provided final results for remaining potential new entry points under the Transit UK scenario in April, for the Global LNG scenario in May, and for the Auctions+ scenario on 19 June. These results will be placed on Ofgem's website.[6]

Capacity release obligations

Policy

1.11. Chapter 11 of the main document sets out our proposals for capacity release obligations. In summary, we are proposing to set entry point specific baselines which will constitute obligations on NGG NTS to release for sale the baseline amounts. We are also proposing mechanisms through which unsold baseline capacity can be reallocated in the light of new information revealed through the long term auctions as to the locational demand for capacity.

Data

1.12. Table 11.1, to Table 11.4 illustrates the results from the load absorption analysis (as previously presented in the Third TPCR Consultation), while Table 11.5 illustrates the results from the supply substitution analysis.

1.13. NGG NTS also provided results for three potential new entry points but these are not shown in the tables for confidentiality reasons, although we intend to publish them for the updated or final proposals. NGG NTS has not provided data on other potential new entry points or on other existing entry points that do not feature in the tables below.

---

[5] Appendix 10, Modelling revenue drivers, pp61-63, including TableA10.6.
[6] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr

Table 11.1 - Network capability in 2007/08 with Auctions+ supply scenario, using "load absorption"

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	98	3	101
Bacton	161	7	168
Isle of Grain	20	5	25
Milford Haven	60	0	60
St. Fergus	106	61	167
Teesside	24	45	69
Barrow	25	29	54
Theddlethorpe	25	10	35
Point of Ayr (Burton Point)	2	17	19
Hole House Farm	2	16	18
Humbly Grove	7	12	19
Hatfield Moor	0	20	20
Aldborough (Garton)	0	15	15
Cheshire	3	23	26
Hornsea	0	30	30
LNG used in network			
Glenmavis	9	15	24
Partington	16	70	86
Dynevor Arms	0	0	0
Avonmouth	3	7	10
Zone			
South East Zone	181	9	190
Easington Area	99	2	101
Northern Triangle	164	92	256
West UK	60	0	60
South West UK	11	13	24
North West Corridor	23	22	45
Superzone			
East Coast	306	5	311

Source: NGG NTS

Table 11.2 - Network capability in 2007/08 with Auctions+ supply scenario, using "50 per cent load absorption / 50 per cent supply substitution"

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	98	3	101
Bacton	161	12	173
Isle of Grain	20	5	25
Milford Haven	60	0	60
St. Fergus	106	61	167
Teesside	24	44	68
Barrow	25	28	53
Theddlethorpe	25	10	35
Point of Ayr (Burton Point)	2	19	21
Hole House Farm	2	15	17
Humbly Grove	7	16	23
Hatfield Moor	0	35	35
Aldborough (Garton)	0	18	18
Cheshire	3	22	25
Hornsea	0	34	34
LNG used in network			
Glenmavis	9	16	25
Partington	16	66	82
Dynevor Arms	0	0	0
Avonmouth	3	9	12
Zone			
South East Zone	181	9	190
Easington Area	99	6	105
Northern Triangle	164	90	254
West UK	60	0	60
South West UK	11	15	26
North West Corridor	23	22	45
Superzone			
East Coast	306	5	311

Source: NGG NTS

Table 11.3 - Network capability in 2008/09 with Auctions+ supply scenario, using "load absorption"

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	100	26	126
Bacton	166	20	186
Isle of Grain	42	21	63
Milford Haven	88	0	88
St. Fergus	98	73	172
Teesside	27	53	80
Barrow	22	52	74
Theddlethorpe	24	39	63
Point of Ayr (Burton Point)	2	30	32
Hole House Farm	2	29	31
Humbly Grove	7	20	27
Hatfield Moor	0	25	25
Aldborough (Garton)	0	25	25
Cheshire	0	81	81
Hornsea	0	30	30
LNG used in network			
Glenmavis	0	26	26
Partington	0	83	83
Dynevor Arms	0	0	0
Avonmouth	1	12	13
Zone			
South East Zone	207	21	228
Easington Area	99	48	147
Northern Triangle	148	119	267
West UK	88	0	88
South West UK	9	16	25
North West Corridor	10	90	100
Superzone			
East Coast	331	52	383

Source: NGG NTS

Table 11.4 - Network capability in 2008/09 with Auctions+ supply scenario, using "50 per cent load absorption / 50 per cent supply substitution"

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	100	31	131
Bacton	166	20	186
Isle of Grain	42	21	63
Milford Haven	88	0	88
St. Fergus	98	76	174
Teesside	27	53	80
Barrow	22	50	72
Theddlethorpe	24	29	53
Point of Ayr (Burton Point)	2	30	32
Hole House Farm	2	27	29
Humbly Grove	7	20	27
Hatfield Moor	0	25	25
Aldborough (Garton)	0	25	25
Cheshire	0	81	81
Hornsea	0	30	30
LNG used in network			
Glenmavis	0	26	26
Partington	0	95	95
Dynevor Arms	0	0	0
Avonmouth	1	13	14
Zone			
South East Zone	207	19	226
Easington Area	99	47	146
Northern Triangle	148	115	263
West UK	88	0	88
South West UK	9	16	25
North West Corridor	10	88	98
Superzone			
East Coast	331	48	379

Source: NGG NTS

Table 11.5 Network capability estimates in 2008/09 from supply substitution analysis

		mscmd		
	Scenario	Baseflow on network	Free increment	Total
Easington	Transit UK	119.0	20.0	139.0
	Global LNG	126.7	10.0	136.7
	Auctions +	99.6	39.7	139.3
Bacton	Transit UK	190.0	7.2	197.2
	Global LNG	190.0	13.5	203.5
	Auctions +	165.5	25.5	191.0
Isle of Grain	Transit UK	31.8	15.3	47.0
	Global LNG	12.7	17.8	30.5
	Auctions +	20.1	25.9	46.0
Milford Haven	Transit UK	45.6	37.8	83.4
	Global LNG	19.0	61.2	80.2
	Auctions +	87.7	1.9	89.6
St Fergus	Transit UK	111.4	56.5	167.9
	Global LNG	117.9	52.5	170.4
	Auctions +	98.1	71.4	169.5
Teesside	Transit UK	27.4	36.0	63.4
	Global LNG	23.7	35.0	58.7
	Auctions +	27.4	52.4	79.8
Barrow	Transit UK	22.2	20.0	42.2
	Global LNG	22.2	56.0	78.2
	Auctions +	22.2	56.0	78.2
Theddlethorpe	Transit UK	23.7	13.0	36.7
	Global LNG	23.7	17.0	40.7
	Auctions +	23.6	29.8	53.4
Point of Ayr	Transit UK	1.8	17.0	18.8
	Global LNG	1.8	27.5	29.3
	Auctions +	1.8	29.4	31.2
Hole House Farm	Transit UK	3.6	17.0	20.6
	Global LNG	8.3	22.3	30.6
	Auctions +	2.4	26.6	29.0
Humbly Grove	Transit UK	0.0	25.0	25.0
	Global LNG	7.4	18.0	25.4
	Auctions +	7.4	12.0	19.4
Hatfield Moor	Transit UK	0.0	26.5	26.5
	Global LNG	2.3	20.5	22.8
	Auctions +	2.3	58.7	61.0
Aldborough	Transit UK	0.0	26.0	26.0
	Global LNG	1.8	19.1	20.9
	Auctions +	19.7	9.5	29.2
Cheshire	Transit UK	0.0	25.0	25.0
	Global LNG	0.0	61.9	61.9
	Auctions +	0.0	60.8	60.8
Hornsea	Transit UK	0.0	23.3	23.3
	Global LNG	0.0	19.4	19.4
	Auctions +	0.0	25.4	25.4

Quantification

1.14. The information from NGG NTS provides data on the base flows on the network and the amount of additional capacity that can be provided at each entry point without incurring additional investment. As noted in the Third TPCR consultation and as NGG NTS pointed out in their response to it[7] it is not possible to accommodate all of the free increments simultaneously. Part of the next stage of the analysis is to consider what level of capacity can be provided simultaneously as, to the extent NGG NTS's obligations exceed what can be provided, it will need to be provided with a buyback allowance.

1.15. In order to provide quantification for this document we have assumed that NGG NTS can provide 90 per cent of the free increments at all entry points simultaneously. This assumption is currently untested.

1.16. We have therefore calculated our initial quantification by taking the average baseflow from Table 11.5 for each entry point and adding to it 90per cent of the average free increment at each entry point. In each case, we took an unweighted average across the three supply scenarios. On the basis of these assumptions the baselines for the existing entry points that NGG NTS has provided data for would be as set out in Table 11.6.

1.17. We chose the supply substitution data in Table 11.5 (instead of the load absorption data in Tables 11.1 to 11.4) for the purpose of our initial baseline proposals, because the key driver for future changes in patterns of gas entry flows appears to be declining UKCS (UK Continental Shelf) supplies. Arguably supply substitution better captures this key driver than load absorption.

1.18. The proposed baselines are based on analysis for (and so apply to) the formula year 2008/09. Since no incremental capacity can be signalled for that year it is not inconsistent with our approach of having all incremental revenues backed by user commitments to specify baselines for this year. However for our final proposals we will also need to specify baselines for formula year 2007/08

7

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/14878_nationalgrid.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/transpcr

Table 11.6 Initial proposals for gas entry baselines (2008/09)

	Initial Baseline mscmd
Easington	136
Bacton	196
Isle of Grain	39
Milford Haven	81
St Fergus	163
Teesside	63
Barrow	62
Theddlethorpe	42
Point of Ayr	24
Hole House Farm	25
Humbly Grove	21
Hatfield Moor	33
Aldborough	24
Cheshire	44
Hornsea	20

Source: Ofgem (based on data provided by NGG NTS)

Implementation

1.19. The long term capacity release process that would follow from our initial proposals is detailed in Chapter 11.

1.20. In the constrained period NGG NTS is not, by definition, able to build any additional capacity. However existing unsold capacity can still be traded in that period.

1.21. Ofgem's proposal is to leave the process of determining the timing and frequency of auctions to the gas industry just as at present. However we proposes introducing an obligation on NGG NTS to facilitate, where requested, the trading of capacity between entry points and allowing NGG NTS to recover from industry its costs of carrying out any necessary modelling work requested by shippers.

1.22. How NGG NTS complies with this obligation is for NGG NTS to determine in consultation with the industry and subject to approval by Ofgem. However, we anticipate that the generic regime could take the following form.

- Before an auction shippers can indicate that they wish to bid for capacity at entry point A for transfer to entry point B.

- Shippers pay NGG NTS its modelling costs of working out an exchange rate from A to B.

- The auction is ran for point A (possibly at the same time as auctions at other points) in which shippers wanting capacity at point A and shippers wanting capacity at point B can bid.

- The winner of the auction gets the capacity at point A and, if they had indicated a desire to do so and got an exchange rate, are obliged to transfer to capacity to point B and NGG NTS is obliged to transfer capacity.

Changes to industry codes

1.23. We will be introducing an obligation on NGG NTS to take all reasonable steps to facilitate the transfer of capacity between different entry points. To the extent changes the industry codes are needed to facilitate this, we anticipate that NGG NTS would bring forward appropriate code modifications.

Revenue Drivers

Policy

1.24. Our proposed policy is that NGG NTS will have nodal revenue drivers at all existing entry points and at those potential new entry points about which NGG NTS or Ofgem have some information at present to indicate that they will come into existence. Our proposal is that NGG NTS should not be constrained to set reserve prices in auctions, and conduct its NPV test, on the basis of the revenue drivers set in the price control. This proposal is in line with our initial views on charging for entry capacity as expressed in the Third TPCR consultation.[8]

Data

1.25. Information from the supply substitution analysis provides information about possible values for revenue drivers. Table 11.7 summarises these results. NGG NTS also provided results for three potential new entry points, but these are not shown for confidentiality reasons. NGG NTS has not provided data on other potential new entry points or on other existing entry points that do not feature in the table.

[8] Paragraph 4.16-4.18

Table 11.7 - Incremental cost estimates in 2008/09 from supply substitution analysis

		UNIT COST (£M/GWh)			
2008/2009	**Scenario**	**25 GWh/d (2.3mscmd)**	**100 GWh/d (9.2mscmd)**	**500 GWh/d (46.1mscmd)**	**1000 GWh/d (92.3mscmd)**
Terminal					
Easington	Transit UK	0.24	0.16	0.58	0.54
	Global LNG	0.42	0.39	0.60	0.65
	Auctions+	0.16	0.22	0.62	0.58
Bacton	Transit UK	0.32	0.58	0.74	0.81
	Global LNG	1.36	0.78	0.99	1.06
	Auctions+	0.20	0.20	0.89	2.13
Isle of Grain	Transit UK	0.36	0.33	0.52	0.90
	Global LNG	0.48	0.41	0.61	0.79
	Auctions+	0.20	0.18	0.82	1.26
Milford Haven	Transit UK	2.53	2.77	2.09	1.87
	Global LNG	1.91	0.71	1.51	0.88
	Auctions+	1.01	1.46	1.43	1.83
St Fergus	Transit UK	0.51	0.43	1.36	1.68
	Global LNG	0.03	0.51	1.68	1.61
	Auctions+	0.16	0.25	1.62	2.00
Teesside	Transit UK	0.33	0.28	0.15	0.52
	Global LNG	0.32	0.18	0.21	0.55
	Auctions+	0.14	0.15	0.22	0.54
Barrow	Transit UK	0.35	0.20	0.18	0.30
	Global LNG	0.44	0.23	0.25	0.61
	Auctions+	0.18	0.19	0.20	0.49
Theddlethorpe	Transit UK	0.81	0.20	0.61	0.61
	Global LNG	1.23	0.44	1.02	0.77
	Auctions+	0.20	0.05	0.23	0.53
Point of Ayr	Transit UK	2.45	1.32	0.34	0.30
	Global LNG	0.29	0.25	0.41	0.76
	Auctions+	0.17	0.20	0.18	0.25
Hole House Farm	Transit UK	2.45	1.32	0.29	0.18
	Global LNG	0.73	0.21	0.25	0.49
	Auctions+	0.18	0.04	0.10	0.16
Humbly Grove	Transit UK	0.32	0.05	0.73	1.31
	Global LNG	2.36	0.87	0.96	0.69
	Auctions+	0.64	0.31	0.22	0.90
Hatfield Moor	Transit UK	1.45	0.26	0.70	0.41
	Global LNG	0.32	0.23	0.38	0.36
	Auctions+	0.24	0.10	0.34	0.27
Aldborough	Transit UK	0.24	0.20	0.61	0.44
	Global LNG	0.70	0.41	0.75	0.64
	Auctions+	0.26	0.25	0.53	0.36
Cheshire	Transit UK	0.81	0.20	0.04	0.04
	Global LNG	0.03	0.03	0.51	0.25
	Auctions+	0.09	0.02	0.06	0.09
Hornsea	Transit UK	0.56	0.55	0.72	0.51
	Global LNG	0.69	0.57	0.73	0.71
	Auctions+	0.10	0.13	0.31	0.33

Source: NGG NTS

Quantification

1.26. For each entry point and modelled increment size, we have taken an arithmetic mean of total estimated network reinforcement costs across the three supply scenarios (Transit UK, Global LNG and Auctions+) and divided this by the modelled increment size, in order to derive a gross unit revenue allowance for each entry point. This gross unit revenue allowance represents our initial point estimate of an entry-point specific revenue driver in 2005/06 formula year prices. As these are gross revenue drivers they will need to be annualised to give the impact on NGG NTS's annual revenues.

1.27. The modelling analysis shows that unit costs can vary quite significantly depending on the size of the increment in capacity being provided. For this reason, we propose setting unit revenue allowances consistent with a range of possible demands for entry capacity. We have therefore set initial "capacity bands" around each of the modelled increment size. These bands are broadly centred round the chosen increment sizes. If demand for capacity falls within this range, the same unit revenue allowance would apply.

1.28. The results of these calculations are illustrated in Table 11.8.

Table 11.8 Initial proposals for gas entry revenue drivers (2008/09)

	Capacity Range (smcmd)			
p/kWh	0 - 50	50-250	250-750	750+
Easington	27.36	25.68	59.96	38.19
Bacton	62.70	52.23	86.93	58.15
Isle of Grain	34.71	30.82	65.06	53.85
Milford Haven	181.80	164.69	167.29	111.38
St Fergus	23.26	39.63	155.55	111.12
Teesside	26.39	20.35	19.26	24.53
Barrow	32.43	20.76	21.08	17.41
Theddlethorpe	74.60	23.01	62.01	41.33
Point of Ayr	97.07	58.93	31.04	19.91
Hole House Farm	111.81	52.52	21.15	11.73
Humbly Grove	106.70	40.96	63.66	63.35
Hatfield Moor	53.45	19.56	47.60	25.97
Aldborough	39.84	28.68	62.84	35.89
Cheshire	30.93	8.48	20.06	10.70
Hornsea	45.04	41.53	58.78	34.28

Buyback incentives

Policy

1.29. Our proposal for buyback is to have an administered buyback price for buybacks relating to the delivery of incremental capacity. For buybacks relating to network operations the buyback price will be uncapped. However NGG NTS will only bear a proportion of the buyback costs and its exposure to these costs will be capped. These proposals are set out in Chapter 11.

Data

1.30. In order to establish an appropriate market based administered buyback price we asked NGG NTS to provide, for each buyback trade taken by NGG NTS since 1 April 2002 data on the volume of buyback capacity, the price paid for the capacity, the location of the capacity buyback, the counter party to the trade, whether the action was taken in the prompt buy back market or through a contract and the reason for taking the buyback action. We then sought to establish a relationship between the system average price (SAP) in the on-the-day commodity market (OCM) and the buyback price for each prompt buyback action taken since 1 April 2002. The administered price is based on the average proportion of the buyback price to the OCM price.

1.31. The table below provides an aggregated monthly summary of the data. For the months excluded from the table no prompt buyback actions were taken. Market maker actions were also excluded.

Table 11.9 - Monthly average summary of buyback pricing data

Month	Average buyback price (p/kWh)	Average SAP price (p/kWh)	Ratio of buyback price to SAP (p/kWh)
April 2002	0.2136	0.4109	51.98%
May 2002	0.2378	0.3994	59.54%
August 2002	0.2128	0.4094	51.97%
September 2002	0.0795	0.4981	15.97%
October 2002	0.1990	0.5867	33.92%
November 2002	0.3879	0.5958	65.10%
December 2002	0.3496	0.6561	53.29%
January 2003	0.3411	0.7414	46.00%
March 2003	0.4989	0.6064	82.26%
April 2003	0.1467	0.6079	24.13%
July 2003	0.1300	0.5748	22.61%
August 2003	0.0400	0.4564	8.77%
September 2003	0.2811	0.4823	58.29%
December 2003	0.3265	1.0099	32.33%
July 2004	0.2687	0.6515	41.24%
November 2004	0.0328	0.9488	3.46%
December 2004	0.4783	1.0547	45.35%
January 2005	0.6718	0.9828	68.35%
April 2005	0.4097	1.0324	39.68%

Quantification

Incremental investment buyback incentive

1.32. Having reviewed data provided by NGG NTS on its buyback actions taken in the prompt buyback market during the current price control period there is some evidence to suggest that the buyback price offered by shippers and accepted by NGG NTS tends to be between 30 to 40 per cent of the relevant system average price (SAP) on the on-the-day commodity market (OCM). On this basis we propose an administered buyback price of 0.52 p/kWh which reflects 35 per cent of the average OCM price for 2005/06. For the avoidance of doubt the figure of 0.52 p/kWh will apply through the period of the next price control and will not be updated if the OCM gas price changes.

1.33. While it is noted that there is significant volatility around the relationship between the average buy-back price and the OCM SAP we consider that the administered buyback price needs only to approximate a market based price to allow shippers and NG to manage buyback risk.

Operational buyback incentive

1.34. The baseline capacity for each node is determined on the basis of the practical maximum physical capacity that can be delivered at each entry point taken in isolation. However, flow patterns across the entry points may mean that total system capacity on any one day is not equal to the sum of the practical maximum physical capacities across entry points. It is therefore likely that under certain demand and supply scenarios NGG NTS may need to take buyback actions in order to deliver baseline capacity. On this basis it is highly unlikely to be appropriate to set a buyback target of zero. However, as a result of the delay to providing data on the baseline flows it has not been possible to undertake the analysis to determine the buyback target. However, we intend to quantify the target using data for 2007/08 by:

- Modelling aggregate system wide network capacity for 2007/08 against different flow scenarios.
- Making some assumptions about the likelihood of each of the different flow scenarios to determine an appropriate volume of system wide network capacity for 2007/08.
- Quantifying the volume differential between the system wide network capacity and the sum of the proposed nodal baselines for 2007/08 to determine the volume of capacity that is likely to be bought back.
- Applying an appropriate market based buyback price to the volume differential to set the buyback target (it may be appropriate to assign a seasonal profile to buyback volumes and apply seasonal buyback prices to get greater accuracy for the buyback target).

1.35. We consider that by separating the buyback incentive a significant element of the buyback risk will be removed from the operational incentive. Therefore the proposal is that the downside sharing factor should be increased to 50% to reflect the reduced risk while the upside sharing factor remains at 50%. Further, that the cap and collar should be increased to £36m. This also ensures that the buyback incentive has symmetrical upside and downside sharing factors ensuring that NGG NTS is equally incentivised to manage over and under spend against the target cost set as part of the incentive.

These proposals reflect initial proposals for the sharing factors. However, it is possible that these proposals may change in light of the scenario analysis undertaken for the buyback target. For example if the analysis indicates that there is a wide range of potential buyback costs it may be appropriate to set a buyback target on the average cost with lower sharing factors so that NGG NTS has financial incentives to manage buyback costs within the wide range. If however the analysis indicates that there is a narrow range of potential buyback costs it may be appropriate to set higher sharing factors so that NGG NTS has strong incentives to manage risks within the narrow range.

Appendix 12 - Impact Assessment - gas entry

Introduction

1.1. This appendix discusses the different impacts that might be expected as a consequence of Ofgem's proposals for gas entry, relative to a 'no change' option and relative to the proposals contained in the Third TPCR consultation. Ofgem welcomes views on the identified impacts in this section and on any impacts which respondents feel have been missed.

1.2. Whilst quantification of the costs and benefits is inherently subjective Ofgem would nonetheless welcome views.

Options

1.3. The options considered in this appendix are:

- No change
- The March proposals
- The June initial proposals

1.4. In turn each option can be considered under four subheadings

- NGG NTS's capacity release obligations
- Revenue driver design
- Buyback Incentive
- Any other factors

No change

Capacity release obligations

1.5. At present NGG NTS is obliged to release (on a financially firm basis) amounts of capacity at each gas entry point specified in its gas transportation licence. These amounts were calculated as 90% of theoretical maximum physical capacity. In the very short term NGG NTS is releases this capacity with a zero reserve price.

1.6. Twenty percent of the capacity at each entry point is not sold in the longer term auctions.

1.7. NGG NTS is permitted to release capacity in excess of the baselines. In the unconstrained period (3 years in advance[9]) NGG NTS releases additional capacity if it receives a user commitment equal to 50% of the NPV of the project. In the constrained period NGG NTS can release 'non-obligated' capacity over the baselines.

NGG NTS

1.8. Under this approach NGG NTS is obliged to release the capacity on a financially firm basis. To the extent it is unable to provide this capacity it faces buyback costs (see below for a discussion of the impact). To the extent it is able to provide capacity above these baselines it is able to earn additional income (see below for discussion of the impact of this).

Existing Shippers

In respect of capacity they have already purchased

1.9. This proposal would have no impact on shippers in relation to capacity they have already purchased

In relation to unpurchased capacity at entry points where they can enter gas

1.10. This approach, by obliging NGG NTS to offer specified amounts of capacity, gives shippers active at a particular entry point an option to purchase unsold capacity at that entry point. In the event that a shipper is the only shipper who can enter gas at a particular entry point it is able to pick up significant amounts of capacity at zero price.

In relation to unpurchased capacity at entry points where they cannot enter gas

1.11. Shippers are permitted to purchase entry capacity at these entry points but will generally not do so as they are unable to use it.

Potential new entrant shippers

1.12. Once new entrant shippers have secured the ability to enter gas at a particular entry point they are able to participate in auctions for capacity like any other shipper. In the constrained period if all the capacity at a given entry point is sold a new entrant shipper is only able to get gas entered at that point if NGG NTS chooses to make non-obligated capacity available.

---

[9] In relation to specific projects NGG NTS can approach Ofgem for an extension of this period.

Gas entry project developers

1.13. Apart from through the purchase on non-obligated capacity the developers of new entry terminals are unable to get access to gas entry capacity within the constrained period.

Consumers

1.14. There are no direct effects on consumers but to the extent any of the other effects identified have an impact on the price of delivered gas they will have an impact on consumers.

Revenue drivers

1.15. At present NGG NTS receives additional revenue for capacity it provides (in the unconstrained period) above the baselines set in the licence. The amount of income NGG NTS receives is, in simple terms, a given amount of revenue per unit of capacity sold[10]. Depending on the bids in the auctions NGG NTS receives a greater or lesser amount of money in relation to the release of capacity. However these amounts are subject to caps and collars. This can be called a variable return.

1.16. At the next price control after the delivery of capacity NGG NTS's costs (subject to efficiency assessment) are included in the RAV with a deemed SO RAV (equal to the amount on which the allowances were based) netted off. NGG NTS therefore earns a regulated return on any difference between actual (efficient) costs and those assumed by Ofgem in setting the licence conditions. NGG NTS will generally continue to earn the variable return for a period of five years[11] after which point efficient costs are included in the RAV.

1.17. The figures underlying the revenue drivers act to determine reserve prices in the capacity auctions and in the test used by NGG NTS to determine whether to release capacity ('the NPV test'). Although this approach is determined by NGG NTS, acting in accordance with its methodology, it is assumed to persist for consideration of the *status quo* option.

[10] In the case of capacity Milford Haven there are two different rates depending on the amount of capacity sold.
[11] This process was detailed in "New entry terminals to Transco's National Transmission System - Ofgem's views on Transco's proposals and Explanatory notes to accompany the section 23 notice of proposed modifications to Transco's gas transporter licence", Ofgem 62/03, June 2003

NGG NTS

1.18. Under these proposals NGG NTS is subject to the difference between estimated costs (underlying the parameters in the licence) and actual (efficient) costs for a variable period from the contractual delivery of capacity until the subsequent price control review. The impact of this exposure, and so the strength of the incentive on NGG NTS to make efficiency savings, therefore reduces as the price control period continues.

1.19. NGG NTS is exposed to the variable rate of return (relating to auction bids) for a rolling period of five years.

1.20. As revenue drivers determine auction reserve prices and NPV tests NGG, NTS potentially faces a risk (if costs increase beyond the levels set in the licence) that developers will choose to bring forward GB projects (relative to those in other countries) as the costs of the network reinforcement in GB are "too low". NGG NTS would therefore be exposed to a risk that it would sell greater amounts of capacity when it is making the greatest loss as a result of providing said capacity. Ofgem anticipates that, given the relatively small proportion of project costs which are accounted for by transmission reinforcement costs, this effect will be relatively minor.

Existing shippers

In relation to unpurchased capacity at entry points where they can enter gas

1.21. The level of the revenue drivers determines various reserve prices in auctions for capacity. This clearly has an impact on shippers seeking to purchase that capacity. Relative to actual costs of capacity some shippers will benefit (where the prices are set too low) and some will lose out (where the prices are set too high).

1.22. Shippers are provided with a degree of certainty as they will know, up to the end of the price control period, what reserve prices they will face in auctions for capacity. As the end of a price control period approaches the level of certainty faced by shippers will be reduced.

Potential new entrant shippers

1.23. The level of the revenue drivers determines various reserve prices in auctions for capacity. This clearly has an impact on shippers seeking to purchase that capacity. Relative to actual costs of capacity some shippers will benefit (where the prices are set too low) and some will lose out (where the prices are set too high).

1.24. Shippers are provided with a degree of certainty as they will know, up to the end of the price control period, what reserve prices they will face in auctions for capacity.

Gas entry project developers

1.25. As the reserve prices and NPV test are influenced by the terms in the price control any developer seeking a new entry point is unable to do so until Ofgem has created a new UCA. Ofgem is currently going through this process[12].

Consumers

1.26. There are no direct effects on consumers but to the extent any of the other effects identified have an impact on the price of delivered gas they will have an impact on consumers.

Buyback regime

1.27. If NGG NTS is unable to provide the capacity it has sold it is obliged to buy it back from those shippers which hold that capacity. Shippers have no obligation to offer their capacity for sale and can set the price if they do decide to offer it for sale. NGG NTS has incentives to minimise the cost of buy backs. The incentive is a sliding scale incentive with a target of £18m in buy back costs a cap of £30m and a collar of £12.5m. Under the incentives any costs from taking buy back actions are netted off against revenues associated with the sale of non obligated capacity, sale of within-day firm and interruptible capacity and entry overrun charges.

1.28. If NGG NTS beats the target it can earn a revenue which is shared 50/50 with shippers up to the cap. If NGG NTS incurs costs greater than the target costs it shares these costs 35/65 with shippers up to the collar. Shippers are exposed to 100% of costs below the collar and 100% of the revenue above the cap. The costs/ revenues incurred by shippers are smeared to all shippers through the neutrality charge on the basis of an individual shipper's end of day firm capacity holdings.

NGG NTS

1.29. NGG NTS's exposure to buy back revenue and cost is limited by the cap and collar. Once it reaches either of these limits it has no financial incentive to manage buy back risk.

Existing shippers

1.30. Shippers can offer to sell their capacity rights to NGG NTS at a price which reflects the value they place on the capacity and are therefore not exposed to any financial risk in relation to undelivered capacity.

---

[12] "Adjusting National Grid's revenue allowance when large new entry points connect to the gas transmission system", Ofgem 50/06, March 2006

1.31. Shippers are also exposed to the costs and revenues arising from the buy back incentive through neutrality charges. To the extent shippers are unable to pass these costs through to consumers it will have an impact on the shippers.

Potential new entrant shippers

1.32. Potential new entrant shippers are likely to face the similar risks as existing shippers

Gas entry project developers

1.33. Gas entry developers with shipper licences are likely to face similar risks as existing shippers. The buyback regime effectively insulates the developer from all the risks of the non-delivery of capacity. NGG NTS is required to buy back capacity at the price set by the developer and the developer is likely to set the price based on the full economic cost of non delivery of capacity. Moreover, the developer is likely to be a monopsony seller of capacity.

Consumers

1.34. As discussed above a proportion of the buy back cost and associated revenues (and all that outside the caps and collars) is smeared to shippers and some proportion of it is likely to be passed on to consumers. Moreover, as NGG NTS has no financial incentive to manage buy back costs once the collar is reached consumer exposure to buy back costs have the potential to be significant.

Other factors

1.35. Maintaining the *status quo* would have the advantage that it would give an indication to industry that Ofgem is committed to the current regime and so give the industry more certainty that it could invest on the basis of the current arrangements. Set against this however is that maintaining the *status quo* would not remove any problem identified from the current regime.

The March proposals

Capacity release

1.36. The Third TPCR consultation proposed removing the specified levels of capacity release. In the unconstrained period NGG NTS would be obliged to release any amount of capacity in respect of which it has received a user commitment. In the constrained period NGG NTS would have an obligation to make available all capacity on its network and operate in accordance with a methodology for capacity release (that we propose that they develop).

1.37. Accompanying that capacity release methodology would be a fully populated and publicly available, network model.

National Grid

1.38. Under this proposal NGG NTS would not know what specific levels of capacity it was obliged to provide. As NGG NTS is not obliged to provide capacity that is not available (as it would be under the *status quo* option) it would face a different level of exposure to buyback risk (see buyback section for additional discussion on this issue).

Existing shippers

In respect of capacity they have already purchased

1.39. There is no direct impact on shippers in this respect. However under this approach the amount of capacity that the shippers expected to be sold in future at entry points would have changed relative to the *status quo* and so potentially the (option) value of their current capacity holdings would change. It is unclear whether this change would be beneficial or detrimental for shippers individually or in aggregate.

In relation to unpurchased capacity at entry points where they can enter gas

1.40. In previous auctions 20% of capacity had been withheld for release in shorter term auctions. In relation to auctions in the current period this means that the 20% (of an unspecified amount) of capacity which was to be released may not be released at a given entry point and so shippers anticipating purchasing it would potentially lose out.

1.41. However capacity could be released at points in which under the *status quo* it could not. Shippers wishing to enter gas at those points would benefit.

1.42. Whether the aggregate of benefits and costs here is positive or negative depends on the efficacy of NGG NTS's methodology in allocating capacity where it is needed, which would in turn depend on the objectives Ofgem sets for that methodology.

Potential new entrant shippers

1.43. Just as for existing shippers potential new entrants could benefit (if they can not get access to capacity where they can enter gas) or lose out (if that capacity is transferred away).

Gas entry project developers

1.44. Gas entry project developers are likely to benefit from this proposal as they will potentially be able to gain capacity at their new entry points during the constrained period that they would not otherwise have been able to gain.

Consumers

1.45. There are no direct impacts on consumers of this aspect of the proposal but to the extent that the impacts on other parties influences the delivered gas price there will be impacts on consumers.

Revenue Drivers

1.46. Under this proposal NGG NTS would continue to have nodal revenue drivers. These revenue drivers would be set out algebraic functions which will calculate additional revenue is determined as a function of capacity. For existing entry points the revenue driver function would likely have zero value over some range (i.e. where capacity can be provided without extra investment) and the point at which it becomes non-zero is referred to as the "trigger point".

1.47. Revenue drivers are fixed for five years and NGG NTS would bear the impact of any difference between outturn costs and the revenue driver for the whole of that period

1.48. Revenue drivers would not be used to set reserve prices in capacity auctions, nor would they be used in the NPV test.

NGG NTS

1.49. The revenue drivers set the revenue NGG NTS gets in respect of additional entry it provides. National Grid will be incentivised to control the costs of the project (as it keeps any savings made for a period of five years) but would face any of the risk associated with changes in project costs for that five year period.

Existing shippers

1.50. NGG NTS's revenue drivers are no longer used to determine reserve prices in auctions. It is therefore likely that NGG NTS's revenue from sales of capacity will differ from that to which they are entitled through their price control. In the event that this happens NGG NTS will recover its allowed revenue by increasing or decreasing (as appropriate) some element of the charge levied on all shippers. Shippers will therefore be exposed, in aggregate, to the difference between auction revenues and NGG NTS's allowed revenues.

1.51. Since capacity reserve prices are no longer determined by parameters of the price control and since Ofgem is not mandating where capacity must be released shippers will have broadly the same level of certainty (or uncertainty) over the prices they will face throughout the price control period.

1.52. A key part of the mechanism design will be to ensure that any such exposure is uncorrelated with capacity purchase decisions.

Potential new entrant shippers

1.53. Other than the impact identified above for existing shippers which will occur when potential new entrants become actual new entrants there is no impact on this class of individual.

Gas entry project developers

1.54. Gas entry project developers will no longer have to wait for Ofgem to modify NGG NTS's licence before they can bid for capacity at, and so have created, a new entry point. The prices they face will be determined by NGG NTS in accordance with its methodology. Ofgem's modification of licence (which will be necessary only for large projects) will only matter for NGG NTS (as the licence determines its revenues) and not for shippers.

Consumers

1.55. The costs borne by shippers (especially those passed through to all shippers in aggregate) will be passed through to consumers. Therefore ultimately customers will be paying for the extension of the gas network. The five year rolling incentive on National Grid is designed to incentivise National Grid to operate efficiently and, after five years, those efficiency savings are passed on to consumers when the (efficiently incurred) costs are included in the RAB.

Buyback incentive

1.56. In the Third TPCR consultation Ofgem proposed retaining the current form of the buy back incentive but limiting its scope to exclude the buy back costs associated with delays to the delivery of incremental capacity.

1.57. For buy back costs associated with the late delivery of incremental capacity Ofgem proposed that NGG NTS would have the right to buy back new issue incremental capacity rights at a specified rate with the option for the price to be reduced if the delays to capacity delivery are outside NGG NTS's control. We proposed that shippers and NGG NTS could agree to vary the buy back price and timescales for capacity delivery away from the default buy back arrangements and that NGG NTS's costs and revenue associated with this incentive would be treated as excluded revenue.

NGG NTS

1.58. NGG NTS 's exposure to buy back cost and revenue for the operational incentive will be limited by the cap and collar.

1.59. NGG NTS 's buy back cost exposure for incremental capacity sold before 1 April 2007 could potentially be the same as under current arrangements if these costs and revenues are captured as part of the operational buy back incentive.

1.60. NGG's buy back cost exposure for new issue incremental capacity is restricted by the administered price but is potentially unlimited if there is no volume cap. NGG NTS 's buy back revenue is also unlimited and dependent on the extent to which shippers are willing to pay to vary the capacity delivery arrangements away from the default arrangements e.g. if shippers are willing to pay for earlier capacity delivery.

Existing shippers

1.61. Shipper exposure to operational buy back risk is similar to the risk it currently faces under the buy back incentive ie its exposure under the neutrality charge is likely is limited as these costs are likely to be passed on to consumers.

1.62. Shippers would continue to set the buy back price for capacity sold before 1 April 2007 and therefore in this respect they are not exposed to buy back risk.

1.63. A shipper who has purchased new issue incremental capacity will be exposed to some buy back risk if their capacity is not delivered on time and if the administered price is lower than the value they place on the capacity. The shipper could also potentially be exposed to costs associated with delays in planning consents without compensation.

Potential new entrant shippers

1.64. Potential new shippers are likely to face similar risks as existing shippers.

Gas entry project developers

1.65. Gas entry project developers with shipper licences are likely to face similar risks as existing shippers. In particular developers will be exposed to some risk for the non delivery of capacity as the administered buy back price may not reflect the value they place on the capacity. Developers could also be exposed to costs associated with delays to planning consents without compensation.

Consumers

1.66. Consumers would be exposed to costs associated with the operational buy back incentive but to the extent that much of the buy back cost risk would be transferred to the incremental buy back incentive this risk would be greatly reduced.

1.67. Consumers would continue to be exposed to any costs arising from a delay to the delivery of incremental capacity sold before 1 April 2007.

1.68. Consumers would not be exposed to the costs associated new issue incremental capacity. Shippers who have purchased rights to new issue incremental capacity but have to sell it back to NGG NTS are less likely to pass these costs on to consumers as this is likely to affect their competitive position in the market.

Current proposals

Capacity release

1.69. The current proposals are detailed in Chapter 11 and Appendix 11. They are briefly summarised here.

1.70. In the unconstrained period NGG NTS will be obliged to release any amount of capacity for which it receives a user commitment.

1.71. In the constrained period NGG NTS will have specified levels of capacity to release at each entry point. However in certain circumstances shippers will be able to get capacity in excess of these levels by asking NGG NTS to allow a transfer of capacity. NGG NTS 's capacity will be released to the shipper(s) who value it most in capacity release auctions (including shippers bidding at one entry point for capacity transferable to another).

NGG NTS

1.72. As NGG NTS is obliged to provide levels of capacity specified by Ofgem it is possible it will be obliged to make available capacity that is not physically possible on its system.

Existing shippers

In respect of capacity they have already purchased

1.73. There is no direct impact on shippers in this respect. However under this approach the nature of the competition shippers face at entry points in the future will have changed (as other shippers could now be competing to buy capacity in order to

transfer it) and so potentially the (option) value of their current capacity holdings would change. It is unclear whether this change would be beneficial or detrimental for shippers individually or in aggregate.

1.74. Under this approach existing shippers will know the amount of capacity that is likely to be available at a given entry point in each auction. They will not however know whether other shippers will be wising to compete for a given unit of capacity in order to transfer it to another entry point.

In relation to unpurchased capacity

1.75. Under these proposals shippers seeking capacity can now purchase it at, and transfer it from, other entry points than the one at which they seek it. This will benefit some shippers (those who faced constraints on available capacity) and be a cost to others (those who now face greater competition for capacity).

Potential new entrant shippers

1.76. Just as for existing shippers potential new entrants could benefit (if they can no get access to capacity where they can enter gas) or lose out (if that capacity is transferred away).

Gas entry project developers

1.77. Gas entry project developers are likely to benefit from this proposal as they will potentially be able to gain capacity at their new entry points during the constrained period that they would not otherwise been able to gain. However their benefit may be less than in the March proposals as the reallocation of capacity is more constrained.

Consumers

1.78. There are no direct impacts on consumers of this aspect of the proposal but to the extent that the impacts on other parties influences the delivered gas price there will be impacts on consumers.

Revenue drivers

1.79. Before receiving incremental revenues from its revenue driver NGG NTS will have to undertake all reasonable capacity substitutions. Thereafter NGG NTS will receive revenue in accordance with its revenue driver.

1.80. Reserve prices and capacity release tests will be de-linked from the magnitudes in the price control.

NGG NTS

1.81. NGG NTS will only receive incremental revenue once it has taken advantage of all possible substitution of capacity. For a given set of trigger points this is likely to result in lower revenues for NGG NTS than the March proposals[13].

1.82. To the extent that NGG NTS fails to convince the regulator that it has made all possible transfers of capacity to utilise capacity efficiently then it will not be remunerated for incremental capacity provided as a consequence of its decision, where it could have been avoided. .

Existing shippers

1.83. NGG NTS 's revenue drivers are no longer used to determine reserve prices in auctions. It is therefore likely that NGG NTS 's revenue from sales of capacity will differ from that to which they are entitled through their price control. In the event that this happens NGG NTS will recover its allowed revenue by increasing or decreasing (as appropriate) some element of the charge levied on all shippers. Shippers will therefore be exposed, in aggregate, to the difference between auction revenues and NGG NTS's allowed revenues.

1.84. A key part of the mechanism design will be to ensure that any such exposure is uncorrelated with capacity purchase decisions.

1.85. Since capacity reserve prices are no longer determined by parameters of the price control shippers will have similar the same level of certainty (or uncertainty) over the prices they will face throughout the price control period. Although to the extent that the periodic determination of where NGG NTS must release capacity impacts on prices there will be less certainty than under the March proposals.

Potential new entrant shippers

1.86. Other than the impact identified above for existing shippers which will occur when potential new entrants become actual new entrants there is no impact on this class of individual.

Gas entry project developers

1.87. Gas entry project developers will no longer have to wait for Ofgem to modify NGG NTS's licence before they can bid for capacity at, and so have created, a new entry point. The prices they face will be determined by NGG NTS in accordance with its methodology. Ofgem's modification of licence (which will be necessary only for

[13] It is however unlikely that the trigger points would be the same under the two different approaches so this effect is ambiguous.

large projects) will only matter for NGG NTS (as it gives it revenues) and not for shippers.

Consumers

1.88. The costs borne by shippers (especially those passed through to all shippers in aggregate) will be passed through to consumers. Therefore ultimately customers will be paying for the extension of the gas network. The five year rolling incentive on NGG NTS is designed to incentivise NGG NTS to operate efficiently and, after five years, those efficiency savings are passed on to consumers when the (efficiently incurred) costs are included in the RAV.

Buyback incentive

1.89. The buyback incentive in the current proposals is, qualitatively, the same as that in the March proposals, albeit with greater detail, and therefore the impacts are, qualitatively the same. The current proposals specify that in relation to incremental incentive parties would be subject to the same construction lead time arrangements and an administered buy back price of 0.52p/kWh, applied to capacity sold after 1 April 2007, which would default to zero after five years (i.e. it is assumed that after five years planning consents have been denied). Within those five years NGG NTS would be able to seek an income adjusting event if it is unable to deliver capacity for reasons outside of its control and shippers and NGG NTS would be able to agree to vary the default arrangements.

1.90. For the operational buy back incentive we proposed similar arrangements to the current buy back incentive. NGG NTS would face a buy back target based on the costs associated with buying back capacity arising from differences in the sum of the prescribed nodal baselines and total system capacity on the network. Under the incentive NGG NTS would be able to net buy back costs with buy back revenue arising from the sale of non obligated capacity and interruptible capacity. Under our proposals NGG NTS would face a cap and collar of £30m each with a 50% upside and downside sharing factor.

NGG NTS

1.91. NGG NTS's exposure to the operational buy back incentive is limited by the cap and collar. NGG NTS's buy back cost exposure for incremental capacity sold before 1 April 2007 could potentially be captured under the operational buy back incentive.

1.92. NGG NTS's exposure to the incremental investment incentive would be limited by the administered buy back price which defaults to zero after five years. Within the five year period NGG NTS would be exposed to buy back volume risk. Given the potential demand for high volume new entry points it may be appropriate to consider an overall cap on exposure.

Existing shippers

1.93. Shipper exposure to operational buy back risk is similar to the risk it currently faces under the buy back incentive i.e. its exposure to neutrality charges is limited as these costs are likely to be passed on to consumers.

1.94. Shippers would continue to set the buy back price for capacity sold before 1 April 2007 and therefore in this respect they are not exposed to buy back risk.

1.95. A shipper who has purchased new issue incremental capacity may be exposed to some buy back risk if their capacity is not delivered on time and if the administered price is lower than the value they place on the capacity. Shippers would be exposed to the costs after five years without compensation when the capacity is assumed to have failed planning consent.

Potential new entrant shippers

1.96. Potential new shippers are likely to face similar risks as existing shippers.

Gas entry project developers

1.97. Gas entry project developers with shipper licences are likely to face similar risks as existing shippers. In particular, developers may be exposed to some risk for the non delivery of capacity if the administered buy back price does not reflect the value they place on the capacity. Developers will also face costs after five years without compensation when the capacity is assumed to have failed planning consent.

Consumers

1.98. Consumers would also be exposed to costs associated with the operational buy back incentive but to the extent that much of the buy back cost risk would be transferred to the incremental buy back incentive this risk would be greatly reduced.

1.99. Consumers would continue to be exposed to any costs arising from a delay to the delivery of incremental capacity sold before 1 April 2007.

1.100. Consumers would not be directly exposed to the costs associated with new issue incremental capacity unless Ofgem grants NGG NTS an income adjusting event due to events arising out of NGG NTS's control. Under these circumstances consumers would be exposed to buy back costs based on administered buy back price for a maximum of five years.

Appendix 13 - Impact Assessment - electricity

Introduction

1.1. This chapter consider the impacts of the main policy initiatives included in our initial proposals in respect of NGET, SPTL and SHETL. The key initiatives being proposed are:

- Revenue drivers
- Innovation incentives
- Performance incentives

1.2. The impacts are considered in respect of:

- The licensees
- Network users
- Consumers

Revenue drivers

Our proposal

1.3. We are proposing to put in place automatic adjustment mechanisms such that the revenues that the companies are allowed to recover flex in the light of revealed demand for network capacity. Our detailed proposals for how these mechanisms might work are set out in Appendix 10 above. In summary, we are proposing separate adjustment mechanisms for local connection costs (triggered by new generation connections) and deeper reinforcement costs (triggered by the aggregate effect of new connection, closures and changes in demand).

Impacts

1.4. The main impact on the **transmission companies** is to make a proportion of their revenue allowances contingent on events. Other things being equal, it therefore makes the revenue allowances less certain ex ante.

1.5. The rationale for revenue drivers is, however, to ensure that revenues adjust in line with changes in significant cost drivers (the volume of new generation connections being recognised as a particularly important one). Therefore another impact of revenue drivers is to provide a mechanism such that the revenue

allowances map more closely the efficient level of costs net of volume effects. Hence, an impact of revenue drivers is to reduce volume risk for the transmission companies, when compared to a fixed allowance.

Alternatives

1.6. We have considered a number of alternative means of addressing the issue of how revenues should be set in the context of uncertainty about what the demands for network capacity might be.

Status quo

1.7. For NGET, the **status quo** option is to retain a simple (non-locational) revenue driver linked to the volume of generation connections. Retaining this approach would, in our view, result in a less robust relationship between costs and revenues. It would be more abstract than an approach using locational cost drivers and from the distinction between local and deep reinforcement cost drivers. We therefore consider the impact of the status quo to be a less effective means of reducing volume risk for NGET when compared to our proposals.

1.8. This argument is the same, only magnified, for SPTL and SHETL - because the current price controls do not embody revenue drivers in any form. Compared to a revenue driver approach, this places all the volume risk (of costs being different to revenues because of the volume of external events, such as new generation connections) with SPTL and SHETL.

1.9. The impact on **network users** of maintaining the status quo is difficult to assess, because it does not look particularly stable in light of the uncertainty surrounding new connections in the generation market. It would involve setting fixed revenue allowances for a much greater proportion of costs than we are currently proposing. If we indicated that we would not reopen the price controls on set, then these fixed allowances would need to be set very high to accommadate the uncertainty or the rate of retun would need to be much higher(and as such would result in network charge increases). A more credible status quo is therefore a fixed allowance plus an expectation of re-opening. The impacts of re-openers are discussed below.

1.10. The impact on **consumers** is similarly difficult to assess - although setting a fixed allowances sufficient to cover all possible investment contingencies would result in significant increases in charges, and there would be a much greater risk of providing funding for investment that would not needed to be undertaken or not undertaken. Such a windfall for the companies would be paid for by consumers.

Re-openers

1.11. An alternative way of handling uncertain costs is to wait for better information to emerge, and then re-open the price controls or create a new supplementary mechanism to similar effect. This is the approach we adopted during the current price control period under the Transmission Investment for Renewables (TIRG) banner.

1.12. In comparison to our proposals, we believe that there are two main impacts on the **transmission companies**. First, timing. Re-opening a price control or creating a new mechanism to sit alongside a price control take up resources for Ofgem and for the transmission companies. Arguably, this time could be better spent focusing on the investment projects in hand rather than the regulatory treatment of the costs. Second, incentives to be efficient. Generally, re-opening price controls or creating supplementary measures in reaction to events dilutes the incentives on the companies to be efficient. At its extreme, the regime can migrate towards cost pass-through, rate of return regulation. The impact of the companies of such a shift in approach would be to increase overall costs of delivery and reduce risk for the companies (which would need to be reflected in the allowed cost of capital).

1.13. The impact on **network users** of adopting an approach based on re-openers is, at best, neutral. At worst, it could result in delays to investment being undertaken as re-openers are negotiated and (potentially) disputed. This in turn could hinder the efficient operation of the market. The impact on **consumers** is similar. At best, a regime based on re-openers could be viewed as neutral while at worst it could increase costs and introduce delays to market entry. Both effects might be expected to act against the interests of consumers. Nevertheless, this will be offset by the effects of avoiding paying for unnecessary expenditure or over funding licensees.

Innovation Incentives

Our proposal

1.14. We are proposing to introduce an **Innovation Funding Incentive** along the lines proposed for electricity distribution companies. These arrangements will make available funding for the electricity transmission companies to increase their expenditure on engineering research and development. We are seeking views on whether and how similar arrangements might be used to bring forward innovation with environmental benefits. We also invite views on whether similar measures are needed for NGG NTS.

Impacts

1.15. The main impact on the **transmission licensees** is the provision of additional funding support for projects which may have a demonstrable benefit, but may not fall within the usual scope of the licensees' investment plans and operations. By

making available an explicit funding mechanism for innovation, which will be judged against defined criteria, we are enabling the licensees to invest in projects that otherwise might not go ahead. Both **consumers** and **end users** might be expected to benefit from projects which increase the efficiency of transmission system operation, investment and maintenance - although, as with all investment in R&D, these benefits are not certain.

Alternatives

Status quo

1.16. If we do not introduce the proposed innovation incentive, then we will continue to rely on R&D being progressed in a commercial setting, e.g. by the transmission companies, and the manufacturers and contractors that they use. The impact of this might be expected to focus expenditure on shorter term innovation which can be used immediately in a commercial setting - given the prevailing regulatory framework and the incentives that this creates (e.g. efficiency savings can only generally be retained for a maximum of five years). While such shorter term innovation is valuable, arguably consumers can be better served by arrangements which facilitate R&D with a shorter term and a longer term perspective.

System Performance

Our proposal

1.17. We are proposing to change the structure of the present reliability incentives. The change will involve moving to a **penalties only** scheme. The rationale behind this change is that we believe that a given level of lost supply should reflect a minimum acceptable standard, rather than providing profit for beating a target which may be the result of circumstance rather than actions taken by the licensees.

Impacts

1.18. The main impact will be that **transmission licensees** will be subject to financial penalties if the minimum level of performance is not met. We consider that the impact is to increase transparency as to what level of performance is expected from the transmission companies. The impact is also to prompt further work on addition performance measures which might further improve the transparency of the regime. The impact on **network users**, and consumers, is lower network charges if the minimum level of performance is not met.

Alternatives

Status quo

1.19. By retaining the **status quo**, the transmission licensees will see revenue allowances increase if performance is higher than the target level and will see revenue allowances fall if performance is lower than the target level. The level of transparency will be broadly similar under both approaches. The impact on network users and consumers could be higher or lower charges.

Appendix 14 - Impact Assessment - environmental

Introduction

1.1. This appendix provides background information on the environmental impacts associated with the operation and future development of the transmission networks. This information will be updated before the updated and final proposals in September and November respectively.

Information on environmental impacts

1.2. The transmission networks can be viewed as having the following broad types of environmental impacts:

Visual amenity

- The circuit length of overhead line is around 22,190 kilometres in GB, with around less than 2% of this passing through National Parks and Areas of Outstanding Natural Beauty. On the gas transmission system, the visual amenity issues are primarily associated with compressor stations, terminals, and other above ground installations (AGIs). A large compressor station is similar in size to a small (100MW) power station. There are 25 compressor stations on the GB network, and numerous other installations.

Noise

- The main sources of noise pollution associated with electricity and gas transmission are overhead lines and substations in electricity and compressor stations in gas. The noise levels associated with overhead lines vary with weather conditions but is generally imperceptible, unless within close proximity. Noise from substations can be substantial within close proximity. However, the noise dissipates with distance and in several experiments has been shown to be well below 30dba, which is equivalent to night time background noise. The same is true of gas compressor stations.

Emissions

- The operation of the transmission system results in emissions and leakages. The main areas are Sulphur Hexafluoride (SF6) and oil in electricity and carbon dioxide emissions and methane from gas compressor stations.

- SF6 is used as an insulator in switchgear. SF6 filled equipment has the advantage of being much smaller in size than conventional oil-filled switchgear. However, leaks and equipment maintenance can result in emissions and it is a very potent greenhouse gas. Leakage of SF6 in 2004/05 in GB was around 15 tonnes, which, is equivalent to around 360 thousand tonnes of CO2.

- Oil is used as an insulator in some cabling and switchgear, and historically has been extensively used for sub-sea connections and occasionally onshore. When oil leaks a substantial proportion is lost into the waterways of Great Britain. In total, around 50,000 litres of oil leaked from electricity transmission assets in 2004/05.

- CO2 emissions arise from NGG NTS's gas-fired compressors on the gas transmission network. Using 2004/05 data, these emissions were around 1.8 million tonnes of CO2.

Losses

- In GB, total losses across the transmission network represent 1.7% of the electricity generated. Reducing transmission losses would results in a reduction in emissions associated with the avoided generation (the effect of which would depend on the type of generation that is displaced).

Impact of allowances for capex and opex

1.3. Revenue allowances set as part of the TPCR will dictate network investment, which in turn will impact on the environment. For example, replacement programmes and the inherent general improvement in asset condition that results might be expected to reduce some oil leaks and emissions (while recognising the possibility for problems to emerge over time with existing ageing asset).

1.4. Similarly, TPCR allowances will be consistent with the companies' legal requirements to meet and beat in an efficient way, the increasingly stringent requirements of environmental legislation. One particular example is the replacement of gas-fired compressors with compressors powered by electric motors consistent with the requirements of the Integrated Pollution Prevention and Control (IPPC) Directive (even though the increased electricity consumption would reduce the net benefit).

1.5. The TPCR allowances will also reflect the changing demands for transmission capacity as revealed by the locational decisions of generators. Initiatives such as the Renewables Obligation, which has resulted in increased development of wind generation in remote areas, mean that our allowances need to accommodate building of new transmission. Whilst this will have a visual detriment and will result in an increase in transmission losses, the connection of renewable generation might bring about an environmental benefit in terms of avoided emissions from fossil-fuelled power stations.

Impact of proposed policy initiatives

Revenue from EU ETS allowances

1.6. The operation of the transmission systems in their current form results in National Grid receiving an allocation of allowances under the EU Emissions Trading Scheme (EU ETS). The more efficient National Grid operates the transmission system, the greater the efficiency savings. We are proposing the companies keep these savings, thereby incentivising reduced carbon emissions. We are also considering whether we need to provide additional incentives to reduce SF6 emissions, given their omission from EU ETS.

Encouraging environmental expenditure

1.7. As noted above, we are considering whether there may be benefits in separating environmental expenditure into an IFI-type incentive to support and protect environmental expenditure planned by the transmission companies. This provides us with an opportunity to encourage projects which deliver environmental benefits. However, given that this may involve capturing significant elements of operational expenditure that are already committed, we will assess the practical application of such a measure.

Measures to provide additional funding for under-grounding

1.8. Under DPCR4, an undergrounding allowance was provided for National Parks and Areas of Outstanding Natural Beauty. The allowance hinged on allowing the distribution licensees to underground up to 1.5% of their network that was in environmentally sensitive areas. This required the consideration of difficult trade-offs between social and environmental effects and the assessment of costs and benefits in circumstances where (on the benefits side at least) the valuation techniques are uncertain, highly dependent on assumptions, and property rights are undefined.

1.9. We therefore think careful consideration is needed before we extend the reasoning and funding applied in the context of the DPCR to transmission. An important consideration is the costs involved. A 400kV underground cable is around 15-20 times more expensive than an overhead line, compared to between 5-10 times for distribution lines, and there are difference in operational efficiency between underground cable and overhead line which would also need to be factored in. As the cost premium is higher, any given level of funding would underground less transmission equipment than distribution. Further, while underground will impact positively on visual amenity, there could be other environmental costs, e.g. altering drainage properties of sensitive peat bog habitats.

Appendix 15 – Responses to the Third TPCR Consultation and Ofgem views

Introduction

1.1. This appendix summarises the responses received to the questions posed in the Third TPCR Consultation published in March 2006, together with our views.

1.2. Please note that this appendix is not intended to be a comprehensive compilation of all of the points raised by respondents, but a summary of key views[14]. If respondents are unsure about how their views have been reflected in this document, please contact us for further information.

Responses to Chapter 2 - Form and structure of the price control

Introduction

1.3. Chapter 2 set out our thoughts on how the transmission price controls should be structured to ensure that the licensees face stable and robust incentives to act efficiently. It highlighted the potential benefits of incentive measures which seek to maintain a consistent strength of incentive over time and which seek to reward licensees more if they take on more challenging cost targets.

1.4. Two transmission licensees and eleven other interested parties commented on the issues raised. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

- **Question 2.1**: Do you think the standard RPI-X framework needs to be refined or augmented in its application to the transmission licensees?
- **Question 2.2**: Do you think that rolling incentive mechanisms are the most appropriate way to deliver a consistent strength of incentives over time, and do you think they are applicable to transmission licensees?
- **Question 2.3**: Given the large bids made by some licensees for asset replacement expenditure, how do you think the regulatory regime should look? Do you think that an "information quality incentive mechanism" is the best way to improve our information on efficient costs, by rewarding licensees more if they accept more challenging cost targets?

[14] Copies of every non-confidential response are available on our website.

➔ **Question 2.4**: Are additional measures needed to promote innovation? What is the scope for innovation by transmission licensees to benefit consumers?

➔ **Question 2.5**: Should the current form and scope of System Operator (SO) incentive schemes be adopted in the next price control period?

➔ **Question 2.6**: To what extent should incentives applying to Transmission Owner (TO) costs and SO internal costs be equalised? Should these costs (e.g. staff costs and IT spend) form part of the TO price control?

Views of transmission licensees

1.5. The four transmission licensees commented on the issues raised in chapter 2, highlighting the following points:

- that five year price controls strike an appropriate balance between incentives to operate efficiently and uncertainties relating to costs and demands on the system;
- some support the use of a rolling incentive mechanism for capital expenditure which should ensure consistency of the strength of the incentive to make efficiency savings throughout the price control period noting that a simple rolling mechanism based upon the allowed return and depreciation for a period of five years would not provide a sufficiently strong incentive;
- rolling incentive mechanisms are likely to increase risk by increasing the period over which transmission companies are exposed to the difference between costs and revenues. The increased incentive to underspend will also encourage transmission companies not to invest;
- one transmission licensee recommends an incentive mechanism that delivers an appropriate strength of incentives, up to 60 per cent of savings;
- transmission licensees were generally opposed to an approach which provides differential rates of return, which is likely to increase the perceptions of regulatory risk;
- limited support for an information quality incentive along the lines adopted for the recent EDPCR. National Grid suggest that a mechanism that allows Ofgem to commit to a range of expenditure over which the rate of return is invariant would be a useful development; and
- some support for longer duration SO incentives. SO incentive regime might also be developed to provide automatic error correction in relation to cost drivers outside the direct control of the licensee.

Views of other respondents

1.6. Eleven other respondents commented on the form and structure of the price controls. The key points were:

- support for continuation of RPI-X price regulation with price controls of five years duration;
- one respondent supported the use of rolling incentives to encourage efficient investment;
- several respondents welcomed the recognition of environmental matters within the TPCR framework and commented that the TPCR should consider opportunities for environmental enhancement in National Parks including the development of special initiatives;
- one respondent commented that meeting these duties ought to imply a demonstrable net reduction in the visual impact of overhead transmission networks on designated areas (taken in aggregate) over the price control period. They also invited Ofgem to investigate the full range of possible costs for undergrounding overhead networks, as a basis for a framework which incentivises the grid companies to identify schemes offering both significant landscape improvements and cost-efficient solutions;
- one respondent noted that the TPCR deals with a substantial amount of investment in networks to accommodate the shifting balance of technologies being connected to the network. It is important that policy decisions are robust as the impact of imperfect decisions is more significant. In these circumstances it would be prudent for the Regulator to consider and set out how it will manage changes that may be needed over the next 5 years and beyond;
- support for the alternative approaches being adopted to respond flexibly to significant ongoing changes in the requirements placed upon transmission networks;
- one other respondent expressed opposition to applying differential rates of return.

Ofgem's views

1.7. We would like to make the following observations in respect of the comments made by respondents:

- we propose to introduce 'rolling incentives' for capital expenditure, where a company is allowed to keep (or bear) a fixed proportion of the difference between allowances and actual costs irrespective of when the difference occurs. In the case of the revenue drivers these will apply on a five year rolling basis. However, a key issue to consider in setting this rolling incentive is the strength of the incentive around a baseline point. We are currently considering a relatively

shallow incentive rate of around 20 per cent, e.g. for an amount of over/underspend, the company would lose/gain 20 per cent of the value of the difference between expenditure and the allowance. This is aimed at incentivising efficiency but not over-encouraging under-spend, as well as discouraging but not excessively penalising over-spend. However, we recognise that there are alternative approaches.;

- We note that under schedule 9 of the electricity act, transmission licensees are required, amongst other things, to do what they reasonably can to mitigate the effects of their activities on certain aspects of the environment. We intend to enable them to fund their investment efficiently, via price control mechanisms, to facilitate their compliance with these requirements. However, we recognise that it measures other than those which are required by schedule 9 need to be explored. We will, therefore , continue to consider other measures as part of the capex assessment work. This may include a cost benefit analysis of undergrounding areas of line where there are visual amenity or other environmental concerns. However, we do not consider that it is appropriate to prescribe a reduction in the amount of overhead lines.

Responses to Chapter 3 - Electricity incentives

Introduction

1.8. Chapter 3 discussed the use of revenue drivers (i.e. methods of linking allowances to future events or triggers) to deal with the uncertainties surrounding the needs of users of the electricity transmission system, set out our views on the need for changes to the access arrangements (recognising that responsibility for this lies with the industry) and highlights the need to review current incentives on system performance and reliability. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

- ➔ **Question 3.1:** Do you agree with our conclusion that the use of locational revenue drivers is the most appropriate way to set allowances for the electricity transmission licensees in the context of significant uncertainty over the future demand (and location of that demand) for network capacity?
- ➔ **Question 3.2:** What factors should we bear in mind in drawing the boundary between fixed baseline revenue allowances and variable revenue allowances to be set through the revenue drivers?
- ➔ **Question 3.3**: Should we seek to true-up the allowances generated by revenue drivers at the end of a 5-year control period? What factors should we take into account?
- ➔ **Question 3.4**: When should we supplement the revenue drivers with other mechanisms to top-up revenue allowances in exceptional circumstances where major investment is needed? How might these other mechanisms work?

➔ **Question 3.5**: Do you agree that, in the current market context, it is important to explore options to change transmission access arrangements? Do you agree with the process we have set out to progress this work?

Views of transmission licensees

1.9. The three electricity transmission licensees commented on the issues raised in Chapter 3, highlighting the following points:

- National Grid and SPTL were relatively supportive of locational revenue drivers, whilst SHETL were firmly opposed as they had concerns regarding accuracy, timing of revenues, lumpiness of investment and increased risk.
- NGET recognised that while locational revenue drivers are likely to be more cost-reflective it is unlikely that they will capture all factors influencing costs. They suggested that revenue drivers should cover both changes in demand and generation as these will interact to drive costs;
- the transmission licensees generally supported disapplication of the revenue drivers for large non-standard projects. National Grid considers that there should be criteria in the licence for disapplying the revenue drivers, whilst SHETL supported a TIRG type mechanism for such projects;
- a key concern of the transmission licensees is the timing of income relative to expenditure. In particular, transmission companies are concerned about a revenue driver scheme that is activated once system capacity has been delivered which might be several years from when costs are first incurred;
- there was support for a full "true-up" at the end of the five year period, with retrospective funding for all costs efficiently incurred consistent with Ofgem's published policy on the treatment of over-spends;
- transmission companies agreed that the transmission access arrangements were not working efficiently when faced with a large volume of connection requests. The licensees recognise that there is merit in considering enhancements to the current regime;
- there was some recognition that the current performance incentive scheme was not effective, however SPTL commented that any performance incentive scheme should be symmetrical.

Views of other respondents

1.10. Nine other respondents, including one confidential response, commented on the electricity incentives chapter of the March document. The key points were:

- respondents recognised the uncertainties surrounding network investment driven by user requirements and generally supported the principle of locational revenue drivers to remunerate transmission licensees as investment is triggered;

- some respondents expressed caution regarding the detail of any revenue driver mechanism and scope for unintended consequences such as perverse incentives to game key system boundaries;

- several respondents gave a broad indication that baseline revenue allowances should reflect what is required for the stewardship of the existing assets as far as possible;

- there was some recognition that it might be necessary to have a mechanism for dealing with exceptional projections, although several respondents expressed caution that such a mechanism should be clearly defined and transparent. Furthermore, Ofgem should undertake a thorough impact assessment before making any adjustment to revenues;

- several respondents indicated support for the principle of access reform, however a range of views were expressed in relation to the detail of possible reforms. Among the different views expressed some respondents recommended capping of security payments, while others commented that it was important that there was an appropriate balance of risks between users, networks and consumers.

Ofgem's views

1.11. We would like to make the following observations in respect of the comments made by respondents:

- any revenue driver will provide an approximation of the average cost of connection, and an incentive for licensees to beat this cost. The rationale for a two part revenue driver described in chapter 10 was to aim to capture as many of the key cost drivers as possible and any mechanism will be extensively tested against historic and forecast data;

- the proposed two part revenue driver will, to some extent, capture the impact of costs on revenues and we are in the process of discussing the timing of funding relative to costs incurred with licensees. Were funding provided later than costs are incurred, we will include costs of financing such that licensees should be revenue neutral in present value terms;

- we are fully considering the treatment of exceptional projects such as the Western Isles and Shetland connections. To the extent that these cannot be included within a standardised framework, we believe that clear criteria for treating them should be determined ex-ante;

- we consider that revenue drivers provide strong incentives for licensees to minimise costs to the benefit of consumers and consider that truing up reduces

these incentive properties. In light of this, we are not minded to adopt retrospective true up of the revenue drivers after 5 years;

- we agree that any set of access arrangements should protect the interests of consumers. Therefore any risk transfer to consumers should be offset by benefits, for example, by an increase in competition. The interaction between user commitment in gas and electricity and consistency between the two is being considered and, where appropriate, will be consulted on and considered in assessing amendment proposals;

- we note the ARODG report has now been published and consider that it will now be for interested parties to raise proposals for change. NGET has an ongoing condition imposed by the Authority in approving GB methodologies to consider long term fixed price access products.

Responses to Chapter 4 - Gas entry incentives

Introduction

1.12. Chapter 4 discussed the obligations on NGG NTS to release gas entry capacity, and how revenue allowances should adjust with any provision of extra capacity that might be required by network users. It also discussed how allowances should be set in respect of costs incurred by NGG NTS in buying back entry capacity rights that have been sold but cannot be accommodated on the network. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

- ➔ **Question 4.1:** Do you agree with our plans to change the nature of NGG NTS's licence obligations to release entry capacity? What particular measures are needed to ensure that the regime is transparent, and ensure against capacity being held back unnecessarily?

- ➔ **Question 4.2:** Do you agree with our plans to refine how the revenue drivers work in cases where NGG NTS provides extra entry capacity, as requested by network users?

- ➔ **Question 4.3:** Do you agree that changes are needed to the arrangements for buying back capacity rights, in particular to ensure a different sharing of risk between shippers, NGG NTS and consumers in respect of capacity which is dependent on large investment projects?

Views of transmission licensees

1.13. NGG NTS was generally supportive of Ofgem's proposals to move to a more flexible system of regulating capacity release than that in the current regime. However National Grid did not believe it would be possible to release a network model as envisaged in Ofgem's proposals.

1.14. NGG NTS felt that it was crucial that the baselines set not exceed the capability of the system and, specifically, pointed out that the correct level of baselines were, in its opinion, less than those set out in Appendix 12 of the March document. National Grid NTS also considered that, since costs elements change during the course of the price control period, Ofgem should give consideration to allowing the UCAs to vary during that period, rather than having them fixed once and unchanging for five years.

1.15. NGG NTS supported the concept of delinking the prices (and reserve prices) for capacity from the UCAs set in its licence.

1.16. However NGG NTS expressed some concerns about an approach of relying purely upon user commitment to signal new investment and wanted to explore mechanisms to release capacity in the absence of timely user commitments.

Other respondent's views

Shippers

1.17. Shippers expressed a general concern that, although some of the problems identified by Ofgem are real and may need addressing, the proposals put forth by Ofgem are extremely significant and introduce significant uncertainty into the market. In particular many shippers had concerns about the degree of discretion given to NGG NTS in Ofgem's preferred model. Shippers requested that Ofgem look at less radical options, for instance involving the reallocation of capacity at existing baselines. They also sought to understand better how the trading and transfer of capacity between nodes would work

1.18. Shippers were concerned that they would be incapable of adequately dealing with a network model issued by NGG and therefore unable to take advantage of it to engage with NGG in the implementation and development of capacity release methodologies. Therefore shippers were also concerned that under Ofgem's preferred approach there was the possibility of significant resource implications for Ofgem (and concomitant uncertainty for industry) if Ofgem were required to resolve a significant number of disputes.

1.19. Shippers also expressed concerns that in bidding in the current regime they did so under the clear understanding that 20% of capacity was withheld to shorter term auctions. By eliminating the concept of baselines this withheld 20% would also be eliminated meaning the purchasing decisions shippers had made would be other than those they would have made had they anticipated this change. Some shippers also felt that the concept of withholding 20% of capacity should be retained in order to allow for new entry.

1.20. Shippers felt that a case could be made for incorporating methodologies in the UNC rather than in NGG NTS's licence.

1.21. One shipper expressed concerns that NGG NTSwould have no incentive to deliver incremental capacity if it were only able to earn regulated rate of return on the investment unless it were given that return on the basis of a high end estimate of costs. However other shippers agreed with Ofgem's view that NGG NTS's return should be based on regulated cost of capital on deemed cost for a five year period.

Storage operators

1.22. One storage operator supported Ofgem's proposal provide sufficient information was given to allow the industry to understand the different scenarios. One storage operator supported Ofgem's proposals for revenue drivers.

Electricity transmission licensees

1.23. One electricity transmission licensee expressed the view that as there is not a "uniform relationship" between the size of flow increment and the cost, and as any cost is the result of subjective modelling, it is not appropriate to use revenue drivers to set NGG NTS's revenues. This company's preferred approach was that remuneration be based on a methodology similar to the TIRG approach in electricity. One electricity transmission licensee supported the delinking of prices (and reserve prices) from the revenue drivers..

Consumers and consumer representatives

1.24. Energywatch was generally supportive of Ofgem's proposals but expressed concerns about information asymmetry and complexity of the arrangements.

Other categories of respondents

1.25. One organisation representing gas engineers and managers expressed concerns at proposals to remove the 1 in 20 obligation. An electricity producers trade organisation agreed the deficiencies in the regime must be addressed but queries whether such a radical change was needed.

Ofgem's views

1.26. In response to the concerns from industry participants about the perceived radical nature of the change in regime proposed Ofgem has reconsidered its approach at this price control. Ofgem remains convinced that, in the long run, a system in which specified levels for capacity released is not desirable, and so retains as a long term aspiration a desire to move to a model without T*ex anteT* baselines. However as set out in this document Ofgem is, for the next price control period, proposing an approach that retains baselines capacity obligations but provides more potential for the reallocation of those baselines between different entry points.

1.27. Ofgem notes concerns from shippers that they based their bidding strategy on the withholding of 20% of capacity. Ofgem also notes however that no undertaking had ever been given as to the level of baselines in subsequent price controls and therefore notes that even if there were a ongoing commitment to retain the withholding of 20% of baselines capacity there was, nonetheless, no commitment as to the numeric value to which that 20% referred.

1.28. Ofgem remains of the view that regulated return is the level of return necessary to remunerate NGG NTS for investment and therefore considers that revenue drivers based thereon are adequate to fund investment.

Responses to Chapter 5 - Gas offtake incentives

Introduction

1.29. Chapter 5 set out our proposals for offtake baselines, revenue drivers and incentives within the next price control period both before and after 1 October 2010, which is the date on which enduring NTS capacity offtake arrangements are expected to be introduced. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter or its related Appendix):

- ➔ **Question 5.1:** Is our proposed approach for the transitional period appropriate?
- ➔ **Question 5.2:** Do you agree with the assessment, set out in this document, of the high level options in the Second Consultation?
- ➔ **Question 5.3:** Is the high level option proposed appropriate?
- ➔ **Question 5.4:** Do you agree with our thoughts on baselines, revenue drivers and payment flows given an emphasis on user commitments?
- ➔ **Question 5.5:** Are the proposals for a gas offtake buyback incentive appropriate?

Views of transmission licensees

1.30. NGG NTS commented on the issues raised in Chapter 5, highlighting the following points:

- NGG NTS believe that the base price control allowance should provide for known investment requirements (e.g. where a user commitment has been provided or there is a clear case for investment to meet the 1 in 20 licence obligation) and revenue drivers should adjust funding in response to less certain developments during the price control period. This would suggest that certain investments due to connect in the transitional period (e.g. Langage) should be remunerated in the

base price control allowance. They are concerned that Ofgem appear to be suggesting, for both the transitional and enduring regime, that revenue drivers should fund all incremental investments above the existing network. They do not support this position;

- NGG NTS agree with the continuation of the "charges foregone" concept. They agree that there is a need for incentives to cover CLNG costs and >15 day costs, but believe that the capacity buyback incentive should be retained for this period as there are still cost liabilities linked with the provision of exit capacity which exist within the UNC that need to be financed and it appears that the appropriate vehicle for this is the capacity buyback incentive.

- NGG NTS do not believe that there should be different approaches applied to entry and offtake with regards to the obligations placed upon NGG NTS to release capacity. They indicated a preference for the approach outlined in the Third TPCR Consultation for gas entry;

- NGG NTS supported the view that baselines should be set to reflect the actual capability of the system and that practical maximum physical capacity is probably the appropriate way forward as it takes into account the interactions between the different points on the system. They believe that it is important to recognise that there are also interactions between the capability which applies at offtake and that at entry. However, they do not agree that the baselines should be flat across the formula period and believe that projects for which there is already a user commitment should be included within the baseline assumption funded through the core revenue control.

Views of other respondents

1.31. A number of other respondents commented on the gas offtake chapter of the Third TPCR Consultation. The key points were:

- Respondents were generally supportive of the proposals set out by Ofgem for the transitional offtake period in the Third TPCR Consultation and welcomed the continuation of the interim regime, although some detailed comments were made;

- There was some support for the introduction of the substitution obligation, however some other respondents expressed concern regarding the application of the substitution obligation and the consequent uncertainty that it may create for shippers;

- A number of respondents stated that the case for reform needed to be made by Ofgem. Other respondents recognised the merit in having end users provide a commitment for NGG NTS investment with one respondent commenting that this will reduce the risk of under recovery from investment. However, other respondents expressed concern at the potential length of financial commitment required and one respondent stated that the reduced risk for NGG NTS should be reflected in a reduced return;

- A number of respondents stated that they remain to be convinced that there should be the same treatment of all offtakes. Irish respondents stated that the Moffat exit point should be treated differently.

Ofgem's views

1.32. We would like to make the following observations in respect of the comments made by respondents:

- We continue to believe that it is appropriate for revenue drivers to apply to all capacity that is delivered after 1 April 2007. The accrual of revenue drivers upon contractual delivery of capacity is consistent with the approach traditionally applied at entry. Furthermore, NGG NTS would be financially neutral between their proposals and what we are proposing as long as the capacity is contractually delivered as the revenue drivers determined will take into account the construction costs incurred in advance of delivery;

- We do not consider that the buyback incentive should be retained for the transitional period given that the UNC liabilities referred to by NGG NTS have historically been at or close to zero and that, in the event of a significant event beyond NGG NTS's control, the income adjusting event provisions could be applied;

- We recognise that there may be interactions between entry and exit baselines. It is our initial proposal that an obligation should be placed upon NGG NTS to revise exit baselines, where appropriate, following entry related investment and vice versa;

- We still consider that it may be appropriate to place a substitution obligation on NGG NTS to substitute unsold capacity between nodes to meet demand. Under this approach, in the event that demand for incremental capacity at another node could be alleviated by baseline substitution, NGG NTS would then be required to apply to Ofgem to adjust the baselines of the affected nodes in accordance with calculated exchange rates. We recognise the importance of consistency between the entry and exit regimes and in light of comments received we have modified our proposals for the entry regime along the line of those proposed for the exit regime;

- We note the comment from respondents that a case for change needs to be made for enduring reform. We have conducted a draft impact assessment in this regard, which is appended to this Initial Proposals document;

- We note the concerns expressed by respondents regarding the extent of commitments required, particularly with respect to existing capacity. As we stated in the Third TPCR Consultation, we would expect an assessment of the commitment required to be informed by consideration of, amongst other things, investment lead times, the profile of investment costs typically incurred within investment lead times, and asset stranding risk;

- We recognise that different NTS users have different characteristics, however where a user is obtaining or receiving services from NGG NTS, the identity of that user should have no bearing on the costs associated with NGG NTS providing that service. We therefore continue to believe that a common framework should be developed for all NTS users, but with sufficient flexibility to allow users to tailor their capacity requests to their individual circumstances. However, we do not believe that it is appropriate for different products to apply to different classes of users where such products fundamentally represent the same underlying NTS service, namely the provision of NTS offtake capacity. Therefore whilst we note the concerns raised by Irish respondents, we continue to propose the common treatment of NTS users. However, we hope to continue discussions with Irish participants to understand, and identify potential ways to mitigate, their concerns.

Responses to Chapter 6 - Expenditure analysis: Capital expenditure

Introduction

1.33. Chapter 6 provided an update on our capital expenditure (capex) assessment of the electricity transmission licensees - NGET, SPTL and SHETL, and the gas transmission licensee - NGG NTS. It outlined the historical and forecast capex information submitted by the licensees, the assessment approaches we have adopted, and our further thoughts on specific capex issues raised in the Second Consultation. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

- ➔ **Question 6.1:** Do you have any comments on our approach to assessing historic and forecast capex? Are there any other factors we should take into account?
- ➔ **Question 6.2:** Should some degree of alignment be adopted for capitalisation of forecast costs across the transmission licensees, or should, especially in the case of the Scottish licensees, the approach be consistent with DPCR?
- ➔ **Question 6.3:** Should some adjustment be made to network flexibility margins, particularly for the NTS 5% planning flow margin?
- ➔ **Question 6.4:** In carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, what new factors need to be taken into account?
- ➔ **Question 6.5:** What would be the most appropriate approach to restoring the incentives for relevant parties to reach the most cost-effective connection design? How should the TPCR allowance take into account the various solutions?

Views of transmission licensees

1.34. The four transmission licensees commented on the issues raised in chapter 6, highlighting the following points:

- There was support for the proposed approach to the assessment of both historical and forecast expenditure. One licensee noted that the efficiency of asset management processes is a key driver underpinning both actual and forecast spend. Several licensees stressed the need to understand the factors driving the evolution of the capital programme within the constraints of the present price controls in order to form a robust view of efficiency;

- National Grid (NGG and NGET) commented that it was important that the process recognised the lessons learned from the NGET extension review and ensured that licensees had an opportunity to challenge the analysis and recommendations of Ofgem and its consultants;

- There was some recognition that while it might be desirable to adopt a consistent approach on capitalisation across all licensees, the scale of divergence across the companies is likely to prevent reasonable comparison. One licensee noted that it would be legitimate and appropriate to have different rates of capitalisation;

- One licensee commented that Ofgem should also consider the impact of "plugs" connections and in particular the loss of locational messages on users that have resulted from the introduction of this policy. NGET noted that this effect+ was acknowledged during the development of the shallow connection charging methodology in England and Wales. The disadvantage of a reduced driver for customers to consider design variation requests was thought to be outweighed by the advantages of removing barriers to new entry and protecting connecting customers from the costs associated with design decisions taken for wider system reasons;

- Two of the licensees, including NGG commented on the issue of 5% flow margin. It was recognised that there might be a need to review the application of such a margin. However, NGG felt that there were also factors that would increase design and operational uncertainties, such as the use of imported LNG and the greater choice of potential supply patterns. The other licensee pointed out that it was for NGG to demonstrate if the flow margin continues to be necessary.

- On the issue of carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, NGET believed the key issue to be to recognise the actual value of constraints.

- On restoring incentives for relevant parties to reach the most cost-effective connection design, two licensees suggested a number of changers to National Grid's charging methodology could restoring the incentives for relevant parties to reach the most cost-effective connection design. For example aligning the charging methodology for the Scottish 132 kV network with the 132kV system in England and Wales.

Views of other respondents

1.35. Three other respondents commented on the analysis of capital expenditure. The key points were:

- Several respondents were supportive of Ofgem's approach to assessing capital expenditure requirements for the coming period;

- On the issue of aligning capitalisation, one respondent pointed out that any decision, with respect to the Scottish companies, must not provide a perverse incentive for those companies to allocate more shared overheads to the transmission company;

- One respondent noted that it was difficult to comment on the substance of the investment plans provided by the licensees without access to appropriate information. They note the differences between the forecasts outlined by Ofgem in the February open letter and those set out in the March document;

- In carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, several respondents noted a review of the SQSS would be welcome. One respondent commented that alternative cost / benefit assessment methodologies should be considered alongside the curtailment cost method;

- One respondent commented that a key issue is striking the right balance between potential over-investment in a network and confidence of compliance with the current (or future modified) SQSS. It is questionable if a five-year horizon allows adequate analysis to be conducted and conclusions drawn. For wind, at least one year-round weather analysis is required. A pragmatic compromise may be derogations from SQSS in recognition of the uncertainties of wind generation;

- There was some recognition that the charging methodology should provide appropriate incentives to make appropriate connection design choices. The key consideration was the potential for saving substantial sums of money, traded off against a very low likelihood of constraint. It was suggested that TNUoS charges could be reduced for a non-firm connection designs;

- Scottish Environment Protection Agency (SEPA) commented on the requirement by National Grid Gas for investment to upgrade their fleet of gas turbine compressors to comply with Integrated Pollution Prevention and Control (IPPC) legislation. It pointed out that a recent studied carried out by NGG concluded that in order to achieve the best environmental outcome, NGG should progress investment at a small number of compressor sites by the installation of new electric drive systems. The Agencies wished to ensure that the required upgrading for environmental improvements is agreed with NGG (and Ofgem) prior to permit issue.

Ofgem's views

1.36. We would like to make the following observations in respect of the comments made by respondents:

- We recognise that it is important to consider the overall interests of consumers, not just in terms of cost, but also reliability, and environmental and safety performance. As such, the capital expenditure assessment workstream has undertaken a significant amount of work to quantify the performance that will be delivered by the capital expenditure bids;

- In light of responses and further analysis, our initial proposal is to continue with individual approach of capitalisation, and to assess the efficient historical and forecast capex on that basis;

- We still believe that the continued application of the 5% flow margin uniformly is no longer appropriate, and will explore with NGG and other relevant parties more appropriate options;

- On the efficient transmission capacity required to accommodate wind generation, we have carried out cost benefit analysis using the costing parameters published in March and developed our initial proposal on this basis;

- With regard to local connection design for smaller wind generation, our initial proposal is based on consideration of cost-effectiveness. We note that there has been recent progress on the restoration of cost signal in transmission charging, which should allow connectees to benefit more directly from choosing less costly connection designs.

- We recognise that there are some differences between the capital expenditure information presented in February and that set out in March. The March figures represent the bids submitted by each of the companies. However, some companies have recognised additional projects that might arise that are not reflected within their capital expenditure plans at present;

- We acknowledge the work done by the environmental agencies, EA and SEPA, in developing a pragmatic approach to the potential upgrade of NGG gas turbines in order to comply with IPPC legislation. A number of the Authority's duties require it to consider the environment and/or environmental matters. These will help inform the decision about appropriate levels of capex allowances for licensees;

Responses to Chapter 7 - Expenditure analysis: Operating expenditure

Introduction

1.37. Chapter 7 provided an update on our assessment of efficient historic and forecast opex for the transmission licensees for electricity (NGET, SPTL and SHETL)

and gas (NGG NTS). We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

➔ **Question 7.1:** Do you have any comments on our approach to assessing historic and forecast opex? Are there any other factors we should take into account?

➔ **Question 7.2:** How should non operational capex be treated with regard to 1) the assessment of efficiency of associated activities such as IT; 2) the treatment of historically incurred overspends; and 3) the approach to future remuneration?

➔ **Question 7.3:** Do you have any comments on our comparison of unit cost trends? Are there reasons why transmission licensees should have performed differently to DNOs?

➔ **Question 7.4:** How should we treat non-controllable costs? Should we take the same approach to network rates as in DPCR?

1.38.

Views of transmission licensees

1.39. The four transmission licensees commented on the issues raised in chapter 7, highlighting the following points:

- National Grid (NGET and NGG NTS) and SPTL both emphasised that their plans were built bottom up and that top-down analysis or benchmarking across the licensees would be inappropriate;
- National Grid (NGG NTS and NGET) stressed that they should have the opportunity to challenge the assumptions and analysis used in determining the allowances;
- National Grid (NGG NTS and NGET) and SPTL considered that non operational capex should be treated as assets with a short life according to the economic life of the asset, rather than the current regulatory life of 40 years. This approach is consistent with that adopted in relation to SO internal incentive scheme. SSE said such items should be expensed;
- National Grid (NGG NTS and NGET) considered that the productivity analysis presented in March did not accurately represent a gap between itself and the DNOs, and that any gap could be explained by more aggressive capitalisation policies adopted by DNOs. Similarly, SHETL commented that the analysis grossly distorts their productivity improvements by using the whole operating expenditure of SHETL, much of which was fixed and uncontrollable.

Views of other respondents

1.40. Three other respondents commented on the analysis of operating expenditure. The key points were:

- One respondent supported the use of top-down and bottom-up analysis to provide a balanced view of opex requirements over the coming period;
- One respondent considered there was not sufficient quantitative analysis or detailed information to make a robust judgement of the appropriate level and treatment of costs;
- Respondents commented that where non-operational assets deliver long term benefits then they should be capitalised accordingly. One respondent commented that current RAV asset life was too long for items such as IT;
- Respondents supported the continued approach to non-controllable costs recognising that licensees have a degree of control of network rates at the periodic valuation of the assets.

Ofgem's views

1.41. We would like to make the following observations in respect of the comments made by respondents:

- We agree that it is important to take a balanced view of the operating cost requirements. We have undertaken top down analysis to assess potential efficiency gains that the licensees could make, however due to the significant differences in the size of the transmission businesses the majority of our effort has been based on bottom up detailed review. For National Grid in particular, the bottom up assessment has focused on the efficiency within each operating unit;
- We recognise that discussion of our findings is a key part in the price control process. After the publication of initial proposals we intend to hold discussions with each of the transmission licensees and share appropriate information to allow understanding of the basis of our proposals;
- We acknowledged in earlier consultation documents that comparisons involving the transmission companies should be done with great care. While it is important that the reasons for any differences between transmission and distribution licensees are consider carefully, we consider that the analysis of comparative efficiency performance presented in March still remains valid. We are happy debate the interpretation or conclusions that should be drawn from the analysis or indeed if other approaches are more meaningful;
- We have considered the treatment of non-operational capital expenditure. We note that two licensees favour an approach that treats expenditure in such items as short life assets. We recognise that such a treatment might have merit,

however we consider that non-operational capital expenditure is economically substitutable with operating expenditure. In light of this, we propose that non-operational expenditure be expensed during the coming price control period;

- We note National Grid's comments that there is an element of control over valuations applied to their networks, albeit a limited control. We consider that network rates are to be included as a non-controllable pass through until 2010 (the end of the current valuation period). However, from 2010 this pass through will be subject to a review of each licensee's performance at the next rating valuation. This reflects the point that the licensees do have some degree of influence over the outcome of the valuation.

Responses to Chapter 8 - Financial issues

Introduction

1.42. Chapter 8 provided an update on our approach to financial issues for the TPCR. In considering these issues we are having regard to the need for the transmission licensees to be able to finance the activities which are the subject of their statutory and licence obligations, provided these are efficiently conducted. We also set out that we will aim to provide appropriate incentives for licensees to make efficiency savings and, to the extent appropriate, allow customers to share in those benefits. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this chapter):

- ➔ **Question 8.1:** Are there other issues that the cost of capital study should address?
- ➔ **Question 8.2:** How should we approach our assumptions for the cost of debt? Should we use medium term historical averages?
- ➔ **Question 8.3:** How should we reflect the risk profiles of licensees in estimating the cost of capital? Are risks below the market average?
- ➔ **Question 8.4:** Should we still use conservative gearing assumptions and assume target ratings "comfortably within" investment grade when setting the cost of capital and assessing financial stability? What financial indicators should we use?
- ➔ **Question 8.5:** Which option (or combination of options) should be used to address the loss of income from pre-vesting assets becoming fully depreciated?
- ➔ **Question 8.6:** Do the existing ring-fencing conditions provide adequate protection for consumers?
- ➔ **Question 8.7:** Is benchmarking the level of total employment costs the best means to incentivise the licensees to control their pension costs?
- ➔ **Question 8.8:** Should there be any ex post adjustments to the licensees' revenue allowances for tax payments?

Views of transmission licensees

1.43. The four transmission licensees commented on the issues raised in chapter 7, highlighting the following points:

- Licensee's recognised that CAPM is the favoured approach to estimating equity returns, however it was argued that other approaches should be considered, such as the dividend growth model;

- All of the licensees acknowledged that the real interest rates are at historically low levels, although they argue that recently observed evidence is a feature of short-term market condition that are not sustainable in the medium to long term. In general, each of the licensees favour the use of medium to long term averages to inform the assumption regarding the cost of debt;

- One licensee commented that Ofgem should recognise that transmission companies are competing with a number of utilities for capital to fund such large-scale infrastructure investment (e.g. railways and water companies also have large current capital programmes). They argued that it is vital that the allowed cost of capital, however derived, is sufficiently attractive to encourage equity investment in the transmission businesses. In this regard, we do not believe that the assumed cost of equity from the last distribution price control review is sufficient given the scale of the transmission investment programmes;

- One licensee commented that it is important that the eventual assumptions on cost of capital are consistent with Ofgem's approach to financeability. In doing so, Ofgem should continue to set assumed returns on the basis of a single A rated company. The other licensees also supported an approach that ensured that companies were able to maintain credit ratings comfortably with investment grade. In light of this, Ofgem should consider an appropriate range of financial indicators;

- In response to the options set out for dealing with the depreciation cliff edge, two licensees commented that the 'do-nothing' option would have a significant impact upon financeability. Of the options set out, they expressed a preference for tilted depreciation. The other licensee also supported tilted depreciation. It was suggested that the repex approach may create significant distortions to incentives given the scale of the investment programmes;

- All of the electricity transmission licensees support the extension of the modified ring fencing arrangements, which were recently adopted in electricity and gas distribution, to electricity transmission networks;

- One licensee commented that remuneration costs should be considered as a package and consequently that companies should be incentivised to control their costs at the level of total employment costs. However, another licensee commented that it would be inappropriate to benchmark total employment costs,

particularly where there are differences in the pensions deficits inherited by each transmission company and actuarial assumptions;

- Licensees supported ex-ante allowances for corporation tax payments, recognising the incentive properties that such an approach has in terms of managing tax liabilities effectively.

Views of other respondents

1.44. Three other respondents commented on the financial issues chapter. The key points were:

- One respondent commented that it will be important to set an appropriate cost of capital to ensure that the transmission companies can attract the necessary investment to support their investment programmes. They commented that Ofgem should consider a range of alternative approaches for estimating the cost of capital;

- Another respondent commented that the EDPCR view of real interest rates seems generous considering the continued low yields on corporate bonds and gilts;

- One respondent noted that the number of monopoly providers in the market that earn guaranteed revenues is not significant. We would therefore suggest that the risks are lower than the market average. Another respondent commented that the risk profile of transmission licensees is significantly lower than the risk faced by other quoted companies in the market and hence that Ofgem should apply an equity β of significantly less than 1 in estimating the cost of equity;

- One respondent questioned why straight line depreciation was adopted in relation to pre-vesting assets. They suggested that the depreciation cliff edge was a question of cash flow and that the solution should be left to the market. Another respondent commented that tilted depreciation should only be adopted where Ofgem is confident that it will not push the problem out to the future;

- There was support for the adoption of the pension principles and tax principles adopted in EDPCR4.

Ofgem's views

1.45. We would like to make the following observations in respect of the comments made by respondents:

- We have previously examined alternative models to the Capital Asset Pricing Model as they arise to assess their appropriateness. The cost of capital study is examining the Fama French model and other models that add explanatory factors alongside the beta estimate of CAPM. We also intend to consider the conclusions alternative models such as dividend growth in determining our assumptions for the cost of equity;

- We acknowledge that both the spot rates on bonds and spreads may prove to be historically low. The continuing use of medium term averages would have merit to ensure that over the life cycle of investment the market rate and the regulatory rate would be similar, albeit the latter has a five year lag. We also recognise that both the current and medium term average cost of debt is lower than assumed at the recent EDPCR;

- We acknowledge that beta estimates suggest that utility companies are below average market risk, although there is evidence of beta instability over time. It is hoped that the cost of capital study will indicate a method (eg. kalman filters) for assessing beta such that it is statistically reliable and can be assessed with confidence notwithstanding continuing evidence of drift in beta over time;

- We agree that a holistic approach to the cost of capital and financeability is desirable. We also understand that at a time of significant investment a rating of "A" appears preferable to a licensee than one of "BBB", albeit both are investment grade. However the overall market cost of a "AAA" wrapped bond is within the allowed debt premium and clearly provides an opportunity for higher gearing at a lower cost of capital of capital to consumers;

- It is desirable to ensure that companies manage total employment costs efficiently. In addition to any benchmarking of total employment costs, we will also continue to follow the well defined principles of assessing and calculating a specific Pension Allowances. These principles and guidelines have been published in past documents for electricity distribution and transmission;

1.46. In setting an ex ante allowances for tax we seek to incentivise the licensee to make use of allowances that may be available. It is hoped that subject to material unforeseen events this would avoid the need for any ex post adjustment